2021-2025 Distribution System Plan Attachments

ATTACHMENT A

March 2020 Customer Engagement Results, Prepared by Innovative Research Group

INNOVATIVE RESEARCH GROUP

Scorecard Survey Results

Public Awareness of Electrical Safety

ENTEGRUS

March 2020

Key Findings

As required by the Ontario Energy Board (OEB), all Ontario-based LDCs must measure public awareness of electrical safety every two years and submit these results as part of their annual Scorecard. To gauge overall electrical safety awareness amongst the general public, six core questions were developed in 2015, via a province-wide industry consultation led by the Electrical Safety Authority (ESA) and Innovative Research Group (INNOVATIVE), and ultimately approved by the OEB.

An index score was applied to each response, where "*best answers*" received a score of 1 and "*other answers*" received a score of less than 1. Outlined below and on the Safety Awareness Dashboard are the percentage of respondents that selected the "*best answer*" for each of the six core questions.

1. **Likelihood to call before you dig:** Over half (54%) would definitely call before digging.
2. **Impact of touching a power line:** A strong majority of respondents (94%) think touching a power line is "very dangerous".
3. **Proximity to overhead power line:** Over 1-in-5 respondents (22%) believe they should maintain a distance of 3 to 6 metres. A plurality (43%) believe they should maintain a distance of 6 metres or more.
4. **Danger of tampering with electrical equipment:** A majority (88%) believe tampering with equipment is "very dangerous".
5. **Proximity to downed power line:** Nearly 3-in-4 (73%) believe they should maintain a distance of 10 metres or more.
6. **Actions taken in vehicle in contact with wires:** A majority (93%) believe they should stay in the vehicle until power has been disconnected from the line.

Entegrus has an overall PAESS score of 81%, representing a 2 percentage decrease from 2018

- **Highest at risk groups:** Women age 18-34 (80% score), those in the St. Thomas or 'rest' region (80%), and those who aren't aware of their home's connection to the local distribution system (76%) have the lowest Overall Safety Awareness Index score.
- **Lowest at risk groups:** Men age 55+ (83% score), and those in Strathroy (86%), have the highest Safety Awareness Index score.

2020 Safety Awareness Dashboard

22%

Believe you should maintain ***3 to 6 metres*** from an overhead powerline

94%

Say it's
Very dangerous
to touch an overhead power line

54% Would ***definitely*** call before digging

Overall Public Safety Awareness Index Score

81%

93%

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

88%

73%

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.

Methodology

Innovative Research Group (INNOVATIVE) was commissioned by **Entegrus** to conduct its 2020 *Public Awareness of Electrical Safety Scorecard* survey as required by the Ontario Energy Board (OEB).

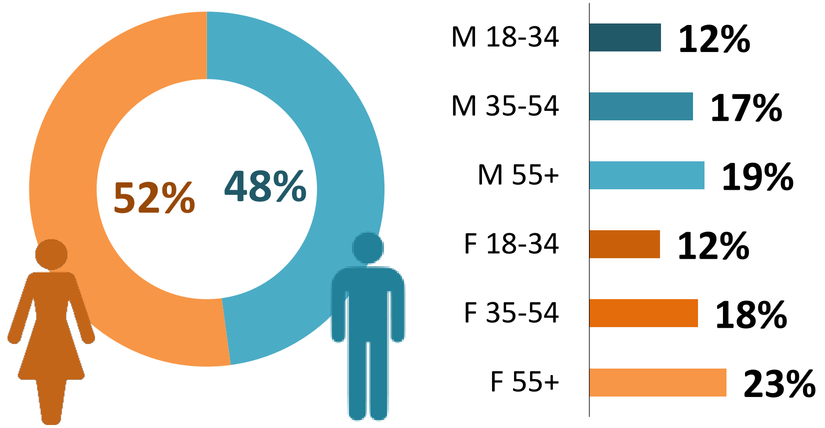
- This survey was conducted by telephone among **600** randomly-selected Ontario residents, 18 years or older, currently residing in **Entegrus'** service territory, between March 2nd and March 16th, 2020.
- Respondents did not need to be Entegrus customers to qualify for this survey. The OEB's standardized methodology defines qualified respondents as adults who principally reside in the LDC's service territory, regardless of whether they are customers or not.
- Both cell phones and landlines are included in the sample to ensure that those who do not have a landline phone are represented in the final sample.
- The sample has been weighted to **n=600** by age, gender and region using the latest Statistics Canada Census data to reflect the actual demographic composition of the adult population residing in the **Entegrus'** service territory.
- After weighting a sample of this size, the aggregated results are considered accurate to within **±4.0%**, 19 times out of 20.
- The margin of error 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.*

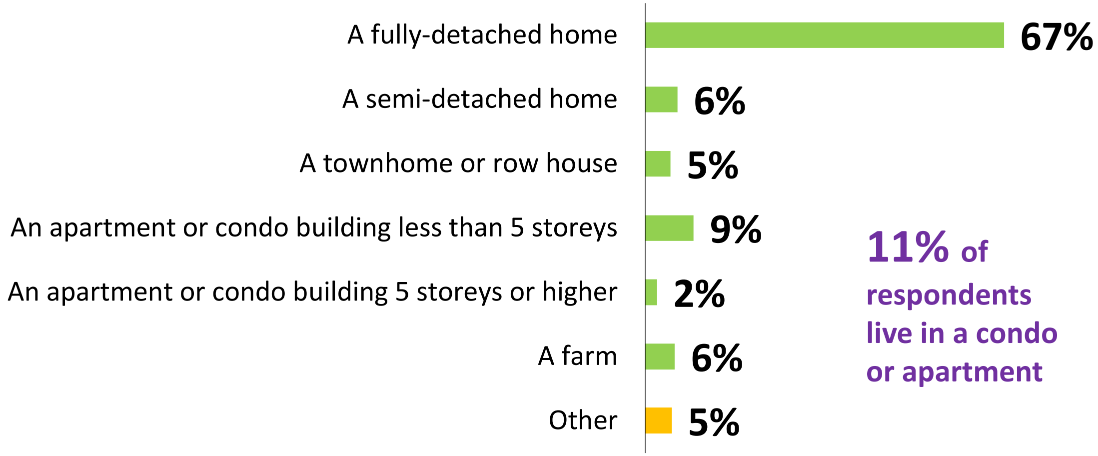
Demographics

Respondent Profile

Age-Gender



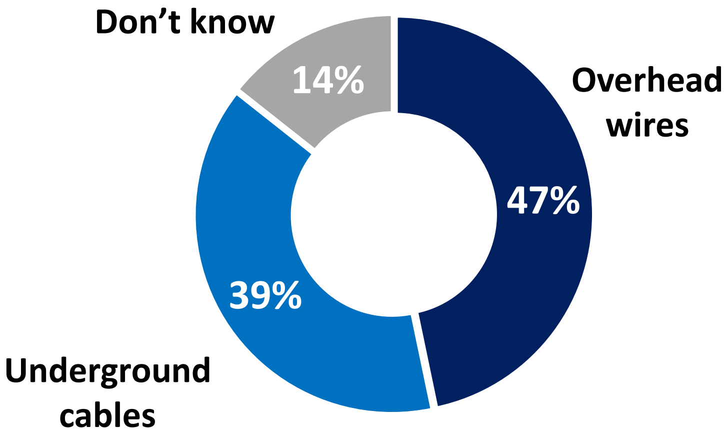
Primary Residence



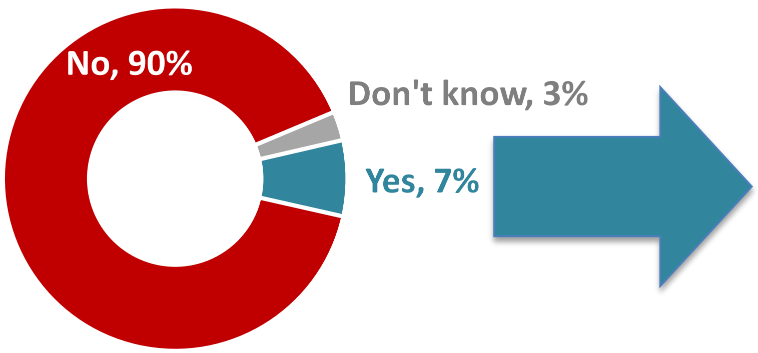
11% of respondents live in a condo or apartment

Note: For the purpose of analysis, those who live on 'a farm' or 'other have been combined.

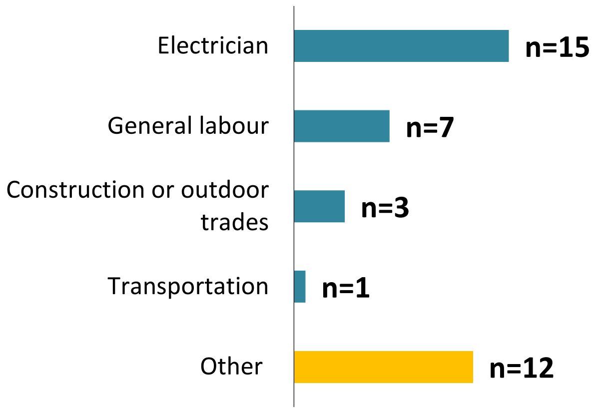
Does your primary residence receive electricity through …



Does your job regularly cause you to come close to energized power lines?



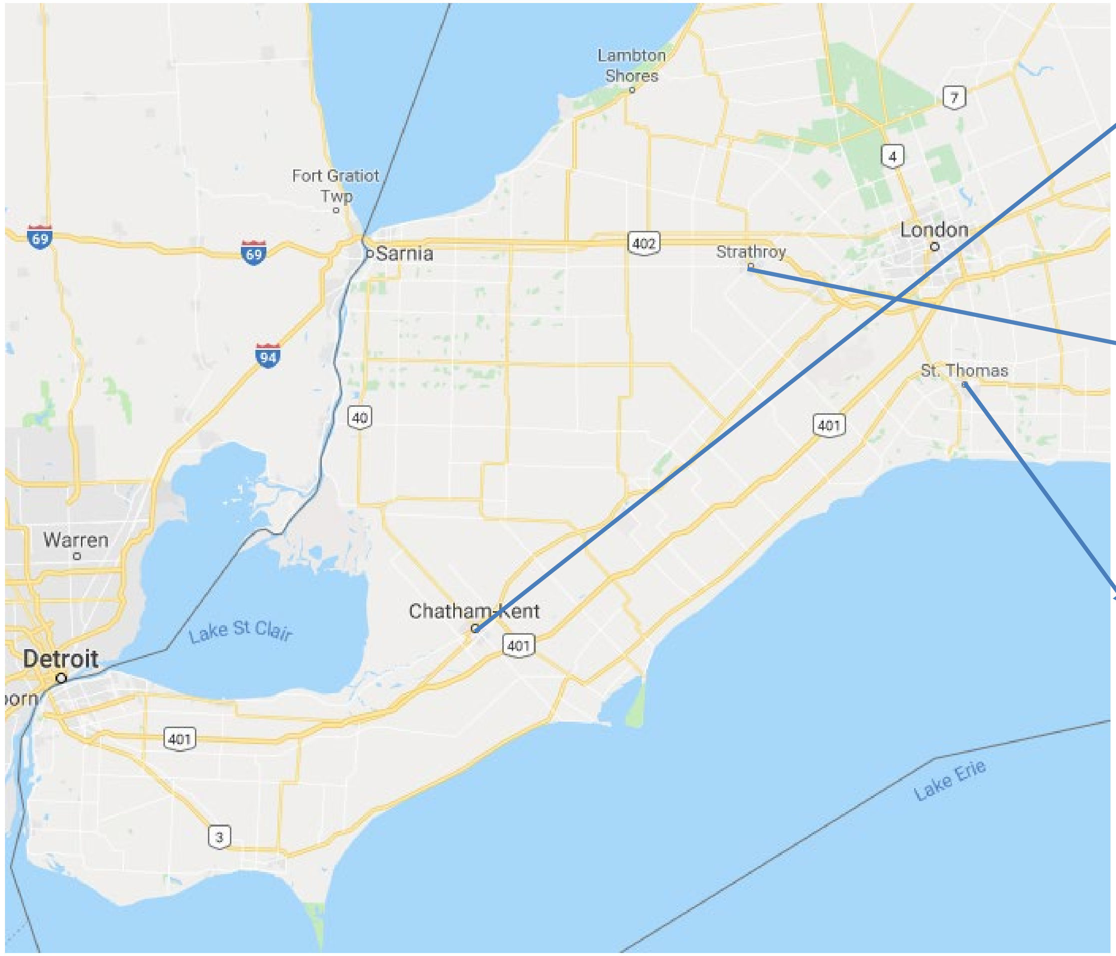
Close to power lines (n=43)

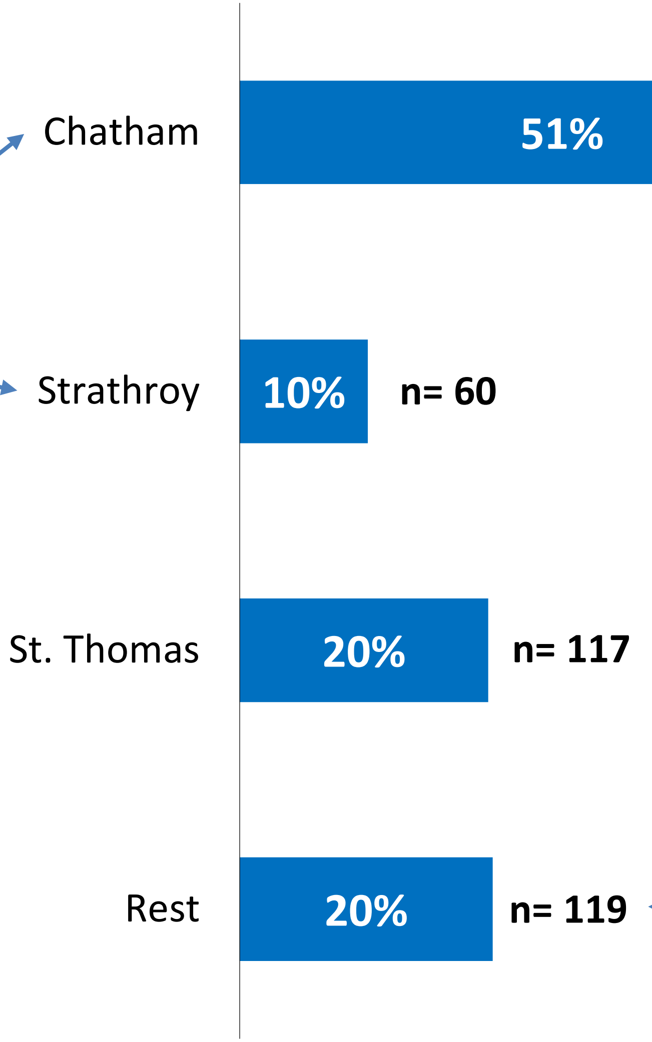


Demographics

Respondent Profile by Region

Sample (n=600) has been weighted based on age, gender, region and mother tongue. Below is the weighted distribution across the Entegrus territory





"Rest" includes:
Mount Brydges
Parkhill
Blenheim
Wallaceburg
Dutton
Dresden
Bothwell
Merlin
Tilbury
Newbury
Wheatley
Ridgetown
Thamesville
Erieau

INNOVATIVE RESEARCH GROUP

Awareness of Electrical Safety

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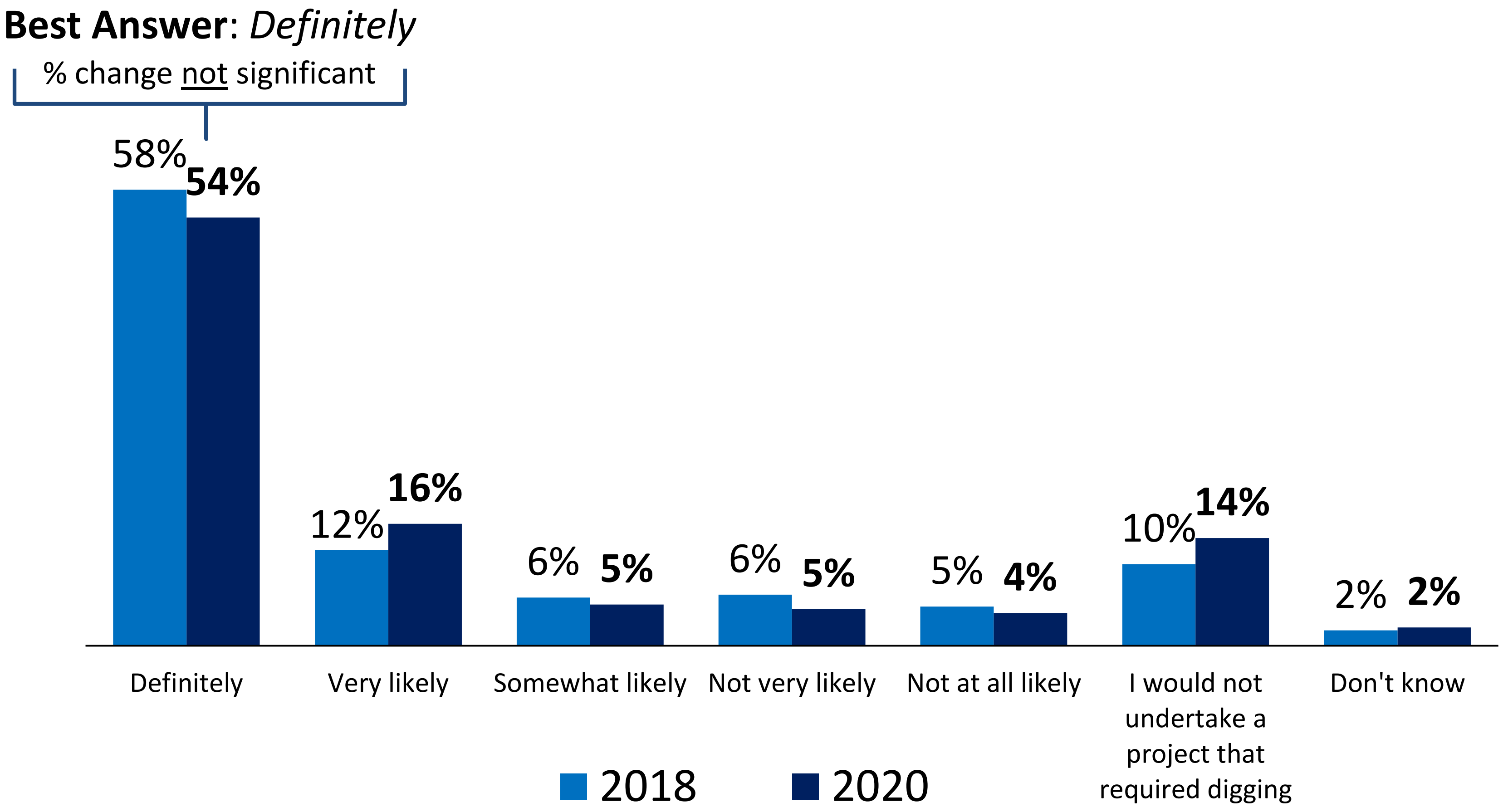
Likelihood to Call Before You Dig

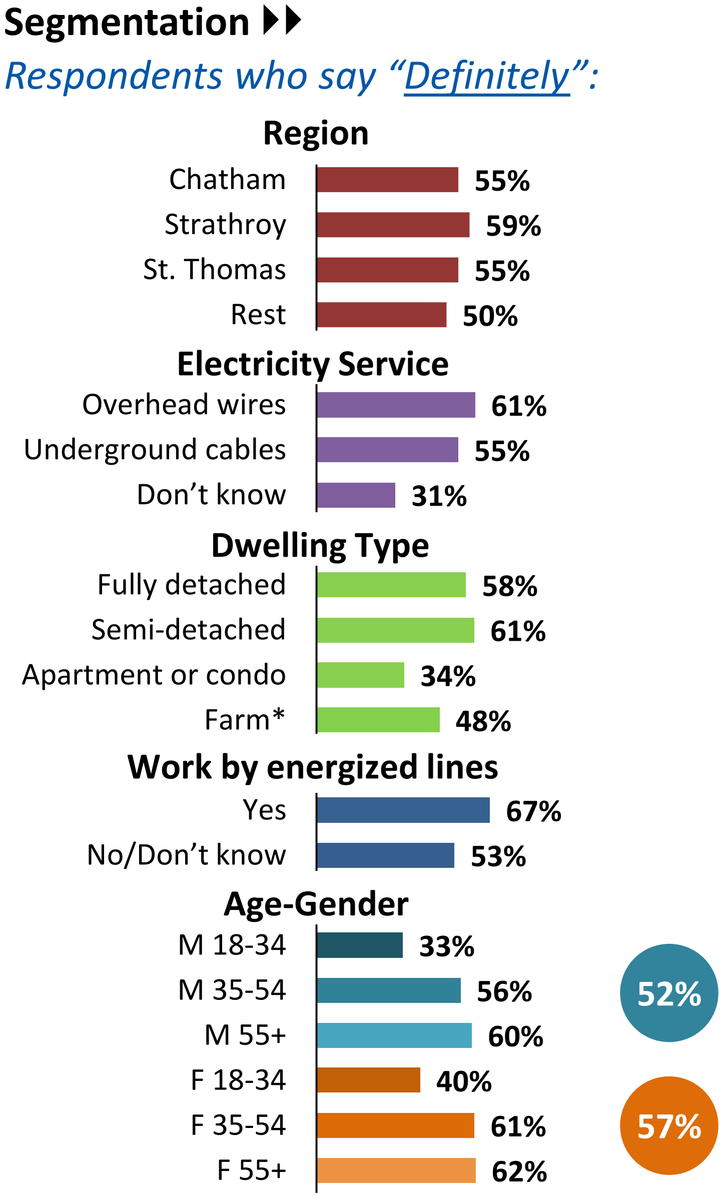
A plurality (54%) chose the best answer 'definitely'; highest among women and those 55 or older

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=600]





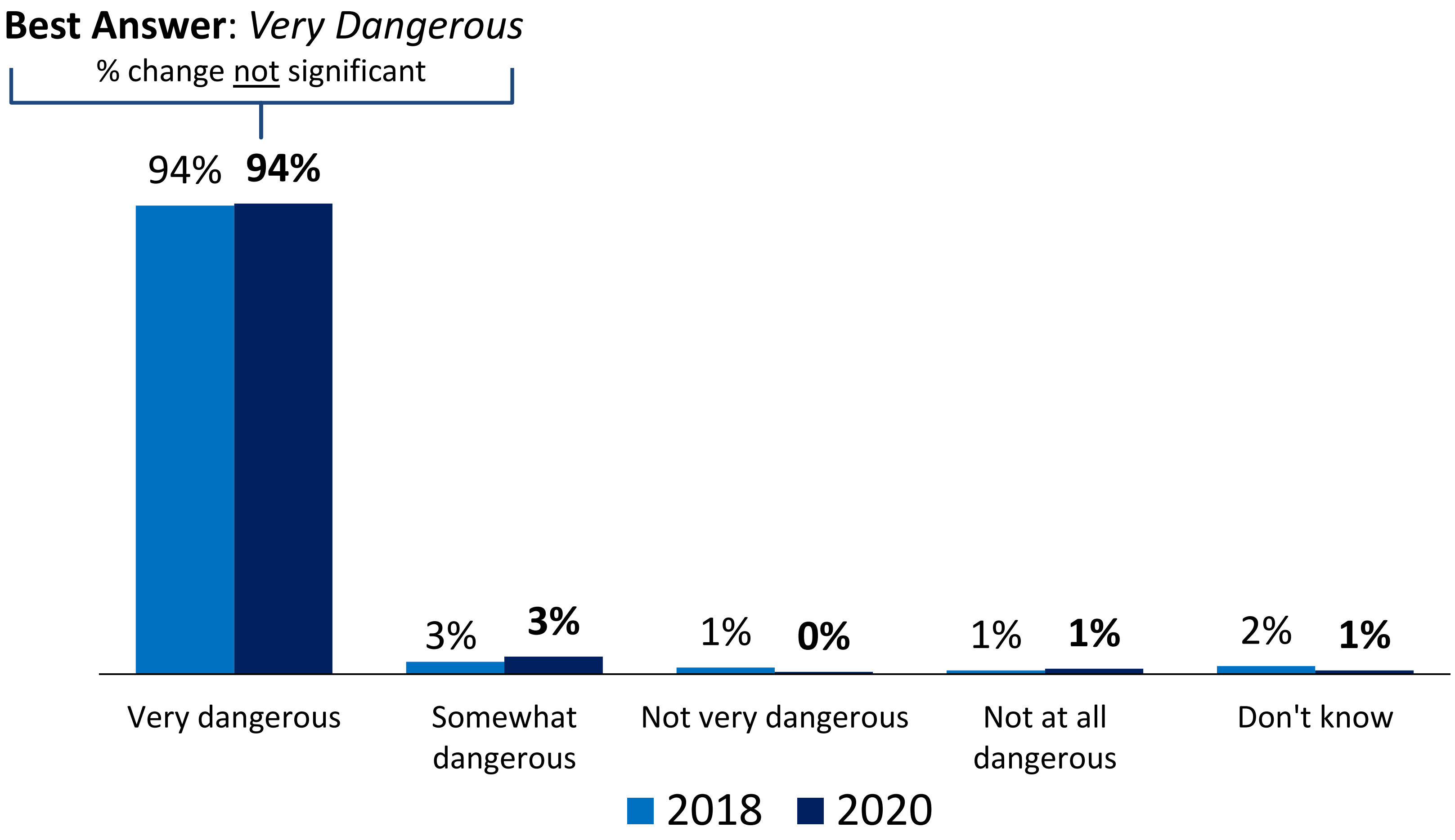
Impact of Touching a Power Line

The majority (94%) say touching a line is ‘very dangerous’; on par with 2018 metrics

Q

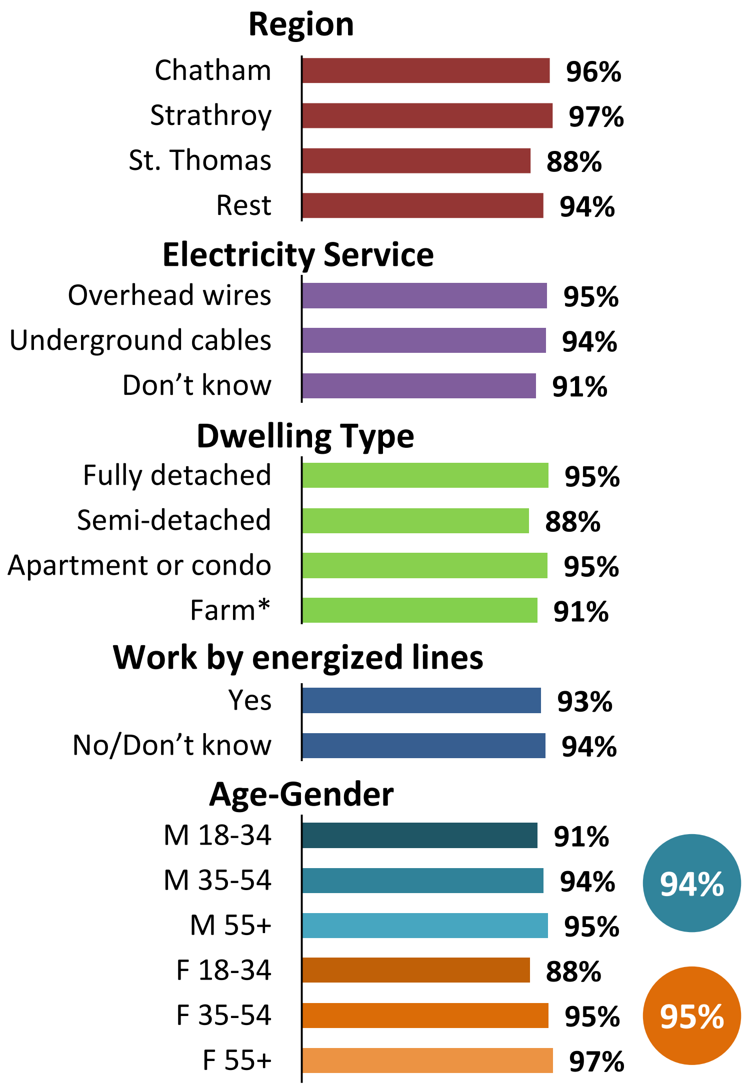
How dangerous do you believe it is to touch - with your body or any object - an overhead power line?

[asked of all respondents, n=600]



Segmentation

Respondents who say “Very Dangerous”:



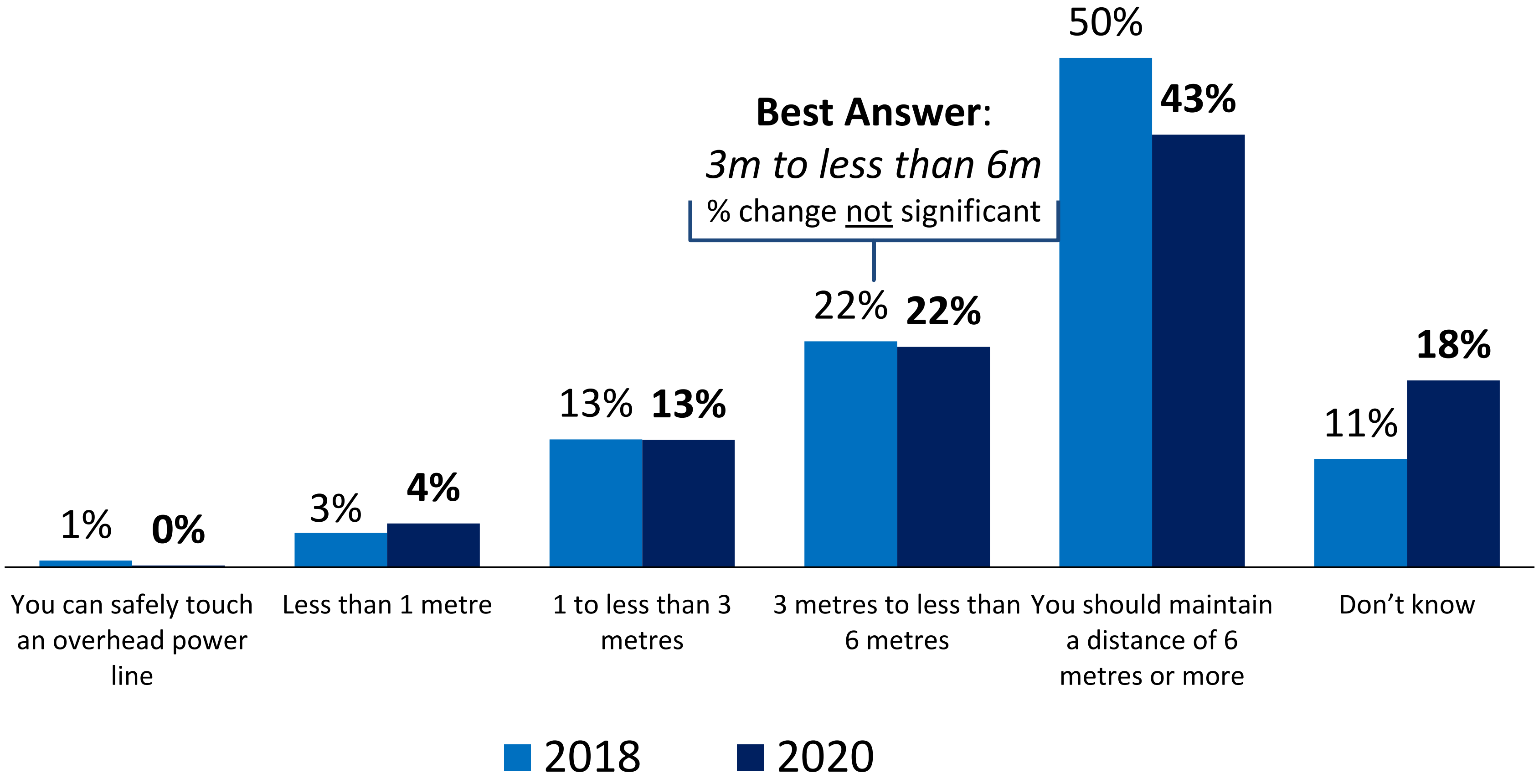
Proximity to Overheard Powerline

22% say ‘3 to <6 metres’ is safe; 7pt decrease those saying ‘6 metres or more’ over 2018 metrics

Q

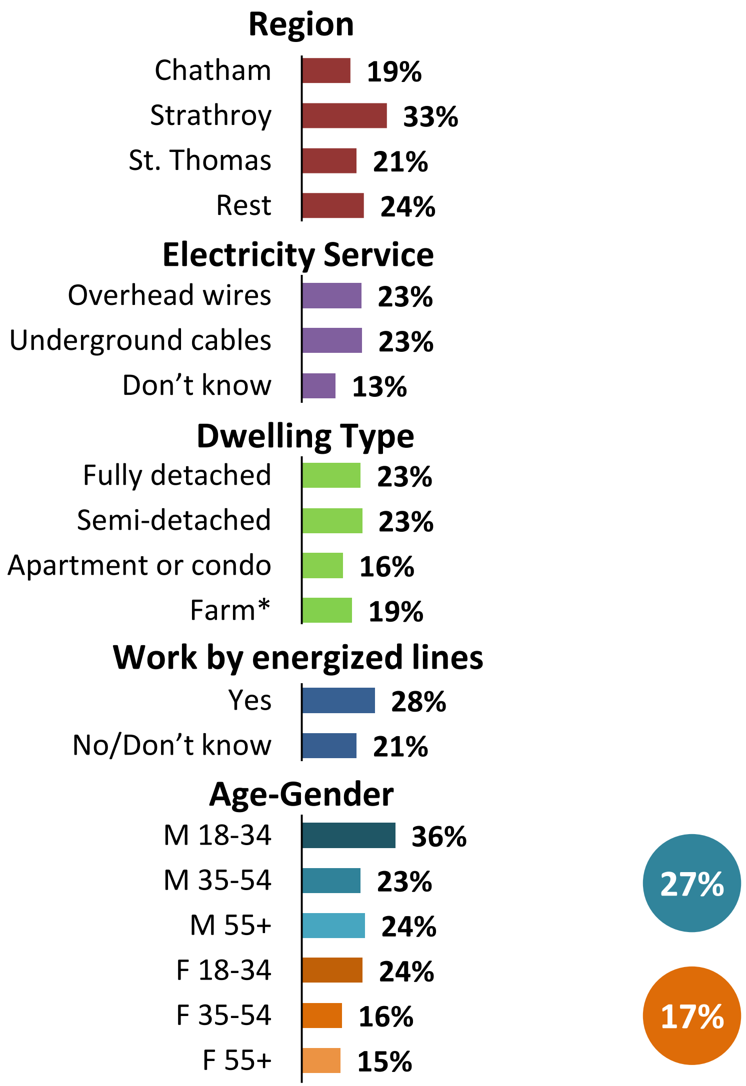
When undertaking outdoor activities – such as, standing on a ladder, cleaning windows or eaves, climbing or trimming trees – how closely do you believe you can safely come to an overhead power line with your body or an object?

[asked of all respondents, n=600]



Segmentation

Respondents who say “3m to <6m”:



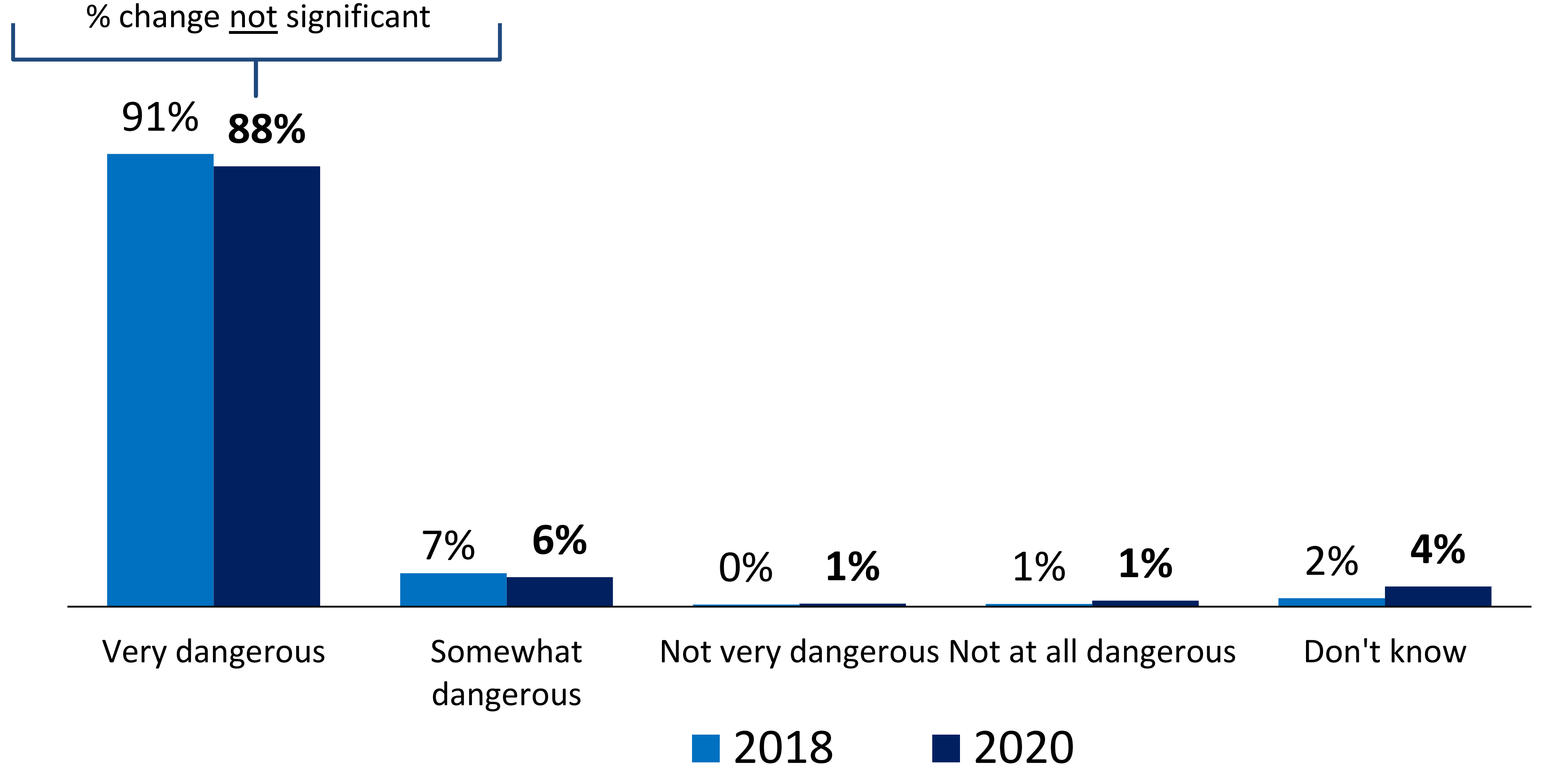
Danger of Tampering with Equipment

The majority (88%) chose the best answer 'very dangerous'; highest among males 55+ and those in Strathroy

Q

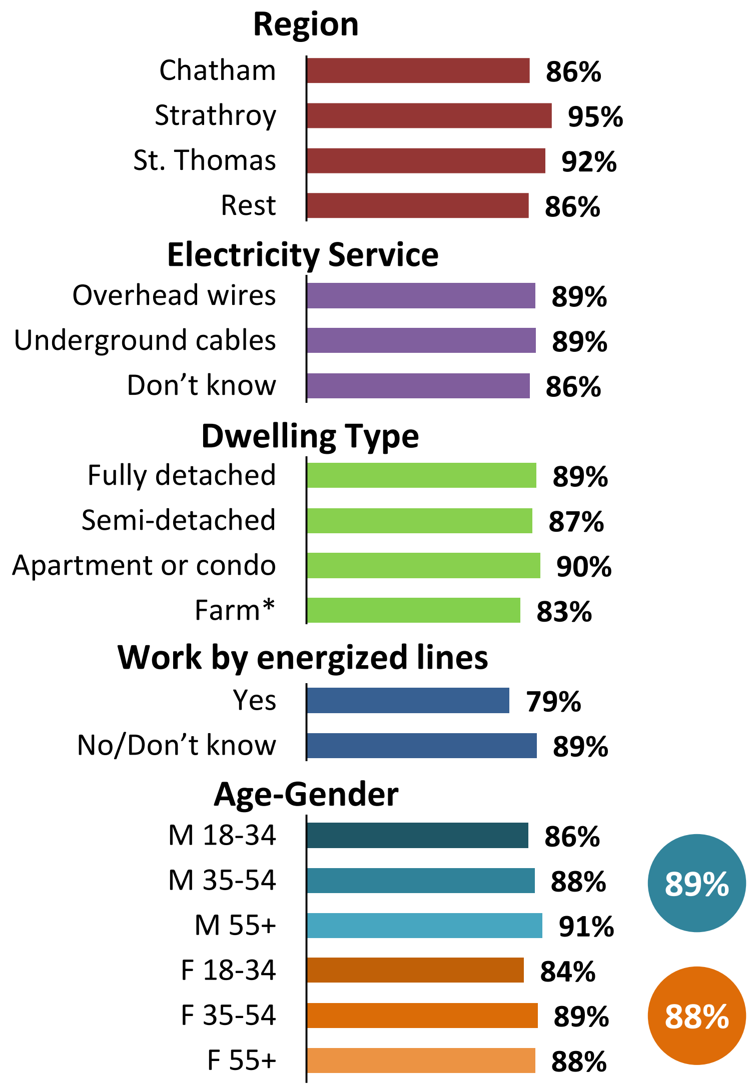
Some electrical utility equipment is located on the ground, such as locked steel cabinets that contain transformers. How dangerous do you believe it is to try to open, remove contents, or touch the equipment inside?
[asked of all respondents, n=600]

Best Answer: *Very Dangerous*



Segmentation

Respondents who say "Very Dangerous":

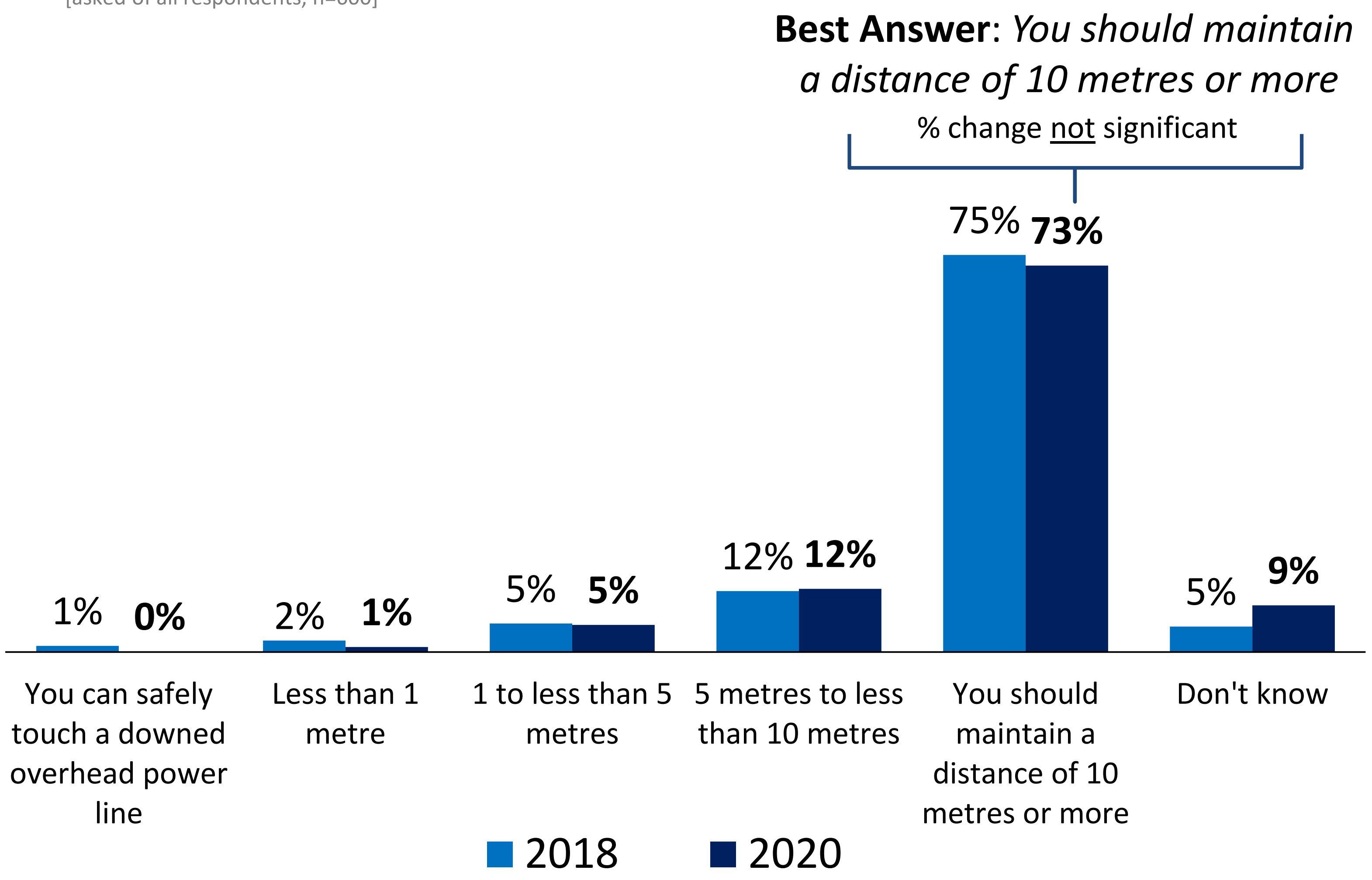


Proximity to Downed Power Line

Nearly 3-in-4 (73%) say '10m or more'; higher among males than females, and those with semi-detached houses

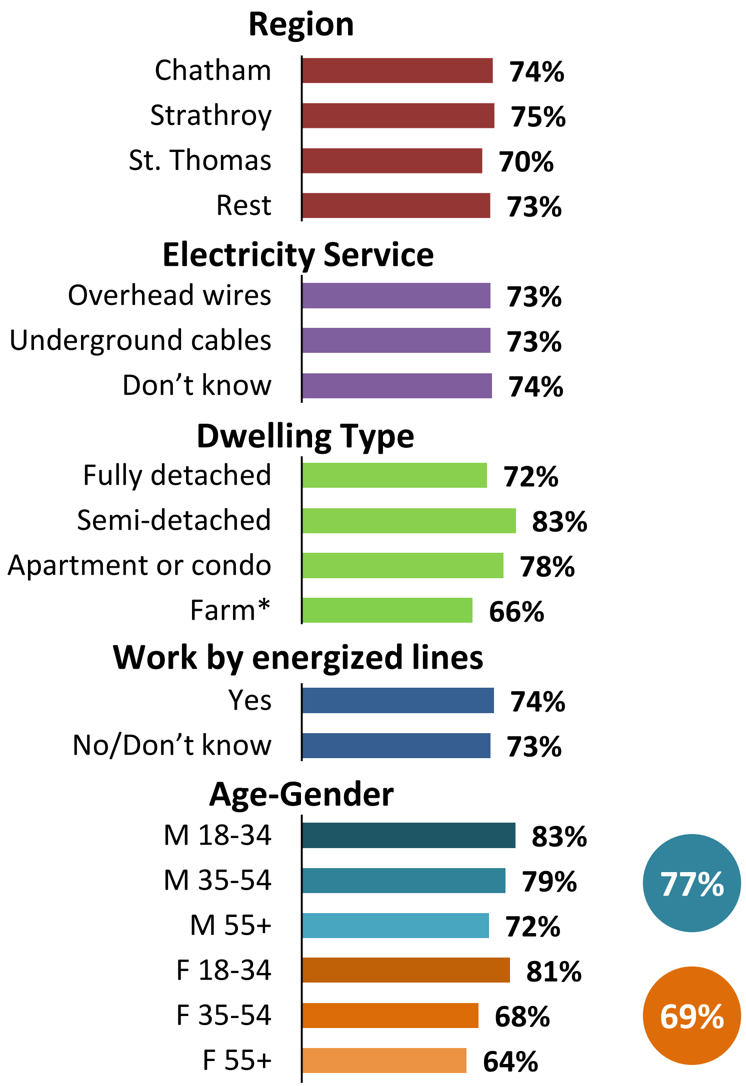
Q How closely do you believe you can safely come to a downed overhead power line, such as a downed line caused by a storm or accident?

[asked of all respondents, n=600]



Segmentation

Respondents who say "10m+":



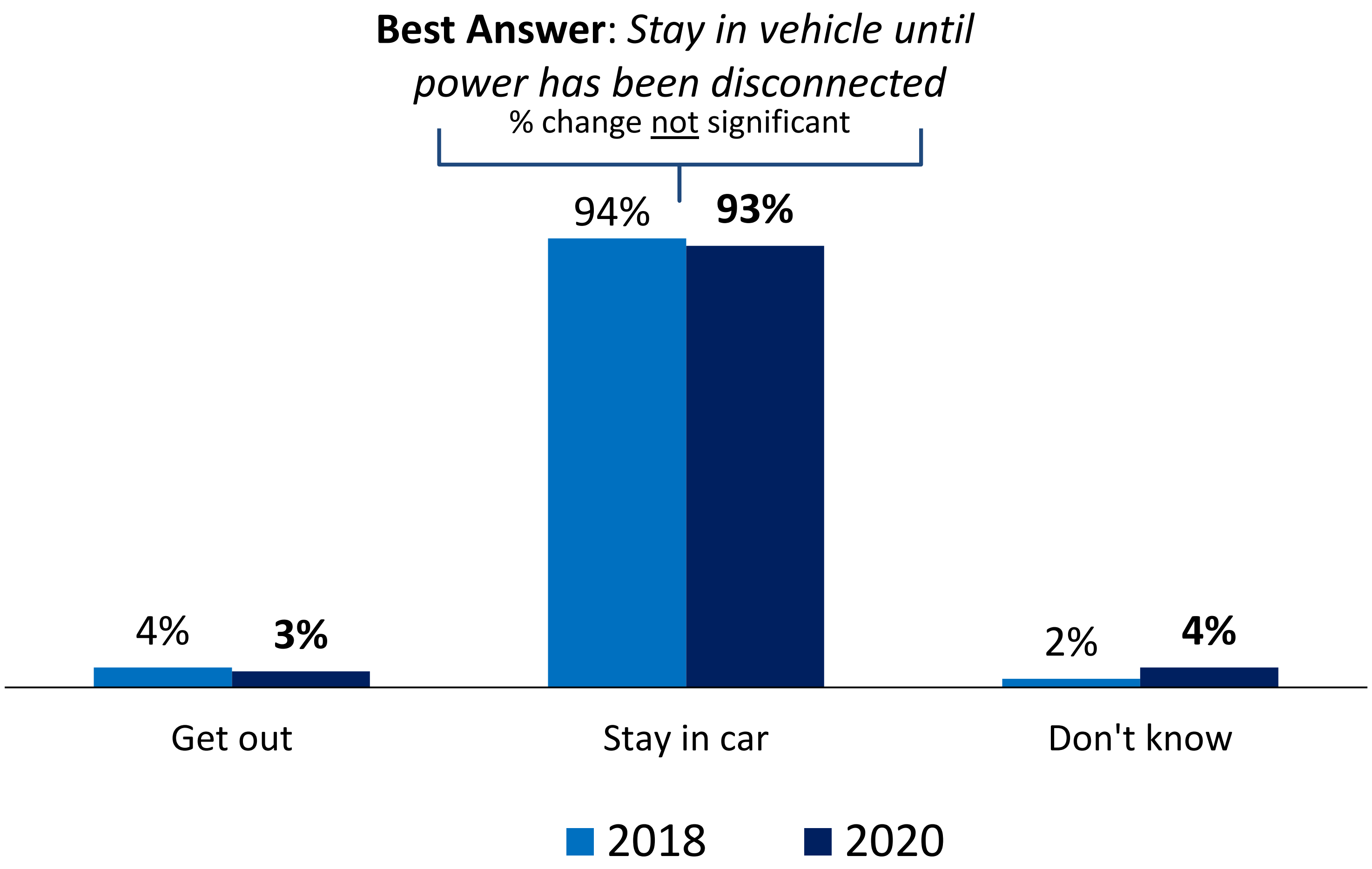
Actions Taken in Vehicle in Contact with Wires

93% say ‘stay in car’; lowest among females 18-34

Q

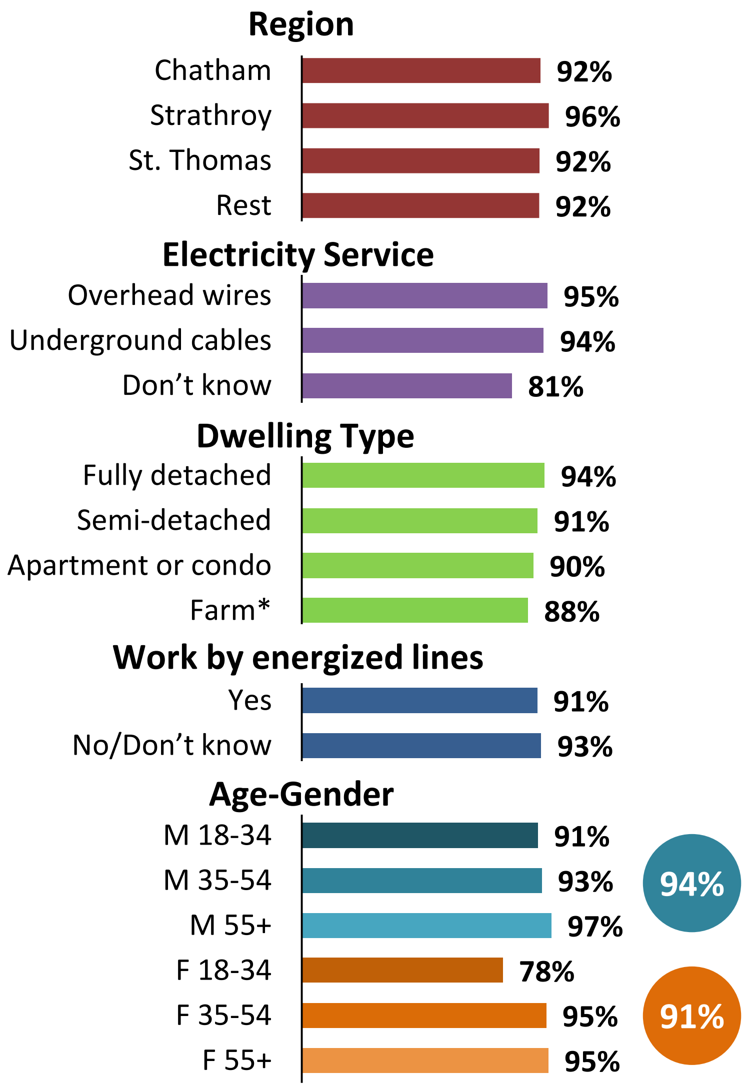
If you were in a vehicle – such as a car, bus, or truck – and an overhead power line came down on top of it, which of the following options do you believe is generally safer?

[asked of all respondents, n=600]



Segmentation

Respondents who say “Stay in the vehicle”:



Actions Taken by Age-Gender

Females 18-34 are least likely to choose the best answer 'stay in the vehicle' and are most at risk

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=600]

Action Taken	Total	Male 18-34	Male 35-54	Male 55+	Female 18-34	Female 35-54	Female 55+
Get out quickly and seek help	**3%**	9%	2%	1%	12%	2%	-
Best Answer: Stay in the vehicle until power has been disconnected from the line	**93%**	91%	93%	97%	78%	95%	95%
Don't know	**4%**	-	5%	2%	10%	4%	5%

Overall Safety Awareness Score

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

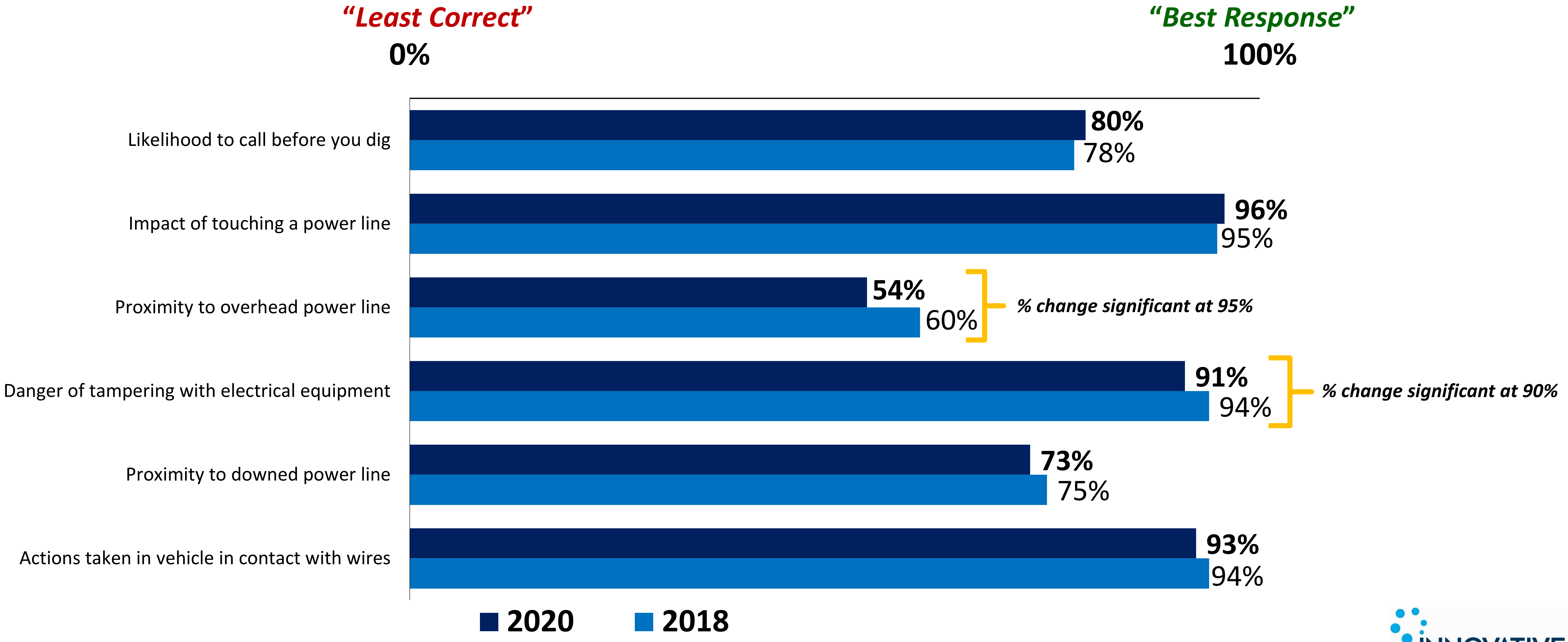
Divide score sections and survey sample size.

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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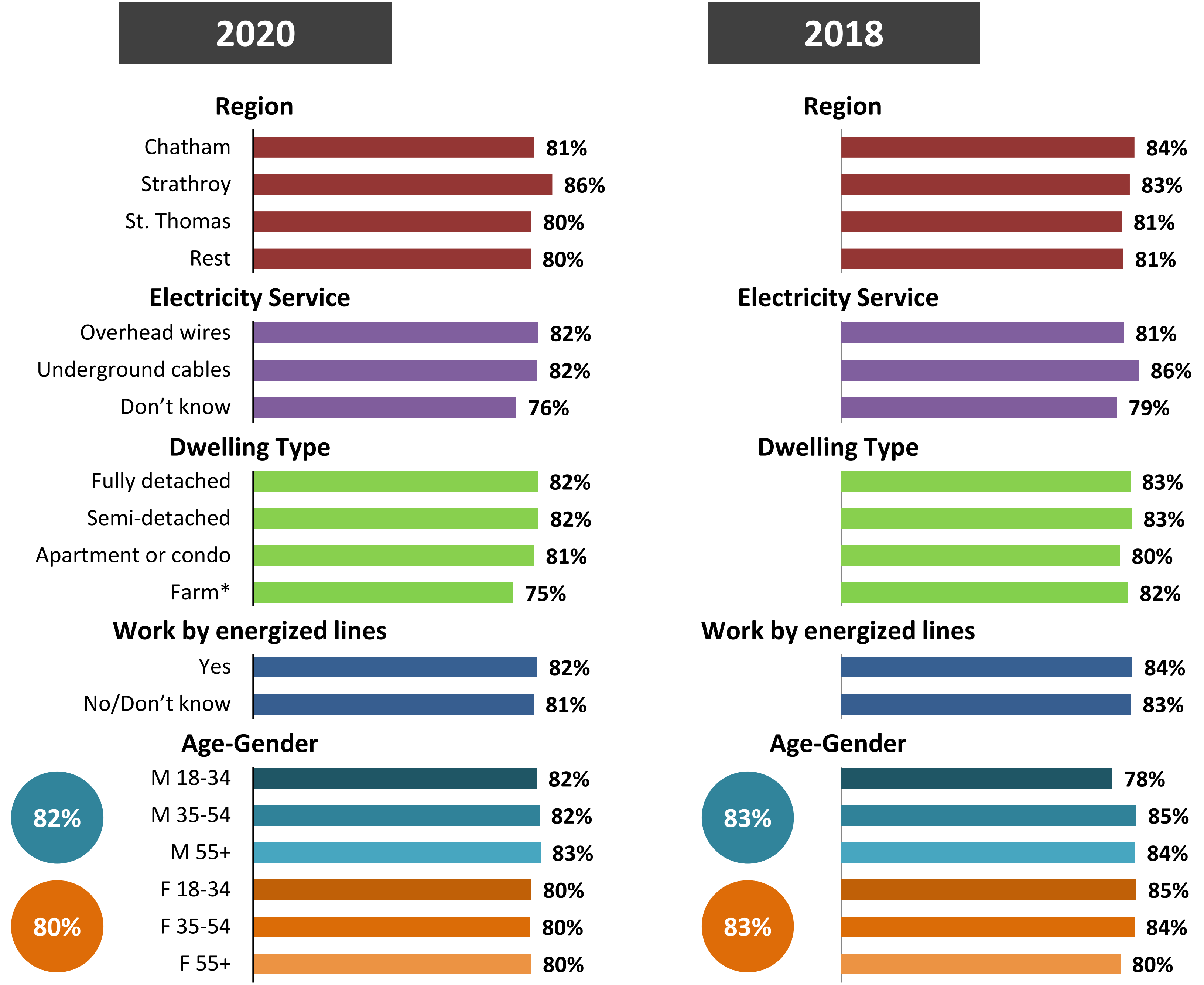
81%

Overall Safety Awareness Score

83% in 2018



Note: *Small n-size, interpret results with caution.

Building Understanding.

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Customer Engagement

Attitudes towards EVs and self-generation

ENTEGRUS™

March 2020

STRICTLY PRIVILEGED AND CONFIDENTIAL

Key Findings

1	**Electric vehicle (EV) adoption doesn't appear to have taken off among Entegrus customers.** Nine-in-10 (91%) of Entegrus customers either own or lease an automobile. An estimated 99% of vehicle owners (and leasers) drive traditional combustion engine automobiles.
2	**… and future adoption of EVs will likely occur very slowly in the coming years.** A slow adoption of EVs is both a result of relatively low projected demand for automobiles (in general) and limited demand for EVs (in particular).
3	**That said, Entegrus appears to be a trusted source for information on making the transition to an EV.** 4-in-10 (41%) customers say they are at least somewhat likely to turn to Entegrus for information and advice when it comes to making the transition to an EV.
4	**Demand for self-generation relatively low.** Again, this is a both a result of only 3-in-10 (29%) residential customers believing their home could support self-generation and only 33% of this group of customers thinking or actively taking steps to produce their own electricity. 2% of Entegrus customers already say they self-generate electricity at home.
5	**Again, Entegrus is a trusted source for information and advice when it comes to self-generation.** More so than transitioning to an EV, two-thirds (67%) of customers say they are at least somewhat likely to turn to Entegrus for information and advice when it comes to residential self-generation options and solutions.

Methodology

Innovative Research Group (INNOVATIVE) was commissioned by **Entegrus** to conduct a regulatory survey in preparation of its upcoming customer engagement in support of its 2021 Distribution System Plan.

- This survey was conducted by telephone among **600** randomly-selected Ontario residents, 18 years or older, currently residing in **Entegrus'** service territory, between March 2nd and March 16th, 2020.
- Of the 600 respondents, this translated into **n=458 customers** eligible to complete Entegrus' regulatory questions.
- Both cell phones and landlines are included in the sample to ensure that those who do not have a landline phone are represented in the final sample.
- The sample has been weighted by age, gender and region using the latest Statistics Canada Census data to reflect the actual demographic composition of the adult population residing in the **Entegrus'** service territory.
- After weighting a sample of this size, the aggregated results are considered accurate to within **±4.6%**, 19 times out of 20.
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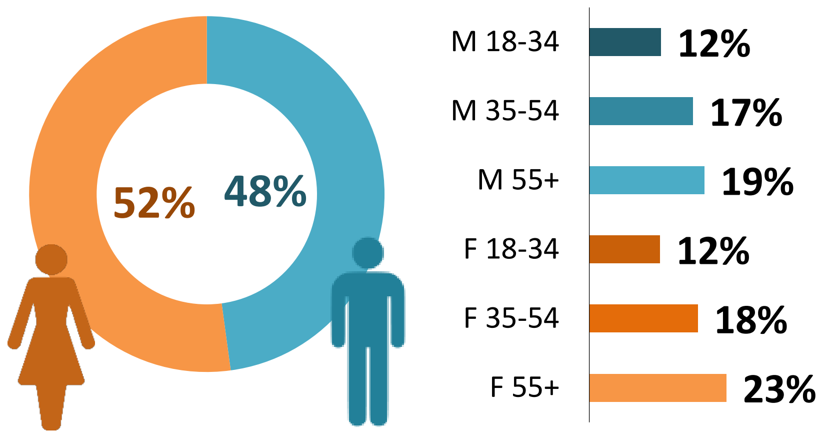
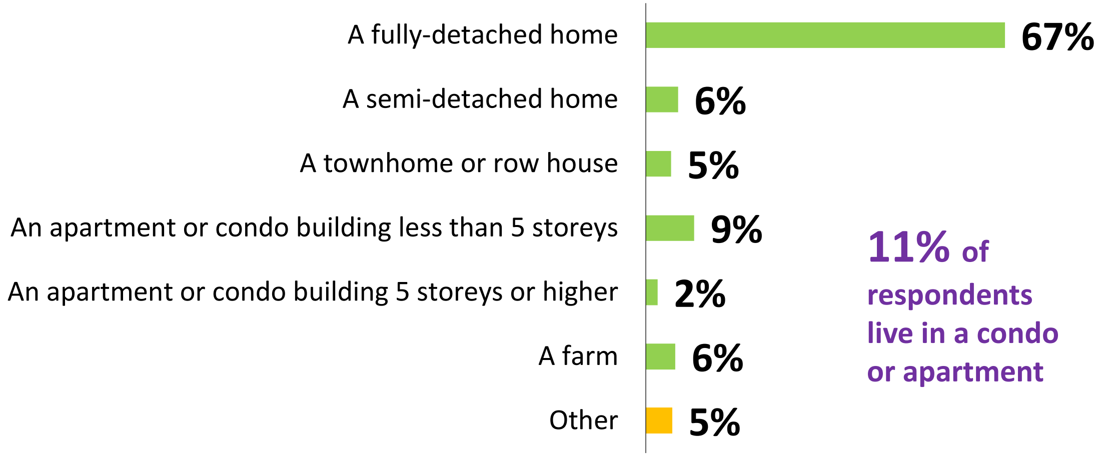
Demographics

Respondent Profile

Age-Gender



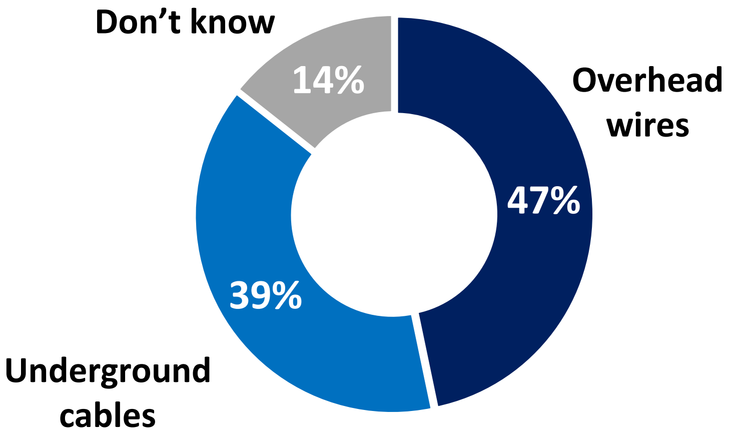
Primary Residence



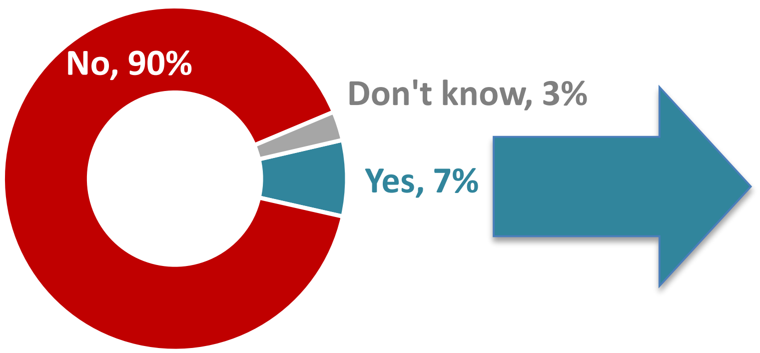
11% of respondents live in a condo or apartment

Note: For the purpose of analysis, those who live on 'a farm' or 'other have been combined.

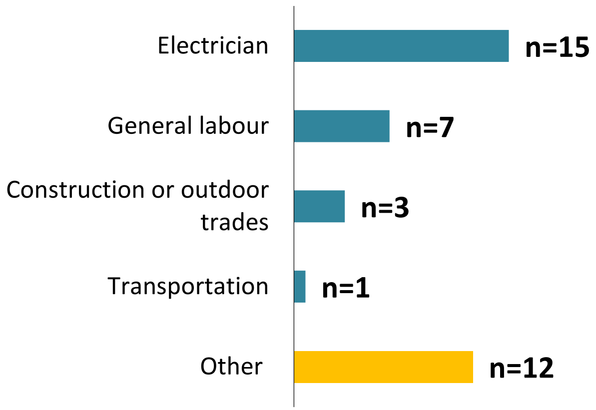
Does your primary residence receive electricity through …



Does your job regularly cause you to come close to energized power lines?



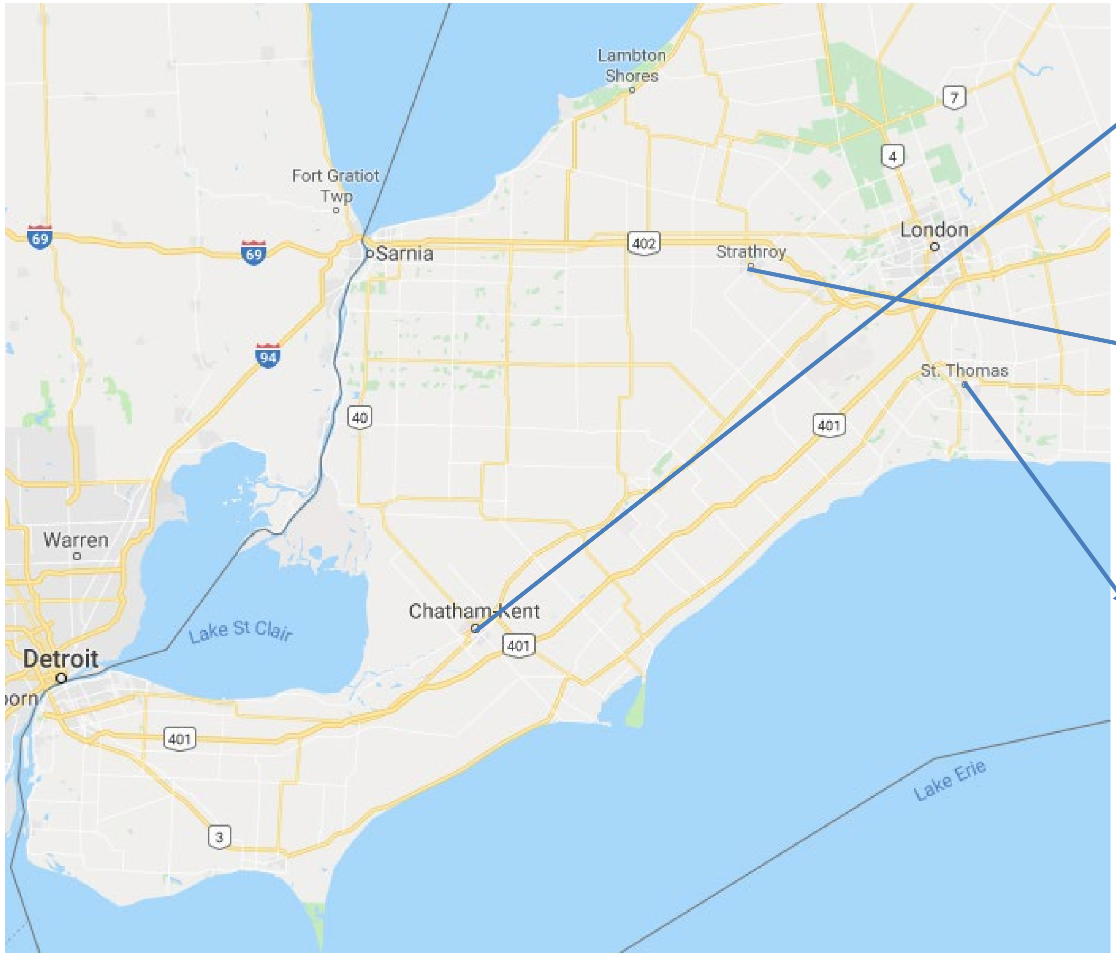
Close to power lines (n=43)

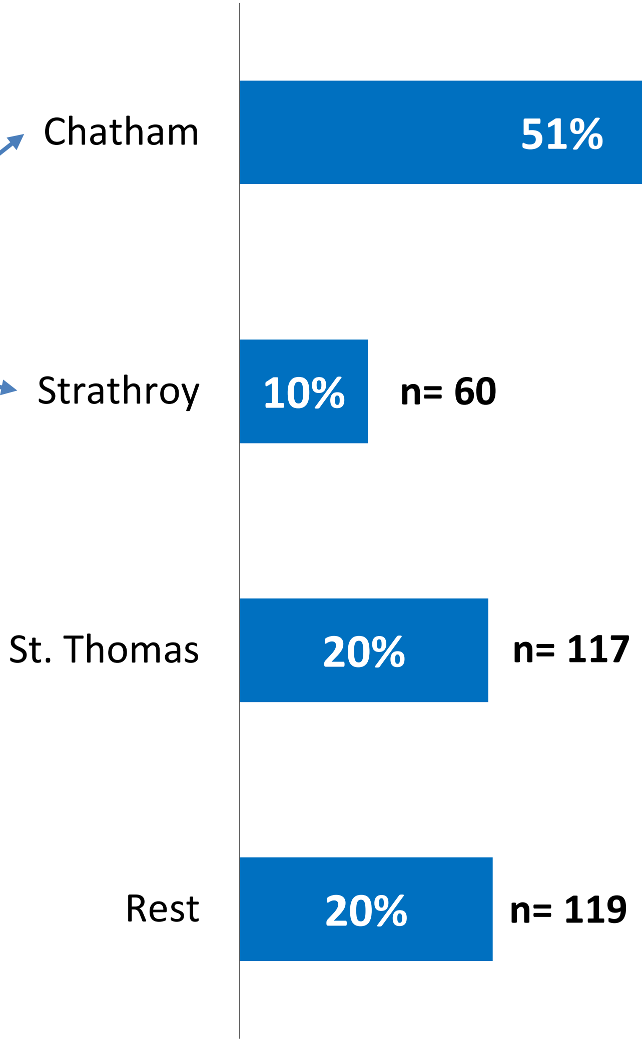


Demographics

Respondent Profile by Region

Sample (n=600) has been weighted based on age, gender, region and mother tongue. Below is the weighted distribution across the Entegrus territory





"Rest" includes:
Mount Brydges
Parkhill
Blenheim
Wallaceburg
Dutton
Dresden
Bothwell
Merlin
Tilbury
Newbury
Wheatley
Ridgetown
Thamesville
Erieau

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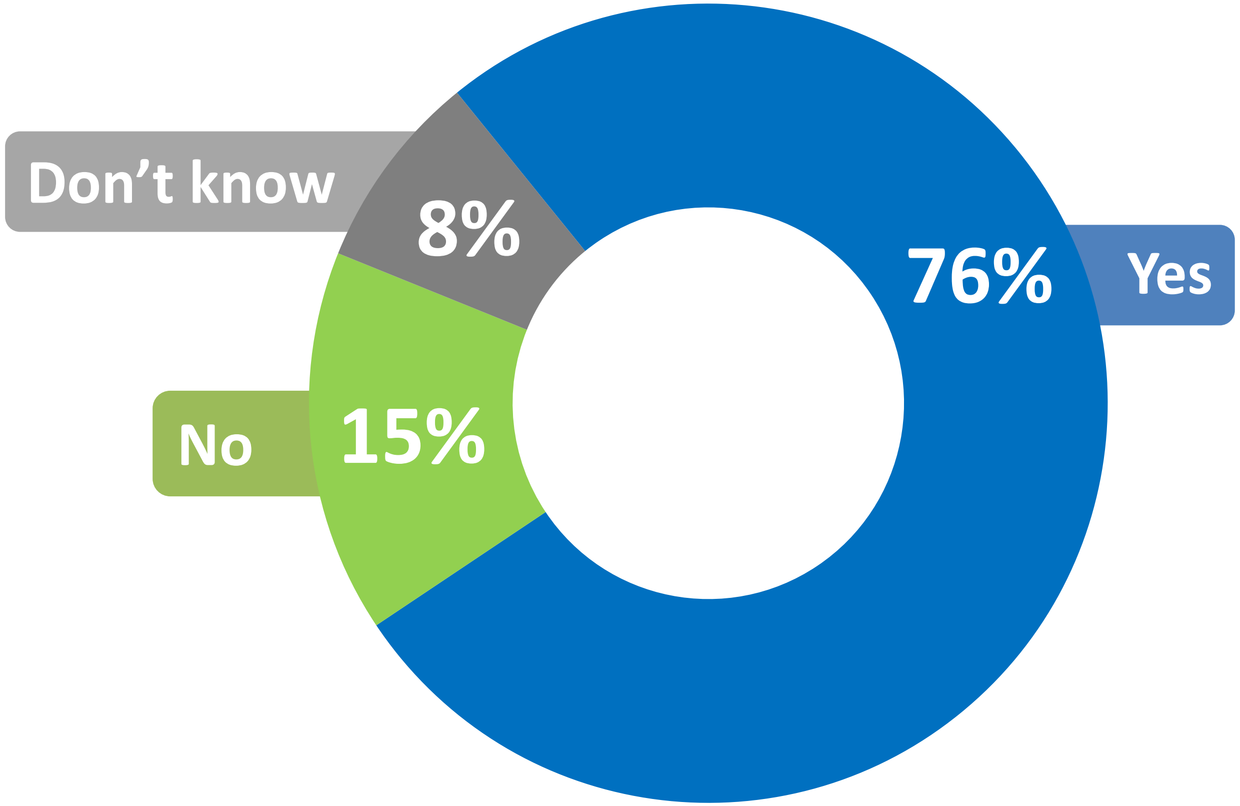
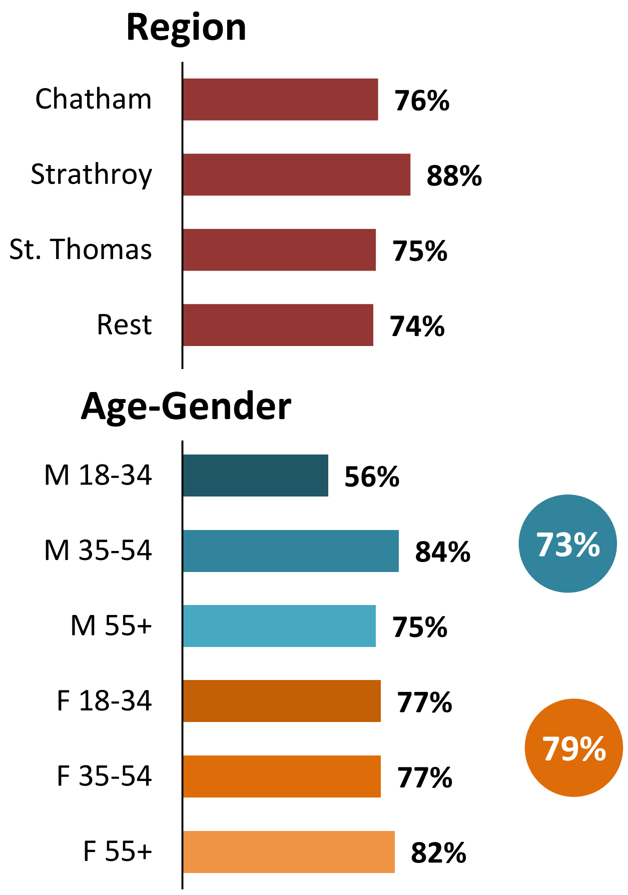
Entegrus Bill

3-in-4 (76%) receive a bill from Entegrus; highest amongst those in Strathroy

Q Can you confirm that your household receives an electricity bill from Entegrus?
[asked of all respondents, n=600]



Segmentation
Respondents who say “Yes”



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Custom Questions

[Asked only of Entegrus ratepayers]

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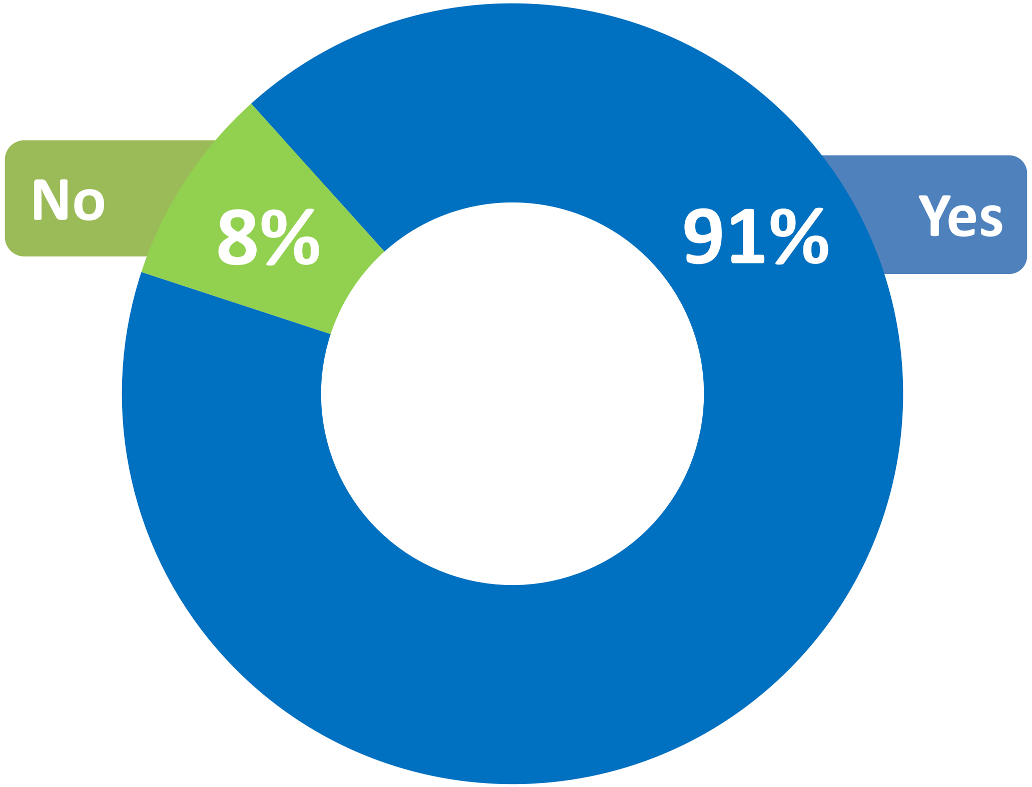
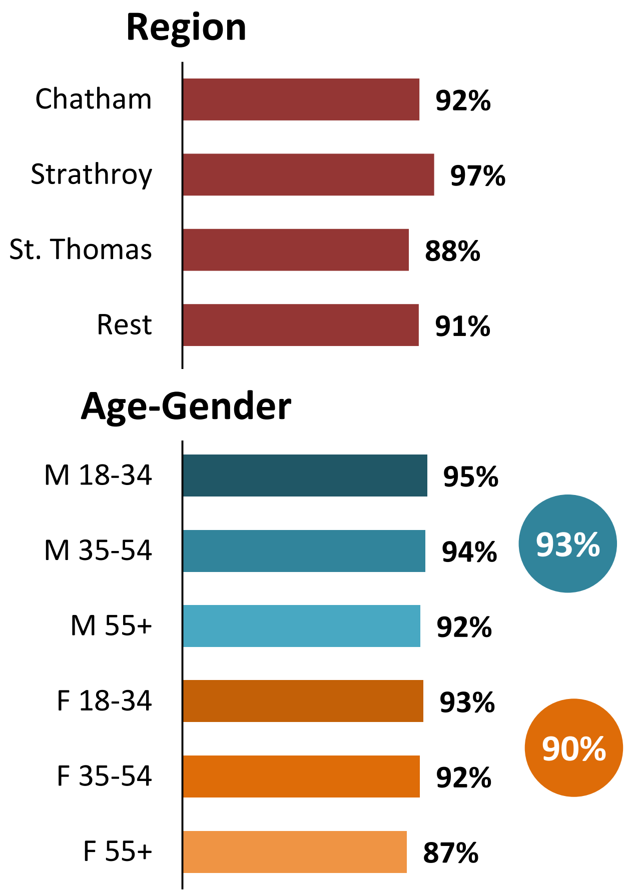
Own an Automobile

9-in-10 (91%) Entegrus customers own or lease a vehicle; highest in Strathroy

Q Do you currently own or lease an automobile ?
[asked of all Entegrus customers; n=458]



Segmentation
Respondents who say "Yes"

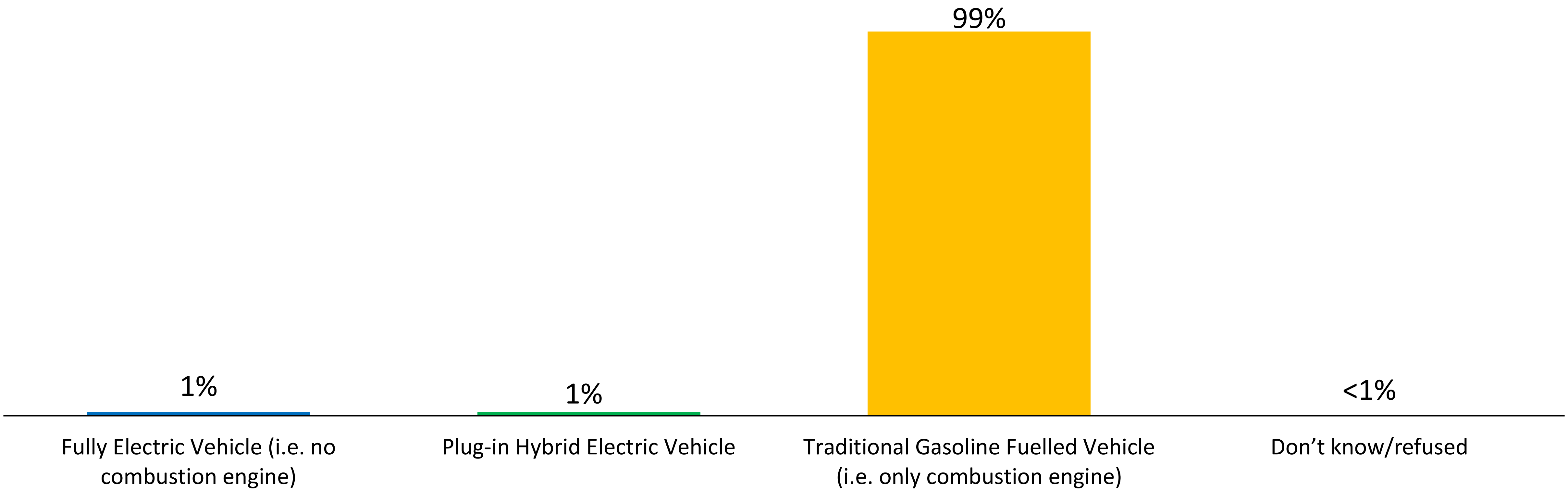


Note: 'Don't know' (<1%) not shown.

Type of Automobile

99% say they drive traditional gasoline fuelled vehicles; 1% say fully electric

Q And which of the following best describes the type of automobile or automobiles you currently own or lease?
[asked of Entegrus customers owning or leasing an automobile; n=419]

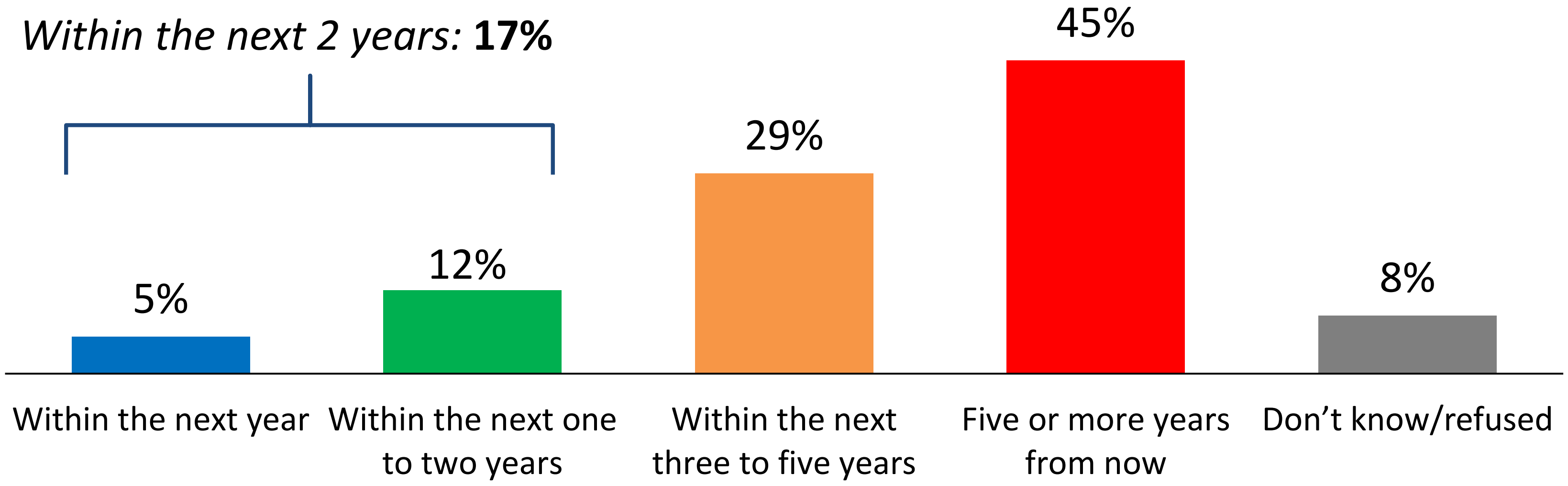


Replacement Timeframe

Less than 1-in-5 (17%) expect to replace their car within the next 2 years

Q When do you anticipate replacing your current automobile?

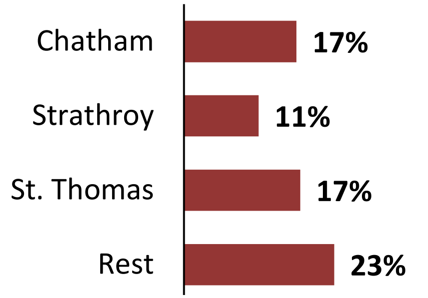
[asked of Entegrus customers owning or leasing an automobile; n=419]



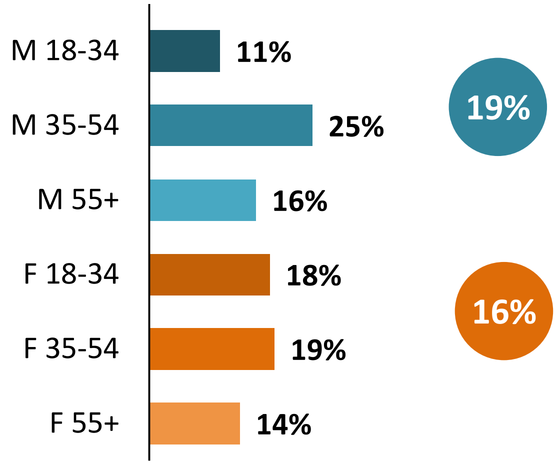
Segmentation

Respondents who say "Within the next year" and "Within the next one to two years"

Region



Age-Gender



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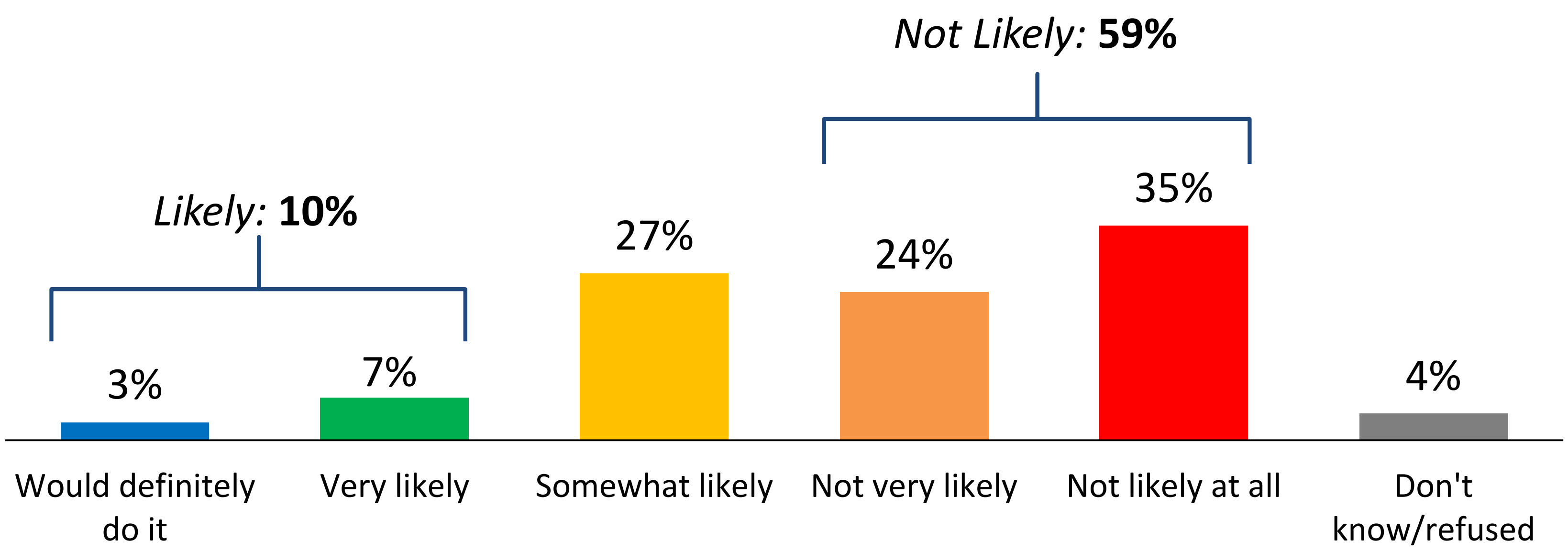
Likelihood to Choose an Electric Vehicle

10% are likely to choose electric; highest in St. Thomas and among males 55+

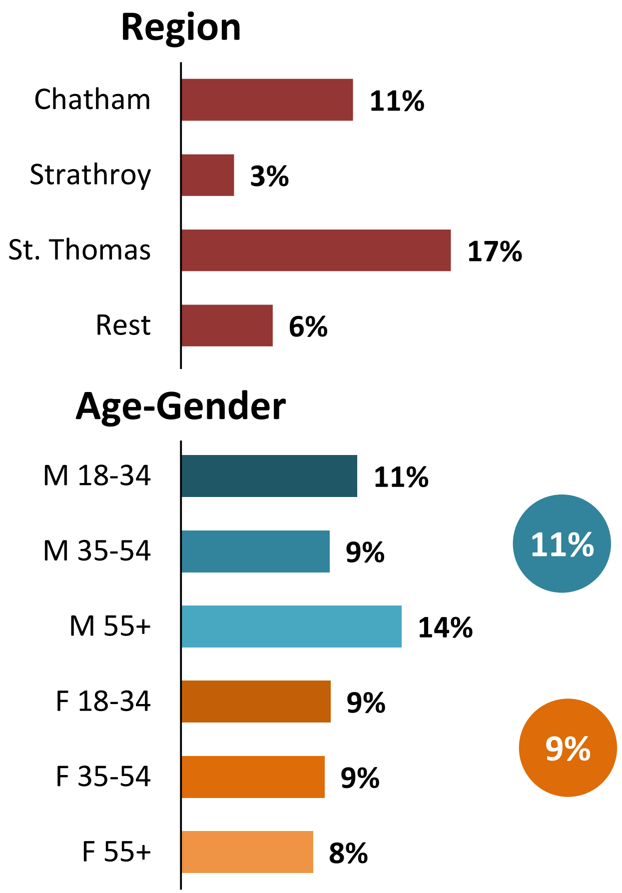
Q How likely would you say you are to buy or lease an electric car when it's time to replace your current one ? Would you say …

[asked of Entegrus customers owning or leasing an automobile; n=419]



Segmentation

Respondents who say "Likely"



Proximity of Vehicle Replace by Likelihood to Buy Electric

Those who anticipate replacing their vehicle within the next year are least likely to consider an EV

		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
How likely would you say you are to buy or lease an electric vehicle when it's time to replace your current one?	Definitely/Very Likely	9%	7%	11%	10%	9%	**10%**
	Somewhat likely	4%	35%	33%	25%	9%	**26%**
	Not very likely	17%	22%	32%	26%	15%	**26%**
	Not likely at all	**65%**	30%	22%	36%	53%	**34%**
	Don't know	4%	6%	2%	4%	15%	**4%**

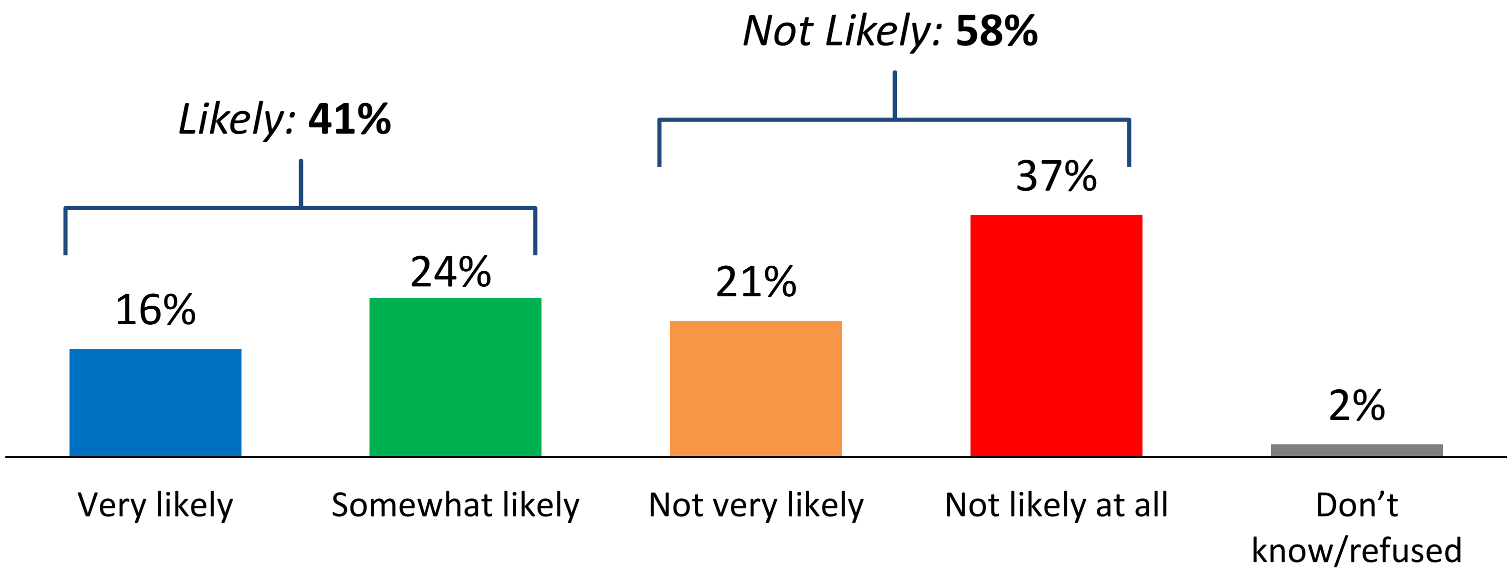
[asked of Entegrus customers owning or leasing an automobile; n=419]

Entegrus Advice & Info

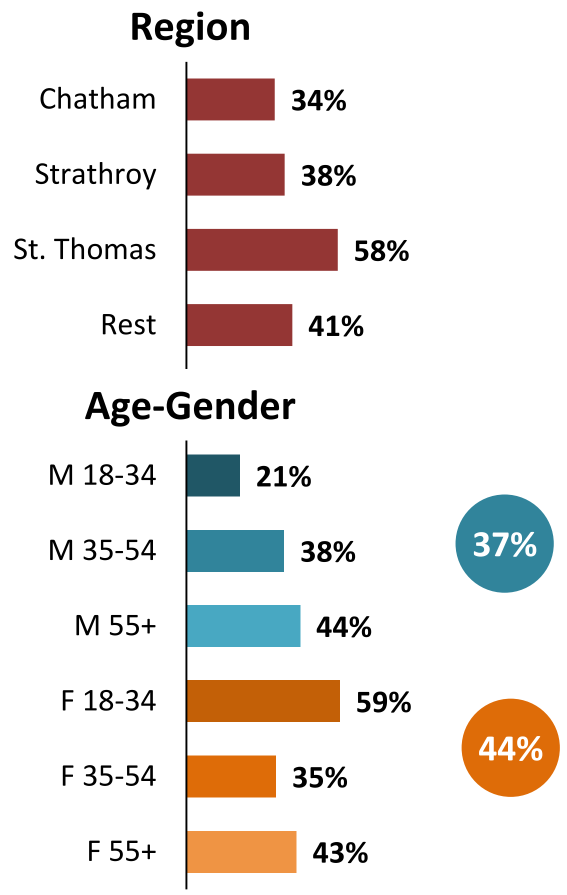
41% likely to seek Entegrus' advice; highest in St. Thomas and with young females

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 Entegrus customers; n=458]



Segmentation
Respondents who say "Likely"



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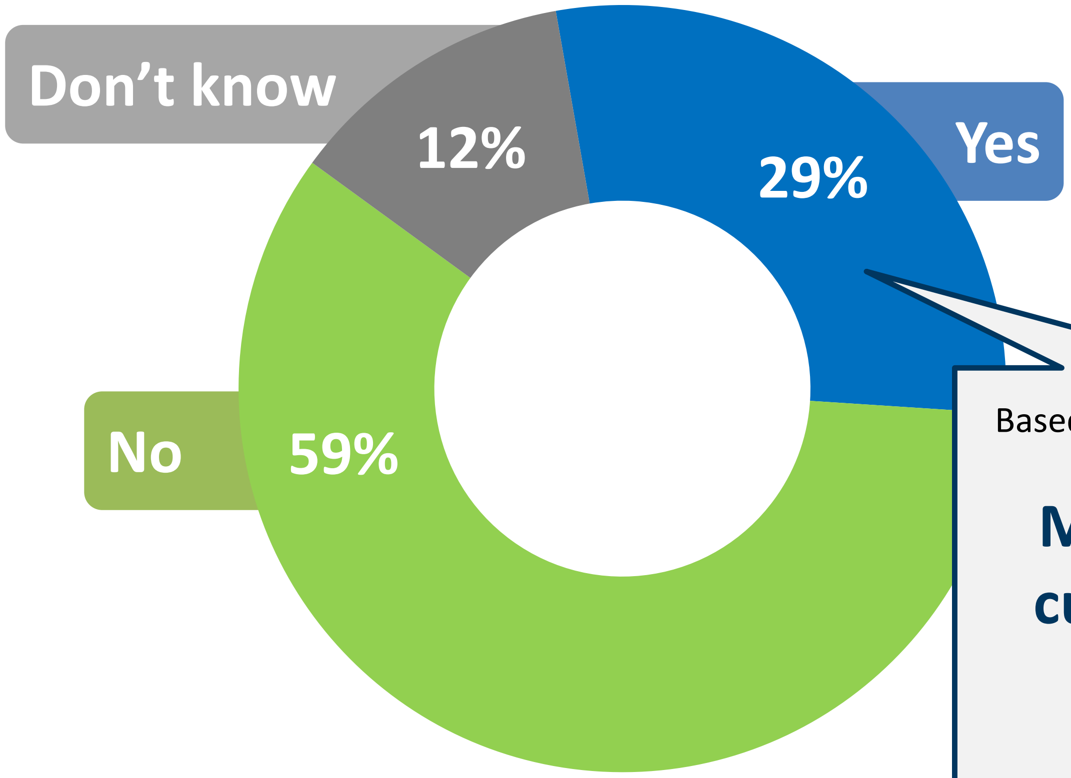
Possibility of Self-Generation

3-in-10 (29%) would be able to self-generate; highest in Chatham and among men

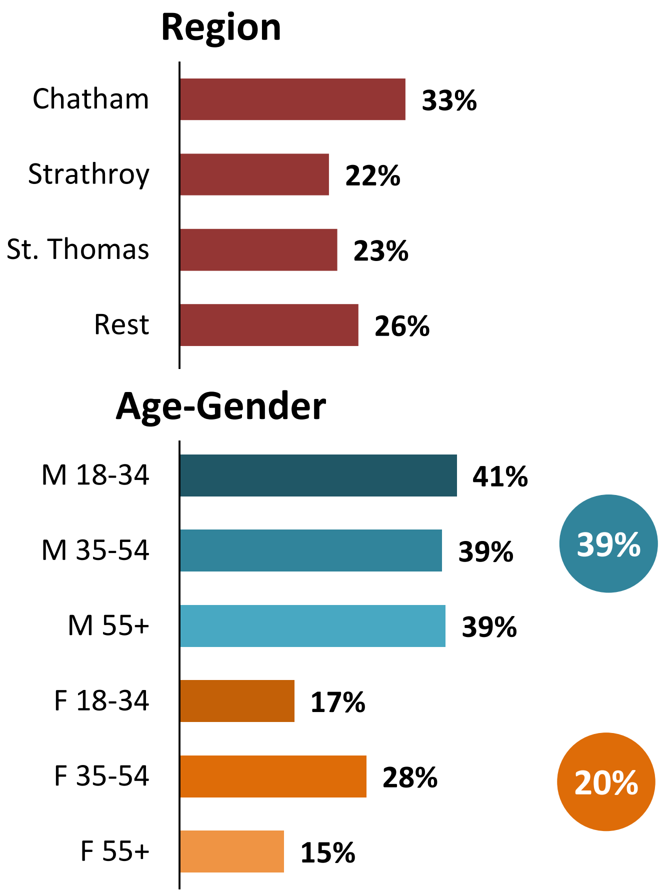
Q Does your current housing situation allow you to invest in technology to self-generate electricity ?
[asked of all Entegrus customers; n=458]



Based on 52,940 Entegrus residential customers…

More than 15,000 customers are in a position to self-generate

Segmentation ▶▶
Respondents who say "Yes"



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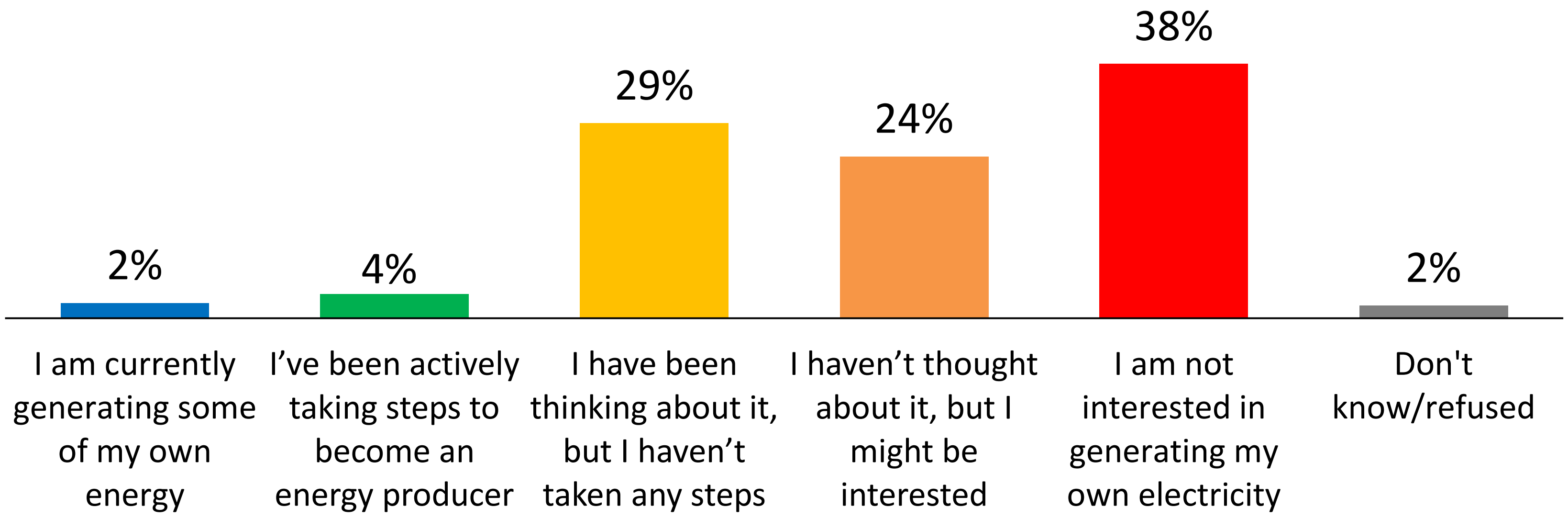
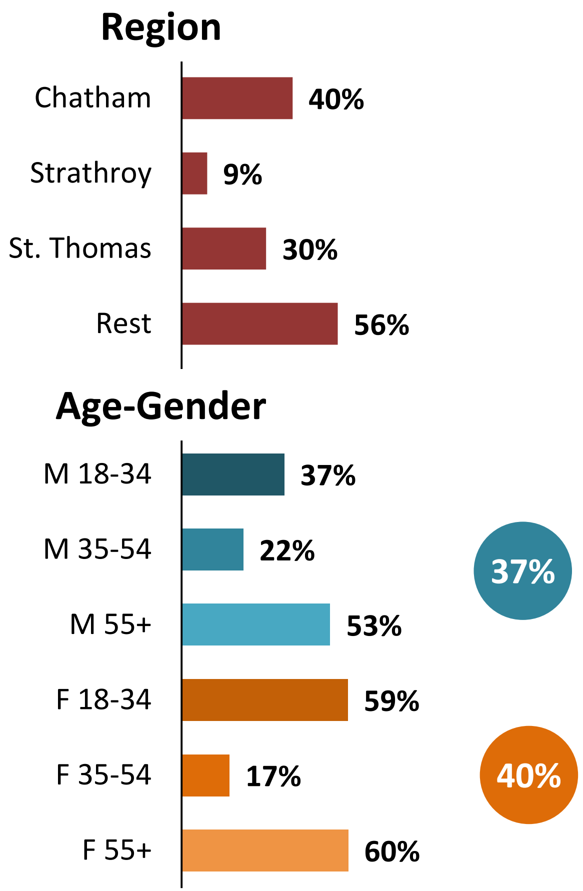
Interest in Self-Generation

38% are not interested; those in Strathroy and those middle aged most interested

Q How would you describe your interest in generating energy yourself? Would you say…
[asked of Entegrus customers whose current situation allows for self-generation; n=132]



Segmentation
Respondents who say "Not interested"

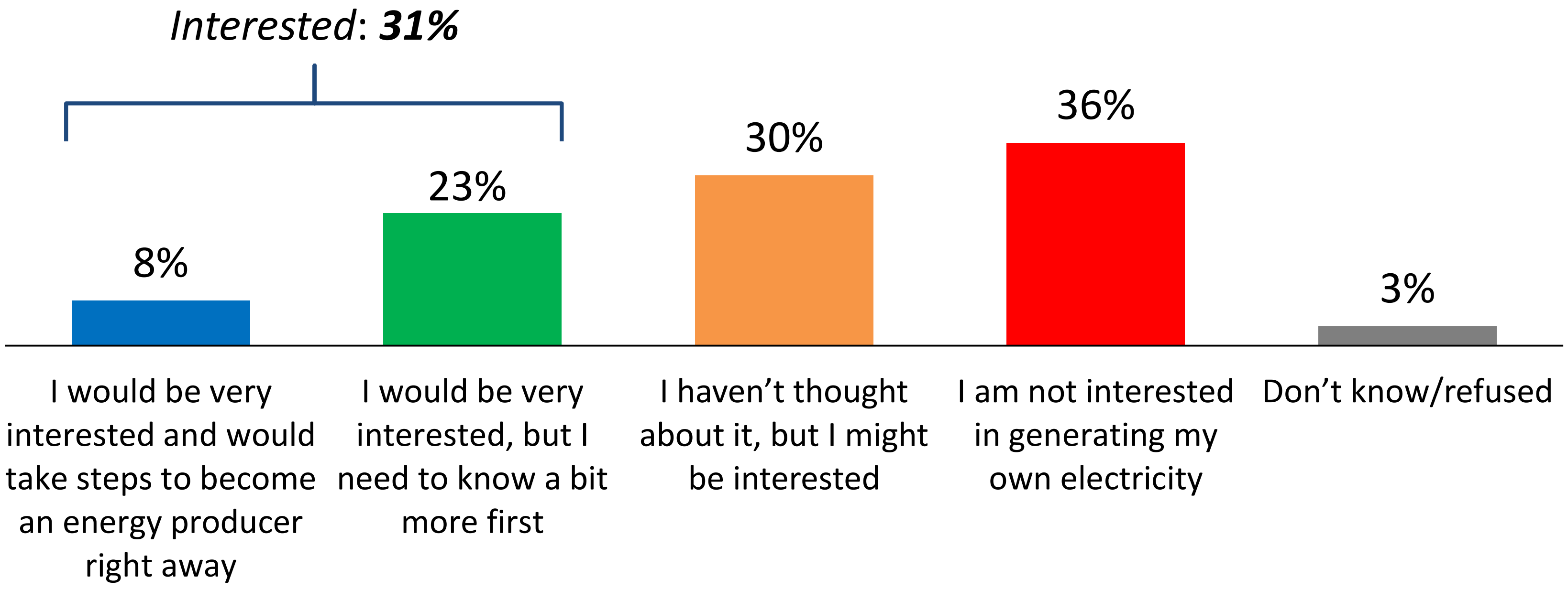


Future Interest in Self-Generation

Nearly one-third (31%) express future interest; highest among the middle aged

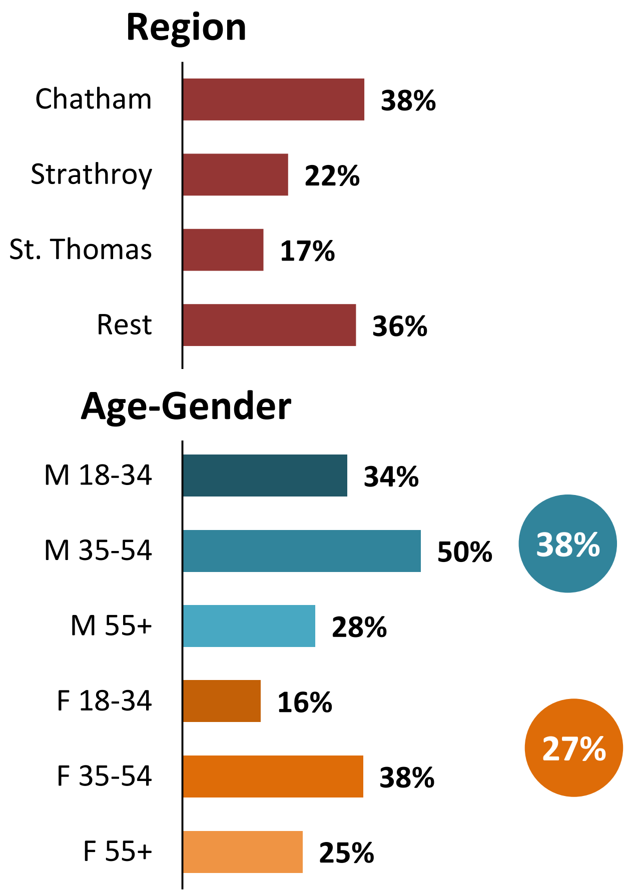
Q If, in the future, your housing situation would allow you to do it, how interested would you be in generating energy yourself? Would you say …

[asked of Entegrus customers who currently are not able to accommodate self-generation; n=326]



Segmentation

Respondents who say “Interested”



INNOVATIVE RESEARCH GROUP

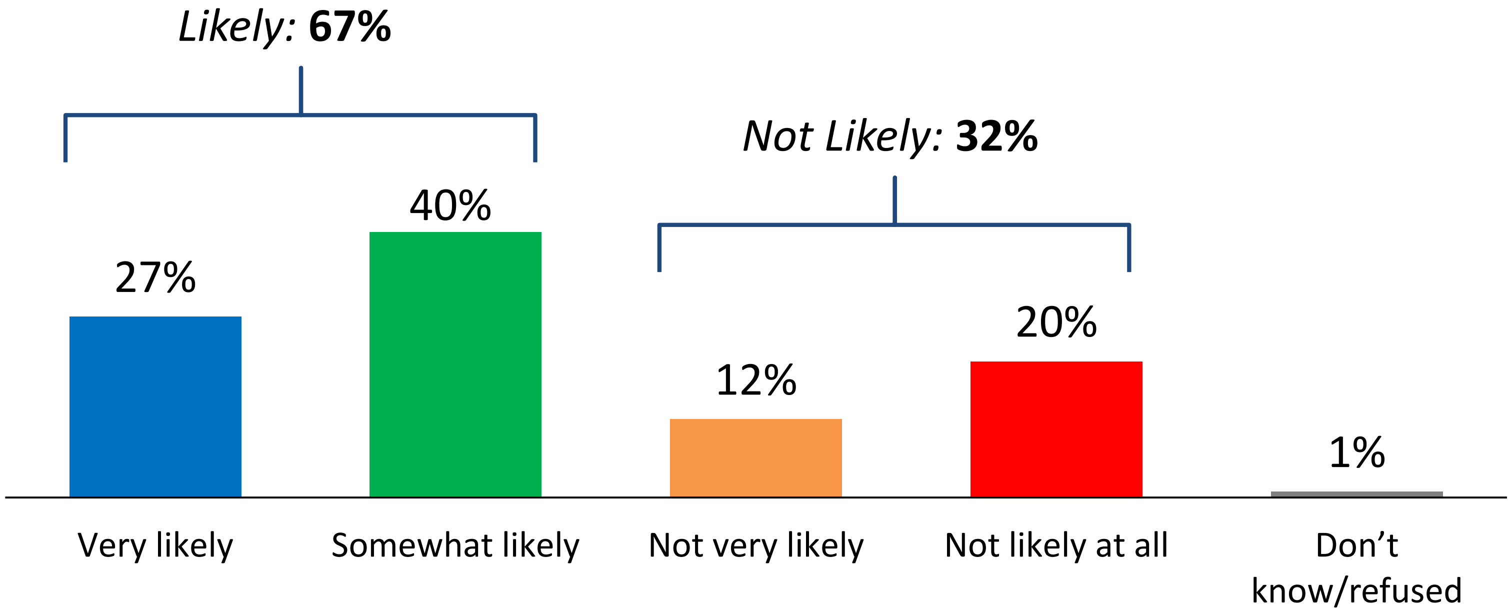
Entegrus Advice & Info

2-in-3 (67%) imagine they would turn to Entegrus; least likely with younger males

Q

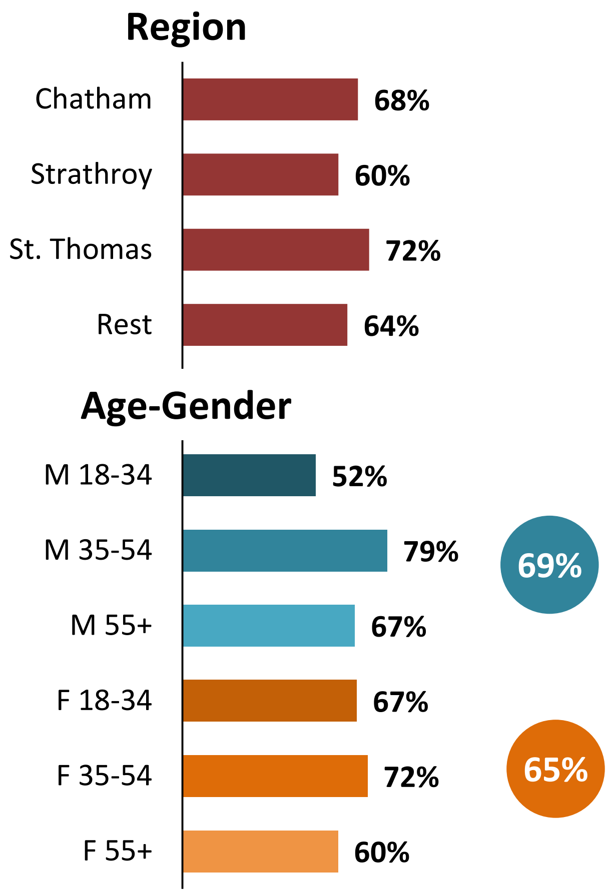
Again, imagine you were looking for advice or information on self-generating electricity, how likely would you be to turn to Entegrus for information and advice? Would you say …

[asked of all Entegrus customers; n=458]



Segmentation

Respondents who say "Likely"



Building Understanding.

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ATTACHMENT B

August 2021 Customer Engagement Results, Prepared by Innovative Research Group

Customer Engagement Overview

2021-2025 Investment Plan

August 2021

Prepared for:

Entegrus Powerlines Inc.
320 Queen Street
Chatham, Ontario
N7M 5K2

Customer Engagement Overview

August 2021

Confidentiality

This Overview and all the information and data contained within it may not be released, shared or otherwise disclosed to any other party, without the prior, written consent of Entegrus Powerlines Inc. ("Entegrus").

Acknowledgement

This Overview has been prepared by Innovative Research Group Inc. ("INNOVATIVE") for Entegrus Powerlines Inc. The conclusions drawn, and opinions expressed are those of the authors.

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Introduction

In April 2021, Innovative Research Group Inc. (INNOVATIVE) was engaged by Entegrus to assist in meeting the utility's customer engagement commitments under the Renewed Regulatory Framework for Electricity Distributors (RRFE).

Entegrus is in the process of finalizing its 2021-2025 Investment Plan and set out to gather meaningful feedback from its customers, specifically when it comes to their needs, the outcomes important to them, and their preferences regarding the pacing and scope of specific investments.

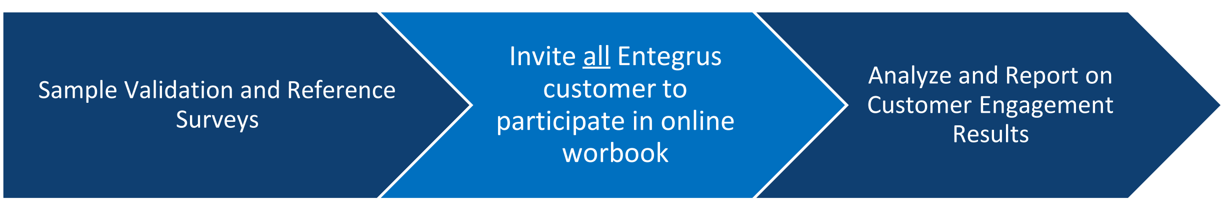
Over the course of this customer engagement, Entegrus gathered feedback from more than 4,000 residential, small business and commercial customers through its customer engagement efforts – that equates to close to 7% of its entire customer base.

Entegrus' 2021-2025 Investment Plan Customer Engagement was designed to build off the utility's past customer engagement efforts and an ongoing dialogue with customers.

Throughout this customer engagement, a concerted effort was made to ensure that all customers – regardless of where they live, where they operate, or how much electricity they use – had an equal opportunity to participate.

To ensure that the results of this customer engagement were representative of the broader Entegrus customer-base, a series of telephone "reference" surveys were deployed. These surveys, conducted amongst a random-sampling of residential and small business customers allowed Entegrus to better understand the demographic makeup of their customer base, allowing them to move to a purely online customer engagement methodology.

As a result of these carefully executed "reference" surveys, INNOVATIVE is confident that the results of this customer engagement are representative of Entegrus' actual customer base.



This document contains a summary of the results from each phase of this customer engagement, with a focus on the generalizable results from the online workbooks, which include more than 4,000 responses from Entegrus customers.

Customer Engagement Key Findings

Entegrus' customer engagement focused primarily on three key areas – customer education (i.e., getting customers up to speed on Entegrus and the state of the system), preferences related to potential investments to be made in the 2021-2025 period, and finally a conversation about priorities beyond 2025.

Overall, we see that most Entegrus customers are currently satisfied with the services that they receive from the utility, with only a very small proportion saying they are dissatisfied. Additionally, there are only very small differences between rate classes, as well as across the "legacy" Entegrus service territory versus St. Thomas.

Satisfaction with Services Provided by Entegrus

Summary of Findings *n-size shown for GS>50 customers due to insufficient sample size*	**Representative Workbook**		
	Residential	Small Business	GS >50 kW
Very satisfied	39%	39%	9/22
Somewhat satisfied	34%	36%	6/22
Neither satisfied nor dissatisfied	20%	19%	3/22
Somewhat dissatisfied	5%	4%	4/22
Very dissatisfied	2%	1%	0/22
Satisfied (Very + Somewhat)	**73%**	**75%**	**15/22**
Dissatisfied (Very + Somewhat)	**6%**	**5%**	**4/22**

When it comes to one of the engagement's objectives of customer engagement, we see that fewer than 1-in-5 customers are aware that the distribution charge for the typical bill is estimated to increase by approximately 2.05% for the next five years, until 2026.

Awareness of Distribution Charge Increase Over Next 5 Years

Summary of Findings *n-size shown for GS>50 customers due to insufficient sample size*	**Representative Workbook**		
	Residential	Small Business	GS >50 kW
Yes	18%	14%	3/22
No	78%	83%	18/22
Don't know	4%	2%	1/22

Making Choices: 2021-2025 Investment Plan

Again, a key priority of this customer engagement was to gather feedback on preferences related to potential investments to be made in the 2021-2025 period.

The workbook explored two specific potential investments – **line modernization and station decommissioning** and **implementing smart grid technology**.

Across both investments, a majority of customers support an approach that invests beyond what is currently included in the utility's "status quo" plans or what is currently included within current rates.

Overall, support for further investment in implementing smart grid technology is marginally higher than support for line modernization/station decommissioning, with 70% or more supporting investment in smart grid investments. A breakdown of these two investments is presented below.

Choice 1: Line Modernization and Station Decommissioning

As noted in the customer engagement workbook, Entegrus is planning to continue to target line modernization to allow removal of four low voltage stations between 2021-2025 (*status quo*). While a plurality of customers support the status quo, a majority of customers across rate classes support some level of accelerated investment to decommission more stations over the same period, knowing that it would cost them additional money starting in 2026.

Summary of Findings *n-size shown for GS>50 customers due to insufficient sample size*	**Representative Workbook**		
	Residential (Main / St. Thomas)	Small Business (Main / St. Thomas)	GS >50 kW (Combined)
Accelerated pace	31% / 30%	36% / 22%	4/22
Faster pace	26% / 27%	29% / 34%	9/22
Status quo	42% / 43%	36% / 45%	10/22

For residential customers, there is a strong correlation between a customer's likelihood to support an option that would result in increased rates and their individual financial circumstances. Those who say their electricity bill has a significant impact on their household finances are much more likely to support the *status quo* option presented. That said, 43% of customers whose bill has a significant impact on their finances still support some level of additional investment.

Choice 2: Implementing Smart Grid Technology

When it comes to implementing smart grid technology, a strong majority of all customers support some additional level of investment. 69% of residential and 72% of small business customers support investments in either medium or high-density intelligent switches in Chatham and St. Thomas.

Summary of Findings *n-size shown for GS>50 customers due to insufficient sample size*	Representative Workbook		
	Residential (Main / St. Thomas)	Small Business (Main / St. Thomas)	GS >50 kW (Combined)
Higher switch density	31% / 30%	27% / 23%	5/22
Medium switch density	37% / 42%	46% / 48%	11/22
Status quo	32% / 28%	27% / 29%	6/22

Again, when looking at residential customers who say their electricity bill has a significant impact on their household finances, we see that a majority of these customers also support some level of additional investment.

Planning for the Future Beyond 2025

Beyond asking customers to reflect on current investment priorities, the customer engagement workbooks also focused on gathering feedback on priorities beyond 2025.

General Priorities

Most customers feel that, above all else, Entegrus should focus on *delivering electricity at reasonable rates*. This is the number one priority across all three rate classes. Ranking just below rates, most customers feel that Entegrus should be focusing on *ensuring reliable electricity service*. In fact, reliability is the top priority for more than 1-in-5 residential and small business customers.

For commercial and industrial customers, 11 out of 22 rank reliability as their top priority, compared to 8 out of 22 who see rates as the most important.

The bottom line is such: customers don't expect Entegrus to just focus on one outcome. In fact, a majority of both residential and small business customers feel that, beyond rates and reliability, *providing quality customer service*, *ensuring the safety of electricity infrastructure*, and *helping customers with conservation and cost savings* are all very important.

Ranking General Priorities (share who select priority in top-3)

Summary of Findings *n-size shown for GS>50 customers due to insufficient sample size*	**Representative Workbook**		
	Residential	Small Business	GS >50 kW
Delivering electricity at reasonable rates	88%	90%	20/22
Ensuring reliable electricity service	74%	79%	19/22
Ensuring the safety of electricity infrastructure	34%	28%	4/22
Helping customers with conservation and cost savings	31%	28%	4/22
Providing quality customer service	26%	27%	5/22
Minimizing the impact on the environment	24%	23%	4/22
Enabling customer choice to access new electricity service	15%	17%	7/22
Proactively preparing for community growth	8%	10%	3/22

That said, among competing priorities, *price* and *reliability* clearly rise to the top, with *proactively preparing for community growth* and *enabling customer choice to access new electricity services (e.g. electricity storage and distributed generation, such as solar panels)* as the lowest priorities.

When looking to the future, it is clear the Entegrus customers expect their utility to focus on the core business of providing reliable electricity at reasonable rates.

Reliability Priorities

In addition to general priorities, customers were also asked about their preferences towards the various types of priorities that the utility could focus on to address system reliability.

When it comes to reliability outcomes, customer preference varies depending on rate class.

For residential customers, priorities are closely divided between the length and frequency of outages during severe weather events and reducing the overall number of outages.

While small business customers have the same three overall priorities, they place a stronger emphasis on reducing the overall number of outages lasting longer than one minute. More than 1-in-3 small business customers see reducing the number of outages as the top priority, compared to 1-in-4 residential customers.

For commercial and industrial customers, the top two priorities are related to the number of outages, both those lasting longer than one minute as well as those lasting less than one minute.

Ranking Reliability Priorities (share who select priority in top-3)

Summary of Findings *n-size shown for GS>50 customers due to insufficient sample size*	**Representative Workbook**		
	Residential	Small Business	GS >50 kW
Reducing the length of time to restore power during severe weather events	81%	68%	11/22
Reducing the # of outages during severe weather events	74%	68%	7/22
Reducing the overall # of outages lasting >1 minute	66%	74%	21/22
Reducing the overall length of day-to-day outages	43%	52%	11/22
Reducing the overall number of outages lasting less than one minute	36%	38%	16/22

It is also important to note that prior to ranking various priorities, including reliability, all customers were asked about their overall satisfaction with the services that they receive from Entegrus. Overall, customers are satisfied with Entegrus and preferences around reliability outcomes are generally dependent on individual circumstances, as well as rate class.

Altogether, residential and small business customers generally have the same priorities, while larger business customers are more concerned with the number of both momentary and extended outages.

Technology Priorities

Finally, customers were asked about their feelings towards various types of investments in technology. When it comes to investments in technology, there are essentially four tiers.

In the first tier, most customers, regardless of rate class, feel that Entegrus should be focusing on *new technology that can help find efficiencies*.

In the second tier, customers would like to see Entegrus focus on *new technology to improve reliability*, or *technology that can help customers better manage their usage*. In fact, a plurality of small business customers see technology to improve reliability as their top priority.

Grouped in the third tier is *technology to reduce environmental impacts* and *technology that enables customer choice.*

Finally, very few customers in any rate class see *new technologies that make it easier to interact with Entegrus* as a top priority. Again, most customers are largely satisfied with the services that they currently receive from Entegrus and would like to see focus placed on *rates* and *reliability* rather than customer service features.

Ranking Technology Priorities (share who select priority in top-3)

Summary of Findings *n-size shown for GS>50 customers due to insufficient sample size*	**Representative Workbook**		
	Residential	Small Business	GS >50 kW
New technology that can help Entegrus find efficiencies	85%	83%	18/22
New technology that would reduce the # and length of outages	64%	66%	19/22
New technology that can help customers better manage usage	62%	57%	16/22
New technology to reduce environmental impact	42%	43%	4/22
New technology that enables customer choice	31%	34%	7/22
New technologies that make it easier to interact with Entegrus	16%	19%	2/22

Workbook Diagnostics

It is important to understand whether customers had a favourable impression of the utility's efforts to gather feedback on its plans and if there are areas that could be improved upon for future engagements.

Overall Impression of Workbook

Overall, most customers across all three rate classes who completed the online workbook had a favourable impression of the exercise.

Summary of Findings *n-size shown for GS>50 customers due to insufficient sample size*	Representative Workbook		
	Residential	Small Business	GS >50 kW
Favourable (Very + Somewhat)	**86%**	**87%**	**20/22**
Unfavourable (Very + Somewhat)	**6%**	**9%**	**1/22**
Don't know	**7%**	**4%**	**1/22**

Volume of Information

Around 4-in-5 customers across all three rate classes who completed the online workbook felt that "just the right amount" of information was provided.

Summary of Findings *n-size shown for GS>50 customers due to insufficient sample size*	Representative Workbook		
	Residential	Small Business	GS >50 kW
Too little information	**4%**	**6%**	**0/22**
Just the right amount	**82%**	**79%**	**19/22**
Too much information	**14%**	**16%**	**3/22**

Strong overall impression of the workbook combined with the volume of information provided indicates that the workbook was positively perceived by nearly all customers and covered the information that was expected. In terms of planning future and ongoing customer engagement efforts, these workbook "diagnostics" indicate that Entegrus has found the right balance between the complexity and accessibility of the information provided.

Customer Engagement Approach

As mentioned earlier, Entegrus and INNOVATIVE developed and executed a customer engagement approach that focused on building off existing and ongoing customer feedback, as well as placing emphasis on the representative nature of the feedback. This approach was intended to both provide Entegrus planners with actionable customer feedback for the current 2021-2025 Investment Plan, as well as begin providing valuable insights for future planning.

While detailed methodologies are contained within the full report (as appendices), this section will highlight some of the key methodological elements of Entegrus' 2021-2025 Investment Plan customer engagement approach.

Summary of Entegrus' Customer Engagement Results

Customer Group	Methodology	Unweighted Sample Size	Field Dates
Residential	Telephone	n=409	June 3 – 25, 2021
Small Business	Telephone	n=103	June 3 – 25, 2021
Sample Validation and Telephone "Reference" Surveys: n=512			
Residential	Online Voluntary	n=8	June 30 – July 20, 2021
Small Business	Online Voluntary	--	June 30 – July 20, 2021
Residential	Online Representative	n=3,856	June 21 – July 20, 2021
Small Business	Online Representative	n=160	June 21 – July 20, 2021
Commercial (GS > 50 kW)	Online Representative	n=22	June 21 – July 20, 2021
Online Workbooks: n=4,046			
Total Customers Engaged as Part of Entegrus' Customer Engagement: 4,558			

The representative stream of the online workbook accounts for 15.5% of all customers with an email address on file (25,991).

Sample Validation and Telephone "Reference" Surveys

In order to support an online-centric approach to engagement, a key objective of *Sample Validation and Telephone "Reference" Surveys* was to develop a detailed understanding of the differences between customers with known email addresses (email sample) and the broader customer base (telephone sample).

INNOVATIVE was able to confidently ascertain the potential differences between these two sample groups by first fielding parallel questions in both online and telephone methodologies (see **Appendix 1.0** for details) and then undertaking a rigorous "sample validation" process.

This sample validation process included comparing known variables (i.e. region and electricity consumption) across the overall population to the sample of that of the population with email addresses. Through this process, INNOVATIVE was able to conclude that no group is substantially underrepresented in the email sample.

Email Sample versus Broader Sample

Overall, Entegrus has obtained email addresses for roughly 50% of all residential and small business customers, and 76% of GS>50 kW customers. This email coverage was critical in facilitating a predominantly “online” approach in Phase II of the engagement.

Rate Class	Full Population	Email Sample	Coverage
Residential	55,725 records	27,493 records	**49%**
GS<50	5,798 records	3,232 records	**56%**
GS>50	570 records	432 records	**76%**

Average consumption is higher among customers with emails than among the whole population. The final data is weighted by consumption quartile to account for this.

Rate Class	Full Population	Email Sample	Coverage
Residential	646 kWh	695 kWh	+7%
GS<50	2,091 kWh	2,347 kWh	+12%
GS>50	88,080 kWh	103,561 kWh	+18%

In addition to overall email coverage of around 50%, INNOVATIVE’s comprehensive sample validation process confirmed that, based on known variables, there is no one sample group that is substantially over or underrepresented in the email sample.

Regional Segmentation

Using the first three digits of postal codes (FSAs), customers are grouped into four unique regions. There is no systematic pattern of regions being over or underrepresented by email.

Dividing Entegrus’ service territory into distinct regions allows INNOVATIVE to ensure that no one area is over or underrepresented in the survey sample. Regions were determined based on population density and further analyzed based on the number of residential and small business customers in each region. For detailed regional analysis, please refer to **Appendix 1.0**.

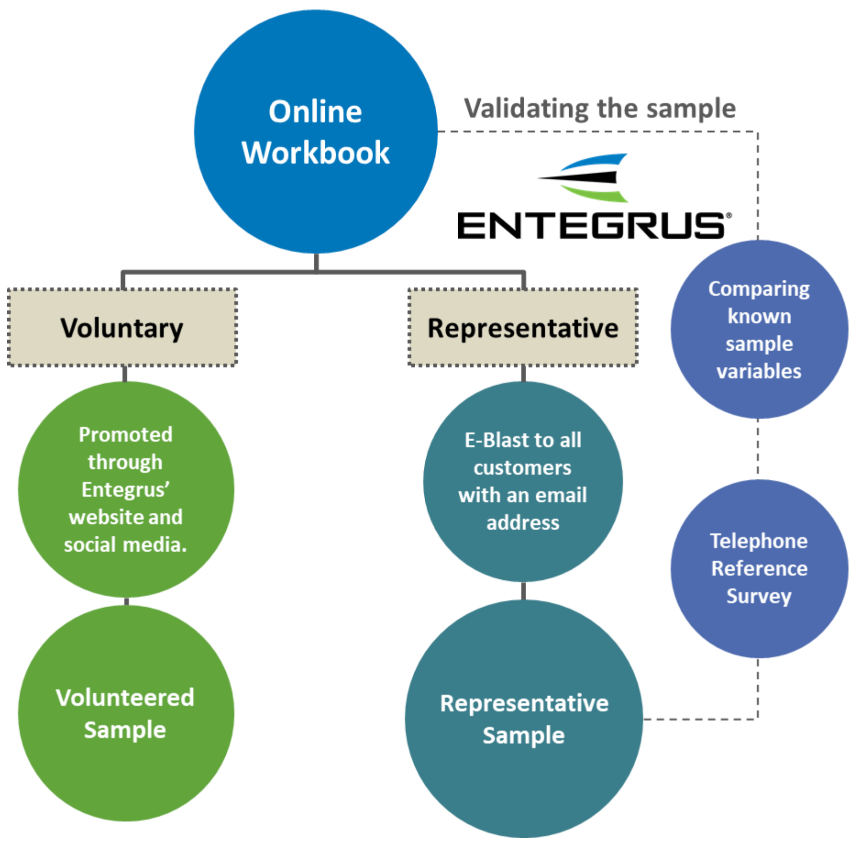
Based on the comparative results of the first phase of the customer engagement, INNOVATIVE is confident that the residential and small business online workbooks are representative of Entegrus’ actual customer base.

Online Workbooks

Following the rigorous sample validation, Entegrus and INNOVATIVE collectively developed an online workbook which was subsequently sent to all customers with an email address on record.

The residential and small business online workbooks featured two input streams:

1. The **representative stream** ensured a representative sample of customers was engaged, allowing for the generalizability of findings.
2. The **voluntary stream** created an open process that allowed anyone who wanted to be heard an opportunity to participate, including those who have not provided the utility with an email address.



With a concerted effort to have customers enter the workbook(s) through the representative stream, only seven residential customers and no small business customers completed the workbook via the voluntary stream.

Similarly, all GS>50 kW customers with an email address on file (recall, there was more than 75% email coverage), were invited to participate in the online workbook, accessible through a unique URL sent directly to customers. There was no voluntary stream for this version of the workbook.

In the **representative stream**, each customer received a unique URL that could be linked back to their annual consumption, region and rate class. In total, the workbook was sent to 25,991 customers through an e-blast from INNOVATIVE.

- 24,133 residential customers;
- 1,597 small business customers; and
- 261 GS > 50 kW customers

Beyond the initial e-blast, customers in all rate classes were sent multiple reminder emails to encourage participation. Additionally, Entegrus placed follow-up telephone calls with GS > 50 kW to encourage survey participation.

For residential and small business rate classes, responses from the representative stream were weighted by region and usage to ensure the responses were representative of the broader customer base. Due to the small sample size amongst GS > 50 kW customers, a decision was made to not weight data and present results in terms of sample size (n-size) rather than percentages. As a result, GS > 50 kW results should be treated as more directional than the other findings.

The **voluntary workbook** was promoted through Entegrus' website and social media.

Because INNOVATIVE cannot definitively link those who completed the online workbook through the voluntary stream, this portion of the sample cannot be deemed representative of the broader Entegrus customer base.

Reporting Timelines

All results from the residential, small business, and commercial & industrial workbooks were shared, in draft, with Entegrus on July 22nd, 2021. This overview document was later shared on August 3rd, 2021.

Throughout the engagement, INNOVATIVE regularly provided Entegrus staff with progress updates, including preliminary results, by way of telephone.

Appendix 1.0

INNOVATIVE
RESEARCH GROUP

2021-2025 Customer Engagement

Online Workbook Report

ENTEGRUS®

July 2021

Table of Contents

Introduction

Representative Online Workbook

Entegrus 2021-2025 Distribution System Plan Customer Engagement

Innovative Research Group Inc. (INNOVATIVE) was engaged by Entegrus Powerlines Inc. to assist in meeting its customer engagement commitments under the Renewed Regulatory Framework for Electricity Distributors and Chapter 5 Filing Requirements. The information contained within this report is the result of a series of customer engagements.

Setting the Context

Entegrus' 2021-2025 Investment Plan Customer Engagement was designed to build off the utility's past customer engagement efforts and an ongoing dialogue with customers.

Entegrus is in the process of finalizing its 2021-2025 Investment Plan. This report covers the results of a series of customer "workbook" surveys that were used to gather customer preferences on program expenditures both in the upcoming five-year period, as well as looking ahead to the future. This "workbook" survey was deployed to all customers with an email address, as well as promoted through a generic link on Entegrus' website and social media platforms.

In order to ensure that the results of these online workbooks was representative of the broader Entegrus customer-base, a series of telephone "reference" surveys were also deployed as part of this engagement. These surveys, conducted amongst a random-sampling of residential and small business customers allowed Entegrus to move to an online methodology to conduct customer feedback, and also helped establish baselines on customer demographics.

Determining the baseline and understanding the difference between customers with known email addresses (email sample), and the broader customer base (telephone sample), was a critical step to migrate to a representative online survey methodology.

Interpreting the Results

For residential and small business (GS<50kW), responses were weighted by region and electricity usage to ensure the responses were representative of the broader customer base. Based on the comparative results of the telephone reference surveys, INNOVATIVE is confident that the residential and small business online workbook results contained within this report are representative of Entegrus' actual customer base.

Introduction

Consumption and Environmental Control Segmentation

Region and Environmental Control Segmentation

In addition to segmenting customers based on whether they not they are part of the legacy Entegrus region, it is important to be able to identify factors that may influence customer preferences and distinguish between what is within, and what is outside of Entegrus' influence or control.

Perceptions of LDCs often tend to move with general perceptions of the sector rather than in response to the local utility.

Throughout this report, environmental control questions are used to help distinguish whether opinions regarding Entegrus' plans are general perceptions or preferences specific to Entegrus.

Segmentation has been used throughout the residential and small business sections of this report to look beyond the topline numbers to analyze the results for key segments:

1. **Region:** Using customer data provided by Entegrus, we split customers into two regions for analysis; legacy Entegrus (all customers outside of St.Thomas), and St. Thomas.

2. **Bill Impact on Finances**: Segmentation that INNOVATIVE refers to as "Bill Impact on Finances" is provided. This segment is determined based on the extent to which customers agree with the following statement:

    a) <u>Residential</u>: *The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.*

    b) <u>Small Business</u>*: The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.*

3. **Vulnerable Consumers**: For residential customers, using a combination of household size and combined household income, the residential portion of this report identifies customers who would be eligible for financial assistance programs. The methodology used to calculate this segmentation is based on the OEB's *Low-income Energy Assistance Program* (LEAP) criteria.

Understanding Segmentation

Segmentation is an effective way of looking past the topline numbers and digging deeper into the needs and preferences of the customer segments above. For instance, while it is valuable to know that, overall, 73% of residential customers are satisfied with Entegrus, it is also important to understand whether satisfaction differs based on region or based on perceptions that may be outside of the utility's influence or control. Segmentation allows readers of this report to quickly look past the topline numbers and understand how various segments of customers feel about various issues.

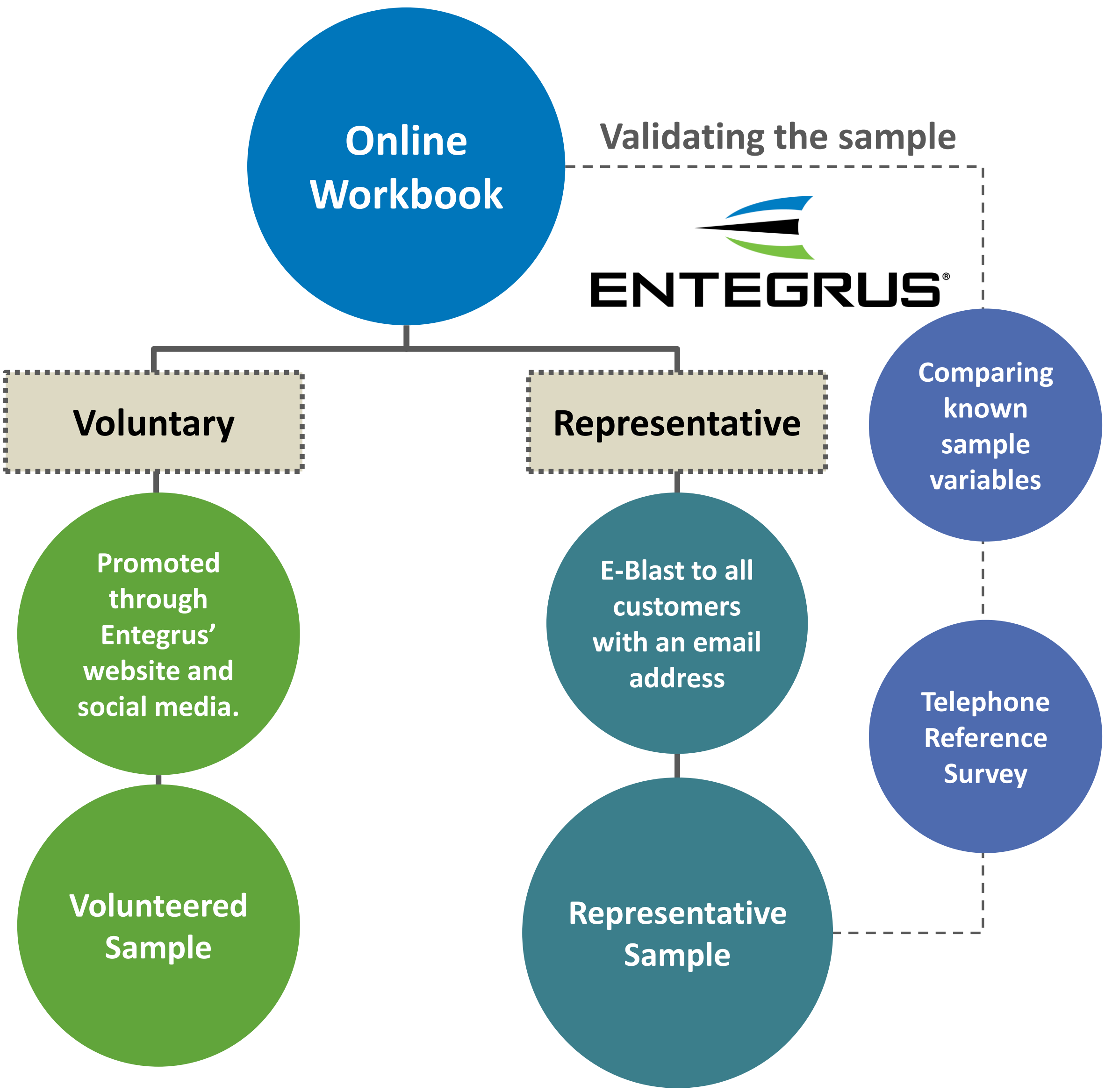
Sample Validation

Overall Approach

Entegrus' residential and small business customer engagement workbooks featured two streams – *representative* and *voluntary*.

The voluntary stream was an open process that allowed anyone who wanted to be heard an opportunity to express themselves, including those who have not provided the utility with an email address. *Those results are summarized in Entegrus' Customer Engagement Overview Report.*

The representative stream ensures a representative sample of customers are engaged, allowing for the generalizability of findings. ***This is a report of those responses.***



Sample Validation

Email Sample vs. Broader Sample

Comparing the overall population to the sample of that population with email addresses across known variables, it is apparent that no group is substantially underrepresented in the email sample.

Overall Coverage

Coverage overall is high but slightly lower among residential customers at 49%. Coverage is highest among large GS customers at 76%.

Rate Class	Full Population	Email Sample	Coverage
Residential	55,725 records	27,493 records	**49%**
GS<50	5,798 records	3,232 records	**56%**
GS>50	570 records	432 records	**76%**

Average Consumption

Average consumption is higher among customers with emails than among the whole population. The final data is weighted by consumption quartile to account for this.

Rate Class	Full Population	Email Sample	Difference
Residential	646 kWh	695 kWh	**+7%**
GS<50	2,091 kWh	2,347 kWh	**+12%**
GS>50	88,080 kWh	103,561 kWh	**+18%**

Sample Validation

Email Sample vs. Broader Sample

Comparing the overall population to the sample of that population with email addresses across known variables, it is apparent that no group is substantially underrepresented in the email sample.

Using the first three digits of postal codes (FSAs), customers are grouped into four unique regions. **There is no systematic pattern of regions being over or underrepresented by email.**

Dividing Entegrus' service territory into distinct regions allows INNOVATIVE to ensure that no one area is over or underrepresented in the survey sample. Regions were determined based on population density and further analyzed based on the number of residential and small business customers in each region.

Rate Class	Region	Share of full population	Share of email sample	Difference
Residential	Chatham	31%	37%	**+6%**
	Strathroy	11%	10%	**-1%**
	St. Thomas	30%	24%	**-6%**
	Rest	28%	29%	**+1%**
Small Business	Chatham	29%	33%	**+4%**
	Strathroy	10%	9%	**-1%**
	St. Thomas	30%	25%	**-6%**
	Rest	31%	34%	**+3%**
GS>50	Chatham	35%	36%	**+2%**
	Strathroy	12%	11%	**-1%**
	St. Thomas	24%	22%	**-3%**
	Rest	29%	31%	**+2%**

INNOVATIVE RESEARCH GROUP

Telephone versus Online

Overview and Demographics

Residential - Comparing Telephone vs. Online: The core objective of the telephone reference survey was to establish a baseline among the broader customer base to mitigate any potential differences in the online workbook sample. Comparing the results from telephone survey versus the online workbook showed that:

1. Overall, the telephone and online samples look very similar on key demographics including gender, age, household size, and household income.

2. The online workbook sample is more likely to agree that their electricity bill has a significant impact on their finances. As such, it appears that the online workbook sample is slightly more vulnerable from a financial perspective than the telephone survey.

3. While overall familiarity with Entegrus is very similar between the surveys, satisfaction with Entegrus is higher among the telephone sample. This is typical when comparing telephone to online results on measures of satisfaction.

The tables below summarize the telephone and online workbook results.

Gender	Telephone Reference Survey	Online Workbook
A man	47%	44%
A woman	53%	53%
Prefer to self describe	-	<1%
Prefer not to say	-	3%

Age	Telephone Reference Survey	Online Workbook
18-24	3%	1%
25-34	12%	10%
35-44	17%	16%
45-54	15%	15%
55-64	21%	24%
65 or older	31%	32%
Prefer not to say	1%	2%

Note: sums added before rounding.

Telephone versus Online

Household Size and Income

The tables below summarize the telephone and online workbook results for two key demographics – household size and household income.

Household Size	Telephone Reference Survey	Online Workbook
Single person household	23%	18%
2 people	44%	46%
3 people	15%	14%
4 people	12%	13%
5 people	5%	5%
6 people	2%	2%
7 or more people	-	1%
Prefer not to say	1%	1%

Household Income	Telephone Reference Survey	Online Workbook
Less than $28,000	14%	10%
$28,000 to less than $39,000	9%	10%
$39,000 to less than $48,000	12%	9%
$48,000 to less than $52,000	7%	7%
$52,000 or more	43%	40%
Prefer not to say/Don’t know	15%	24%

Telephone versus Online

Attitudes Towards Electricity

The tables below summarize the telephone and online workbook results for two key "environmental controls" – bill impact on household finances and general perceptions of Ontario's electricity sector.

The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.	Telephone Reference Survey	Online Workbook
Strongly agree	25%	28%
Somewhat agree	31%	39%
Somewhat disagree	21%	17%
Strongly disagree	20%	12%
Don't know/No opinion	3%	4%
Agree (Strongly + Somewhat)	**56%**	**67%**
Disagree (Strongly + Somewhat)	**41%**	**29%**

Customers are well served by the electricity system in Ontario.	Telephone Reference Survey	Online Workbook
Strongly agree	32%	25%
Somewhat agree	49%	51%
Somewhat disagree	6%	12%
Strongly disagree	3%	6%
Don't know/No opinion	9%	7%
Agree (Strongly + Somewhat)	**81%**	**75%**
Disagree (Strongly + Somewhat)	**9%**	**18%**

Telephone versus Online

Number of Outages and Bill Familiarity

Residential

The tables below summarize the telephone and online workbook results for the number of outages customers' have experienced in the past 12 months and familiarity with the amount of the bill that goes to Entegrus.

Number of Outages in Past Year	Telephone Reference Survey	Online Workbook
No outages	33%	16%
1 outage	18%	29%
2 outages	17%	26%
3 or more outages	26%	21%
Don't know	6%	8%

Bill Familiarity	Telephone Reference Survey	Online Workbook
Very familiar	11%	13%
Somewhat familiar	22%	34%
Not familiar	56%	52%
Don't know	11%	1%
Familiar (Very + Somewhat)	**33%**	**47%**

Note: sums added before rounding.

Telephone versus Online

Entegrus Familiarity and Satisfaction

Residential

The tables below summarize the telephone and online workbook results for familiarity with Entegrus, and satisfaction with services received from Entegrus.

Familiarity with Entegrus	Telephone Reference Survey	Online Workbook
Very familiar	21%	13%
Somewhat familiar	55%	61%
Not familiar	17%	26%
Don’t know	7%	1%
Familiar (Very + Somewhat)	**76%**	**73%**

Satisfaction with Entegrus	Telephone Reference Survey	Online Workbook
Very satisfied	49%	39%
Somewhat satisfied	37%	34%
Neither satisfied nor dissatisfied	6%	20%
Somewhat dissatisfied	5%	5%
Very dissatisfied	1%	2%
Don’t know	2%	1%
Satisfied (Very + Somewhat)	**86%**	**73%**
Dissatisfied (Very + Somewhat)	**6%**	**6%**

Note: sums added before rounding.

Telephone versus Online

Overview and Number of Outages

Small Business - Comparing Telephone vs. Online: The core objective of the telephone reference survey was to establish a baseline among the broader customer base to mitigate any potential differences in the online workbook sample. Comparing the results from telephone survey versus the online workbook showed that:

1. Core firmographics like industry and number of employees are quite consistent across samples with a plurality reporting being in the commercial industry.

2. As with the residential results, online respondents are more likely to report a significant bill impact than telephone respondents. At the same time, sector confidence is consistent across the two small business samples.

3. Again, consistent with the residential results, telephone respondents are more likely to say they are satisfied with Entegrus than online respondents. This is a consistent finding when comparing satisfaction across telephone and online studies.

The tables below summarize the telephone and online workbook results.

Industry	Telephone Reference Survey	Online Workbook
Commercial	37%	38%
Manufacturing/Industrial	6%	7%
Hospitality	4%	2%
Restaurant/Tavern	10%	3%
Retail	18%	18%
Real Estate	15%	16%
Other	10%	16%
Don't know	1%	0%

Number of Employees	Telephone Reference Survey	Online Workbook
1 person	9%	10%
2 to 5 people	47%	44%
6 to 10 people	22%	23%
11 to 25 people	10%	15%
26 to 50 people	6%	5%
More than 50 people	3%	3%
Prefer not to say	3%	<1%

Note: sums added before rounding.

Telephone versus Online

Attitudes Towards Electricity

The tables below summarize the telephone and online workbook results for two key "environmental controls" – bill impact on organization's bottom line and general perceptions of Ontario's electricity sector.

The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.	Telephone Reference Survey	Online Workbook
Strongly agree	25%	32%
Somewhat agree	34%	35%
Somewhat disagree	19%	18%
Strongly disagree	11%	9%
Don't know/No opinion	11%	6%
Agree (Strongly + Somewhat)	**59%**	**67%**
Disagree (Strongly + Somewhat)	**30%**	**27%**

Customers are well served by the electricity system in Ontario.	Telephone Reference Survey	Online Workbook
Strongly agree	32%	24%
Somewhat agree	38%	52%
Somewhat disagree	8%	15%
Strongly disagree	7%	4%
Don't know/No opinion	16%	4%
Agree (Strongly + Somewhat)	**70%**	**76%**
Disagree (Strongly + Somewhat)	**15%**	**20%**

Telephone versus Online

Number of Outages and Bill Familiarity

The tables below summarize the telephone and online workbook results for the number of outages customers' have experienced in the past 12 months and familiarity with the amount of the bill that goes to Entegrus.

Number of Outages in Past Year	Telephone Reference Survey	Online Workbook
No outages	43%	24%
1 outage	13%	24%
2 outages	17%	26%
3 or more outages	11%	9%
Don't know	14%	17%

Bill Familiarity	Telephone Reference Survey	Online Workbook
Very familiar	7%	12%
Somewhat familiar	26%	41%
Not familiar	53%	46%
Don't know	14%	1%
Familiar (Very + Somewhat)	**32%**	**53%**

Note: sums added before rounding.

Telephone versus Online

Entegrus Familiarity and Satisfaction

The tables below summarize the telephone and online workbook results for familiarity with Entegrus, and satisfaction with services received from Entegrus.

Familiarity with Entegrus	Telephone Reference Survey	Online Workbook
Very familiar	20%	19%
Somewhat familiar	50%	64%
Not familiar	19%	16%
Don’t know	10%	<1%
Familiar (Very + Somewhat)	**71%**	**84%**

Satisfaction with Entegrus	Telephone Reference Survey	Online Workbook
Very satisfied	46%	39%
Somewhat satisfied	42%	36%
Neither satisfied nor dissatisfied	3%	19%
Somewhat dissatisfied	2%	4%
Very dissatisfied	4%	1%
Don’t know	3%	0%
Satisfied (Very + Somewhat)	**88%**	**75%**
Dissatisfied (Very + Somewhat)	**6%**	**5%**

Note: sums added before rounding.

Residential Customers

Online Workbook Results

Online Workbook
Survey Design & Methodology

INNOVATIVE was engaged by Entegrus Powerlines Inc. to gather input on their proposed distribution system plan. Throughout this report, actual pages of the workbook that customers completed are included in the order that they were seen and are indicated by a watermark that says "workbook page".

Field Dates & Workbook Delivery

The **Residential Online Workbook** was sent to all Entegrus residential customers who have provided the utility with an email address. Customers had an opportunity to complete the workbook between **June 21st and July 20th, 2021**.

Each customer received a unique URL that could be linked back to their annual consumption, region and rate class.

In total, the residential workbook was sent to **24,133** customers via e-blast from INNOVATIVE. Reminder emails were sent weekly to those who had not yet completed the workbook.

Residential Online Workbook Completes

A total of **3,856** (unweighted) Entegrus residential customers completed the online workbook via a unique URL.

Sample Weighting

The residential online workbook sample has been weighted proportionately by consumption quartiles and region in order to be representative of the broader Entegrus service territory.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by quartile and region.

	Consumption Quartiles				Total
	First	Second	Third	Fourth	
Chatham	208 (286)	355 (294)	353 (294)	347 (290)	1263 (1163)
St. Thomas	232 (273)	330 (307)	307 (290)	241 (270)	1110 (1141)
Strathroy	67 (131)	98 (92)	126 (103)	123 (107)	414 (433)
Rest	184 (260)	277 (257)	303 (263)	304 (282)	1068 (1062)
Total	691 (950)	1060 (950)	1089 (950)	1015 (950)	3856 (3800)

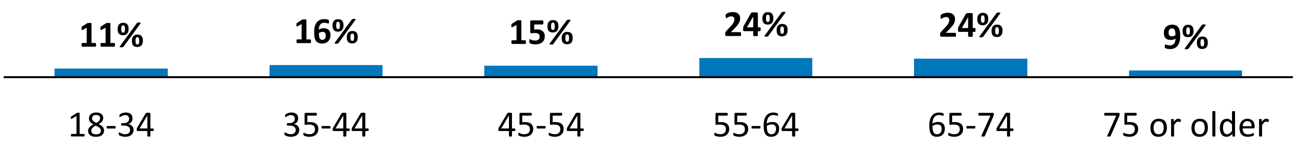
Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Online Workbook

Demographic breakdown

Residential

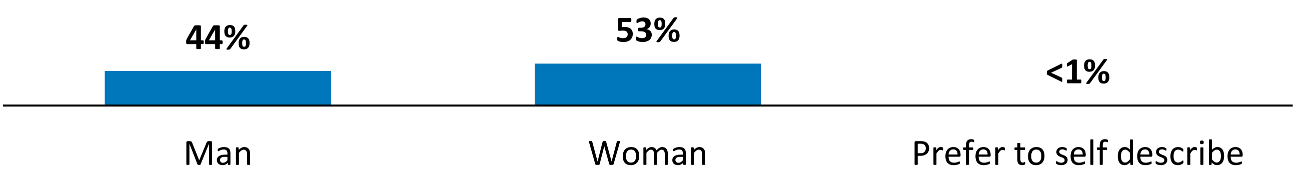
Q Age



"Prefer not to say"(2%) not shown.

n=3,800

Q Gender



"Prefer not to say"(3%) not shown.

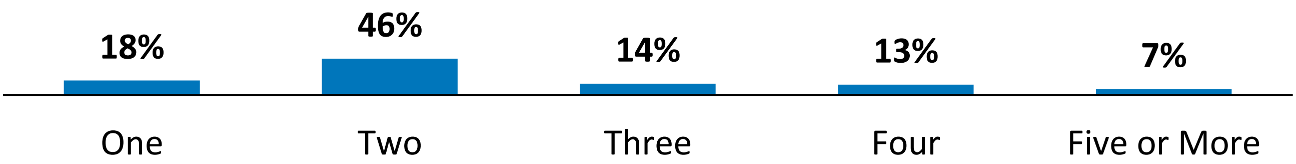
n=3,800

Online Workbook

Demographic breakdown

Residential

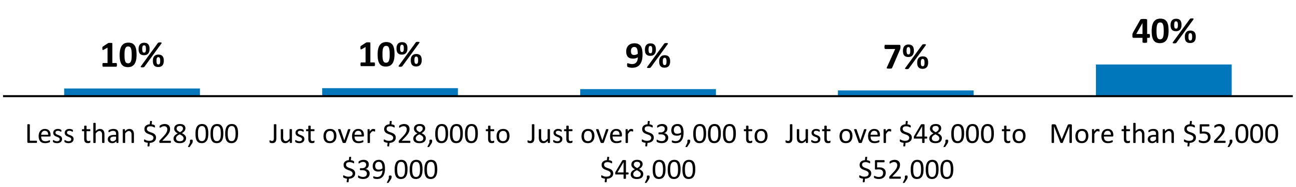
Q Household Size



"Prefer not to say" (1%) not shown.

n=3,800

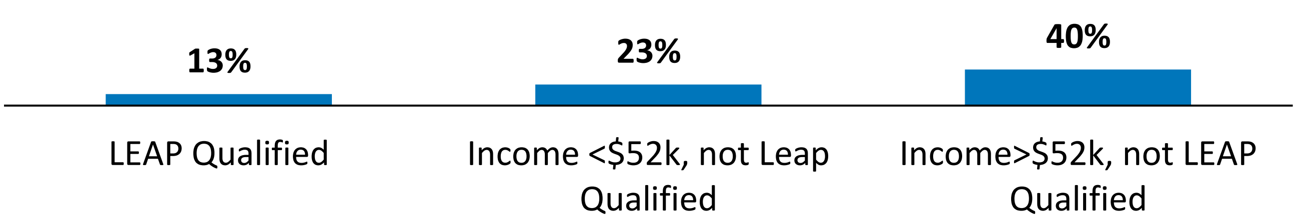
Q After Tax Household Income



"Prefer not to say" (24%) not shown.

n=3,800

Q **LEAP Qualification** (calculated based on household size and income)



"Prefer not to say" (24%) not shown.

n=3,800

INNOVATIVE RESEARCH GROUP

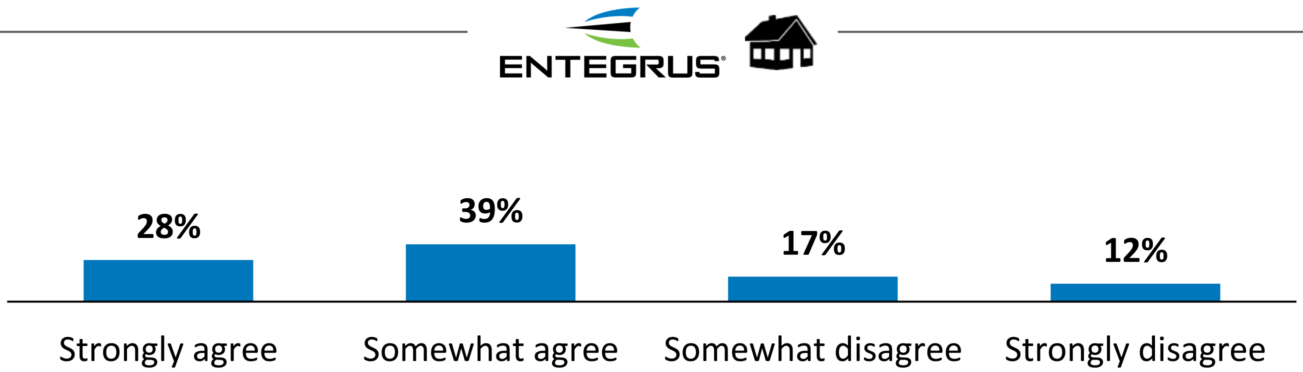
Online Workbook

Environmental Controls

Residential

Now we would like to shift the focus, and ask you some general questions about the electricity system in Ontario. To what extent do you agree or disagree with the following statements?

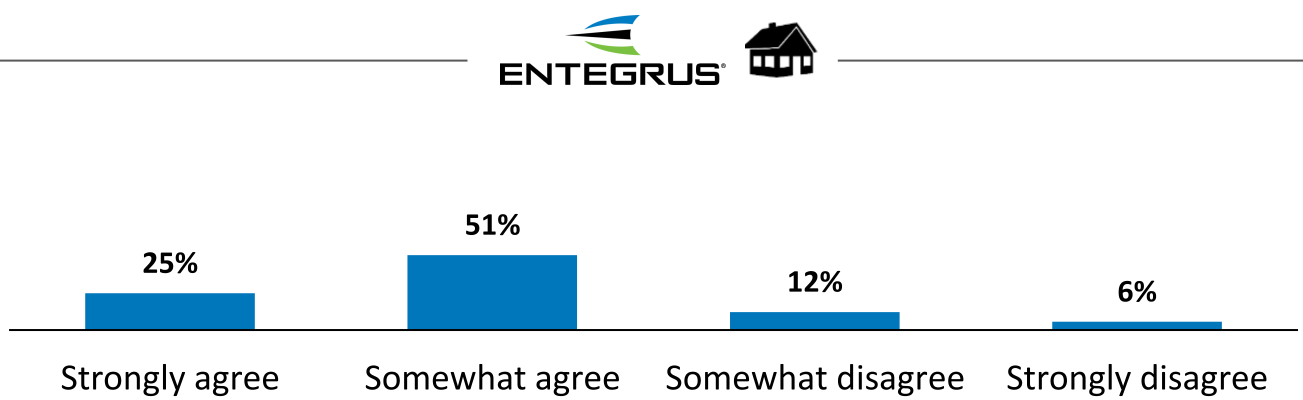
Q The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.



"Don't know/no opinion" (4%) not shown.

n=3,800

Q Customers are well served by the electricity system in Ontario.



"Don't know/no opinion" (7%) not shown.

n=3,800

Online Workbook

Planning for the Future: 2021-2025 Investment Plan

Residential

About this Customer Engagement

Welcome to Entegrus' customer engagement survey!

As Entegrus plans for the future, they need your input on choices that will impact the services you receive and the rates that you pay for the delivery of electricity.

- **Entegrus is currently in the process of developing its investment plan for 2021 to 2025.** This plan will determine the investments Entegrus makes in equipment and infrastructure, the services it provides, and the rates you pay.
- **Entegrus is now looking for your input on its draft plan** to ensure it is making spending decisions that matter to you, the customer.
- **Later this year, Entegrus will provide its investment plan** to the public regulator, the Ontario Energy Board (OEB) for its scrutiny.
- **Between now and 2025, Entegrus will execute its 2021 to 2025 investment plan,** ultimately, impacting the services you receive and the delivery of electricity throughout the communities that Entegrus serves.

This survey will take approximately 20-30 minutes to complete and can be done so at your convenience. Once you begin, your progress will be saved, and you can return to the customer engagement at any time.

All individual responses will be kept confidential. Innovative Research Group (INNOVATIVE), an independent research company, has been hired to gather your feedback.

Those who complete the questions that follow will be invited to enter a draw to win one of two (2) $500 prepaid VISA gift cards.

Electricity 101

Who is Entegrus?

Entegrus is a regulated electricity distributor that owns and operates distribution systems serving 17 communities in Southwestern Ontario, stretching between Wheatley (to the west), St. Thomas (to the east), Parkhill (to the north) and Lake Erie (to the south). The Entegrus service territory covers an area of approximately 5,600 square kilometres and the distance and time between Parkhill and Wheatley is about 170km. or a two-hour drive.

The utility's service territory today is a product of multiple mergers and acquisitions of previously independent distributors dating back to the late-1990s. The electrification of Southwestern Ontario dates back to the early 1900s. Most of the initial system expansion in the Entegrus communities occurred between 1950 and 1970. Some of the equipment in Entegrus' distribution system is more than 50 years old.

The most recent and significant addition to Entegrus' asset base is the amalgamation of Entegrus' assets with those of the former St. Thomas Energy, approved by the OEB on March 15, 2018.

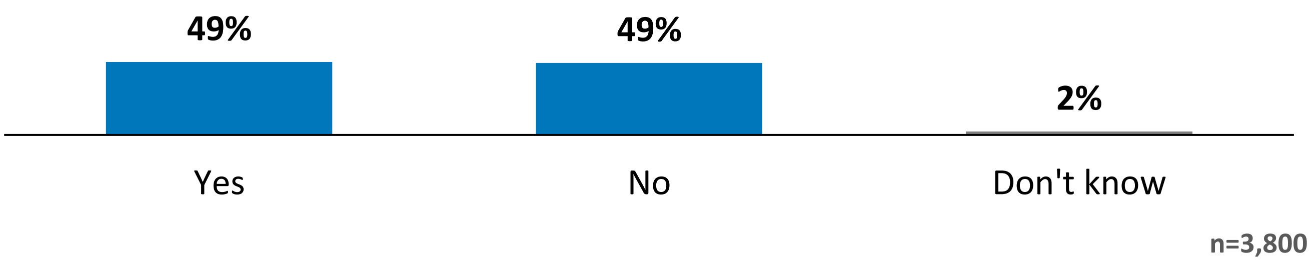
Online Workbook

Familiarity with St.Thomas Merger

Residential

Q Had you heard of the Entegrus merger with St. Thomas Energy before this survey?

ENTEGRUS



	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No Impact
Yes	37%	77%	44%	49%	54%
No	60%	21%	53%	49%	44%
Don’t know	2%	2%	2%	2%	2%

Electricity 101

What is Entegrus’ role in Ontario’s electricity system?

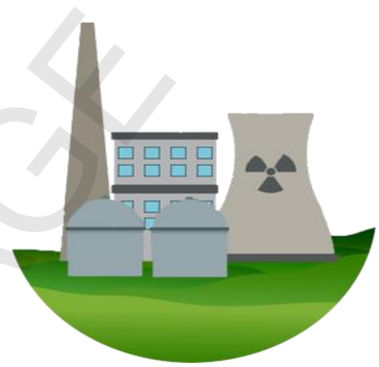
Ontario's electricity system is owned and operated by public, private and municipal corporations across the province. It is made up of three key components: **generation**, **transmission** and **distribution**.

Generation

Where electricity comes from

Ontario gets its electricity from a mix of energy sources. About half comes from nuclear power. The remainder comes from a mix of hydroelectric, natural gas, wind and solar.

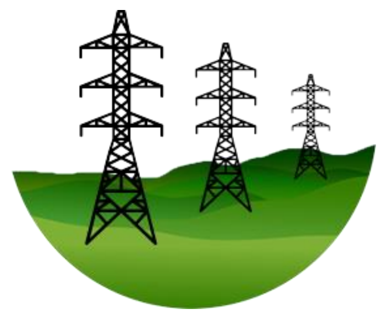
Ontario Power Generation, a government-owned company, generates almost half of Ontario’s electricity. The other half comes from multiple generators who have contracts with the grid operator to provide power from a variety of sources.



Transmission

How electricity travels across Ontario

Once electricity is generated, it must be transported to urban and rural areas across the province. This happens by way of high voltage transmission lines that serve as highways for electricity. The province has more than 30,000 kilometres of transmission lines, most of which is owned and operated by Hydro One.

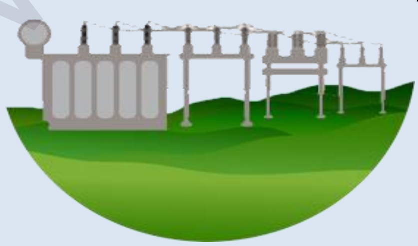


Local Distribution

How electricity is delivered to the end-consumer

Entegrus is responsible for the last step of the journey: distributing electricity to customers through its distribution system.

- Entegrus manages all aspects of the electricity distribution business throughout 17 communities in Southwestern Ontario and is regulated by the Ontario Energy Board (OEB).
- Entegrus is jointly owned by the Municipality of Chatham-Kent (72%), the Corporation of the City of St. Thomas (20%) and Corix Infrastructure Inc. (8%).
- Entegrus is entirely funded through the rates its customers pay and does not receive taxpayer money to fund its operations or its investments in the distribution system.

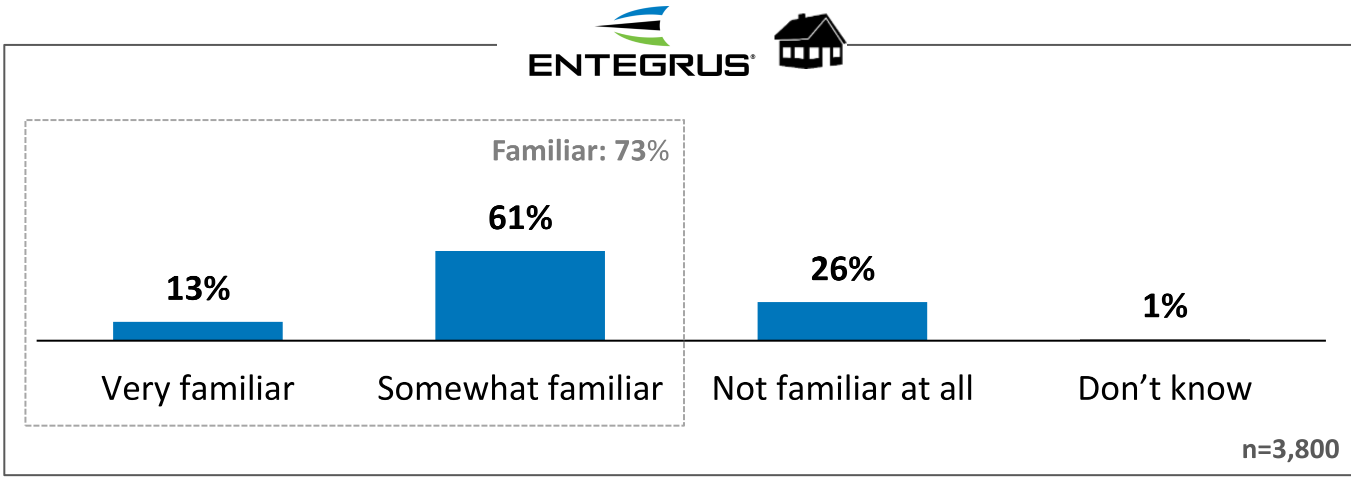


Online Workbook

Familiarity with Entegrus

Residential

Q How familiar are you with Entegrus, which operates the electricity distribution system in your community?



	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No Impact
Very familiar	14%	9%	14%	11%	14%
Somewhat familiar	61%	59%	55%	63%	62%
Not familiar at all	24%	32%	30%	25%	23%
Don't know	1%	1%	1%	1%	1%
Familiar (Very + Somewhat)	**76%**	**68%**	**68%**	**74%**	**76%**

Online Workbook

Planning for the Future: 2021-2025 Investment Plan

Residential

Electricity 101

How much of my electricity bill goes to Entegrus?

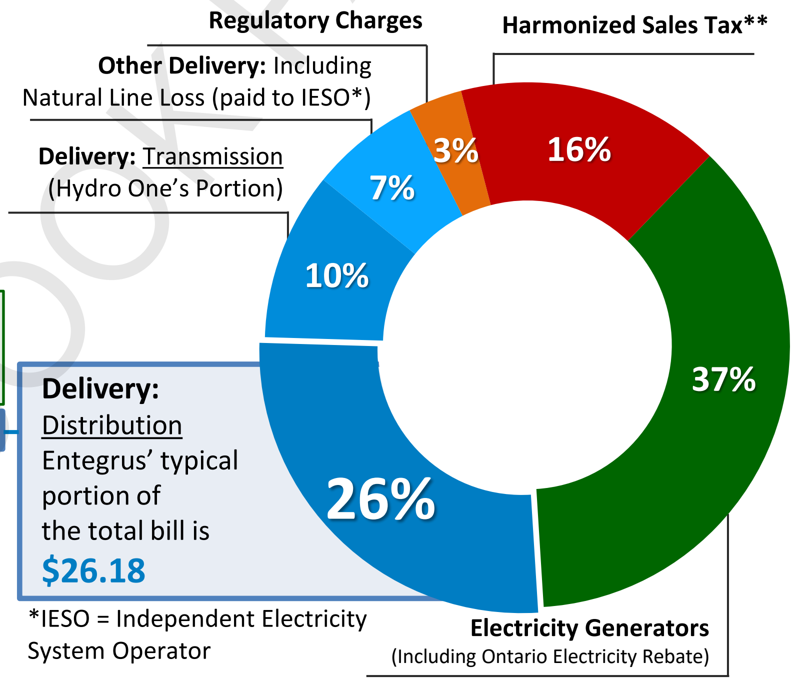
- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board (OEB), the provincial energy regulator.
- While **Entegrus** is responsible for collecting payment for the entire electricity bill – as well as water charges for many of its communities – Entegrus retains only a portion of the electricity delivery charge. The electricity delivery charge also includes Hydro One transmission costs and system losses.
- Distribution makes up about 26% of the typical residential customer's bill.
- The rest of your bill is passed onto provincial transmission companies, power generation companies, the provincial government and regulatory agencies.

Entegrus Sample Monthly Bill
(Based on monthly usage of 750 kWh)

Account Number:
000 000 000 000 0000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
Off-Peak @ 8.2 ¢/kWh	39.36
Mid-Peak @ 11.3 ¢/kWh	15.26
On-Peak @ 17 ¢/kWh	22.95
Delivery	43.13
Regulatory Charges	3.30
Total Electricity Charges	**$123.99**
HST	16.12
Ontario Electricity Rebate	(-$41.17)
Total Amount	**$98.95**



** HST is calculated before applying the Ontario Electricity Rebate and is therefore above 13%.

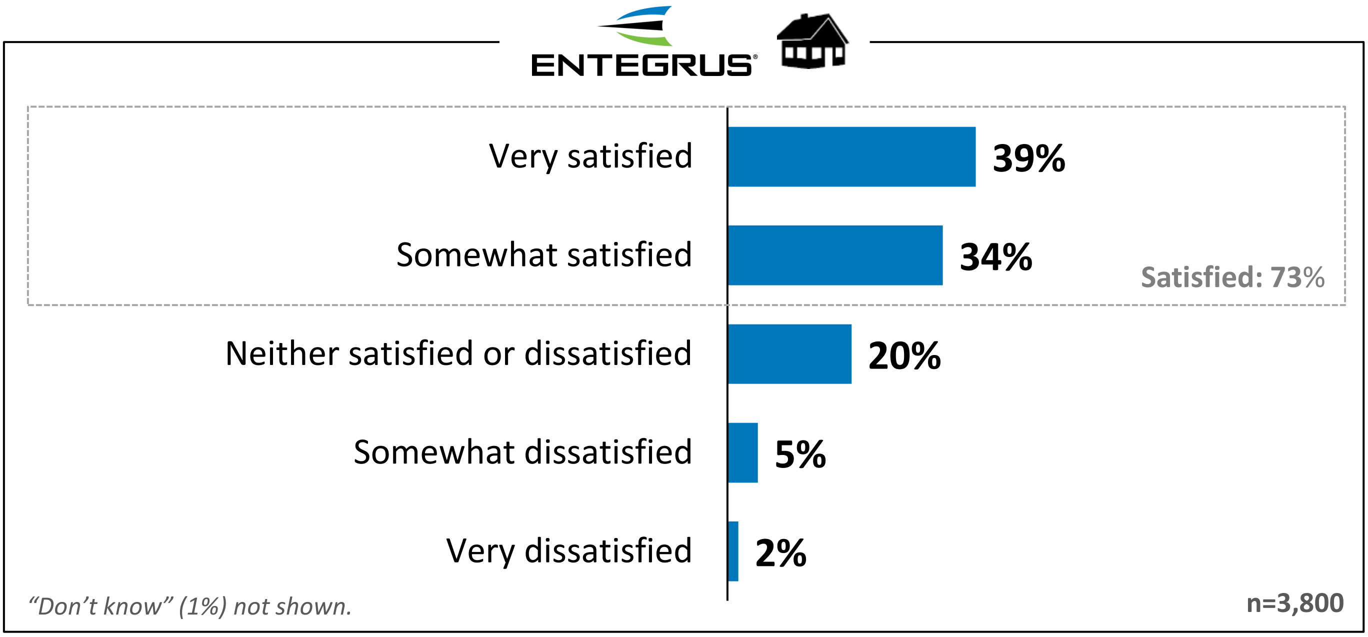
Note: In the workbook, bill impacts differed based on rate zone (Entegrus main or St.Thomas). Entegrus main shown above.

INNOVATIVE RESEARCH GROUP

Online Workbook

Overall Satisfaction with Entegrus

Q Thinking specifically about the services provided to you and your community by Entegrus, overall, how satisfied or dissatisfied are you with the services that you receive?



	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No Impact
Very satisfied	39%	39%	31%	37%	48%
Somewhat satisfied	36%	30%	33%	36%	32%
Neither satisfied nor dissatisfied	18%	23%	22%	21%	16%
Somewhat dissatisfied	5%	5%	8%	4%	3%
Very dissatisfied	2%	2%	5%	1%	1%
Satisfied (Very + Somewhat)	**75%**	**69%**	**64%**	**73%**	**80%**
Dissatisfied (Very + Somewhat)	**6%**	**7%**	**13%**	**5%**	**3%**

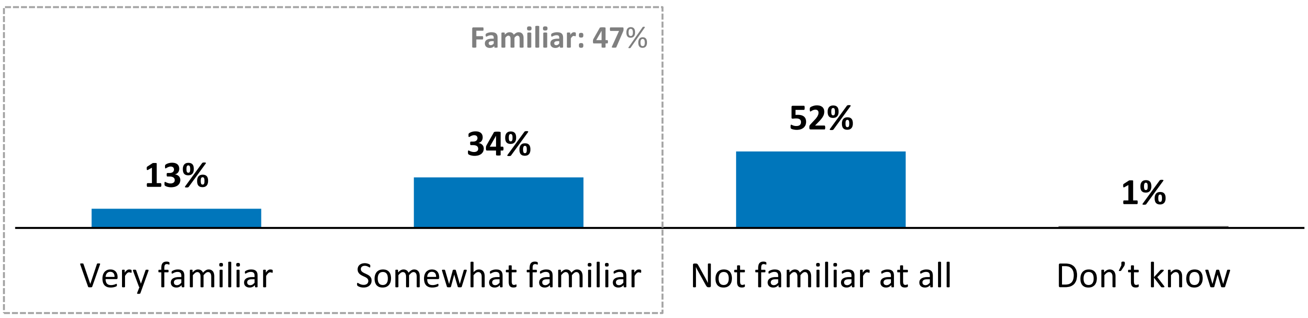
Online Workbook

Residential

Familiarity with Percentage of Bill Remitted to Entegrus

Q Before this survey, how familiar were you with the amount of your electricity bill that went to Entegrus?

ENTEGRUS



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	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No Impact
Very familiar	13%	12%	18%	11%	12%
Somewhat familiar	36%	29%	34%	37%	32%
Not familiar at all	49%	58%	47%	52%	56%
Don’t know	1%	1%	2%	1%	1%
Familiar (Very + Somewhat)	**50%**	**41%**	**51%**	**47%**	**43%**

Online Workbook

How Entegrus can Improve Services to Customers

Residential

Q Is there anything in particular you would like Entegrus to do to improve its services to you?

Additional Comments	%
Lower rates/no increases	8.1%
Improve infrastructure and reliability	3.2%
Adjust/eliminate time of use charges/offer flat rates	2.3%
Lower delivery charge/debt repayment fees/water service charge	1.9%
Improve pole/line maintenance/better tree clearing	1.2%
Improve billing issues	1.1%
Satisfied with service – no improvements	0.9%
Seniors/low-income discounts/programs	1.1%
Improve outage communication	0.9%
More incentives and education for energy conservation	0.7%
Improve online resources	0.4%
Improve customer service	0.4%
More alternative/green energy sources and less fossil fuels	0.3%
Find efficiencies, lower operating costs/reduce salaries	0.3%
Be more transparent	0.2%
Other	1.8%
Don’t know	0.4%
None	74.9%

Note: Only responses >0.1% shown

Online Workbook

Planning for the Future: 2021-2025 Investment Plan

Residential

Entegrus Background

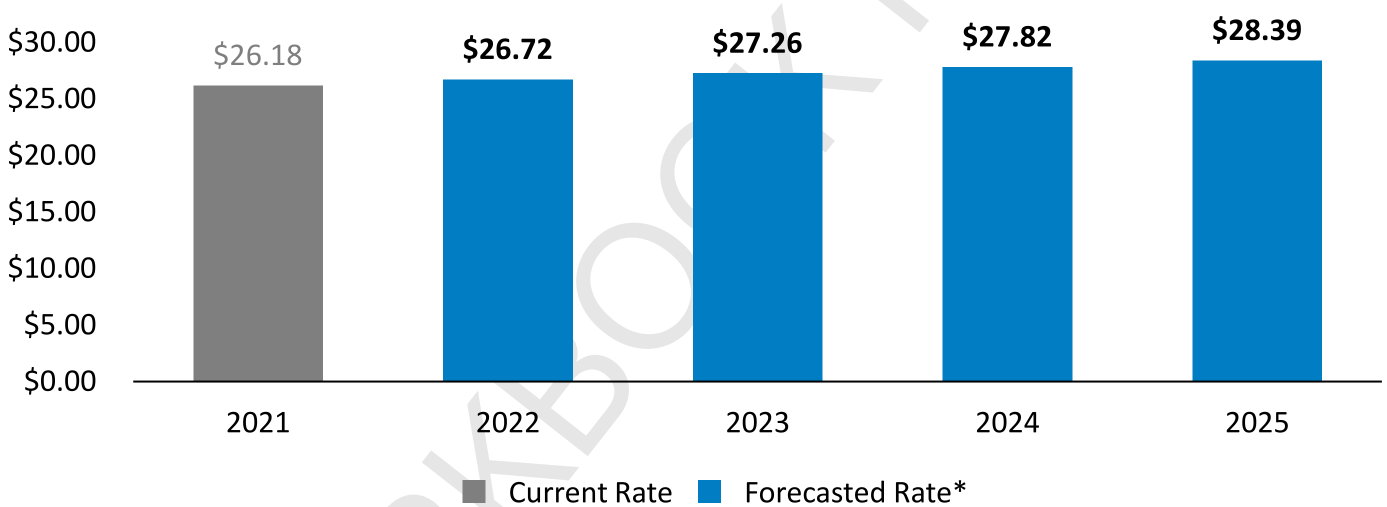
How much can you expect to pay over the next few years?

Prior to merging, both **Entegrus** and **St. Thomas Energy** had their rates set by the OEB, meaning the amount they can charge customers for the delivery of electricity.

While the merger was finalized in April 2018, for the eight years that follow the OEB has limited your future rate increases to less than inflation. That means that each year Entegrus is permitted to increase rates to reflect inflation minus savings targets established by the OEB. This requires Entegrus to keep cost increases below inflation.

For a residential customer like yourself, the distribution charge for the **typical bill is estimated to increase by approximately 2.05%** on average for the next five years (based on 2020 OEB inflation), until 2026.

Distribution Portion of the Bill per Month (2019-2025)



* These estimates are preliminary and are subject to your feedback as the investment plan is finalized.

Where does your money go?

Entegrus has two budgets; **operating and capital.** The operating budget covers recurring expenses, such as salaries, taxes, fuel costs, and rent. Until 2026, Entegrus cannot ask for any additional money for operating expenses.

This engagement is about the capital budget. This budget covers things like poles, wires, cables, transformers, meters, computers and programs, vehicles, and buildings.

Note: In the workbook, distribution portion differed based on rate zone (Entegrus main or St.Thomas). Entegrus main shown above.

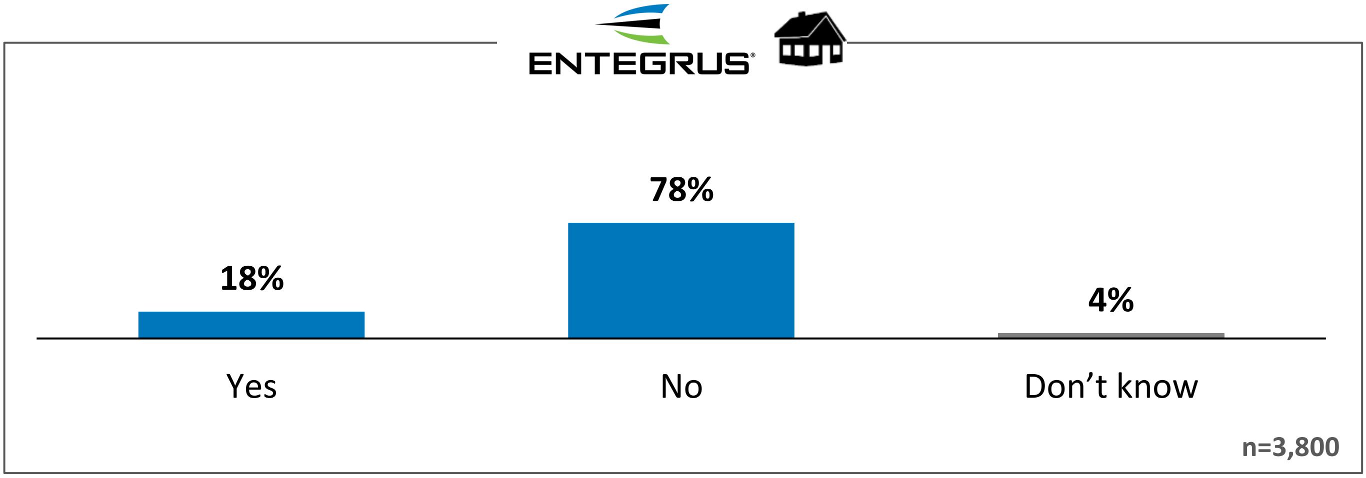
INNOVATIVE RESEARCH GROUP

Online Workbook

Familiarity with Bill Increase over Next 5 Years

Residential

Q Before this survey, were you aware that for a residential customer like yourself, the distribution charge for the typical bill is estimated to increase by approximately 2.05% on average for the next five years, until 2026?



	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No Impact
Yes	19%	16%	22%	17%	17%
No	78%	80%	74%	80%	81%
Don't know	3%	4%	4%	4%	3%

Entegrus Background

How are rates staying below inflation?

Entegrus' 2021 to 2025 investment plan sets out to balance a stronger investment focus on reliability and unprecedented customer growth with an objective of keeping distribution rates affordable for customers.

Accordingly, while investment levels have increased above historic levels in 2019 and 2020 and will continue to remain at higher levels through 2025, there are no proposed incremental rate impacts arising from this investment plan for the period from 2021-2025.

In order to safeguard against reliability deterioration, Entegrus' shareholders have decided to spend above the currently approved rates with no added cost to customers from 2021-2025. These additional investments will address aging infrastructure to safeguard reliability and thereby also ensure a strong foundation to enable future customer investments in electric vehicles and customer-owned electricity generation.

Spending above current rates

As mentioned earlier, Entegrus is entirely funded through the rates its customers pay and does not receive taxpayer money to fund its operations or its investments in the distribution system.

That said, Entegrus shareholders have decided that the need for additional reliability investments cannot be put on hold, nor should customers be faced with incremental rate increases at this time. As such, over the 2018 to 2020 period, Entegrus invested an incremental $5.7 million in the distribution system beyond what was originally planned to address reliability and harmonize systems post-merger. For the 2021 to 2025 period, approximately $63 million will be invested in the distribution system, **including an estimated incremental $6.5 million to address reliability, at no additional cost to customers over that period.**

Finding internal cost savings

According to the latest data published by the Ontario Energy Board of approximately 60 electricity providers from across the province, Entegrus had the 15th lowest total cost per customer. That means Entegrus is among the most efficient electricity distributors in Ontario.

Benchmarking isn't the only way that Entegrus measures its operational efficiency. Entegrus is a member of the GridSmartCity Co-operative, an organization that brings together 15 Ontario LDCs to collaborate and share knowledge, skills and expertise – with some of the goals being increased efficiency and cost savings through economies of scale.

Cost saving benefits include negotiated group rates for services and group savings on the procurement of wood poles, cables, wires, and transformers.

Additionally, through its merger with St. Thomas Energy, Entegrus continues to see annual savings of approximately $1.4 million each year through shared operating, maintenance, and administrative costs.

Entegrus Background

What is this engagement about?

This customer engagement is about finding the right balance between the service you receive and the price you pay.

The point of this engagement is to allow customers like yourself to provide feedback on whether Entegrus planners have found the right balance or whether they should consider different options that better reflect your views.

As mentioned earlier, Entegrus' 2021 to 2025 investment plan sets out to balance a stronger investment focus on reliability and unprecedented customer growth with an objective of keeping distribution rates affordable for customers.

Affordability is at the core of Entegrus' plans.

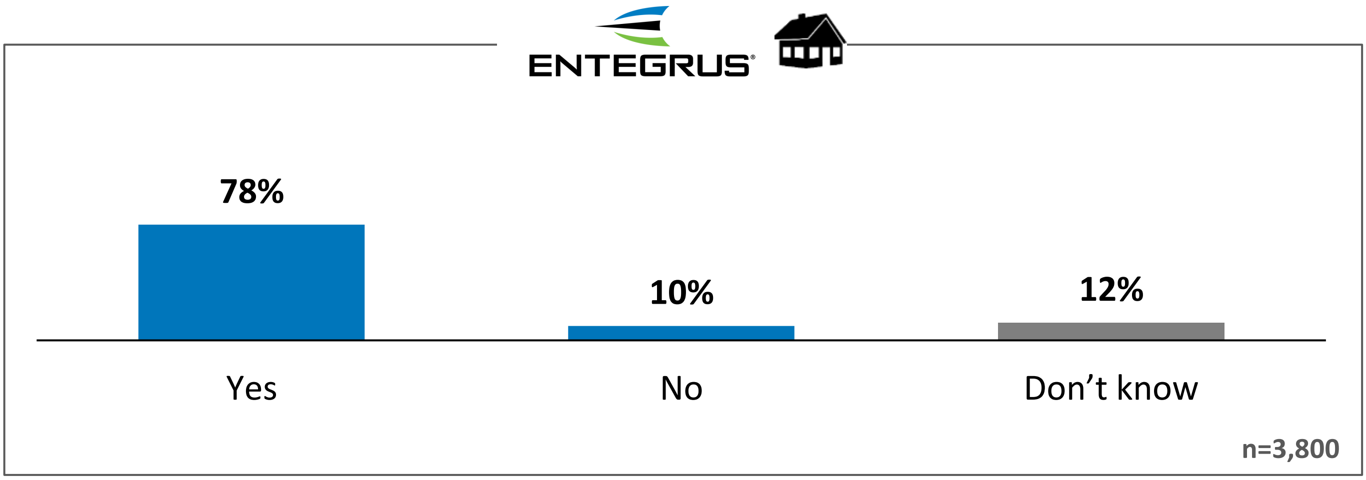
Before Entegrus finalizes its plans, it is coming to its customers with a final set of choices. For each choice, Entegrus has identified an option to stay within existing rates (including the incremental investments Entegrus is already planning). It has also identified options to increase investments where it will provide meaningful benefits to customers.

Online Workbook

Purpose of Customer Engagement

Residential

Q Do you feel that the purpose of this customer engagement is clear?



	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No Impact
Yes	78%	78%	72%	79%	82%
No	9%	11%	15%	9%	7%
Don't know	12%	11%	13%	12%	10%

Additional Comments	%
Lower rates/no increases	1.5%
Clearer/detailed breakdown of proposed increases	1.2%
Survey is biased/don't trust it	0.5%
Survey is confusing/need more information	0.5%
Other	0.8%
Don't know	0.3%
None	95.3%

Note: Only responses >0.1% shown

INNOVATIVE RESEARCH GROUP

Entegrus Background

What are the key investment drivers for 2021 to 2025?

Entegrus has identified three primary investment drivers for the 2021 to 2025 period – **aging infrastructure (reliability), customer growth,** and **grid modernization**.

A damaged Entegrus distribution pole.

Aging Infrastructure: Recall, much of the initial economic expansion in Entegrus' service territory occurred between 1950 and 1970. That means parts of Entegrus' distribution system are now more than 50 years old.

Entegrus' 2021-2025 plan demonstrates a notable increased focus on replacing aging infrastructure. This is driven by the fact that portions of the distribution system have degraded beyond the expectation of the utility's 2016-2020 plans.

- This additional degradation became apparent in 2017 and 2018 when new technology and additional engineering staff enabled Entegrus to conduct a deeper system-wide infrastructure assessment, including resistograph pole testing.
- This assessment identified that the level of asset degradation was higher than originally forecast. Simultaneously, in 2018, customers began to experience an increase in power outages.

Overall, the additional work to replace aging infrastructure will mitigate reliability issues and provide a stronger distribution system foundation for later integration of future customer investments in electric vehicle and customer-owned electricity generation in the next planning cycle from 2026 to 2030.

Entegrus Background

What are the key investment drivers for 2021 to 2025?

Customer Growth: Even though many developers initially put projects on hold as a result of the COVID-19 pandemic, by the summer of 2020 Entegrus continued to experience unprecedented customer growth. High residential growth continues to occur in St. Thomas and other communities in the Entegrus northeast region including Strathroy and Mt. Brydges. Residential growth and significant levels of activity required to prepare the Entegrus distribution system to support fibre-to-the-home expansion by telecoms is also occurring in Chatham-Kent.

While customer growth remains high it is currently difficult to predict whether this trend will continue beyond 2021 given the circumstances of the pandemic.

A new subdivision located in St.Thomas

System Modernization: As described previously, the Entegrus service territory extends over an area of 5,600 square kilometres. Servicing each community requires significant travel. Being able to troubleshoot problems remotely reduces and in some cases eliminates the need to send a crew out for repairs.

While Entegrus' primary focuses are on reliability and servicing customer growth while keeping distribution rates affordable, the 2021 to 2025 plans do include focus on system modernization, including some automated distribution restoration technologies.

The plans also include further harmonization of legacy systems across the merged entity to help enable future investments in technology including electric vehicles and customer-owned electricity generation.

Online Workbook

Planning for the Future: 2021-2025 Investment Plan

Residential

Entegrus Background

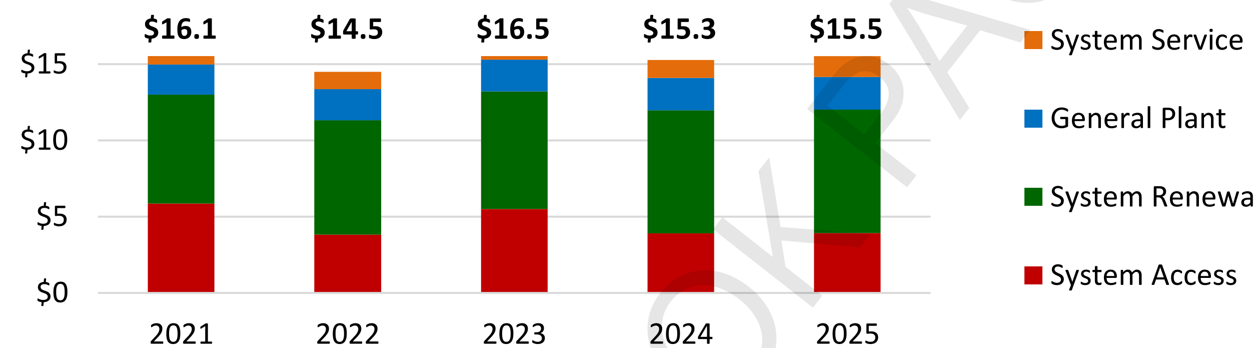
How does Entegrus plan future investments in the system?

Entegrus' **capital budget** covers items that have lasting benefits over many years such as investments in the core distribution system including poles, wires, cables, switches, and transformers.

Based on initial information and input from Entegrus' internal engineering and technical experts and emerging pressures on the distribution system, **<u>Entegrus' draft capital budget is estimated to be $77.9 million over the five-year period between 2021 and 2025</u>.**

Entegrus plans its capital investments in four categories.

2021-2025 Forecasted Capital Investments (Millions)*



** These estimates are preliminary, and are subject to your feedback as the business plan is finalized.*

System Access ($23 Million, averaging $4.6 per year)

"Must do" investments for new subdivisions, new upgraded commercial and industrial services, and relocating assets based on road infrastructure needs. Entegrus is expected to recover close to 65% of these costs from developers, internet providers, and larger business customers.

System Renewal ($38.5 Million, averaging $7.7 per year)

Replacement of aged overhead wires, poles, and pole mounted transformers, underground cables and transformers and distribution station upgrades.

General Plant ($10.4 Million, averaging $2.1 per year)

These are investments needed to support the distribution system, such as tools, vehicles, buildings, and computers.

System Service ($6 Million, averaging $1.2 per year)

These investments consist of projects that address capacity constraints, improve system reliability and supply new growth.

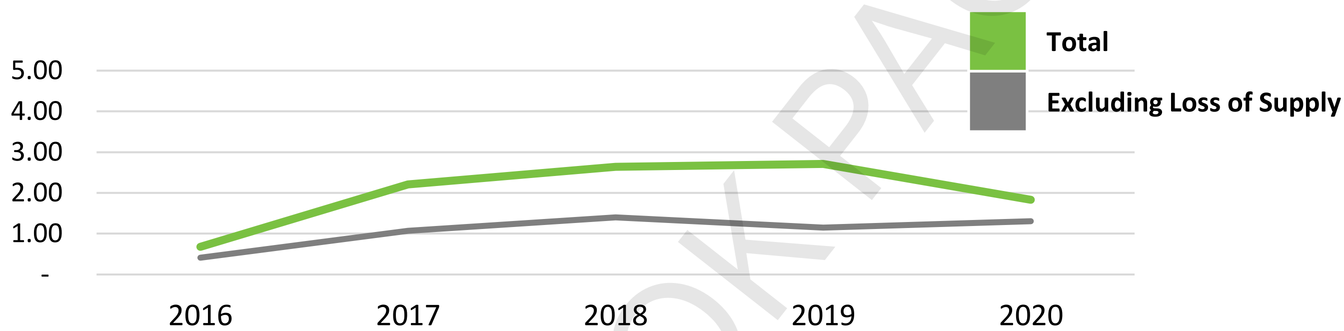
Entegrus Background

How does Entegrus' distribution system perform?

Entegrus tracks both the average number of power outages per customer and how long those interruptions last. Keep in mind that these are system averages, and your actual experience may be different. Some customers connected to newer lines may not experience any outages while others may experience more than the average number of outages each year.

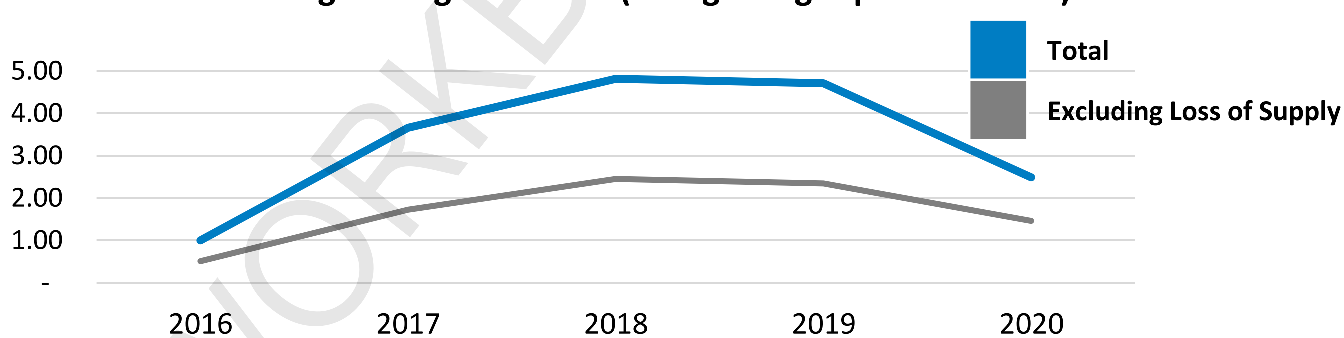
Between 2016 and 2020, the typical Entegrus customer (excluding St. Thomas) experienced about two outages per year.

Average number of outages (outages per customer)



Over the same period, the average **duration** of an outage has been about 3.3 hours, some of which has been driven by loss of power supply due to significant weather events. Meaning when the power does go out, Entegrus is typically able to restore power in about three hours.

Average outage duration (outage length per customer)



Loss of supply occurs when there is an interruption to the supply of electricity from the upstream electrical system operated by Hydro One. These failures are largely out of the control of Entegrus but there are investments that can be made to attempt to reduce the impacts of these outages including a more intelligent system that can automatically re-route power when one of these outages does occur. In fact, investments by Entegrus in automated switches have already avoided 18,000 customer outage hours between 2017 and 2020.

Note: St.Thomas outage statistics shown for St.Thomas customers

Entegrus Background

How does Entegrus' distribution system perform?

Recently, Entegrus, with the help of an independent third party, conducted a system-wide study to better understand the health of the system and the long-term implications on system reliability. This study concluded that the deterioration in Entegrus' reliability measures (illustrated above) required **timely and proactive intervention to maintain current levels of reliability** and start to slow, or halt, the reliability deterioration trend before it becomes irreversible.

An Entegrus crew working to restore power during a winter storm.

Some of the effects of the proactive intervention undertaken in 2020 have already resulted in improvement; however, favourable weather and pandemic-related factors, such as fewer scheduled outages and less foreign interference (i.e. fewer vehicle accidents impacting the distribution system) contributed to the 2020 results.

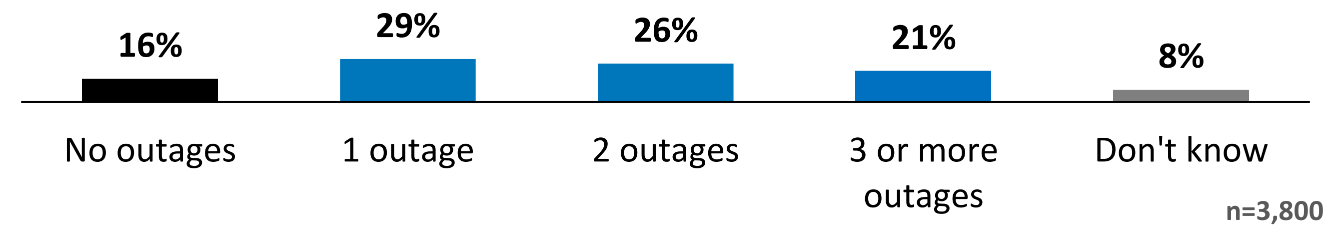
Online Workbook

Number of Outages Experienced

Residential

Q Have you experienced any power outages at home in the past 12 months which lasted longer than one minute?

ENTEGRUS



	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No Impact
No outages	12%	25%	14%	16%	17%
1 outage	27%	34%	25%	30%	32%
2 outages	28%	22%	29%	25%	24%
3 or more outages	26%	8%	27%	19%	18%

Entegrus Background

What contributes to a power outage?

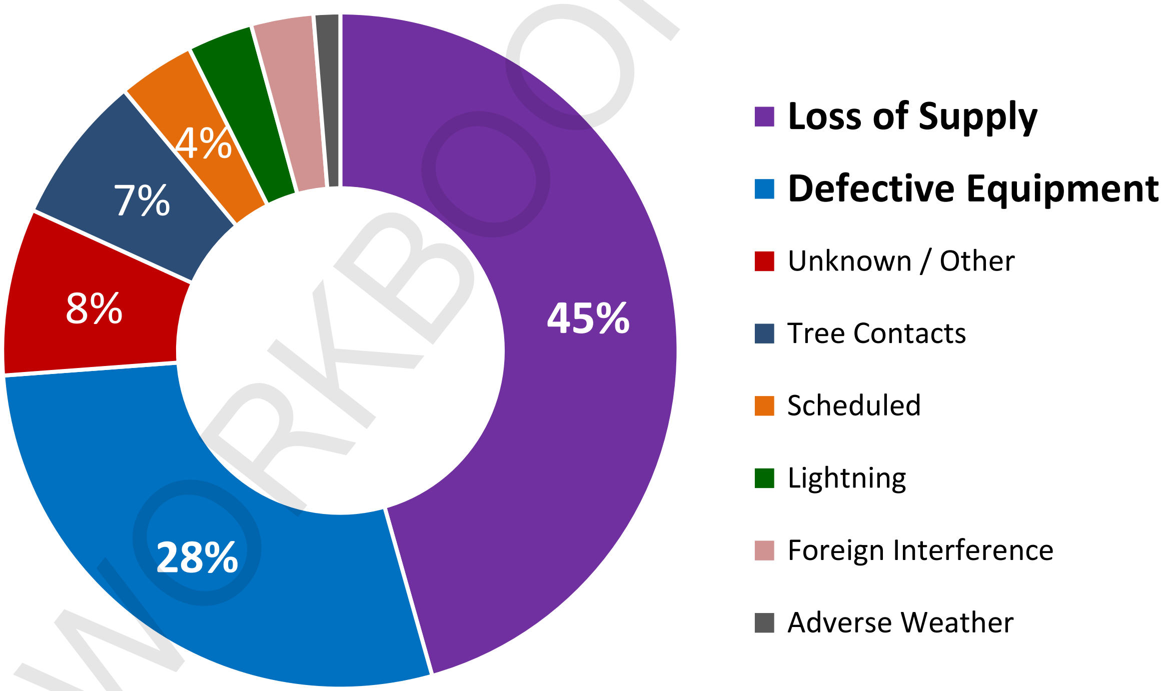
In order to provide feedback on Entegrus' plan, it's important to understand how the distribution system has performed in the past as well as what is expected in the future.

A core objective of Entegrus' 2021-2025 plan is to maintain reliability while making targeted improvements to those areas experiencing below average service.

In the Entegrus communities, the two primary contributors to outages account for 1-in-3 of all outages:

1. **Loss of supply** from the transmission system accounted for 45% of customer hours of interruption between 2016-2020. This is the single largest outage cause.
2. **Defective equipment** accounted for 28% of customer hours of interruption over the same period.

Customer Outage Duration (Hours) by Cause 2016-2020



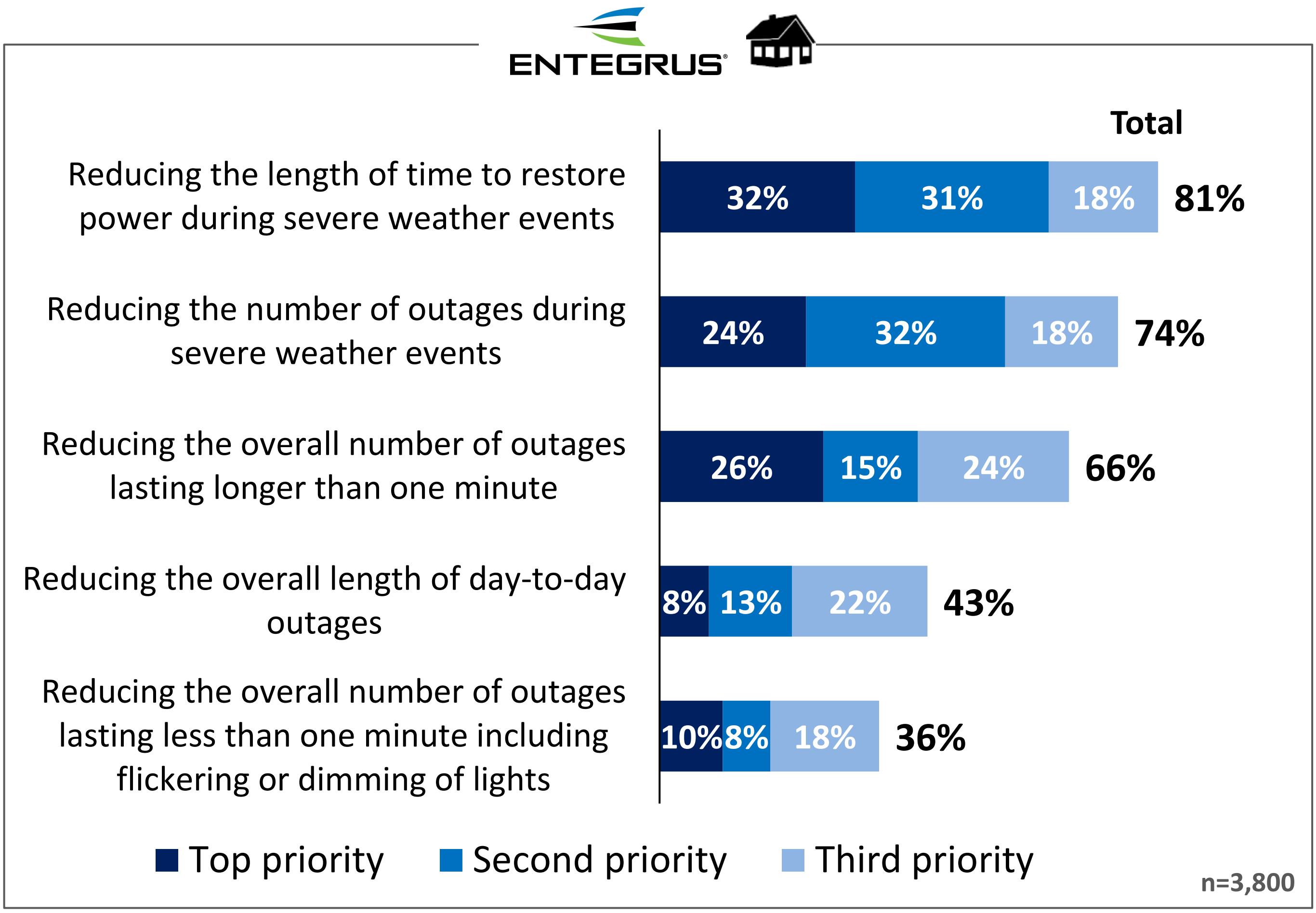
Note: St.Thomas outage statistics shown for St.Thomas customers

Online Workbook

Reliability Priorities

Residential

Q Among the following reliability outcomes, which are the most important to you? *While all of these priorities may be important to you, please rank your top 3 priorities – where '1' would be most important, '2' the second most important, and '3' the third most important.*



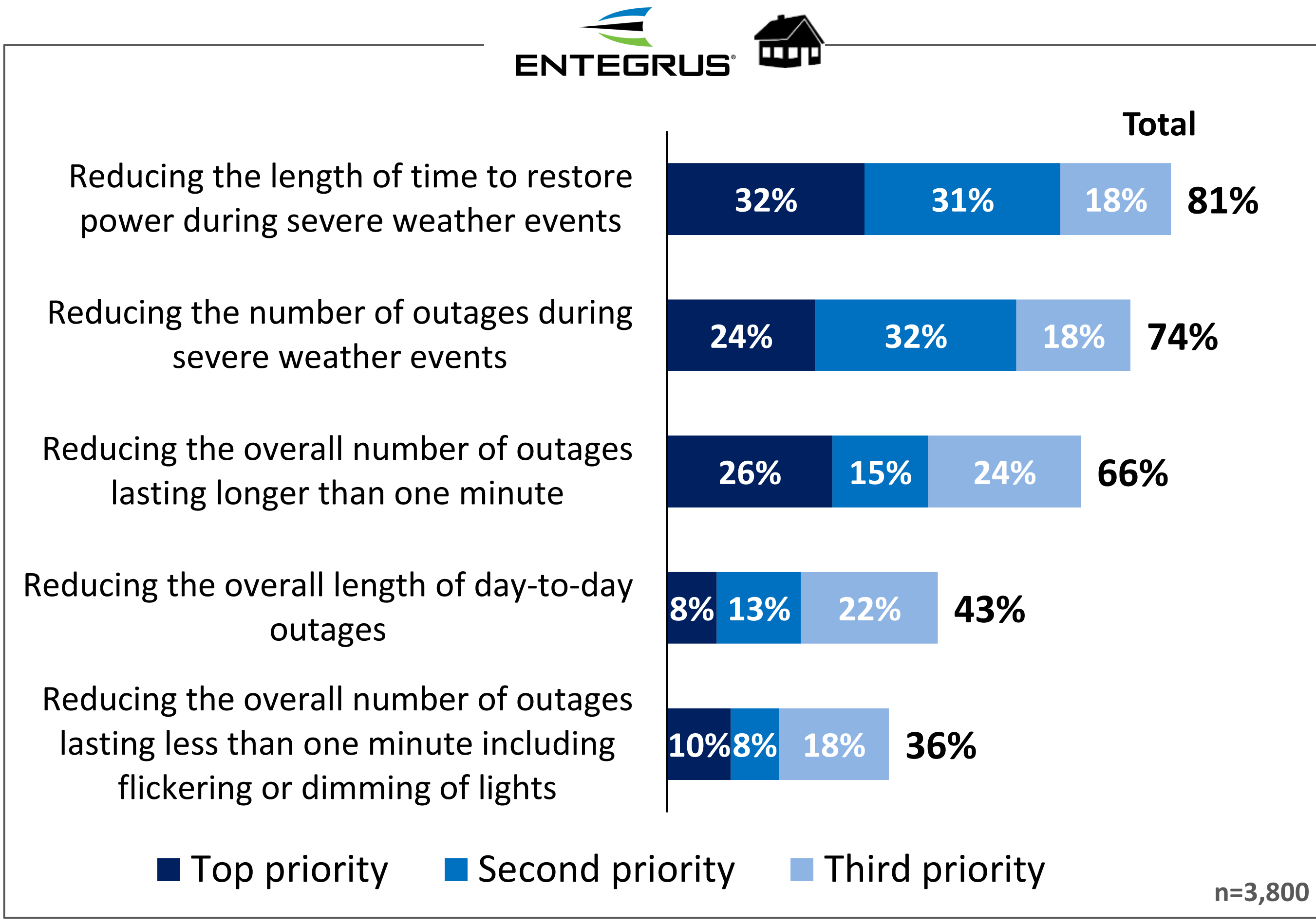
Region % who choose priority in their top 3	Legacy Entegrus	St. Thomas
Reducing the length of time to restore power during severe weather events	79%	84%
Reducing the # of outages during severe weather events	73%	78%
Reducing the overall # of outages lasting >1 minute	68%	63%
Reducing the overall length of day-to-day outages	44%	41%
Reducing the overall number of outages lasting less than one minute including flickering or dimming of lights	36%	33%

Online Workbook

Reliability Priorities

Residential

Q Among the following reliability outcomes, which are the most important to you? *While all of these priorities may be important to you, please rank your top 3 priorities – where '1' would be most important, '2' the second most important, and '3' the third most important.*



Bill Impact on Finances % who choose priority in their top 3	Significant impact	Impact	No impact
Reducing the length of time to restore power during severe weather events	78%	80%	83%
Reducing the # of outages during severe weather events	77%	75%	71%
Reducing the overall # of outages lasting >1 minute	66%	66%	66%
Reducing the overall length of day-to-day outages	42%	42%	46%
Reducing the overall number of outages lasting less than one minute including flickering or dimming of lights	37%	37%	33%

Entegrus Background

How can Entegrus improve the services you receive?

As previously mentioned, Entegrus has committed to the OEB to limit your future rate increases to less than inflation until 2026.

An Entegrus crew installing a new pole.

That said, as part of the OEB policies, there is an option for utilities to apply for additional rate increases for discrete projects that are prudent, needed and not supported by existing rates. However, as previously noted, Entegrus has decided to continue to make certain additional reliability investments without asking customers for rate increases at this time, to keep distribution rates affordable in 2021-2025.

Looking ahead, Entegrus has identified two projects that will help mitigate reliability issues related to degraded infrastructure and provide a stronger distribution system foundation for later integration of electric vehicle and customer-owned generation infrastructure investments in the next planning cycle from 2026 to 2030. Entegrus is looking for your thoughts to determine whether it should pursue these two projects, financing these on its own until 2026, with no additional charges to customers.

As noted above, Entegrus will only be asking for increases of less than inflation from customers for the next five years and any investments made now will not impact your rates until the next planning period between 2026 and 2030.

Online Workbook

Residential

Planning for the Future: 2021-2025 Investment Plan

Line Modernization and Station Decommissioning

About 15% of Entegrus' customers are serviced by low voltage distribution systems. These low voltage lines were built in the 1950's, 1960's and 1970's and represent some of Entegrus' oldest distribution assets.

A low voltage transformer station.

These low voltage lines have much less capacity than modern lines and are supported by stations that are required to deliver this lower voltage. These stations look like small houses, or in some cases, are fenced-in areas containing weatherized electrical equipment. During an outage, the modern lines cannot be used to restore power to the low voltage lines, because they don't operate at the same voltage levels.

Due to the limited capacity of the low voltage lines, they are not suited for smart grid technology or customer-owned electricity generation. As such, this equipment has become functionally outdated and the risk of equipment failure is increasing.

For the past 10 years, Entegrus has focused on converting these low voltage lines to the modern technology. When enough lines are converted, Entegrus can decommission and sell the land that contains the low voltage stations.

Investing in these projects offers three primary benefits:

1. **Improved reliability through the new lines and transformers;**

2. **Increased capacity on each line to support customer growth, smart grid technology, and customer-owned electricity generation; and**

3. **Improved outage restoration from the enhanced back-up and availability of tie points at this higher voltage level.**

Entegrus currently has 19 of these stations supporting these low voltage lines still in use. To balance replacing other degraded assets and supporting customer growth, Entegrus planners are targeting the removal of 4 stations by 2025. At this pace, all of the low voltage lines would be replaced by modern lines and all the stations would be decommissioned beyond 2040.

However, because this equipment does not pose an urgent threat to reliability, if unforeseen distribution system priorities emerge over that period, it is the practice of Entegrus to divert resources away from these 4 lines modernization and station decommissioning projects to resolve more pressing priorities.

Online Workbook

Residential

Choice 1: Line Modernization and Station Decommissioning

Which of the following options do you prefer?

Option	Description	Expected Outcome
Accelerated Paced Line Modernization *Additional $0.50 - $0.70 per month starting in 2026*	Line modernization to allow the removal of 6 low voltage Stations to occur from 2021-2025 regardless of other priorities.	• Complete line modernization of all low voltage equipment and Station decommissioning by 2035 • Reduce risk of deterioration of reliability • Avoid some Station maintenance costs.
Faster Paced Line Modernization *Additional $0.25 - $0.35 per month starting in 2026*	Line modernization to allow the removal of 5 low voltage Stations to occur in 2021-2025 regardless of other priorities.	• Complete line modernization of all low voltage equipment and Station decommissioning by 2040 • Risk of deterioration of reliability continues • Escalating Station maintenance versus obsolescence.
Status Quo *Within current rates*	Continue to target line modernization to allow removal of 4 low voltage Stations, to occur in 2021-2025. Allow for diversion from this plan if other priorities emerge.	• Maintain low voltage Stations beyond 2040 • Higher risk of deterioration of reliability continues • Escalating Station maintenance versus obsolescence.
Additional Feedback (Optional)		

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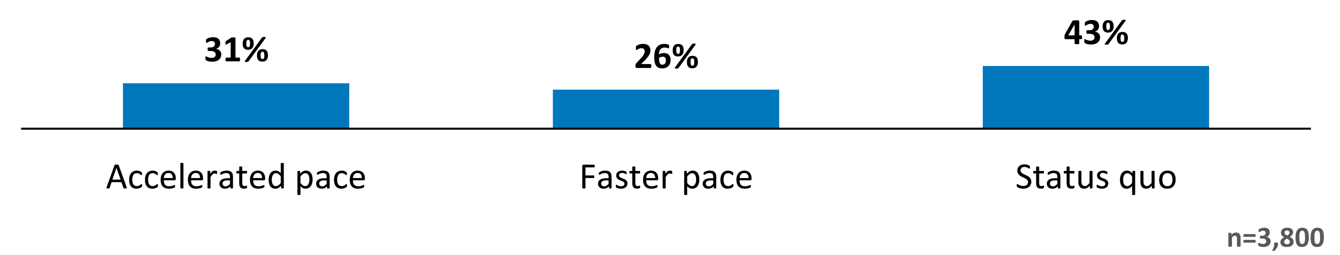

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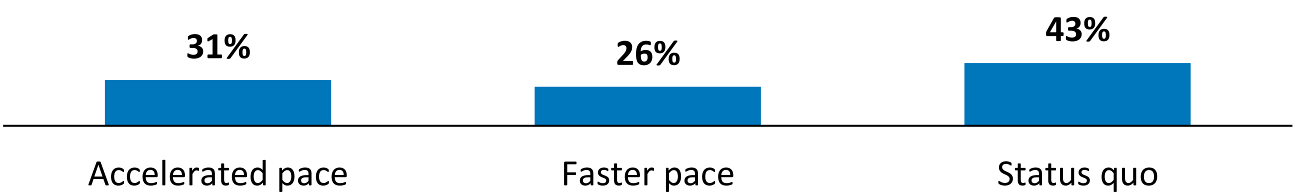
Online Workbook

Residential

Choice 1: Line Modernization and Station Decommissioning

Q Which of the following options do you prefer?

ENTEGRUS



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Region

	Legacy Entegrus	St. Thomas
Accelerated	31%	30%
Faster	26%	27%
Status quo	42%	43%

	Bill impact on finances			LEAP qualification		
	Significant impact	Impact	No Impact	LEAP qualified	Not LEAP, Income <$52k	Not LEAP, Income >$52k
Accelerated	20%	30%	41%	27%	30%	36%
Faster	23%	29%	26%	23%	27%	26%
Status quo	57%	41%	33%	50%	43%	38%

INNOVATIVE RESEARCH GROUP

Online Workbook

Choice 1: Line Modernization and Station Decommissioning

Residential

Q Which of the following options do you prefer?

Additional Comments	%
Small price to pay/rate increase is reasonable	2.0%
Lower rates/no increase	1.5%
Upgrade now to avoid future cost increases	0.8%
Find efficiencies from within/upgrades should have been planned in budget	0.5%
Good reliable service/no complaints	0.3%
Greener alternatives/environmental implications	0.3%
Decrease outages/increase reliable service	0.3%
Introduce programs for low income families/seniors	0.2%
Need more information/what areas are affected	0.2%
Bury the lines/move underground	0.2%
Electric cars/charging stations – negative comment	0.2%
Increase only temporary to accommodate upgrades/decrease after upgrades	0.2%
Other	0.9%
Don’t know	0.3%
None	91.9%

Note: Only responses >0.1% shown

Implementing Smart Grid Technology

New technology has changed the way that Entegrus can manage and monitor the distribution system.

Intelligent (automated) switches

Intelligent (automated) switches allow Entegrus to automatically reroute power during outages and planned maintenance, reducing the length of time customers are without power and reducing reliance on crews travelling to the site to physically re-route power. When this automatic rerouting occurs, impacted neighbourhoods would experience an outage lasting less than one minute, rather than a lengthier interruption.

Entegrus has recently used automated switch technology to target more rural communities experiencing poor reliability due to loss of supply. These communities are served by two long lines from the provincial transmission system, and the technology allows the two lines to automatically back each other up when one line experiences an outage, eliminating the need for manual intervention.

However, Entegrus now sees an opportunity to roll this technology out in larger cities that have many interconnecting lines that can form “grids”. Doing so will offer multiple alternative paths for electricity to flow, bypassing the fault and avoiding potential widespread outages. Entegrus ran a successful pilot of intelligent switch technology on a single feeder line in Chatham in 2020.

Not only do these intelligent switches help reduce the length of time customers are without power, but they also help create a more integrated, advanced system that is better equipped to handle future technological advancements including electric vehicles and customer-owned electricity generation.

In its current draft plan, in order to afford to invest more dollars in replacement of poles and wires while limiting cost increases to customers, Entegrus plans to selectively install 6 more of these intelligent switches in 2021-2025. That said, there is a near term opportunity for a broad roll out of intelligent switches in the larger communities of Chatham and St. Thomas where there is the opportunity to increase connectivity by creating a medium or higher density of intelligent switches.

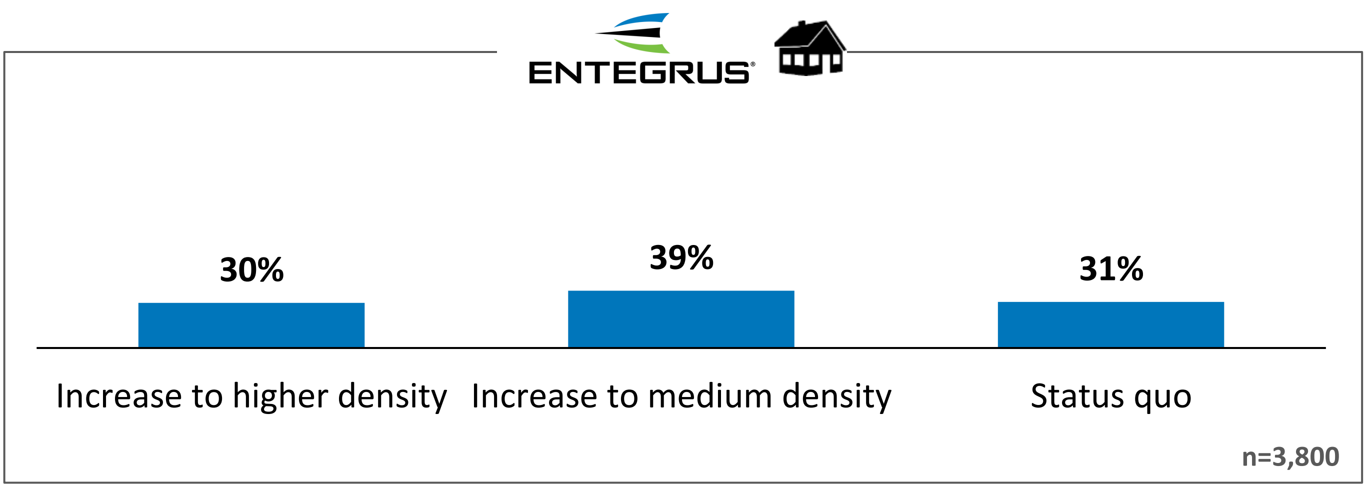
Online Workbook

Choice 2: Implementing Smart Grid Technology

Residential

Which of the following options do you prefer?

Option	Description	Expected Outcome
Increase to Higher Intelligent Switch Density in Chatham & St. Thomas *Additional $0.40- $0.70 per month starting in 2026*	Install an additional 18 switches in Chatham and an additional 10 switches in St. Thomas	Reduce outage duration by about 20% - 25% and outage frequency > 1 minute by about 30% - 40%
Increase to Medium Intelligent Switch Density in Chatham & St. Thomas *Additional $0.20 - $0.35 per month starting in 2026*	Install an additional 11 switches in Chatham and an additional 6 switches in St. Thomas	Reduce outage duration by about 15% - 20% and outage frequency >1 minute by about 25% - 30%
Status Quo – Stay with Low Intelligent Switch Density in Chatham & St. Thomas *Within current rates*	No additional investment in intelligent switches beyond the few in the current plan.	Increased risk of potential deterioration of reliability in the medium term.
Additional Feedback (Optional)		



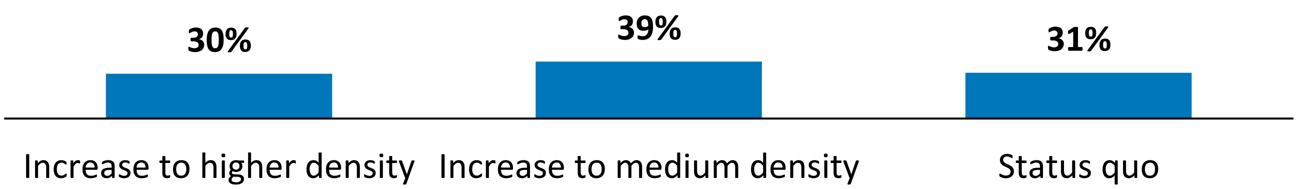
Online Workbook

Choice 2: Implementing Smart Grid Technology

Residential

Q Which of the following options do you prefer?

ENTEGRUS



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Region

	Legacy Entegrus	St. Thomas
Higher density	31%	30%
Medium density	37%	42%
Status quo	32%	28%

	Bill impact on finances			LEAP qualification		
	Significant impact	Impact	No Impact	LEAP qualified	Not LEAP, Income <$52k	Not LEAP, Income >$52k
Higher density	22%	30%	38%	26%	30%	36%
Medium density	33%	41%	40%	35%	41%	36%
Status quo	45%	28%	22%	38%	29%	28%

INNOVATIVE RESEARCH GROUP

Online Workbook

Choice 2: Implementing Smart Grid Technology

Residential

Q Which of the following options do you prefer?

Additional Comments	%
Need more information/transparency on costs	1.1%
Do not live in the area/doesn’t impact me	0.8%
Reliability is vital/cost is accessible	0.7%
Lower rates/no increase	0.7%
Invest money in technology and infrastructure	0.6%
Company should incur the costs – result of poor planning	0.5%
Make improvements as needed – control costs	0.4%
Cost should be incurred by developer/those that benefit from the upgrade	0.4%
Maintain status quo/not the time for increases during COVID recovery	0.3%
Cyber security needs to be considered	0.2%
Other	0.7%
Don’t know	0.1%
None	93.4%

Note: Only responses >0.1% shown

Online Workbook

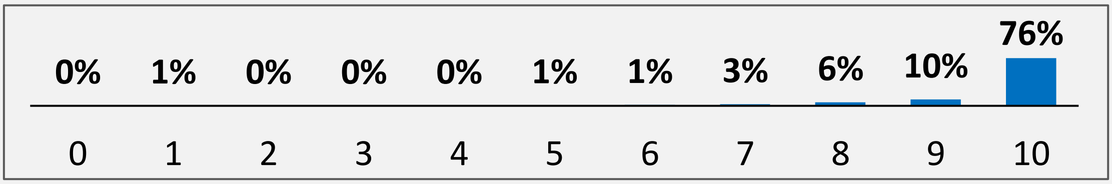
Importance of Entegrus Priorities

Residential

Q How importance are each of the following Entegrus priorities to you as a customer?

Delivering electricity at reasonable rates [average = **9.5**]

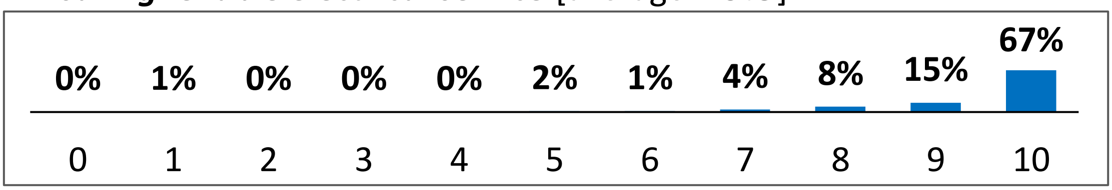
Not at all important



Extremely important

Ensuring reliable electrical service [average = **9.3**]

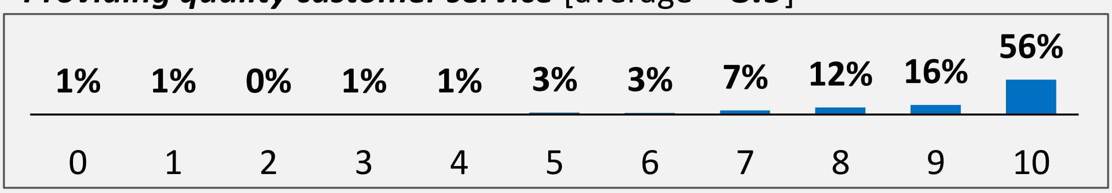
Not at all important



Extremely important

Providing quality customer service [average = **8.9**]

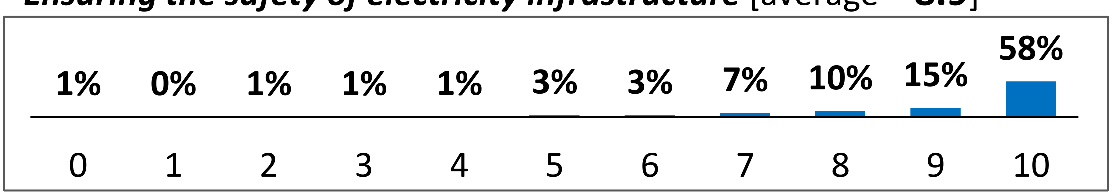
Not at all important



Extremely important

Ensuring the safety of electricity infrastructure [average = **8.9**]

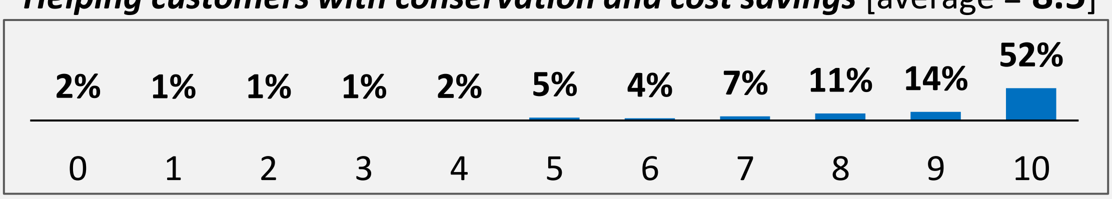
Not at all important



Extremely important

Helping customers with conservation and cost savings [average = **8.5**]

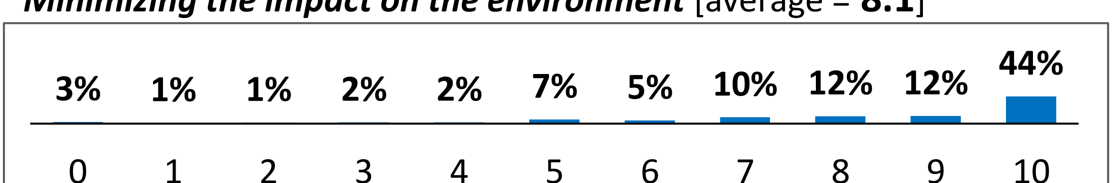
Not at all important



Extremely important

Minimizing the impact on the environment [average = **8.1**]

Not at all important



Extremely important

Note: "Don't know" not shown.

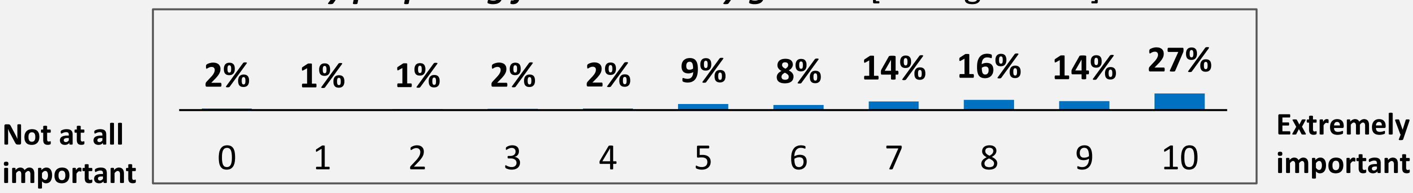
Online Workbook

Importance of Entegrus Priorities

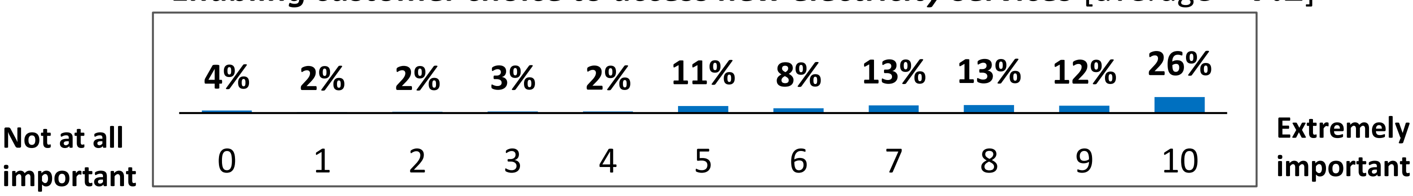
Residential

Q How importance are each of the following Entegrus priorities to you as a customer?

Proactively preparing for community growth [average = **7.6**]



Enabling customer choice to access new electricity services [average = **7.2**]



	Region		Bill impact on finances		
Average Score	Legacy Entegrus	St. Thomas	Significant impact	Impact	No Impact
Delivering electricity at reasonable rates	9.4	9.5	9.6	9.5	9.3
Ensuring reliable electrical service	9.3	9.2	9.1	9.3	9.4
Providing quality customer service	8.9	8.9	8.9	8.9	8.9
Ensuring the safety of electricity infrastructure	8.9	8.9	8.6	9.0	9.1
Helping customers with conservation and cost savings	8.5	8.6	8.8	8.6	8.2
Minimizing the impact on the environment	8.0	8.1	7.8	8.1	8.2
Proactively preparing for community growth	7.5	7.6	7.2	7.6	7.8
Enabling customer choice to access new electricity services	7.2	7.2	7.4	7.2	7.0

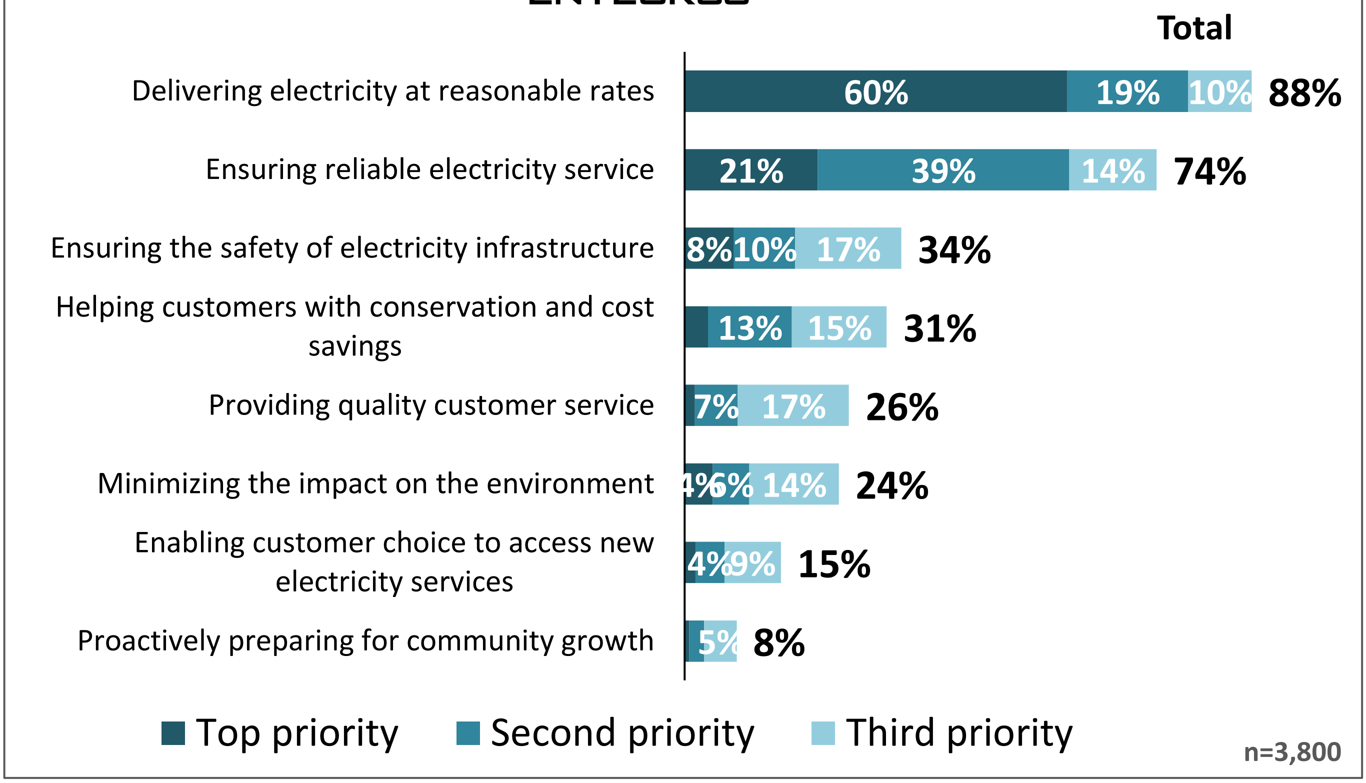
Note: “Don’t know” not shown.

Online Workbook

Ranking Entegrus Priorities

Residential

Q Thinking again about the things that Entegrus should be focusing on, please rank your top 3 priorities – where '1' would be the most important, '2' the second most important, and '3' the third most important.



Region % who choose priority in their top 3	Legacy Entegrus	St. Thomas
Delivering electricity at reasonable rates	89%	88%
Ensuring reliable electricity service	74%	73%
Ensuring the safety of electricity infrastructure	34%	34%
Helping customers with conservation and cost savings	31%	33%
Providing quality customer service	27%	23%
Minimizing the impact on the environment	24%	23%
Enabling customer choice to access new electricity services	14%	17%
Proactively preparing for community growth	8%	8%

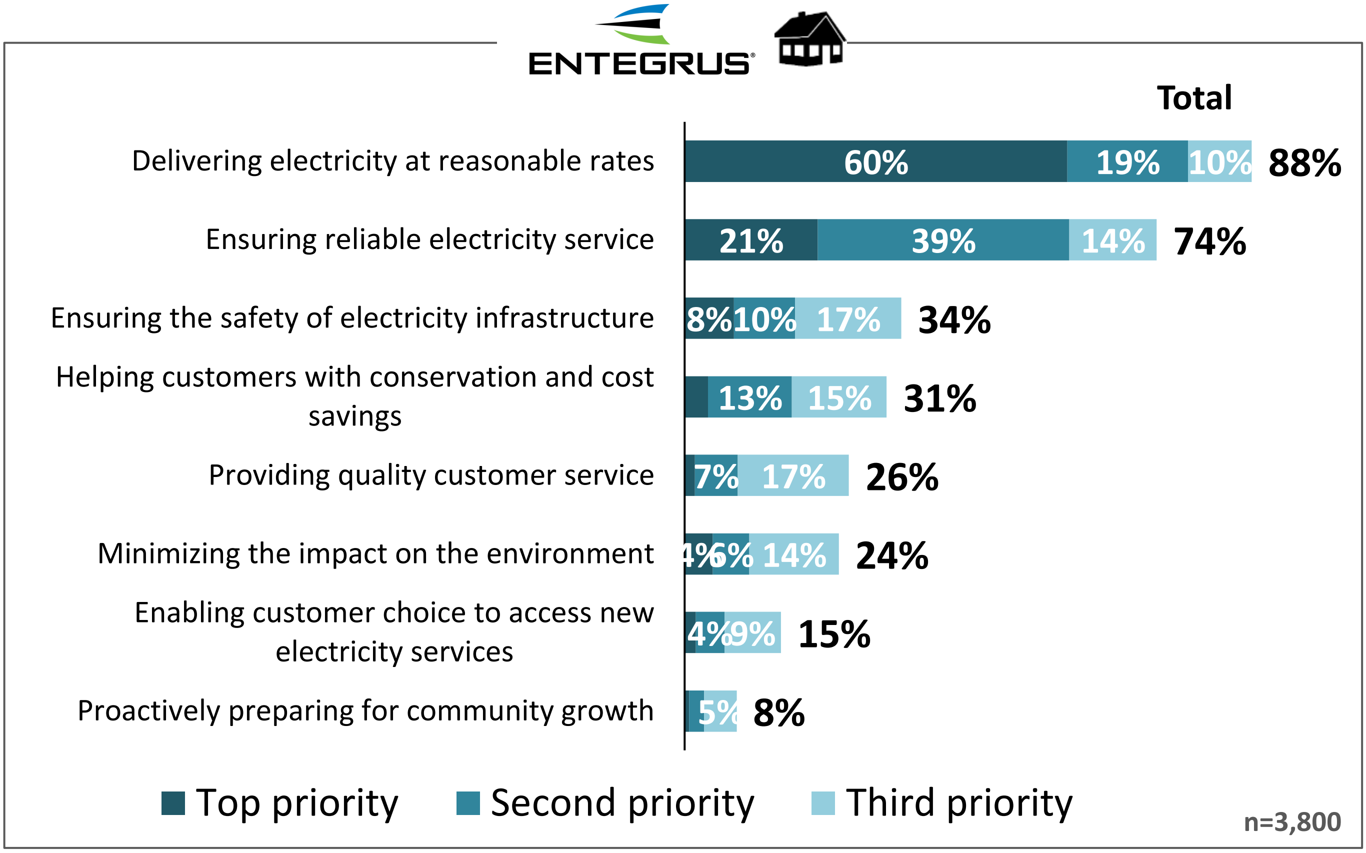
Online Workbook

Ranking Entegrus Priorities

Residential

Q

Thinking again about the things that Entegrus should be focusing on, please rank your top 3 priorities – where '1' would be the most important, '2' the second most important, and '3' the third most important.



Bill impact on finances % who choose priority in their top 3	Significant impact	Impact	No impact
Delivering electricity at reasonable rates	94%	90%	82%
Ensuring reliable electricity service	67%	74%	79%
Ensuring the safety of electricity infrastructure	23%	34%	43%
Helping customers with conservation and cost savings	43%	32%	20%
Providing quality customer service	30%	25%	22%
Minimizing the impact on the environment	19%	23%	29%
Enabling customer choice to access new electricity services	18%	13%	15%
Proactively preparing for community growth	6%	9%	10%

Online Workbook

Additional Entegrus Priorities

Residential

Q

The list above may not include all the outcomes that matter to you. Are there any other important priorities that Entegrus should be focusing on that weren't included in the list above?

Additional Comments	%
Lower costs/keep reasonably priced	2.5%
Environmentally friendly alternatives	1.5%
Reliable service/reduce outages and time to restore power	0.5%
Provide quality customer service	0.5%
All options are equally important	0.4%
Ensure safety/upgrades to aging infrastructure	0.3%
Bury the lines	0.2%
Transparency/breakdown of charges	0.2%
Ensure the safety of workers	0.2%
Other	1.6%
Don't know	0.3%
None	92.0%

Note: Only responses >0.1% shown

Online Workbook

Importance of Technology Priorities

Residential

Q How importance are each of the following investments in new technology that Entegrus could focus on?

New technology that can help Entegrus find efficiencies and reduce customer costs [average = **8.8**]

Not at all important	0	1	2	3	4	5	6	7	8	9	10	Extremely important
	1%	0%	0%	1%	1%	3%	3%	7%	13%	16%	53%	

New technology that would reduce the number and length of outages [average = **8.3**]

Not at all important	0	1	2	3	4	5	6	7	8	9	10	Extremely important
	1%	1%	1%	1%	1%	5%	5%	10%	16%	18%	39%	

New technology that can help customers better manager their electricity usage [average = **7.9**]

Not at all important	0	1	2	3	4	5	6	7	8	9	10	Extremely important
	2%	1%	1%	1%	2%	7%	6%	11%	16%	16%	33%	

New technology to reduce the environmental impact of Entegrus' operations [average = **7.5**]

Not at all important	0	1	2	3	4	5	6	7	8	9	10	Extremely important
	4%	2%	2%	3%	3%	9%	7%	11%	14%	13%	32%	

New technology that enables customer choice to access new electricity services [average = **7.0**]

Not at all important	0	1	2	3	4	5	6	7	8	9	10	Extremely important
	4%	2%	2%	3%	3%	12%	9%	13%	15%	12%	21%	

New technologies that make it easier to interact with Entegrus [average = **6.4**]

Not at all important	0	1	2	3	4	5	6	7	8	9	10	Extremely important
	7%	3%	3%	4%	4%	14%	9%	13%	13%	12%	16%	

Note: "Don't know" not shown.

Online Workbook

Importance of Technology Priorities

Residential

Q How importance are each of the following investments in new technology that Entegrus could focus on?

	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No Impact
New technology that can help Entegrus find efficiencies and reduce customer costs	8.8	8.8	8.8	8.8	8.8
New technology that would reduce the number and length of outages	8.4	8.1	8.0	8.4	8.5
New technology that can help customers better manage their electricity usage	7.9	7.9	7.9	8.0	7.8
New technology to reduce the environmental impact of Entegrus' operations	7.5	7.5	7.2	7.5	7.6
New technology that enables customer choice to access new electricity services	7.0	6.9	7.1	7.0	6.8
New technologies that make it easier to interact with Entegrus	6.4	6.3	6.6	6.4	6.1

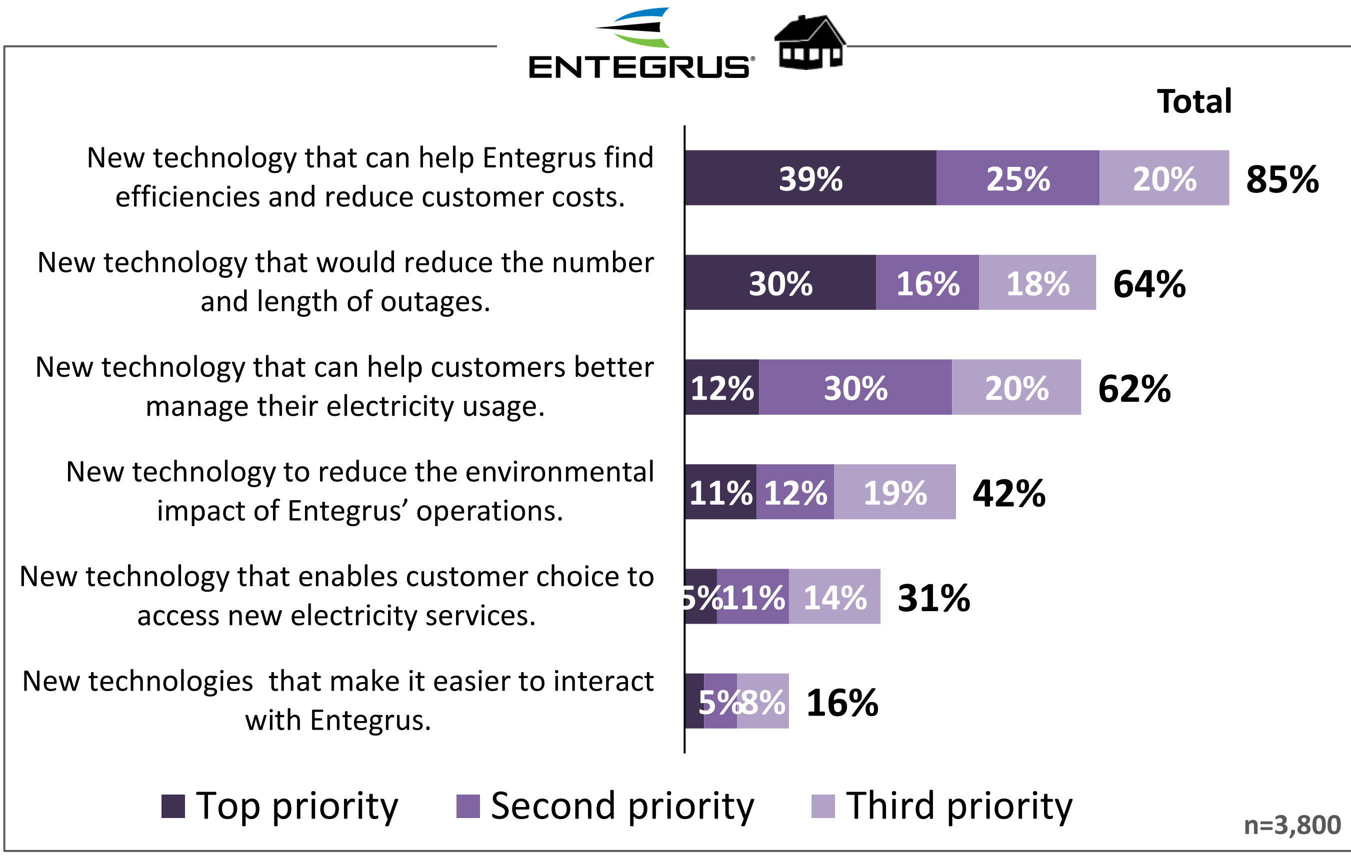
Note: "Don't know" not shown.

Online Workbook

Ranking Technology Priorities

Residential

Q Thinking again about the things that Entegrus should be focusing on, please rank your top 3 technology priorities – where '1' would be the most important, '2' the second most important, and '3' the third most important.



Region % who choose priority in their top 3	Legacy Entegrus	St. Thomas
New technology that can help Entegrus find efficiencies	85%	85%
New technology that would reduce the # and length of outages	68%	56%
New technology that can help customers better manage usage	60%	65%
New technology to reduce environmental impact	41%	44%
New technology that enables customer choice	30%	33%
New technologies that make it easier to interact with Entegrus	16%	17%

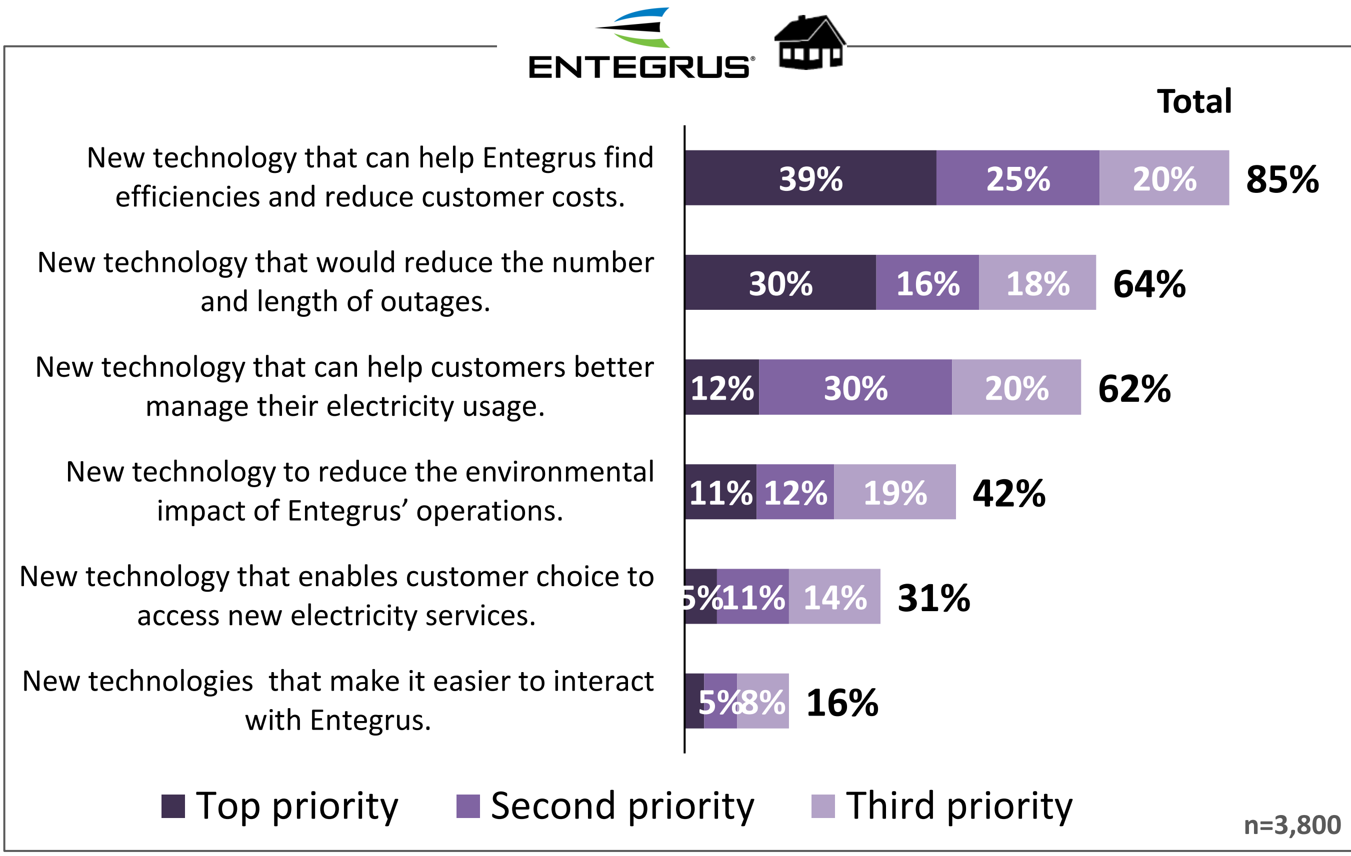
Online Workbook

Ranking Technology Priorities

Residential

Q

Thinking again about the things that Entegrus should be focusing on, please rank your top 3 technology priorities – where '1' would be the most important, '2' the second most important, and '3' the third most important.



Bill impact on finances % who choose priority in their top 3	Significant impact	Impact	No impact
New technology that can help Entegrus find efficiencies	84%	85%	85%
New technology that would reduce the # and length of outages	58%	66%	67%
New technology that can help customers better manage usage	65%	64%	57%
New technology to reduce environmental impact	38%	40%	48%
New technology that enables customer choice	34%	29%	30%
New technologies that make it easier to interact with Entegrus	21%	15%	13%

INNOVATIVE RESEARCH GROUP

Online Workbook

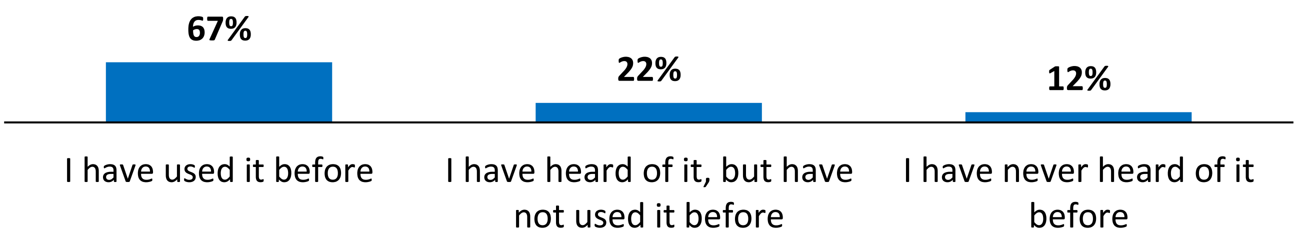
Entegrus' Digital Tools – The Entegrus.com Website

Residential

Q How familiar are you with the following digital tools that are offered by Entegrus?

The Entegrus.com website

ENTEGRUS

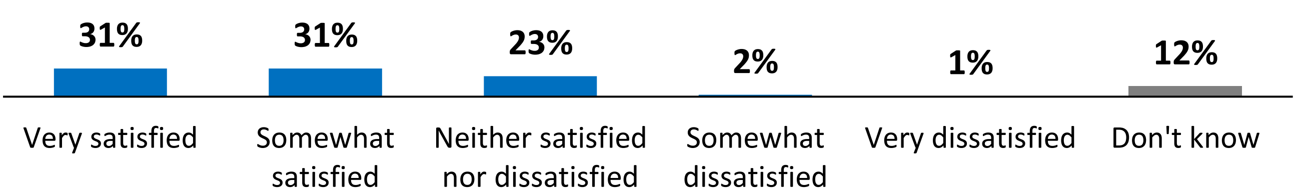


n=3,800

	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No impact
Have used it	65%	70%	66%	66%	68%
Have heard of it, but not used it	23%	19%	21%	23%	21%
Have not heard of it	12%	12%	14%	11%	10%

Q Please indicate whether you are satisfied or dissatisfied with each of the following tools.

ENTEGRUS



n=3,360

	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No impact
Satisfied (Very + Somewhat)	62%	64%	62%	61%	64%
Neutral	22%	25%	23%	25%	20%
Dissatisfied (Very + Somewhat)	3%	3%	5%	2%	3%

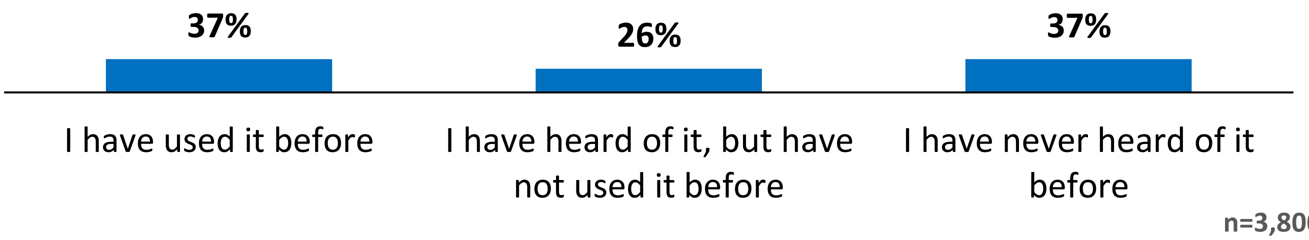
Online Workbook

Entegrus' Digital Tools – The Online Outage Map

Residential

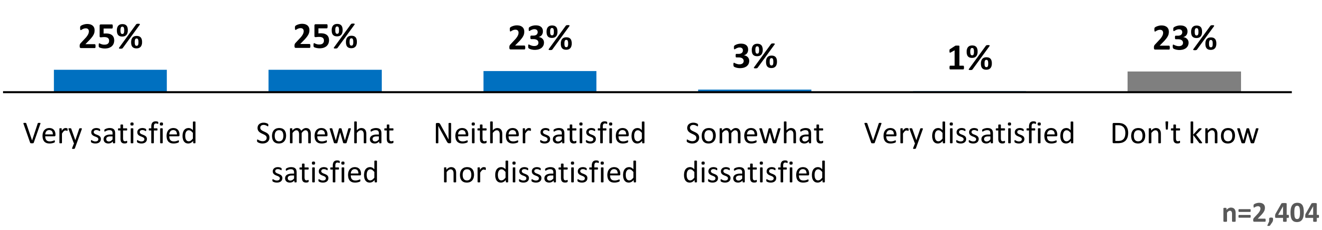
Q How familiar are you with the following digital tools that are offered by Entegrus?

The online outage map



	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No impact
Have used it	43%	23%	37%	36%	38%
Have heard of it, but not used it	26%	26%	27%	26%	26%
Have not heard of it	31%	51%	36%	38%	36%

Q Please indicate whether you are satisfied or dissatisfied with each of the following tools.



	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No impact
Satisfied (Very + Somewhat)	53%	39%	51%	50%	48%
Neutral	22%	27%	24%	24%	22%
Dissatisfied (Very + Somewhat)	4%	5%	4%	3%	5%

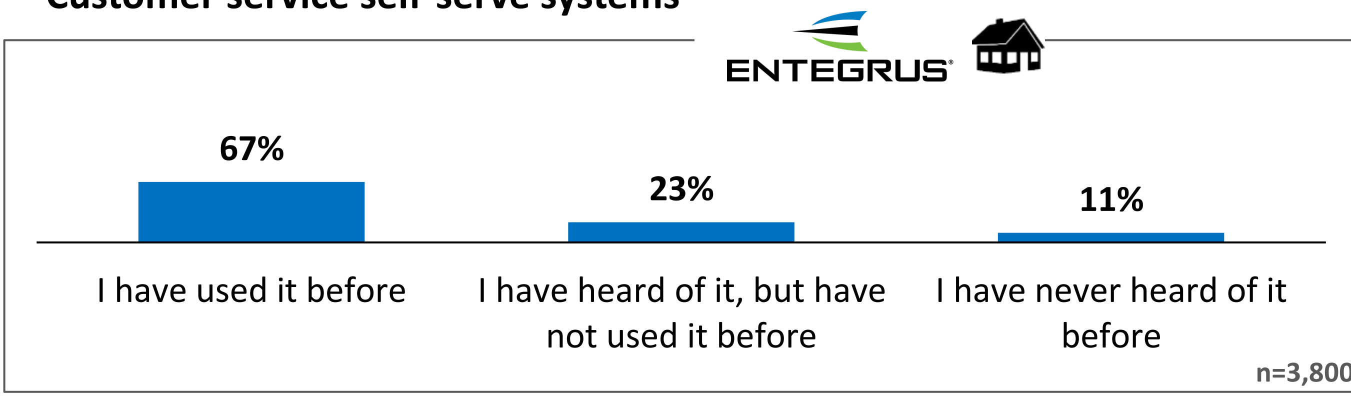
Online Workbook

Residential

Entegrus' Digital Tools – Customer Service Self-Serve Systems

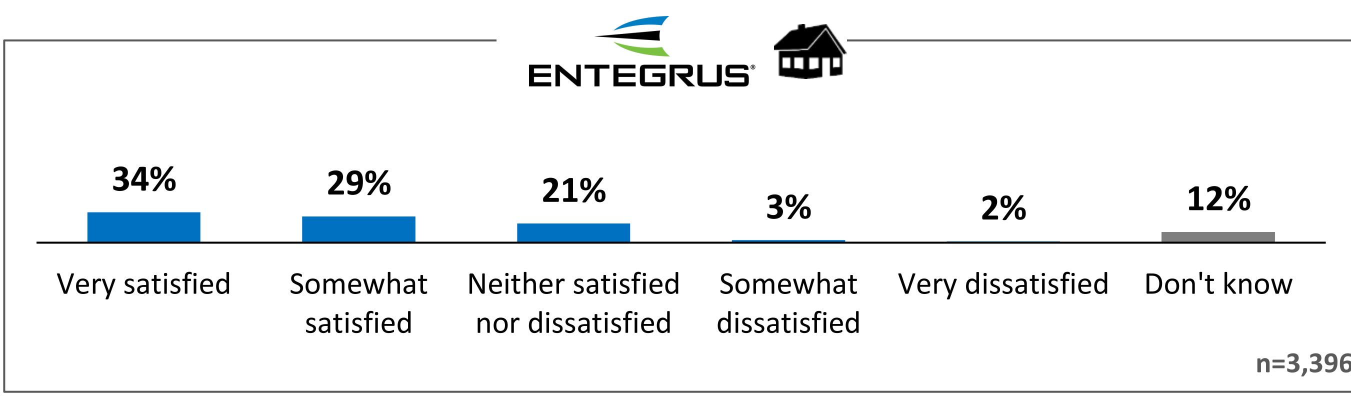
Q How familiar are you with the following digital tools that are offered by Entegrus?

Customer service self-serve systems



	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No impact
Have used it	65%	70%	65%	67%	68%
Have heard of it, but not used it	24%	20%	22%	23%	23%
Have not heard of it	11%	10%	13%	10%	9%

Q Please indicate whether you are satisfied or dissatisfied with each of the following tools.



	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No impact
Satisfied (Very + Somewhat)	62%	64%	60%	63%	64%
Neutral	21%	21%	23%	22%	18%
Dissatisfied (Very + Somewhat)	4%	5%	6%	3%	4%

Online Workbook

Additional Digital Tools or Services

Residential

Q Are there any additional digital tools or services that you would like Entegrus to provide?

Additional Comments	%
Improvements to the website/make digital tools more user friendly	0.9%
Mobile app for outage communication and updates	0.8%
Prefer ability to speak with a live agent	0.6%
All is good/satisfied with digital tools	0.6%
Not tech savvy/prefer to use paper	0.6%
Clearer breakdown of charges, including time of use	0.5%
Better outage communication/text notifications	0.5%
Lower the rates	0.4%
Ability to see usage in real time	0.3%
Billing issues/payment options	0.3%
Tools and programs to help reduce costs	0.3%
Other	0.9%
Don’t know	0.2%
None	93.1%

Note: Only responses >0.1% shown

INNOVATIVE
RESEARCH GROUP

Residential Customers

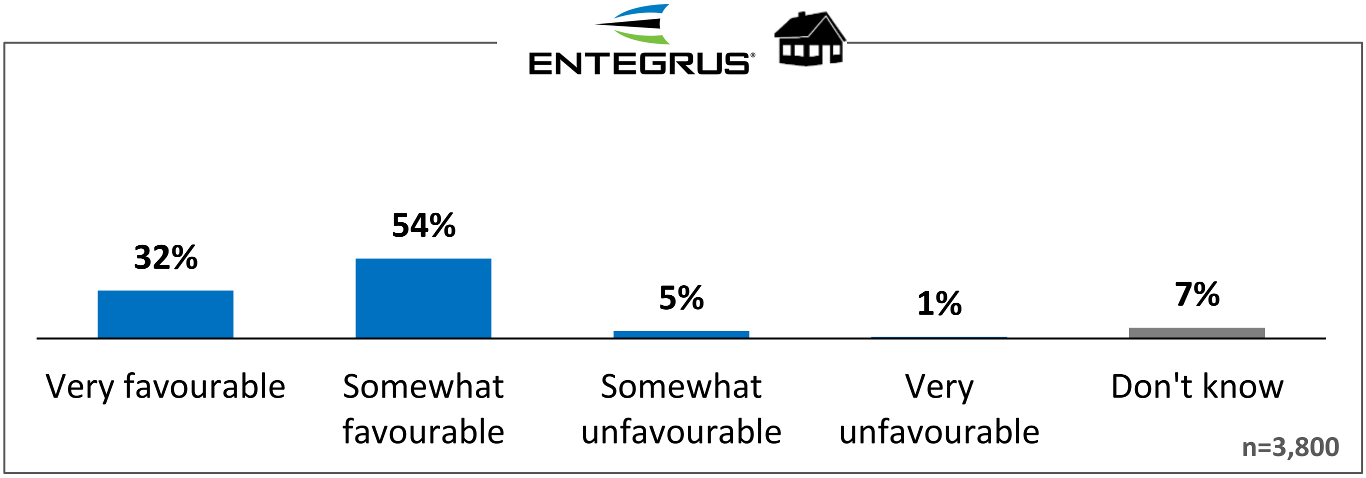
Workbook Diagnostics

Online Workbook

Workbook Impression

Residential

Q Overall, did you have a favourable or unfavourable impression of the customer engagement you just completed?

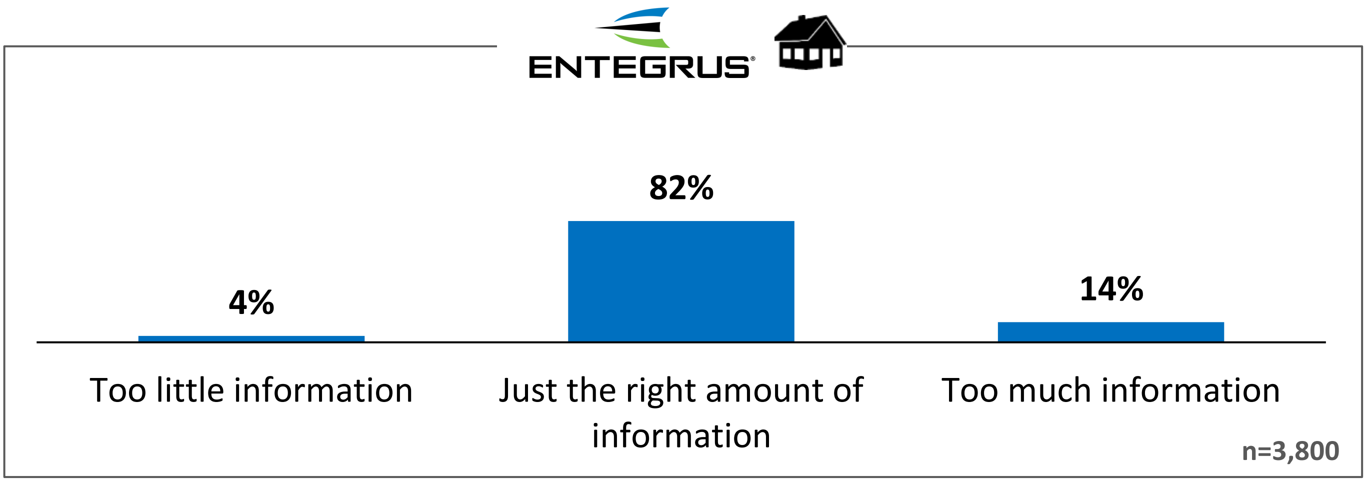


	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No Impact
Very favourable	32%	32%	26%	31%	39%
Somewhat favourable	54%	53%	52%	57%	52%
Somewhat unfavourable	5%	6%	8%	4%	4%
Very unfavourable	1%	1%	2%	0%	1%
Favourable (Very + Somewhat)	**87%**	**85%**	**79%**	**89%**	**91%**
Unfavourable (Very + Somewhat)	**6%**	**7%**	**10%**	**4%**	**5%**

Online Workbook
Amount of Information

Residential

Q In this customer engagement, do you feel that Entegrus provided too much information, not enough, or just the right amount?



	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No Impact
To little information	4%	4%	7%	3%	3%
Just the right amount	82%	82%	78%	84%	83%
Too much information	14%	13%	14%	13%	13%

Online Workbook

Content Missing from Engagement

Residential

Q Was there any content missing that you would have liked to have seen included in this customer engagement?

Additional Comments	%
Survey was too long/complicated	1.7%
Plans to lower costs	0.7%
Transparency regarding operations and spending	0.6%
Clearer explanations of charges and rates	0.6%
Survey was biased/don’t trust it	0.5%
Future plans for the system and associated costs	0.4%
Alternative/green energy plans	0.4%
More discussion/information on water charges	0.4%
Plans to use/adapt to new technology	0.4%
Infrastructure upgrades – timelines and costs	0.3%
Reasons for outages/why some regions experience more	0.3%
General positive comment	0.3%
Help for seniors/lower income households	0.2%
Information on consumption and conservation efforts	0.2%
Other	1.5%
Don’t know	0.2%
None	91.4%

Note: Only responses >0.1% shown

Online Workbook
Outstanding Questions

Residential

Q Is there anything that you would still like answered?

Additional Comments	%
Reduce costs/water and sewage charges	1.6%
Will lines be buried underground?	0.6%
Information on green energy initiatives	0.5%
Billing issues/end time of use	0.4%
Survey is biased/too long	0.3%
Survey is informative/well done	0.3%
Good reliable service	0.3%
Information on grid upgrades, poles and cables	0.3%
Transparency on operations, profits, costs	0.3%
Solar panels/wind turbines – negative comment	0.3%
Continue to upgrade to avoid service disruptions	0.3%
Would like updates/findings of study	0.2%
Electric cars and charging stations information	0.2%
Breakdown/explanation of charges	0.2%
Other	1.5%
None	92.7%

Note: Only responses >0.2% shown

Small Business Customers

Online Workbook Results

Online Workbook
Survey Design & Methodology

INNOVATIVE was engaged by Entegrus Powerlines Inc. to gather input on their proposed distribution system plan. Throughout this report, actual pages of the workbook that customers completed are included in the order that they were seen and are indicated by a watermark that says “workbook page”.

Field Dates & Workbook Delivery

The **Small Business Online Workbook** was sent to all Entegrus small business customers who have provided the utility with an email address. Customers had an opportunity to complete the workbook between **June 21st and July 20th, 2021**.

Each customer received a unique URL that could be linked back to their annual consumption, region and rate class.

In total, the small business workbook was sent to **1,597** customers via e-blast from INNOVATIVE. Reminder emails were sent weekly to those who had not yet completed the workbook.

Residential Online Workbook Completes

A total of **160** (unweighted) Entegrus small business customers completed the online workbook via a unique URL.

Sample Weighting

The small business online workbook sample has been weighted proportionately by consumption quartiles and region in order to be representative of the broader Entegrus service territory.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by quartile and region.

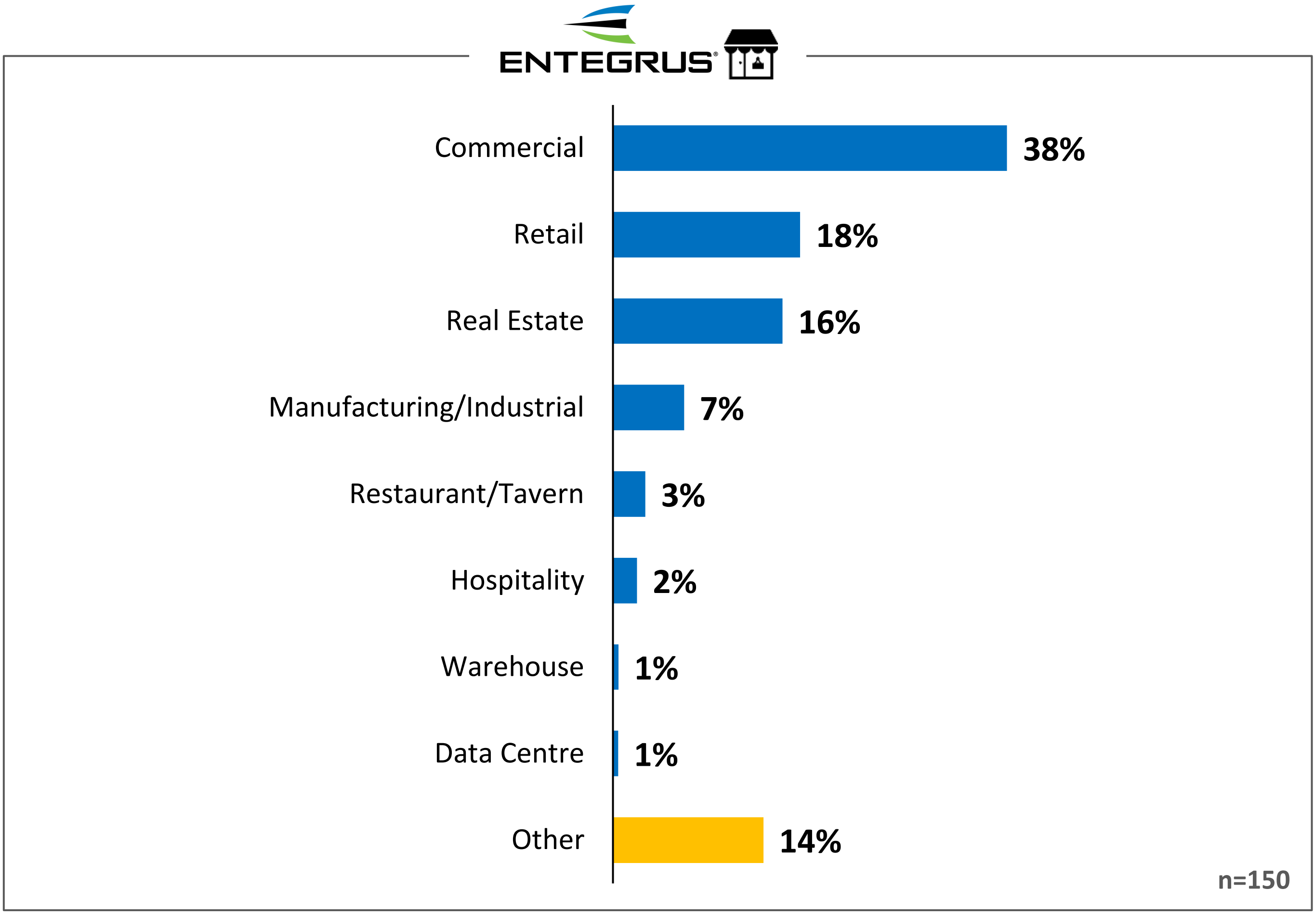
	Consumption Quartiles				Total
	First	Second	Third	Fourth	
Chatham	6 (10)	11 (10)	16 (11)	16 (12)	49 (43)
St. Thomas	13 (13)	8 (13)	14 (10)	9 (9)	44 (46)
Strathroy	4 (3)	4 (3)	1 (4)	3 (4)	12 (14)
Rest	11 (11)	18 (11)	14 (13)	12 (12)	55 (47)
Total	34 (38)	41 (37)	45 (37)	40 (38)	160 (150)

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

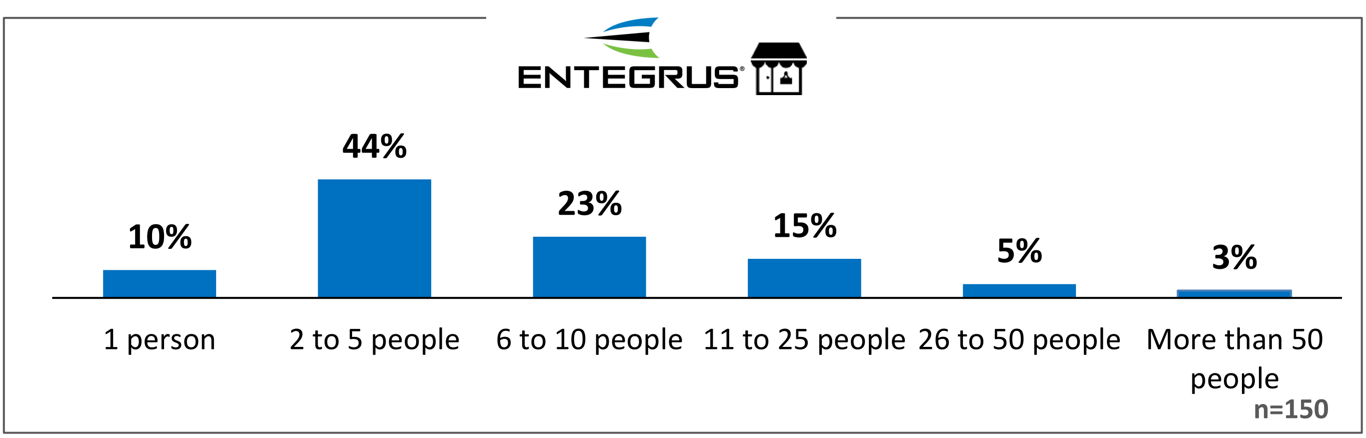
Online Workbook

Demographic breakdown

Q Which of the following best describes the sector in which your business operates? Would you say…



Q Including yourself, how many people work at your organization?



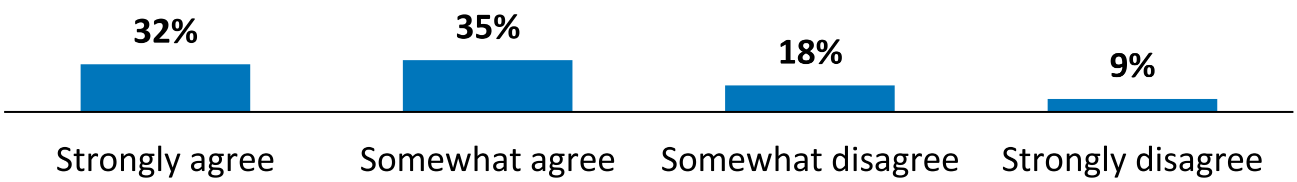
Online Workbook
Environmental Controls

Small Business

Now we would like to shift the focus, and ask you some general questions about the electricity system in Ontario. To what extent do you agree or disagree with the following statements?

Q The cost of my organization's electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.

ENTEGRUS

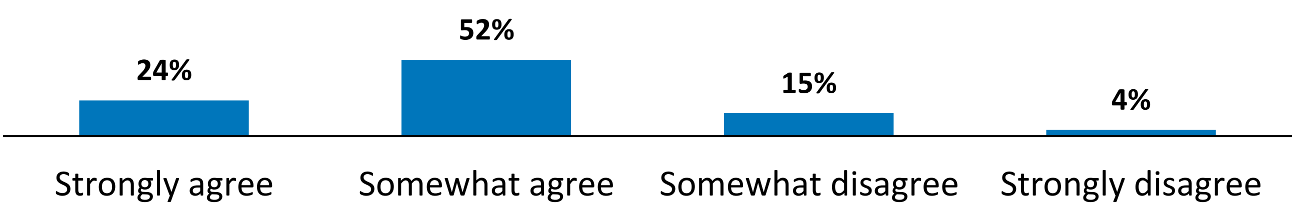


"Don't know/no opinion" (6%) not shown.

n=150

Q Customers are well served by the electricity system in Ontario.

ENTEGRUS



"Don't know/no opinion" (4%) not shown.

n=150

Online Workbook

Planning for the Future: 2021-2025 Investment Plan

Small Business

About this Customer Engagement

Welcome to Entegrus' customer engagement survey!

As Entegrus plans for the future, they need your input on choices that will impact the services you receive and the rates that you pay for the delivery of electricity.

- **Entegrus is currently in the process of developing its investment plan for 2021 to 2025.** This plan will determine the investments Entegrus makes in equipment and infrastructure, the services it provides, and the rates you pay.
- **Entegrus is now looking for your input on its draft plan** to ensure it is making spending decisions that matter to you, the customer.
- **Later this year, Entegrus will provide its investment plan** to the public regulator, the Ontario Energy Board (OEB) for its scrutiny.
- **Between now and 2025, Entegrus will execute its 2021 to 2025 investment plan,** ultimately, impacting the services you receive and the delivery of electricity throughout the communities that Entegrus serves.

This survey will take approximately 20-30 minutes to complete and can be done so at your convenience. Once you begin, your progress will be saved, and you can return to the customer engagement at any time.

All individual responses will be kept confidential. Innovative Research Group (INNOVATIVE), an independent research company, has been hired to gather your feedback.

Those who complete the questions that follow will be invited to enter a draw to win one of two (2) $500 prepaid VISA gift cards.

Electricity 101

Who is Entegrus?

Entegrus is a regulated electricity distributor that owns and operates distribution systems serving 17 communities in Southwestern Ontario, stretching between Wheatley (to the west), St. Thomas (to the east), Parkhill (to the north) and Lake Erie (to the south). The Entegrus service territory covers an area of approximately 5,600 square kilometres and the distance and time between Parkhill and Wheatley is about 170km. or a two-hour drive.

The utility's service territory today is a product of multiple mergers and acquisitions of previously independent distributors dating back to the late-1990s. The electrification of Southwestern Ontario dates back to the early 1900s. Most of the initial system expansion in the Entegrus communities occurred between 1950 and 1970. Some of the equipment in Entegrus' distribution system is more than 50 years old.

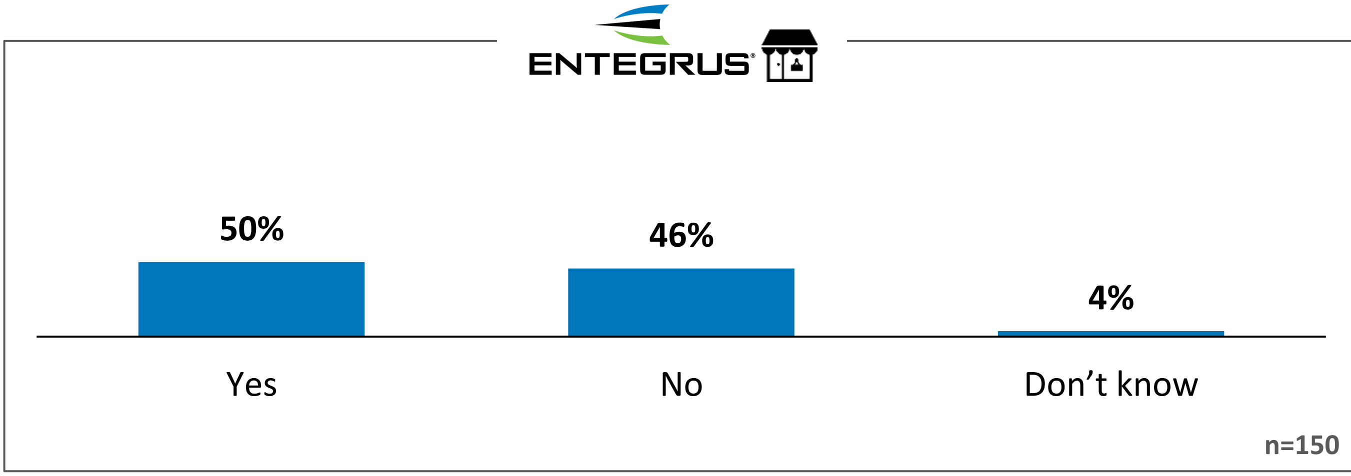
The most recent and significant addition to Entegrus' asset base is the amalgamation of Entegrus' assets with those of the former St. Thomas Energy, approved by the OEB on March 15, 2018.

Online Workbook

Familiarity with St.Thomas Merger

Small Business

Q Had you heard of the Entegrus merger with St. Thomas Energy before this survey?



	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No Impact
Yes	46%	61%	52%	50%	49%
No	52%	33%	48%	44%	47%
Don't know	3%	6%	--	6%	5%

Electricity 101

What is Entegrus' role in Ontario's electricity system?

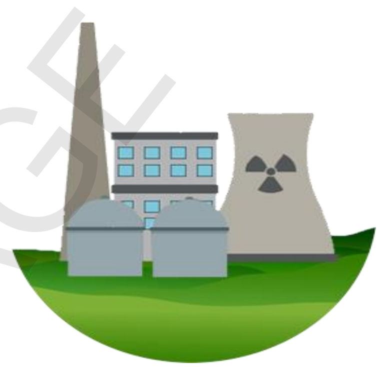
Ontario's electricity system is owned and operated by public, private and municipal corporations across the province. It is made up of three key components: **generation**, **transmission** and **distribution**.

Generation

Where electricity comes from

Ontario gets its electricity from a mix of energy sources. About half comes from nuclear power. The remainder comes from a mix of hydroelectric, natural gas, wind and solar.

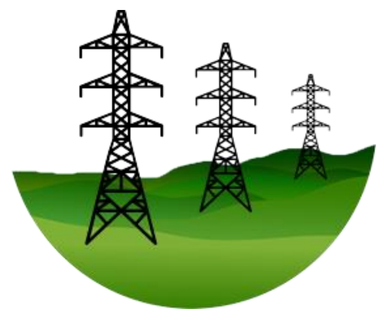
Ontario Power Generation, a government-owned company, generates almost half of Ontario's electricity. The other half comes from multiple generators who have contracts with the grid operator to provide power from a variety of sources.



Transmission

How electricity travels across Ontario

Once electricity is generated, it must be transported to urban and rural areas across the province. This happens by way of high voltage transmission lines that serve as highways for electricity. The province has more than 30,000 kilometres of transmission lines, most of which is owned and operated by Hydro One.

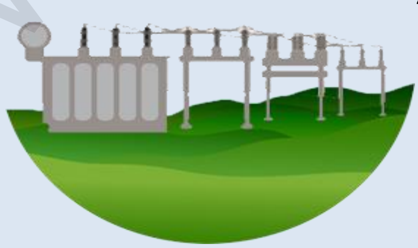


Local Distribution

How electricity is delivered to the end-consumer

Entegrus is responsible for the last step of the journey: distributing electricity to customers through its distribution system.

- Entegrus manages all aspects of the electricity distribution business throughout 17 communities in Southwestern Ontario and is regulated by the Ontario Energy Board (OEB).
- Entegrus is jointly owned by the Municipality of Chatham-Kent (72%), the Corporation of the City of St. Thomas (20%) and Corix Infrastructure Inc. (8%).
- Entegrus is entirely funded through the rates its customers pay and does not receive taxpayer money to fund its operations or its investments in the distribution system.



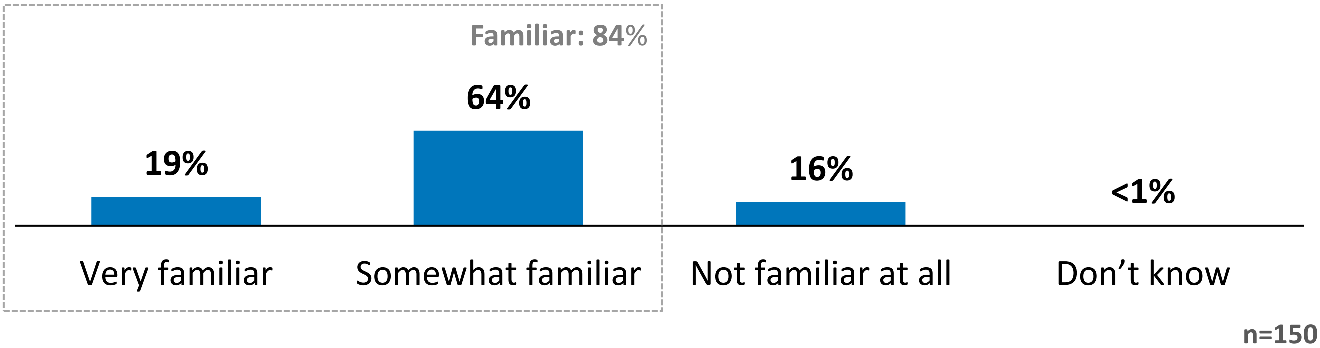
Online Workbook

Familiarity with Entegrus

Small Business

Q How familiar are you with Entegrus, which operates the electricity distribution system in your community?

ENTEGRUS



	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No Impact
Very familiar	26%	5%	21%	18%	19%
Somewhat familiar	59%	76%	62%	67%	62%
Not familiar at all	15%	18%	16%	13%	18%
Don't know	--	2%	--	1%	--
Familiar (Very + Somewhat)	**85%**	**80%**	**84%**	**85%**	**82%**

Online Workbook

Planning for the Future: 2021-2025 Investment Plan

Small Business

Electricity 101

How much of my electricity bill goes to Entegrus?

- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board (OEB), the provincial energy regulator.
- While **Entegrus** is responsible for collecting payment for the entire electricity bill – as well as water charges for many of its communities – Entegrus retains only a portion of the electricity delivery charge. The electricity delivery charge also includes Hydro One transmission costs and system losses.
- Distribution makes up about 22% of the typical small business customer's bill.
- The rest of your bill is passed onto provincial transmission companies, power generation companies, the provincial government and regulatory agencies.

Entegrus Sample Monthly Bill

(Based on monthly usage of 2,000 kWh)

Account Number:
000 000 000 000 0000

Meter Number:
00000000

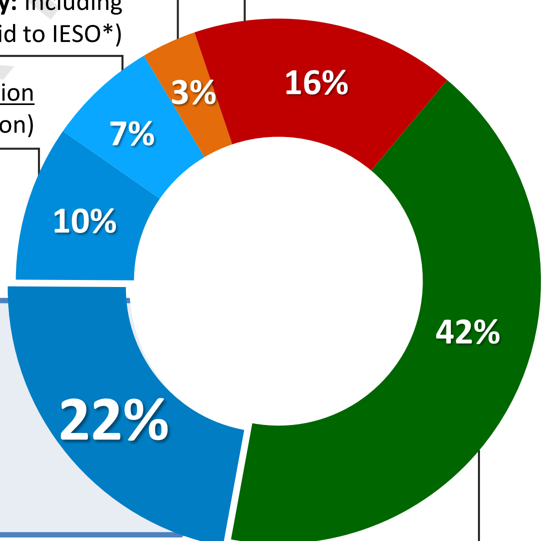
Your Electricity Charges	
Electricity	
Off-Peak @ 8.2 ¢/kWh	104.96
Mid-Peak @ 11.3 ¢/kWh	40.68
On-Peak @ 17 ¢/kWh	61.20
Delivery	95.58
Regulatory Charges	8.39
Total Electricity Charges	**$310.81**
HST	40.40
Ontario Electricity Rebate	(-$103.19)
Total Amount	**$248.02**

Regulatory Charges

Harmonized Sales Tax**

Other Delivery: Including Natural Line Loss (paid to IESO*)

Delivery: Transmission (Hydro One's Portion)



Delivery:
Distribution
Entegrus' typical portion of the total bill is
$55.09

*IESO = Independent Electricity System Operator

Electricity Generators
(Including Ontario Electricity Rebate)

** HST is calculated before applying the Ontario Electricity Rebate and is therefore above 13%.

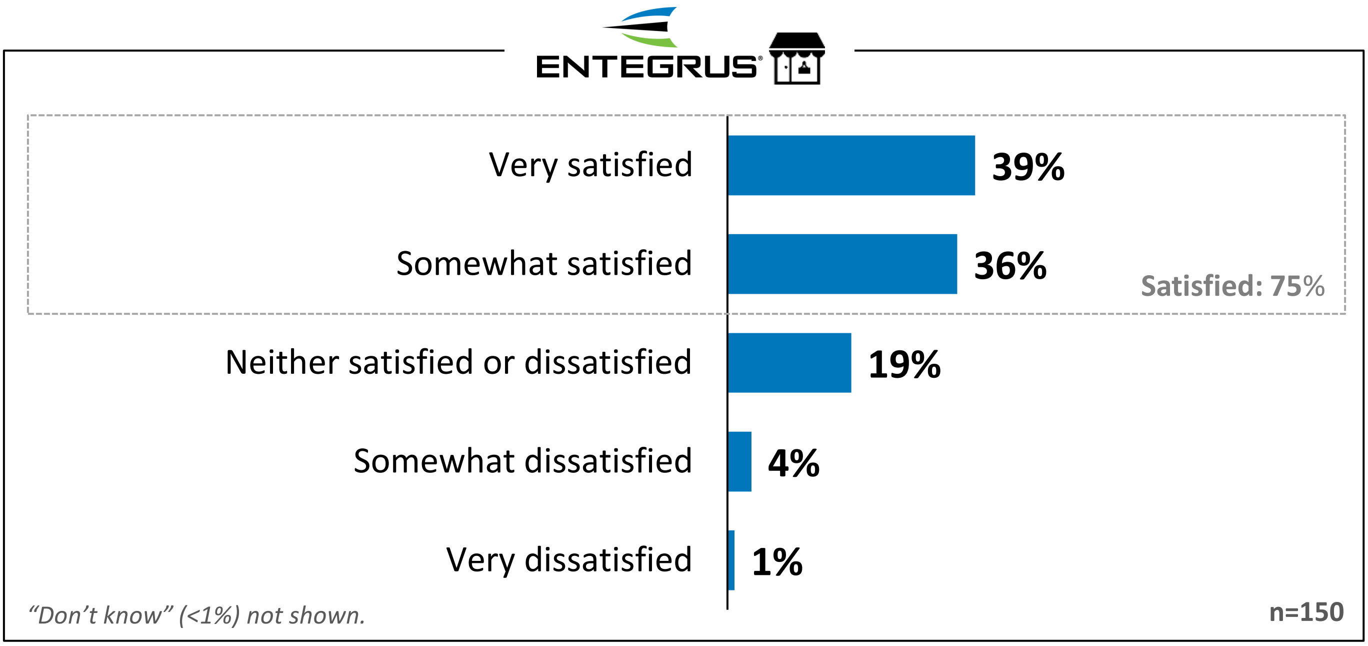
Note: In the workbook, bill impacts differed based on rate zone (Entegrus main or St.Thomas). Entegrus main shown above.

Online Workbook

Overall Satisfaction with Entegrus

Small Business

Q Thinking specifically about the services provided to you and your community by Entegrus, overall, how satisfied or dissatisfied are you with the services that your organization receives?



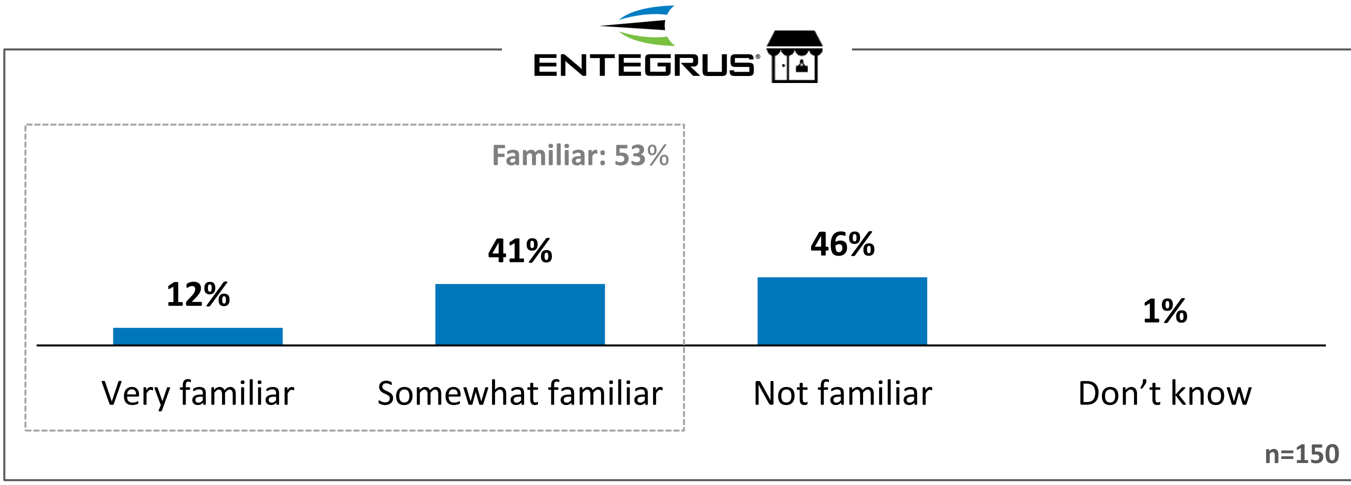
	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No Impact
Very satisfied	38%	41%	36%	36%	45%
Somewhat satisfied	38%	31%	39%	41%	28%
Neither satisfied nor dissatisfied	18%	22%	16%	23%	20%
Somewhat dissatisfied	5%	--	8%	--	3%
Very dissatisfied	--	4%	--	--	3%
Satisfied (Very + Somewhat)	**76%**	**73%**	**75%**	**77%**	**73%**
Dissatisfied (Very + Somewhat)	**5%**	**4%**	**8%**		**7%**

Online Workbook

Familiarity with Percentage of Bill Remitted to Entegrus

Small Business

Q Before this survey, how familiar were you with the amount of your organization's electricity bill that went to Entegrus?



	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No Impact
Very familiar	14%	7%	21%	6%	9%
Somewhat familiar	40%	45%	44%	48%	32%
Not familiar at all	45%	48%	33%	45%	59%
Don't know	1%	--	2%	--	--
Familiar (Very + Somewhat)	**54%**	**52%**	**65%**	**55%**	**41%**

Online Workbook

How Entegrus can Improve Services to Customers

Small Business

Q Is there anything in particular you would like Entegrus to do to improve its services to your organization?

Additional Comments	%
Lower rates/no increases	4.4%
Improve billing issues	2.9%
Improve infrastructure and reliability	2.8%
More incentives and education for energy conservation	2.6%
Lower or remove delivery charge/debt repayment fees/water service charge	1.7%
Improve customer service	1.5%
Adjust/eliminate time of use charges	0.9%
Improve online resources	0.5%
Different rates for different demographics	0.5%
Improve outage communication	0.5%
More alternative/green energy sources and less fossil fuels	0.4%
Other	3.5%
None	77.7%

Entegrus Background

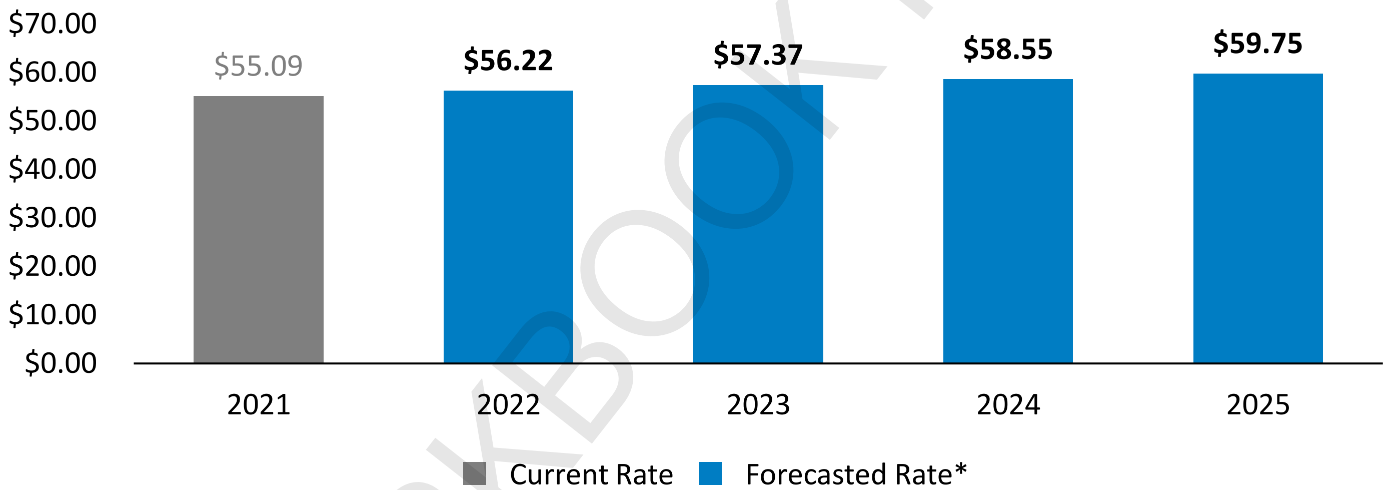
How much can you expect to pay over the next few years?

Prior to merging, both **Entegrus** and **St. Thomas Energy** had their rates set by the OEB, meaning, the amount they can charge customers for the delivery of electricity.

While the merger was finalized in April 2018, for the eight years that follow the OEB has limited your future rate increases to less than inflation. That means that each year Entegrus is permitted to increase rates to reflect inflation minus savings targets established by the OEB. This requires Entegrus to keep cost increases below inflation.

For a small business customer like yourself, the distribution charge for the **typical bill is estimated to increase by approximately 2.05%** on average for the next five years (based on 2020 OEB inflation), until 2026.

Distribution Portion of the Bill per Month (2021-2025)



* These estimates are preliminary and are subject to your feedback as the investment plan is finalized.

Where does your money go?

Entegrus has two budgets; **operating and capital.** The operating budget covers recurring expenses, such as salaries, taxes, fuel costs, and rent. Until 2026, Entegrus <u>cannot</u> ask for any additional money for operating expenses.

<u>This engagement is about the capital budget</u>. This budget covers things like poles, wires, cables, transformers, meters, computers and programs, vehicles, and buildings.

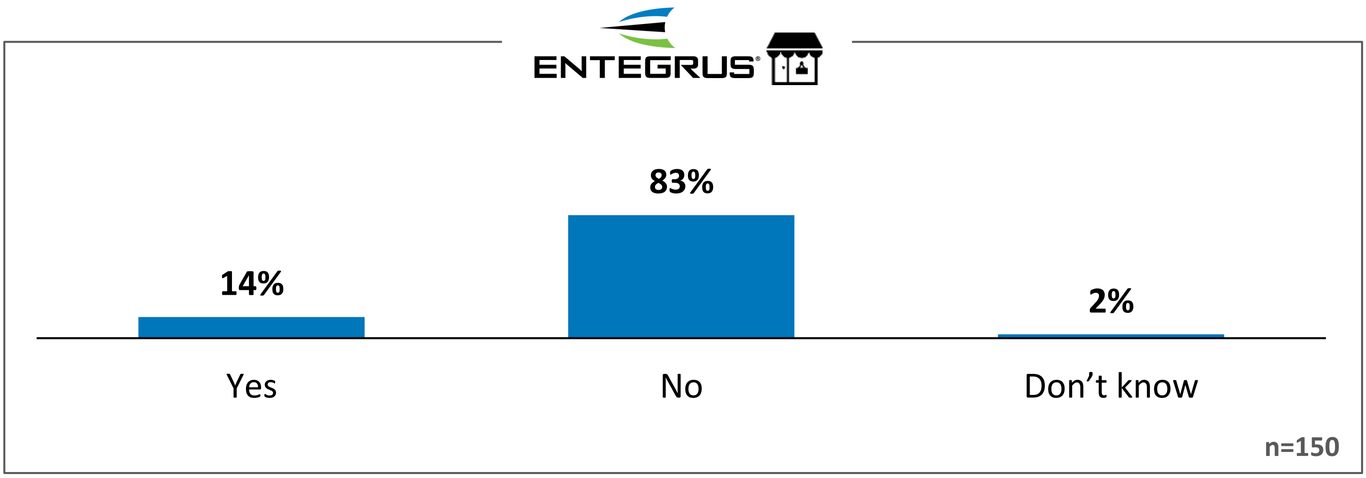
Note: In the workbook, bill impacts differed based on rate zone (Entegrus main or St.Thomas). Entegrus main shown above.

Online Workbook

Familiarity with Bill Increase over Next 5 Years

Small Business

Q Before this survey, were you aware that for a small business customer like yourself, the distribution charge for the typical bill is estimated to increase by approximately 2.05% on average for the next five years, until 2026?



	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No Impact
Yes	15%	12%	16%	17%	10%
No	83%	84%	84%	80%	87%
Don't know	2%	4%	--	4%	3%

Entegrus Background

How are rates staying below inflation?

Entegrus' 2021 to 2025 investment plan sets out to balance a stronger investment focus on reliability and unprecedented customer growth with an objective of keeping distribution rates affordable for customers.

Accordingly, while investment levels have increased above historic levels in 2019 and 2020 and will continue to remain at higher levels through 2025, there are no proposed incremental rate impacts arising from this investment plan for the period from 2021-2025.

In order to safeguard against reliability deterioration, Entegrus' shareholders have decided to spend above the currently approved rates with no added cost to customers from 2021-2025. These additional investments will address aging infrastructure to safeguard reliability and thereby also ensure a strong foundation to enable future customer investments in electric vehicles and customer-owned electricity generation.

Spending above current rates

As mentioned earlier, Entegrus is entirely funded through the rates its customers pay and does not receive taxpayer money to fund its operations or its investments in the distribution system.

That said, Entegrus shareholders have decided that the need for additional reliability investments cannot be put on hold, nor should customers be faced with incremental rate increases at this time. As such, over the 2018 to 2020 period, Entegrus invested an incremental $5.7 million in the distribution system beyond what was originally planned to address reliability and harmonize systems post-merger. For the 2021 to 2025 period, approximately $63 million will be invested in the distribution system, **including an estimated incremental $6.5 million to address reliability, at no additional cost to customers over that period.**

Finding internal cost savings

According to the latest data published by the Ontario Energy Board of approximately 60 electricity providers from across the province, Entegrus had the 15th lowest total cost per customer. That means Entegrus is among the most efficient electricity distributors in Ontario.

Benchmarking isn't the only way that Entegrus measures its operational efficiency. Entegrus is a member of the GridSmartCity Co-operative, an organization that brings together 15 Ontario LDCs to collaborate and share knowledge, skills and expertise – with some of the goals being increased efficiency and cost savings through economies of scale.

Cost saving benefits include negotiated group rates for services and group savings on the procurement of wood poles, cables, wires, and transformers.

Additionally, through its merger with St. Thomas Energy, Entegrus continues to see annual savings of approximately $1.4 million each year through shared operating, maintenance, and administrative costs.

Entegrus Background

What is this engagement about?

This customer engagement is about finding the right balance between the service you receive and the price you pay.

The point of this engagement is to allow customers like yourself to provide feedback on whether Entegrus planners have found the right balance or whether they should consider different options that better reflect your views.

As mentioned earlier, Entegrus' 2021 to 2025 investment plan sets out to balance a stronger investment focus on reliability and unprecedented customer growth with an objective of keeping distribution rates affordable for customers.

Affordability is at the core of Entegrus' plans.

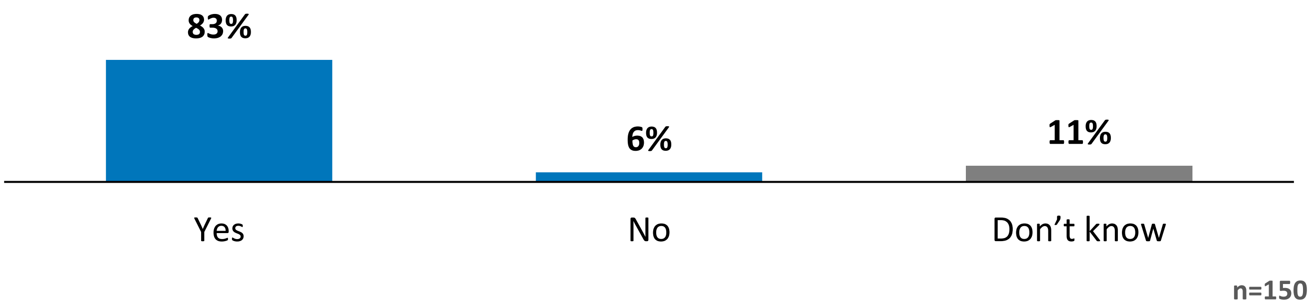
Before Entegrus finalizes its plans, it is coming to its customers with a final set of choices. For each choice, Entegrus has identified an option to stay within existing rates (including the incremental investments Entegrus is already planning). It has also identified options to increase investments where it will provide meaningful benefits to customers.

Online Workbook

Purpose of Customer Engagement

Small Business

Q Do you feel that the purpose of this customer engagement is clear?



	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No Impact
Yes	83%	81%	80%	81%	86%
No	6%	7%	8%	3%	9%
Don't know	11%	11%	12%	16%	5%

Additional Comments	%
Clearer/more detailed breakdown of proposed increases	2.2%
Survey is confusing/too long/need more information	1.8%
Outages/surges – general	0.6%
Rate increases are reasonable/upgrades are necessary	0.4%
None	95.0%

Entegrus Background

What are the key investment drivers for 2021 to 2025?

Entegrus has identified three primary investment drivers for the 2021 to 2025 period – **aging infrastructure (reliability), customer growth,** and **grid modernization**.

A damaged Entegrus distribution pole.

Aging Infrastructure: Recall, much of the initial economic expansion in Entegrus' service territory occurred between 1950 and 1970. That means parts of Entegrus' distribution system are now more than 50 years old.

Entegrus' 2021-2025 plan demonstrates a notable increased focus on replacing aging infrastructure. This is driven by the fact that portions of the distribution system have degraded beyond the expectation of the utility's 2016-2020 plans.

- This additional degradation became apparent in 2017 and 2018 when new technology and additional engineering staff enabled Entegrus to conduct a deeper system-wide infrastructure assessment, including resistograph pole testing.
- This assessment identified that the level of asset degradation was higher than originally forecast. Simultaneously, in 2018, customers began to experience an increase in power outages.

Overall, the additional work to replace aging infrastructure will mitigate reliability issues and provide a stronger distribution system foundation for later integration of future customer investments in electric vehicle and customer-owned electricity generation in the next planning cycle from 2026 to 2030.

Entegrus Background

What are the key investment drivers for 2021 to 2025?

Customer Growth: Even though many developers initially put projects on hold as a result of the COVID-19 pandemic, by the summer of 2020 Entegrus continued to experience unprecedented customer growth. High residential growth continues to occur in St. Thomas and other communities in the Entegrus northeast region including Strathroy and Mt. Brydges. Residential growth and significant levels of activity required to prepare the Entegrus distribution system to support fibre-to-the-home expansion by telecoms is also occurring in Chatham-Kent.

While customer growth remains high it is currently difficult to predict whether this trend will continue beyond 2021 given the circumstances of the pandemic.

A new subdivision located in St.Thomas

System Modernization: As described previously, the Entegrus service territory extends over an area of 5,600 square kilometres. Servicing each community requires significant travel. Being able to troubleshoot problems remotely reduces and in some cases eliminates the need to send a crew out for repairs.

While Entegrus' primary focuses are on reliability and servicing customer growth while keeping distribution rates affordable, the 2021 to 2025 plans do include focus on system modernization, including some automated distribution restoration technologies.

The plans also include further harmonization of legacy systems across the merged entity to help enable future investments in technology including electric vehicles and customer-owned electricity generation.

Online Workbook

Planning for the Future: 2021-2025 Investment Plan

Small Business

Entegrus Background

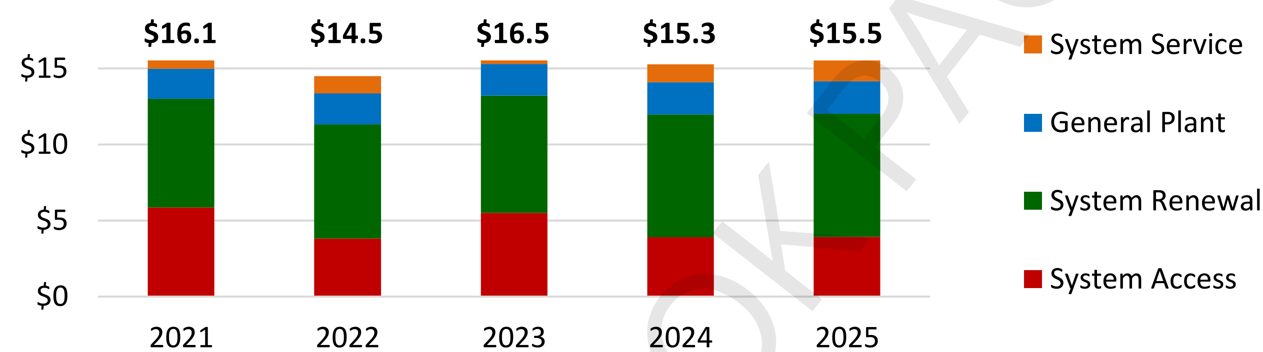
How does Entegrus plan future investments in the system?

Entegrus' **capital budget** covers items that have lasting benefits over many years such as investments in the core distribution system including poles, wires, cables, switches, and transformers.

Based on initial information and input from Entegrus' internal engineering and technical experts and emerging pressures on the distribution system, **Entegrus' draft capital budget is estimated to be $77.9 million over the five-year period between 2021 and 2025**.

Entegrus plans its capital investments in four categories.

2021-2025 Forecasted Capital Investments (Millions)*



** These estimates are preliminary, and are subject to your feedback as the business plan is finalized.*

System Access ($23 Million, averaging $4.6 per year)

"Must do" investments for new subdivisions, new upgraded commercial and industrial services, and relocating assets based on road infrastructure needs. Entegrus is expected to recover close to 65% of these costs from developers, internet providers, and larger business customers.

System Renewal ($38.5 Million, averaging $7.7 per year)

Replacement of aged overhead wires, poles, and pole mounted transformers, underground cables and transformers and distribution station upgrades.

General Plant ($10.4 Million, averaging $2.1 per year)

These are investments needed to support the distribution system, such as tools, vehicles, buildings, and computers.

System Service ($6 Million, averaging $1.2 per year)

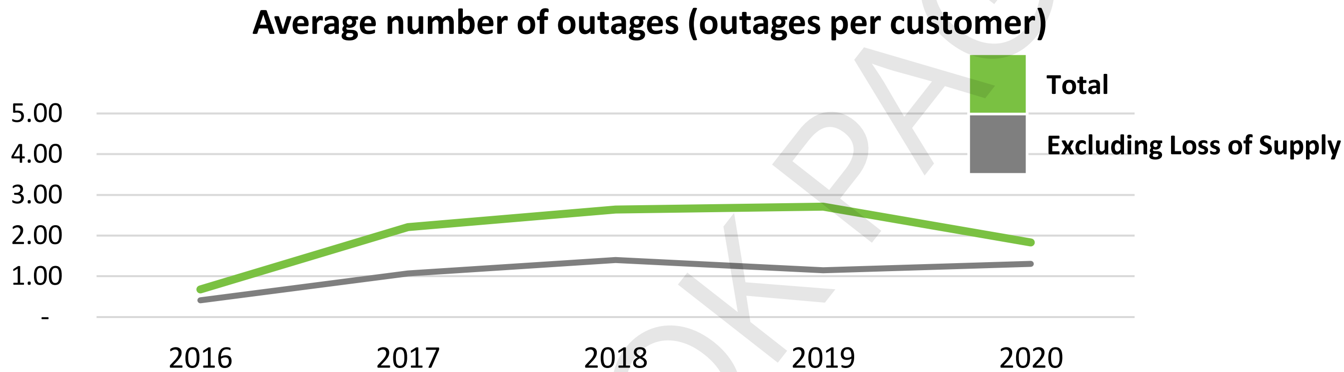
These investments consist of projects that address capacity constraints, improve system reliability and supply new growth.

Entegrus Background

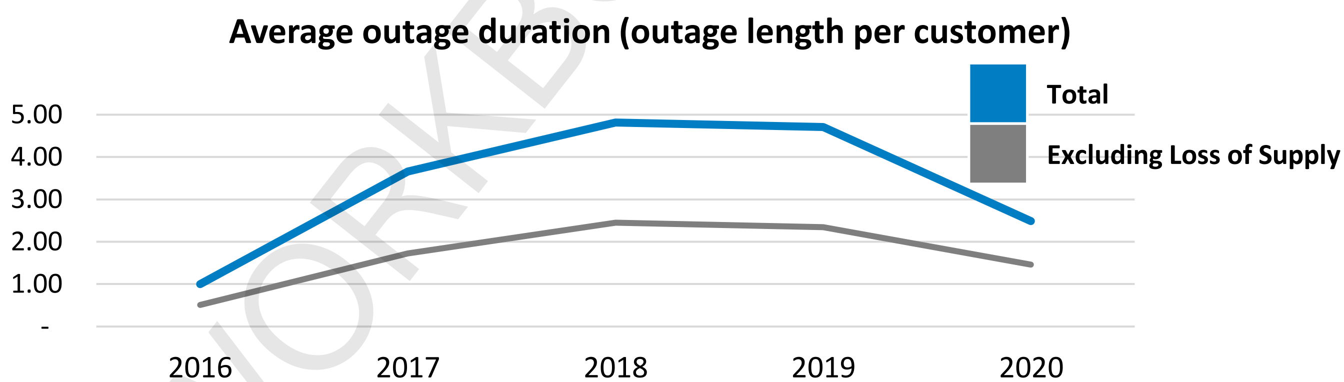
How does Entegrus' distribution system perform?

Entegrus tracks both the average number of power outages per customer and how long those interruptions last. Keep in mind that these are system averages, and your actual experience may be different. Some customers connected to newer lines may not experience any outages while others may experience more than the average number of outages each year.

Between 2016 and 2020, the typical Entegrus customer (excluding St. Thomas) experienced about two outages per year.



Over the same period, the average **duration** of an outage has been about 3.3 hours, some of which has been driven by loss of power supply due to significant weather events. Meaning when the power does go out, Entegrus is typically able to restore power in about three hours.



Loss of supply occurs when there is an interruption to the supply of electricity from the upstream electrical system operated by Hydro One. These failures are largely out of the control of Entegrus but there are investments that can be made to attempt to reduce the impacts of these outages including a more intelligent system that can automatically re-route power when one of these outages does occur. In fact, investments by Entegrus in automated switches have already avoided 18,000 customer outage hours between 2017 and 2020.

Note: St.Thomas outage statistics shown for St.Thomas customers

Entegrus Background

How does Entegrus' distribution system perform?

Recently, Entegrus, with the help of an independent third party, conducted a system-wide study to better understand the health of the system and the long-term implications on system reliability. This study concluded that the deterioration in Entegrus' reliability measures (illustrated above) required **timely and proactive intervention to maintain current levels of reliability** and start to slow, or halt, the reliability deterioration trend before it becomes irreversible.

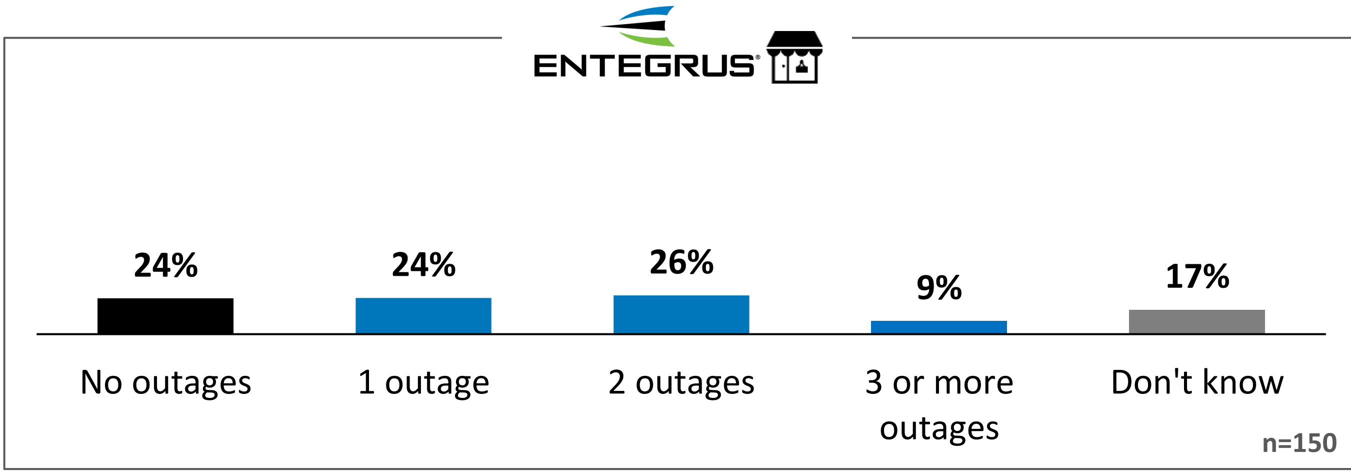
An Entegrus crew working to restore power during a winter storm.

Some of the effects of the proactive intervention undertaken in 2020 have already resulted in improvement; however, favourable weather and pandemic-related factors, such as fewer scheduled outages and less foreign interference (i.e. fewer vehicle accidents impacting the distribution system) contributed to the 2020 results.

Online Workbook

Number of Outages Experienced

Q Have you experienced any power outages at your business in the past 12 months which lasted longer than one minute?



	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No Impact
No outages	16%	42%	19%	17%	36%
1 outage	27%	20%	22%	23%	29%
2 outages	30%	18%	31%	38%	9%
3 or more outages	13%	--	13%	10%	4%

Entegrus Background

What contributes to a power outage?

In order to provide feedback on Entegrus' plan, it's important to understand how the distribution system has performed in the past as well as what is expected in the future.

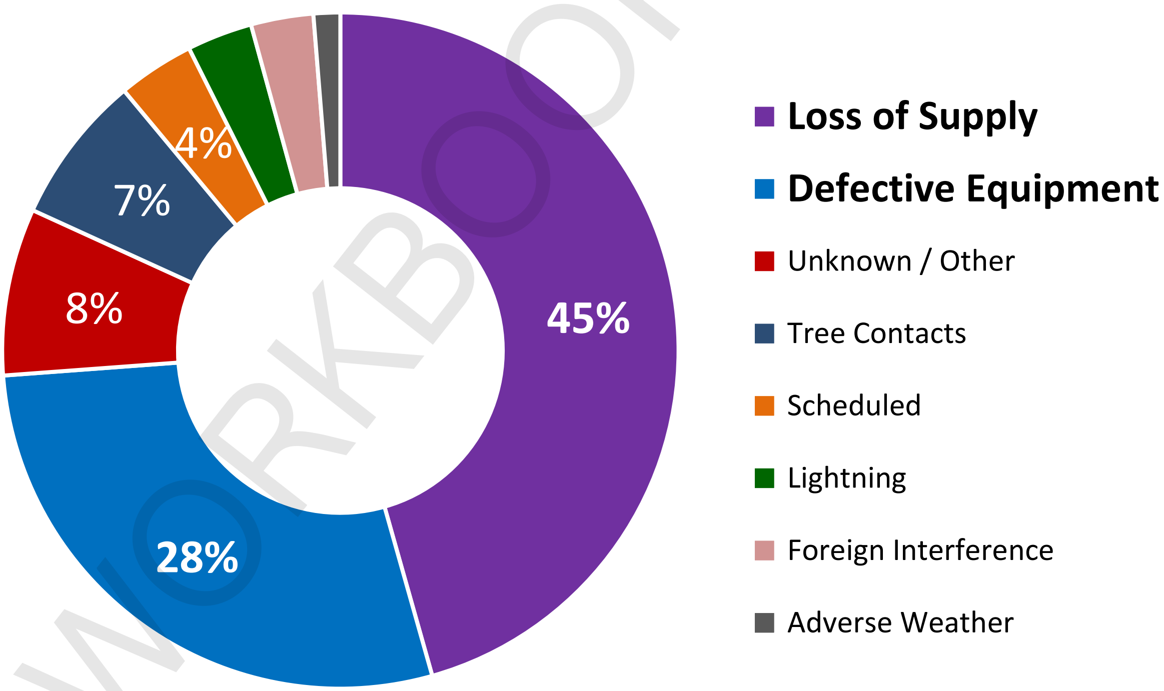
A core objective of Entegrus' 2021-2025 plan is to maintain reliability while making targeted improvements to those areas experiencing below average service.

In the Entegrus communities, the two primary contributors to outages account for 1-in-3 of all outages:

1. **Loss of supply** from the transmission system accounted for 45% of customer hours of interruption between 2016-2020. This is the single largest outage cause.

2. **Defective equipment** accounted for 28% of customer hours of interruption over the same period.

Customer Outage Duration (Hours) by Cause 2016-2020



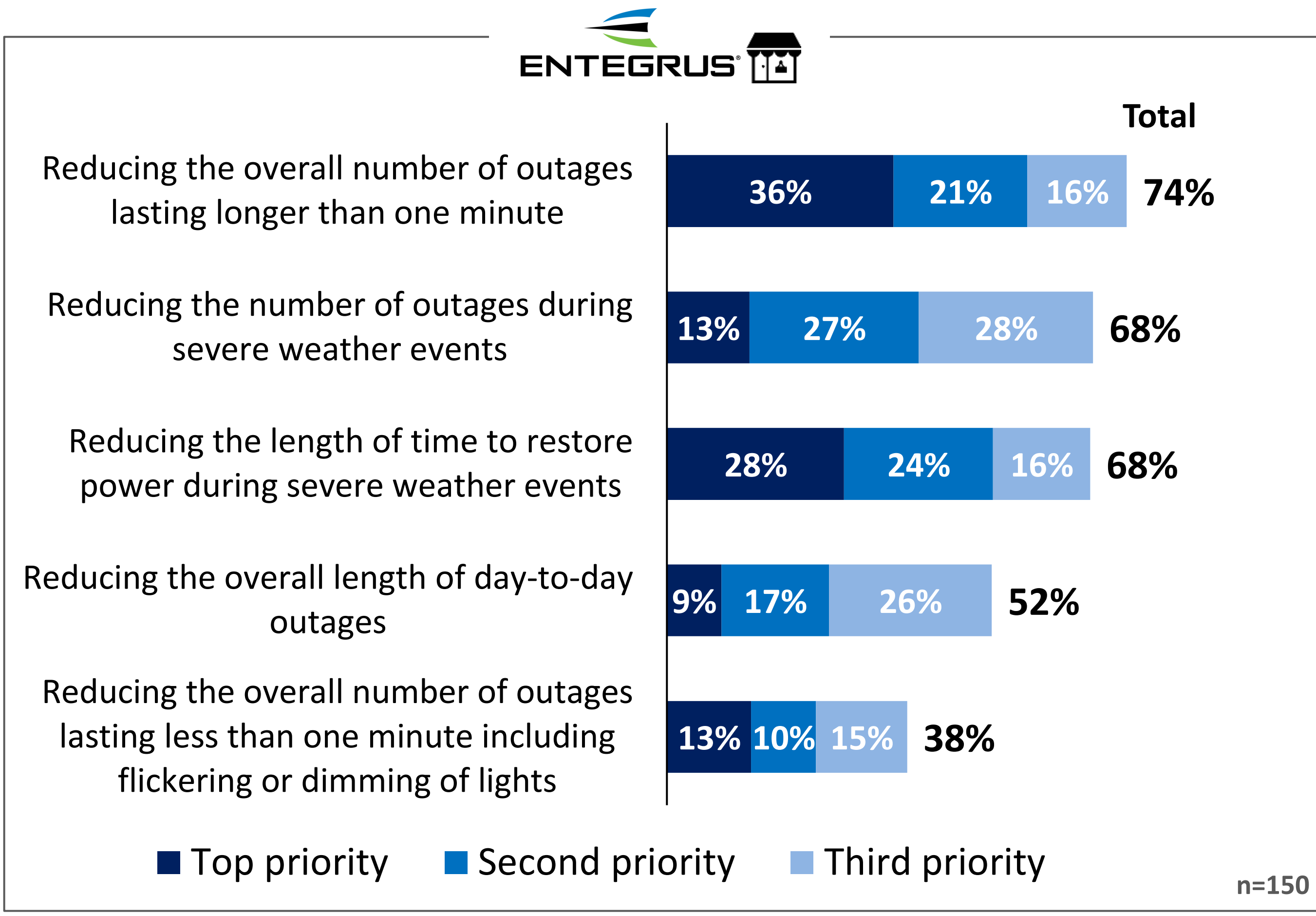
Note: St.Thomas outage statistics shown for St.Thomas customers

Online Workbook

Reliability Priorities

Q

Among the following reliability outcomes, which are the most important to you? *While all of these priorities may be important to you, please rank your top 3 priorities – where '1' would be most important, '2' the second most important, and '3' the third most important.*

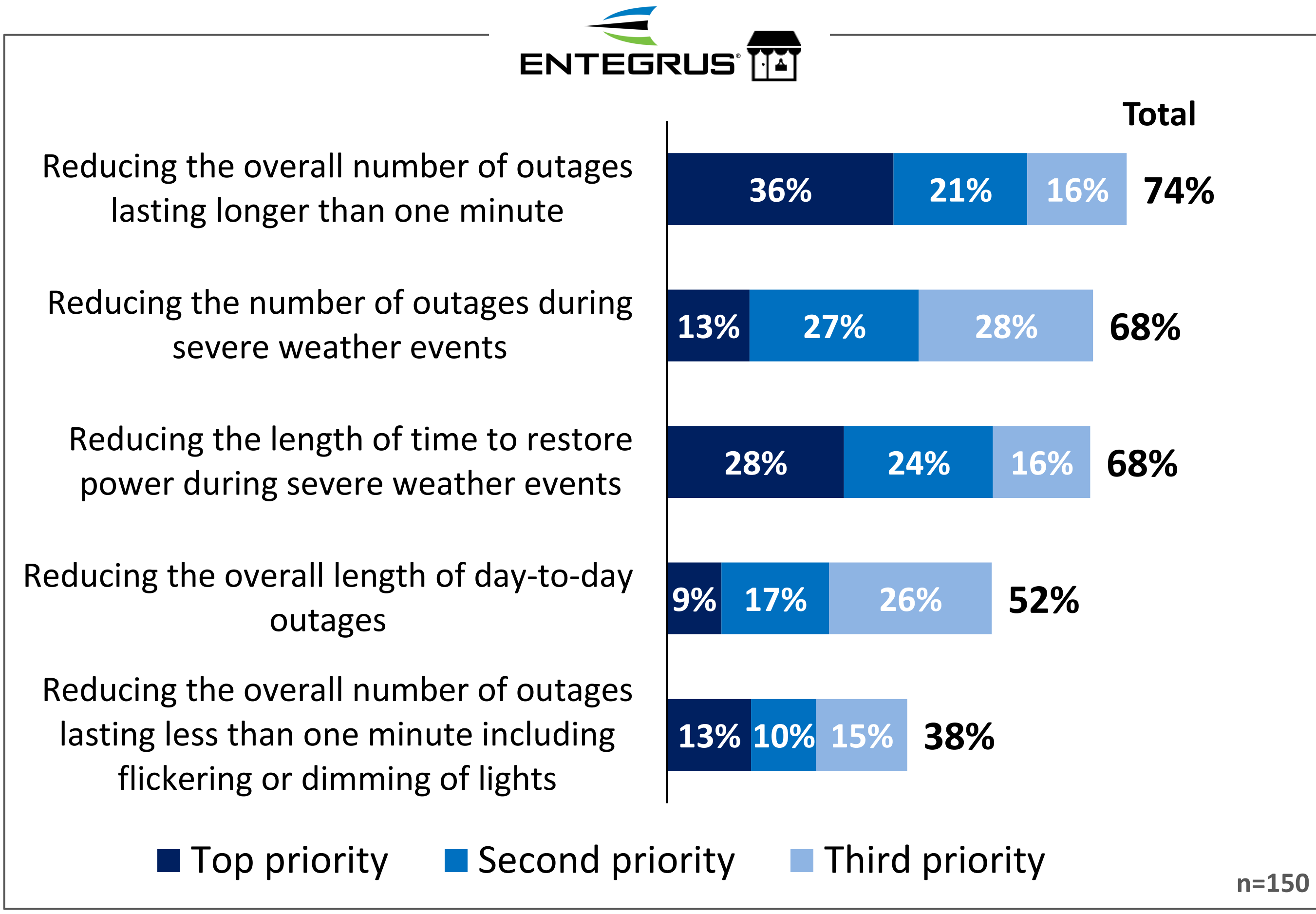


Region % who choose priority in their top 3	Legacy Entegrus	St. Thomas
Reducing the overall # of outages lasting >1 minute	71%	81%
Reducing the # of outages during severe weather events	69%	67%
Reducing the length of time to restore power during severe weather events	67%	69%
Reducing the overall length of day-to-day outages	55%	45%
Reducing the overall number of outages lasting less than one minute including flickering or dimming of lights	39%	38%

Online Workbook
Reliability Priorities

Small Business

Q Among the following reliability outcomes, which are the most important to you? *While all of these priorities may be important to you, please rank your top 3 priorities – where '1' would be most important, '2' the second most important, and '3' the third most important.*



Bill Impact on Finances % who choose priority in their top 3	Significant impact	Impact	No impact
Reducing the overall # of outages lasting >1 minute	67%	78%	76%
Reducing the # of outages during severe weather events	80%	64%	61%
Reducing the length of time to restore power during severe weather events	69%	66%	69%
Reducing the overall length of day-to-day outages	49%	49%	58%
Reducing the overall number of outages lasting less than one minute including flickering or dimming of lights	35%	44%	36%

Entegrus Background

How can Entegrus improve the services you receive?

As previously mentioned, Entegrus has committed to the OEB to limit your future rate increases to less than inflation until 2026.

An Entegrus crew installing a new pole.

That said, as part of the OEB policies, there is an option for utilities to apply for additional rate increases for discrete projects that are prudent, needed and not supported by existing rates. However, as previously noted, Entegrus has decided to continue to make certain additional reliability investments without asking customers for rate increases at this time, to keep distribution rates affordable in 2021-2025.

Looking ahead, Entegrus has identified two projects that will help mitigate reliability issues related to degraded infrastructure and provide a stronger distribution system foundation for later integration of electric vehicle and customer-owned generation infrastructure investments in the next planning cycle from 2026 to 2030. Entegrus is looking for your thoughts to determine whether it should pursue these two projects, financing these on its own until 2026, with no additional charges to customers.

As noted above, Entegrus will only be asking for increases of less than inflation from customers for the next five years and any investments made now will not impact your rates until the next planning period between 2026 and 2030.

Making Choices (1 of 2)

Line Modernization and Station Decommissioning

About 15% of Entegrus' customers are serviced by low voltage distribution systems. These low voltage lines were built in the 1950's, 1960's and 1970's and represent some of Entegrus' oldest distribution assets.

A low voltage transformer station.

These low voltage lines have much less capacity than modern lines and are supported by stations that are required to deliver this lower voltage. These stations look like small houses, or in some cases, are fenced-in areas containing weatherized electrical equipment. During an outage, the modern lines cannot be used to restore power to the low voltage lines, because they don't operate at the same voltage levels.

Due to the limited capacity of the low voltage lines, they are not suited for smart grid technology or customer-owned electricity generation. As such, this equipment has become functionally outdated and the risk of equipment failure is increasing.

For the past 10 years, Entegrus has focused on converting these low voltage lines to the modern technology. When enough lines are converted, Entegrus can decommission and sell the land that contains the low voltage stations.

Investing in these projects offers three primary benefits:

1. **Improved reliability through the new lines and transformers;**
2. **Increased capacity on each line to support customer growth, smart grid technology, and customer-owned electricity generation; and**
3. **Improved outage restoration from the enhanced back-up and availability of tie points at this higher voltage level.**

Entegrus currently has 19 of these stations supporting these low voltage lines still in use. To balance replacing other degraded assets and supporting customer growth, Entegrus planners are targeting the removal of 4 stations by 2025. At this pace, all of the low voltage lines would be replaced by modern lines and all the stations would be decommissioned beyond 2040.

However, because this equipment does not pose an urgent threat to reliability, if unforeseen distribution system priorities emerge over that period, it is the practice of Entegrus to divert resources away from these 4 lines modernization and station decommissioning projects to resolve more pressing priorities.

Online Workbook

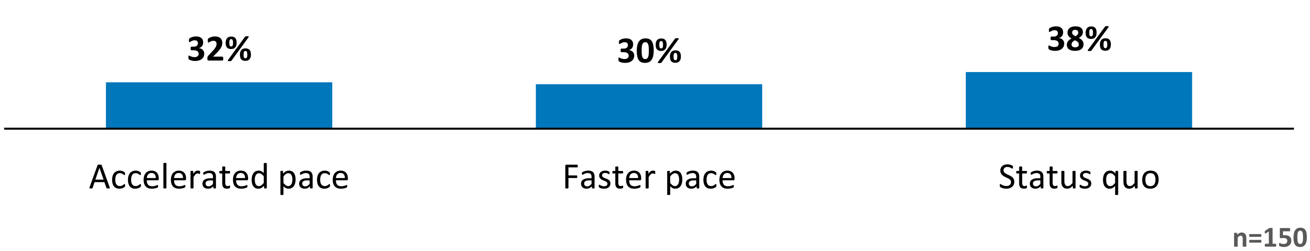
Choice 1: Line Modernization and Station Decommissioning

Small Business

Which of the following options do you prefer?

Option	Description	Expected Outcome
Accelerated Paced Line Modernization *<u>Additional</u> $1.00 - $1.40 per month starting in 2026*	Line modernization to allow the removal of 6 low voltage Stations to occur from 2021-2025 regardless of other priorities.	• Complete line modernization of all low voltage equipment and Station decommissioning by 2035 • Reduce risk of deterioration of reliability • Avoid some Station maintenance costs.
Faster Paced Line Modernization *<u>Additional</u> $0.50 - $0.70 per month starting in 2026*	Line modernization to allow the removal of 5 low voltage Stations to occur in 2021-2025 regardless of other priorities.	• Complete line modernization of all low voltage equipment and Station decommissioning by 2040 • Risk of deterioration of reliability continues • Escalating Station maintenance versus obsolescence.
Status Quo *Within current rates*	Continue to target line modernization to allow removal of 4 low voltage Stations, to occur in 2021-2025. Allow for diversion from this plan if other priorities emerge.	• Maintain low voltage Stations beyond 2040 • Higher risk of deterioration of reliability continues • Escalating Station maintenance versus obsolescence.
Additional Feedback (Optional)		

ENTEGRUS



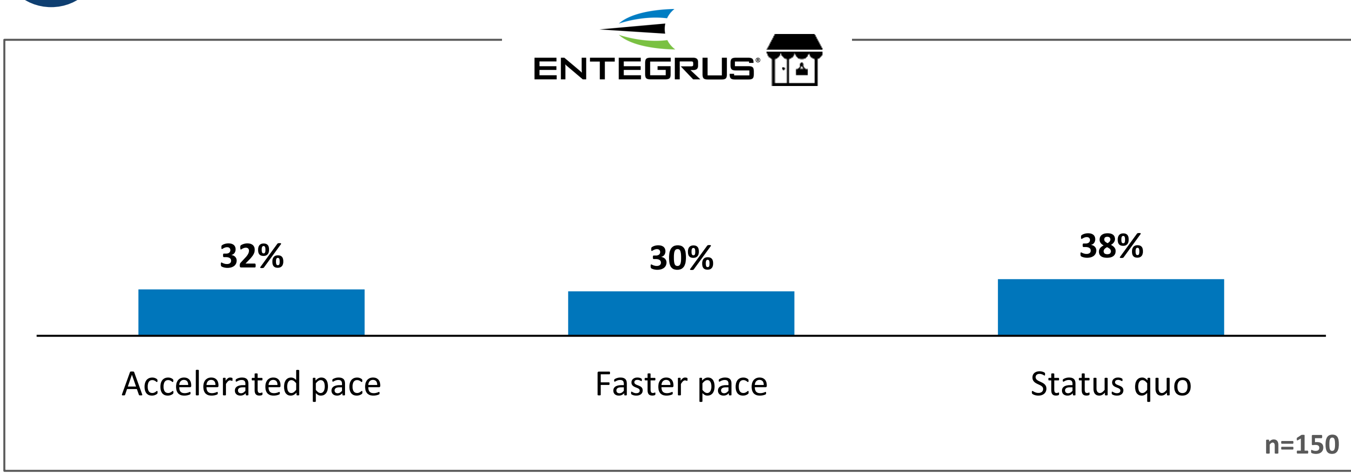
INNOVATIVE RESEARCH GROUP

Online Workbook

Choice 1: Line Modernization and Station Decommissioning

Small Business

Q Which of the following options do you prefer?



	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No Impact
Accelerated pace	36%	22%	39%	26%	29%
Faster pace	29%	34%	22%	30%	38%
Status quo	36%	45%	39%	43%	33%

INNOVATIVE RESEARCH GROUP

Online Workbook

Choice 1: Line Modernization and Station Decommissioning

Small Business

Q Which of the following options do you prefer?

Additional Comments	%
Find efficiencies from within/upgrades should have been planned into budget	1.2%
Greener alternatives/environmental implications	1.1%
Good reliable service – no complains	0.6%
Small price to pay/rate increase is reasonable	0.4%
Don’t know	0.6%
None	96.1%

Making Choices (2 of 2)

Implementing Smart Grid Technology

New technology has changed the way that Entegrus can manage and monitor the distribution system.

Intelligent (automated) switches

Intelligent (automated) switches allow Entegrus to automatically reroute power during outages and planned maintenance, reducing the length of time customers are without power and reducing reliance on crews travelling to the site to physically re-route power. When this automatic rerouting occurs, impacted neighbourhoods would experience an outage lasting less than one minute, rather than a lengthier interruption.

Entegrus has recently used automated switch technology to target more rural communities experiencing poor reliability due to loss of supply. These communities are served by two long lines from the provincial transmission system, and the technology allows the two lines to automatically back each other up when one line experiences an outage, eliminating the need for manual intervention.

However, Entegrus now sees an opportunity to roll this technology out in larger cities that have many interconnecting lines that can form “grids”. Doing so will offer multiple alternative paths for electricity to flow, bypassing the fault and avoiding potential widespread outages. Entegrus ran a successful pilot of intelligent switch technology on a single feeder line in Chatham in 2020.

Not only do these intelligent switches help reduce the length of time customers are without power, but they also help create a more integrated, advanced system that is better equipped to handle future technological advancements including electric vehicles and customer-owned electricity generation.

In its current draft plan, in order to afford to invest more dollars in replacement of poles and wires while limiting cost increases to customers, Entegrus plans to selectively install 6 more of these intelligent switches in 2021-2025. That said, there is a near term opportunity for a broad roll out of intelligent switches in the larger communities of Chatham and St. Thomas where there is the opportunity to increase connectivity by creating a medium or higher density of intelligent switches.

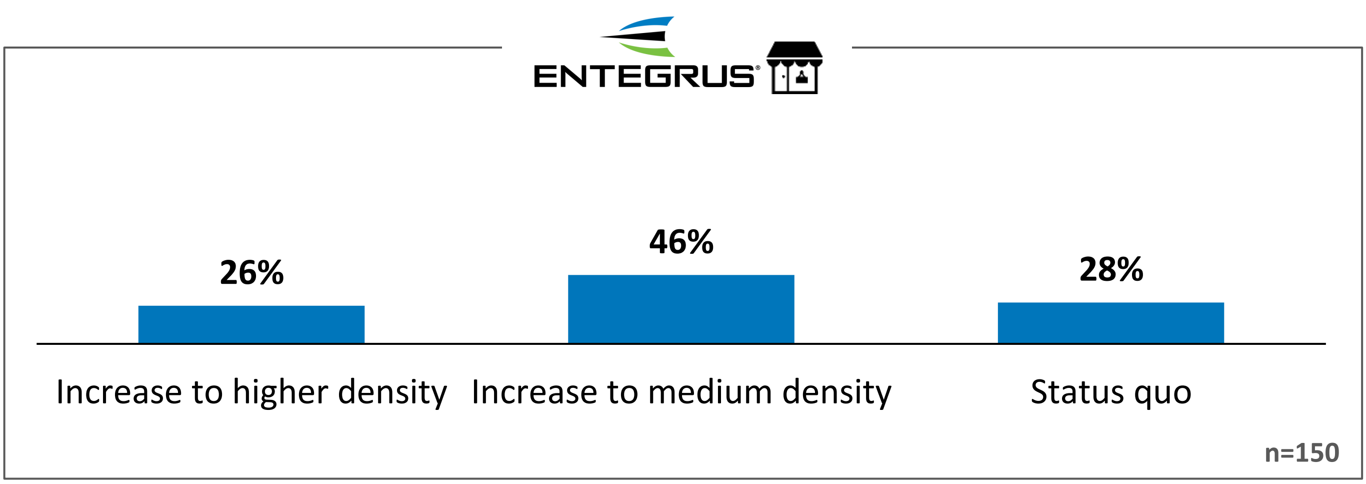
Online Workbook

Choice 2: Implementing Smart Grid Technology

Small Business

Which of the following options do you prefer?

Option	Description	Expected Outcome
Increase to Higher Intelligent Switch Density in Chatham & St. Thomas *Additional $0.70- $1.00 per month starting in 2026*	Install an additional 18 switches in Chatham and an additional 10 switches in St. Thomas	Reduce outage duration by about 20% - 25% and outage frequency > 1 minute by about 30% - 40%
Increase to Medium Intelligent Switch Density in Chatham & St. Thomas *Additional $0.35 - $0.50 per month starting in 2026*	Install an additional 11 switches in Chatham and an additional 6 switches in St. Thomas	Reduce outage duration by about 15% - 20% and outage frequency >1 minute by about 25% - 30%
Status Quo – Stay with Low Intelligent Switch Density in Chatham & St. Thomas *Within current rates*	No additional investment in intelligent switches beyond the few in the current plan.	Increased risk of potential deterioration of reliability in the medium term.
Additional Feedback (Optional)		



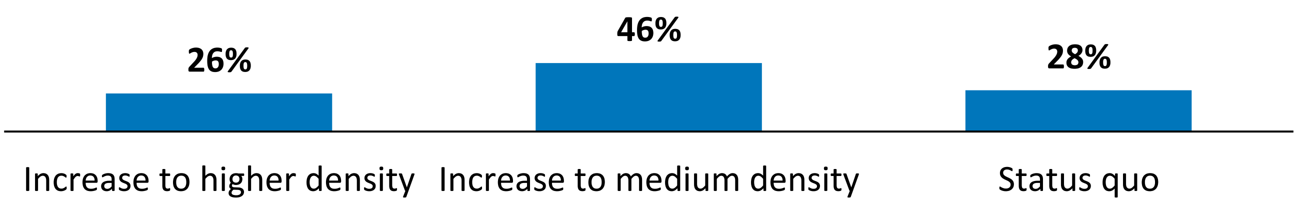
Online Workbook

Choice 2: Implementing Smart Grid Technology

Small Business

Q Which of the following options do you prefer?

ENTEGRUS



n=150

	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No Impact
Accelerated pace	27%	23%	22%	25%	29%
Faster pace	46%	48%	46%	44%	50%
Status quo	27%	29%	32%	31%	21%

INNOVATIVE RESEARCH GROUP

Online Workbook

Choice 2: Implementing Smart Grid Technology

Small Business

Q Which of the following options do you prefer?

Additional Comments	%
Need more information/transparency of costs	1.1%
Company should incur costs – result of poor planning	0.9%
Consider environment/other forms of energy	0.7%
Do not live in the area/does not impact me	0.6%
Reliability is vital/cost is acceptable	0.6%
Maintain status quo/not the time for increases during COVID recovery	0.4%
Other	0.4%
Don’t know	0.6%
None	94.6%

Online Workbook

Importance of Entegrus Priorities

Small Business

Q How importance are each of the following Entegrus priorities to you as a customer?

Delivering electricity at reasonable rates [average = **9.5**]

Not at all important 0	1	2	3	4	5	6	7	8	9	10 Extremely important
0%	1%	0%	0%	1%	0%	1%	3%	5%	11%	76%

Ensuring reliable electrical service [average = **9.3**]

Not at all important 0	1	2	3	4	5	6	7	8	9	10 Extremely important
0%	0%	0%	0%	2%	3%	0%	4%	5%	15%	69%

Providing quality customer service [average = **8.9**]

Not at all important 0	1	2	3	4	5	6	7	8	9	10 Extremely important
0%	0%	1%	0%	1%	2%	2%	7%	16%	15%	52%

Ensuring the safety of electricity infrastructure [average = **8.8**]

Not at all important 0	1	2	3	4	5	6	7	8	9	10 Extremely important
1%	1%	0%	2%	0%	3%	1%	8%	13%	17%	52%

Helping customers with conservation and cost savings [average = **8.5**]

Not at all important 0	1	2	3	4	5	6	7	8	9	10 Extremely important
1%	1%	1%	2%	3%	4%	5%	10%	13%	9%	53%

Minimizing the impact on the environment [average = **7.7**]

Not at all important 0	1	2	3	4	5	6	7	8	9	10 Extremely important
5%	1%	1%	3%	2%	5%	5%	13%	10%	12%	40%

Note: "Don't know" not shown.

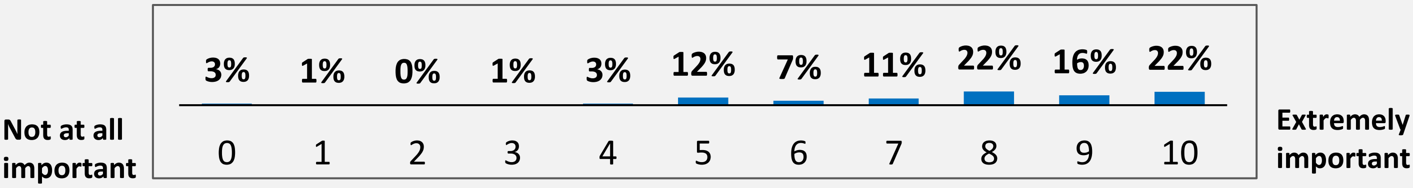
Online Workbook

Importance of Entegrus Priorities

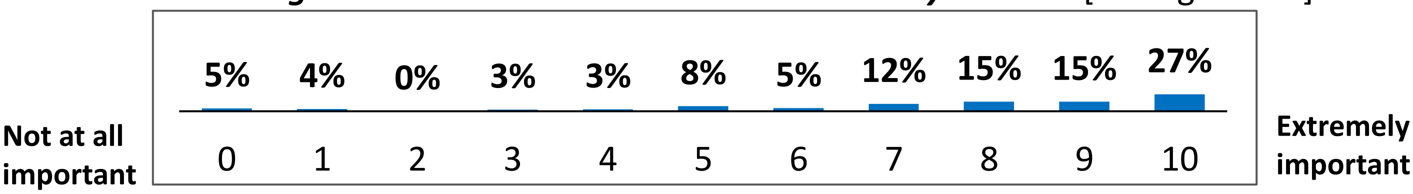
Small Business

Q How importance are each of the following Entegrus priorities to you as a customer?

Proactively preparing for community growth [average = **7.5**]



Enabling customer choice to access new electricity services [average = **7.3**]



Average Score	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No Impact
Delivering electricity at reasonable rates	9.5	9.3	9.6	9.5	9.3
Ensuring reliable electrical service	9.5	8.8	9.4	9.4	9.1
Providing quality customer service	8.9	8.9	8.9	8.9	8.8
Ensuring the safety of electricity infrastructure	9.0	8.1	8.8	9.0	8.5
Helping customers with conservation and cost savings	8.7	8.2	8.7	8.6	8.2
Minimizing the impact on the environment	7.7	7.8	7.0	8.3	7.8
Proactively preparing for community growth	7.7	7.1	7.0	7.8	7.6
Enabling customer choice to access new electricity services	7.6	6.8	7.1	7.4	7.5

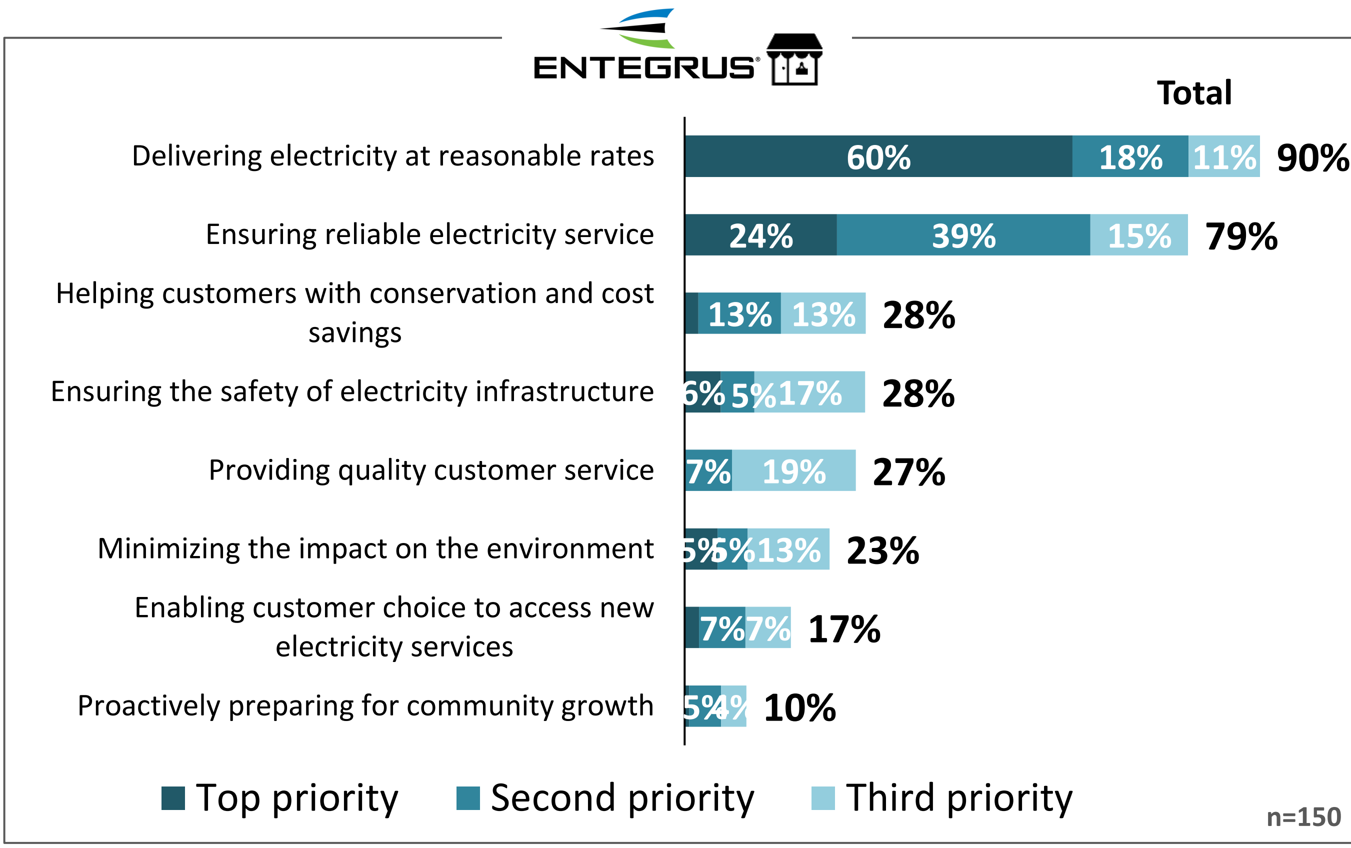
Note: “Don’t know” not shown.

Online Workbook

Ranking Entegrus Priorities

Small Business

Q Thinking again about the things that Entegrus should be focusing on, please rank your top 3 priorities – where ‘1’ would be the most important, ‘2’ the second most important, and ‘3’ the third most important.



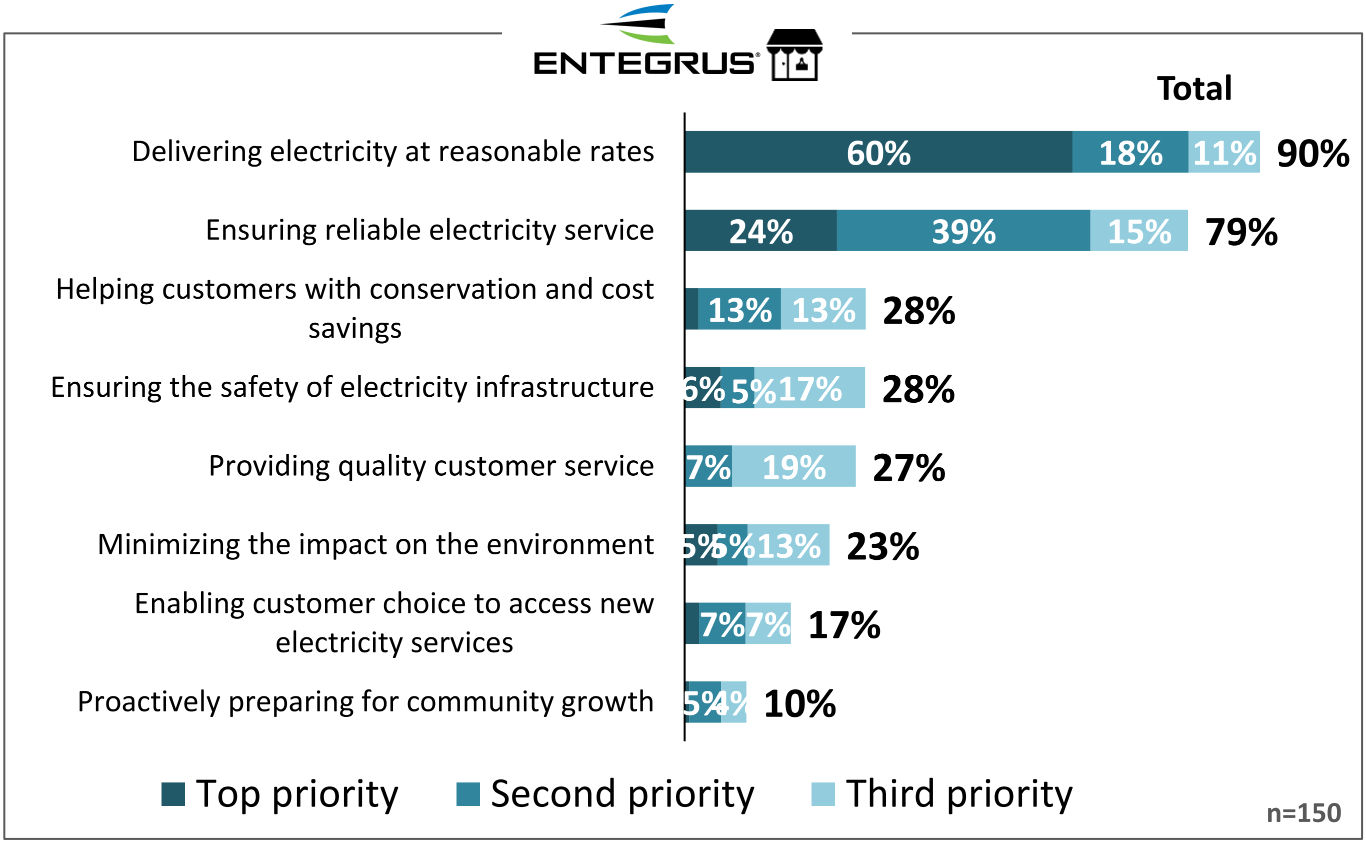
Region % who choose priority in their top 3	Legacy Entegrus	St. Thomas
Delivering electricity at reasonable rates	93%	81%
Ensuring reliable electricity service	82%	72%
Helping customers with conservation and cost savings	28%	29%
Ensuring the safety of electricity infrastructure	29%	27%
Providing quality customer service	24%	33%
Minimizing the impact on the environment	19%	32%
Enabling customer choice to access new electricity services	16%	18%
Proactively preparing for community growth	10%	8%

Online Workbook

Ranking Entegrus Priorities

Small Business

Q Thinking again about the things that Entegrus should be focusing on, please rank your top 3 priorities – where '1' would be the most important, '2' the second most important, and '3' the third most important.



Bill impact on finances % who choose priority in their top 3	Significant impact	Impact	No impact
Delivering electricity at reasonable rates	96%	89%	84%
Ensuring reliable electricity service	76%	81%	79%
Helping customers with conservation and cost savings	38%	25%	21%
Ensuring the safety of electricity infrastructure	28%	19%	38%
Providing quality customer service	17%	31%	31%
Minimizing the impact on the environment	17%	26%	25%
Enabling customer choice to access new electricity services	22%	16%	12%
Proactively preparing for community growth	6%	12%	11%

Online Workbook

Additional Entegrus Priorities

Small Business

Q

The list above may not include all the outcomes that matter to you. Are there any other important priorities that Entegrus should be focusing on that weren't included in the list above?

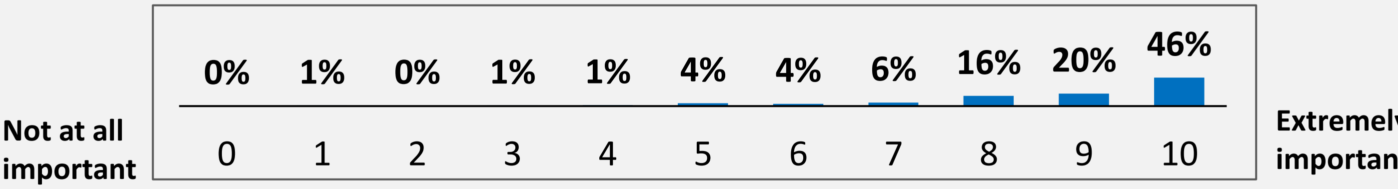
Additional Comments	%
Environmentally friendly alternative sources	3.0%
Lower costs/keep reasonable price	1.0%
Reliable service/reduces outages and time to restore power	0.6%
Maintenance/tree clearing and poles	0.5%
Ensure safety/repairs and upgrades to aging infrastructure	0.4%
Other	1.0%
Don't know	0.5%
None	92.9%

Online Workbook

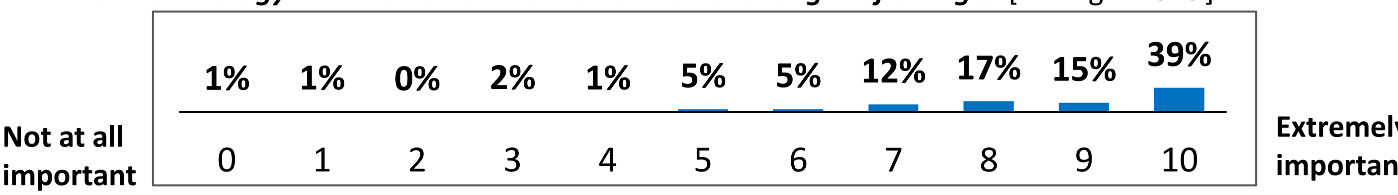
Importance of Technology Priorities

Q How importance are each of the following investments in new technology that Entegrus could focus on?

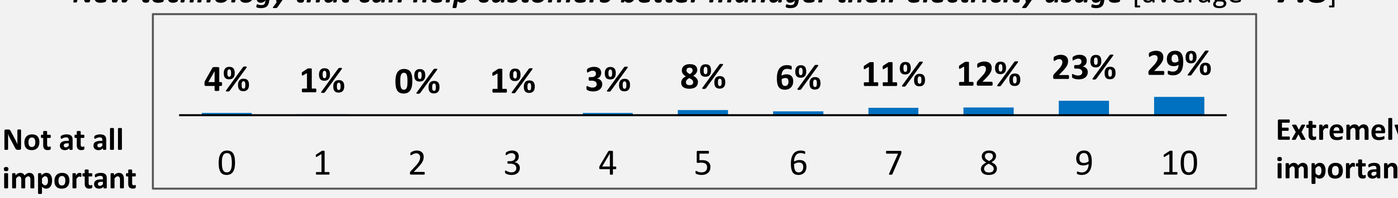
New technology that can help Entegrus find efficiencies and reduce customer costs [average = **8.7**]



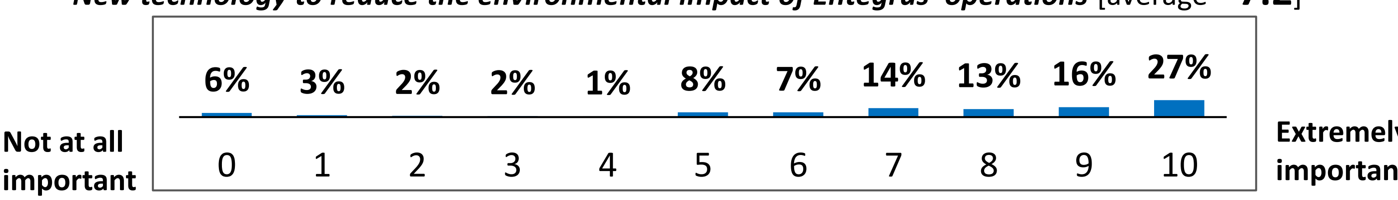
New technology that would reduce the number and length of outages [average = **8.3**]



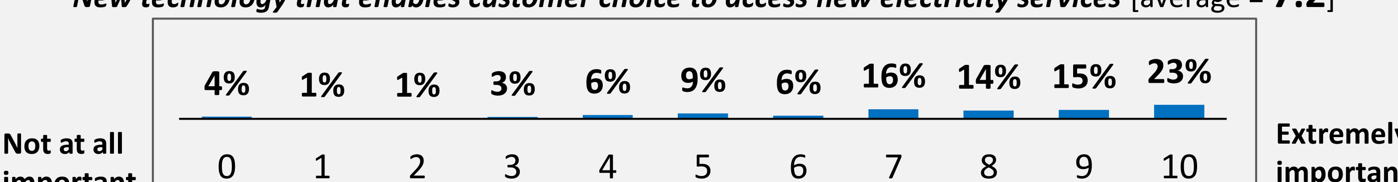
New technology that can help customers better manager their electricity usage [average = **7.8**]



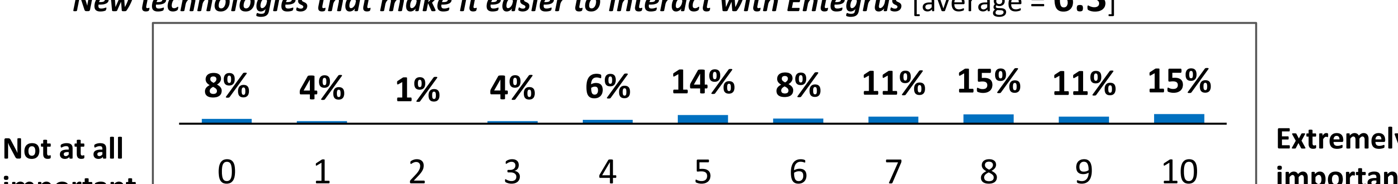
New technology to reduce the environmental impact of Entegrus' operations [average = **7.2**]



New technology that enables customer choice to access new electricity services [average = **7.2**]



New technologies that make it easier to interact with Entegrus [average = **6.3**]



Note: "Don't know" not shown.

Online Workbook

Importance of Technology Priorities

Small Business

Q How importance are each of the following investments in new technology that Entegrus could focus on?

	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No Impact
New technology that can help Entegrus find efficiencies and reduce customer costs	8.8	8.6	8.9	8.6	8.7
New technology that would reduce the number and length of outages	8.5	7.9	8.2	8.4	8.3
New technology that can help customers better manage their electricity usage	7.8	7.8	8.0	7.8	7.6
New technology to reduce the environmental impact of Entegrus' operations	7.3	7.0	7.0	7.6	7.0
New technology that enables customer choice to access new electricity services	7.4	6.7	7.3	7.5	6.7
New technologies that make it easier to interact with Entegrus	6.5	5.6	6.6	6.4	5.8

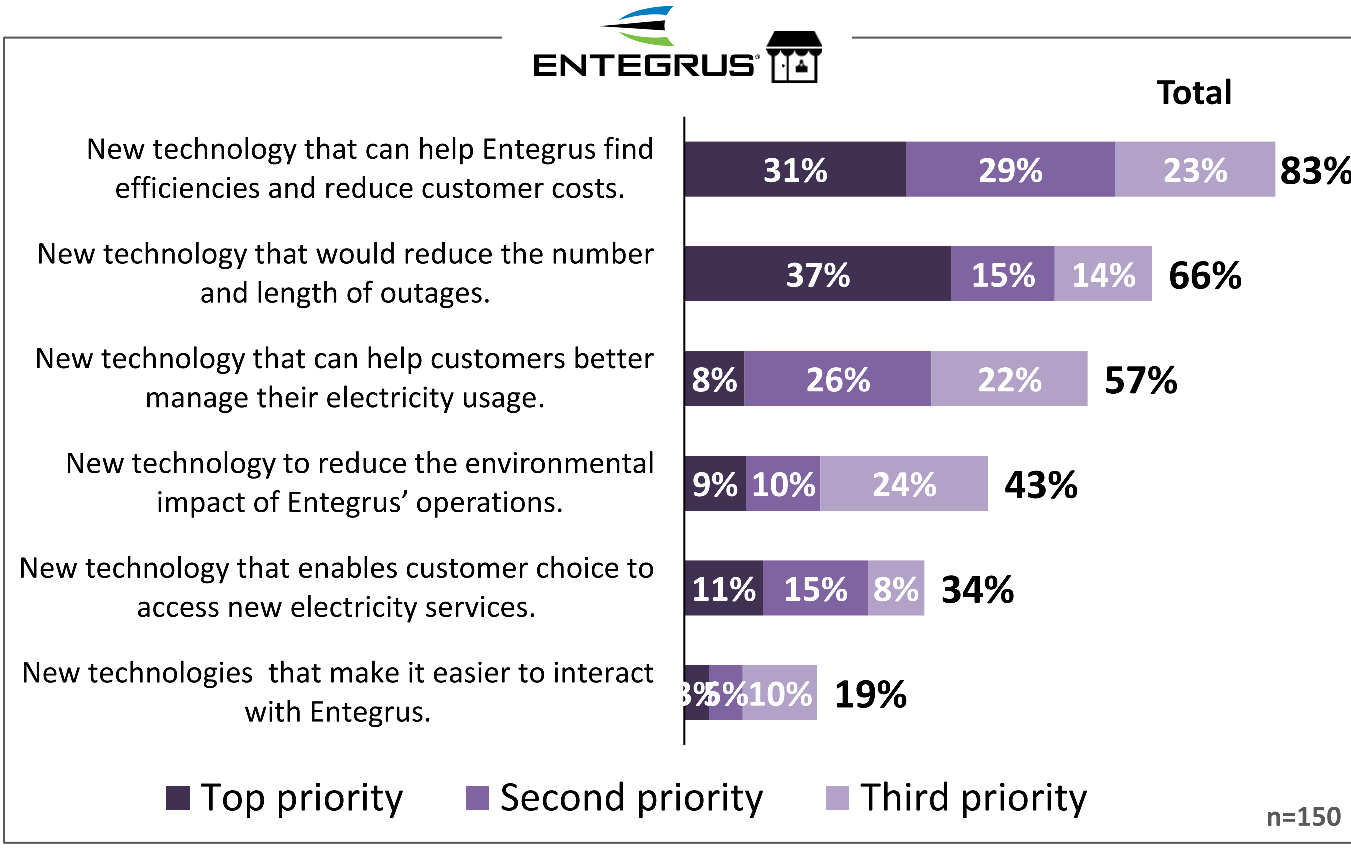
Note: "Don't know" not shown.

Online Workbook

Ranking Technology Priorities

Small Business

Q Thinking again about the things that Entegrus should be focusing on, please rank your top 3 technology priorities – where '1' would be the most important, '2' the second most important, and '3' the third most important.



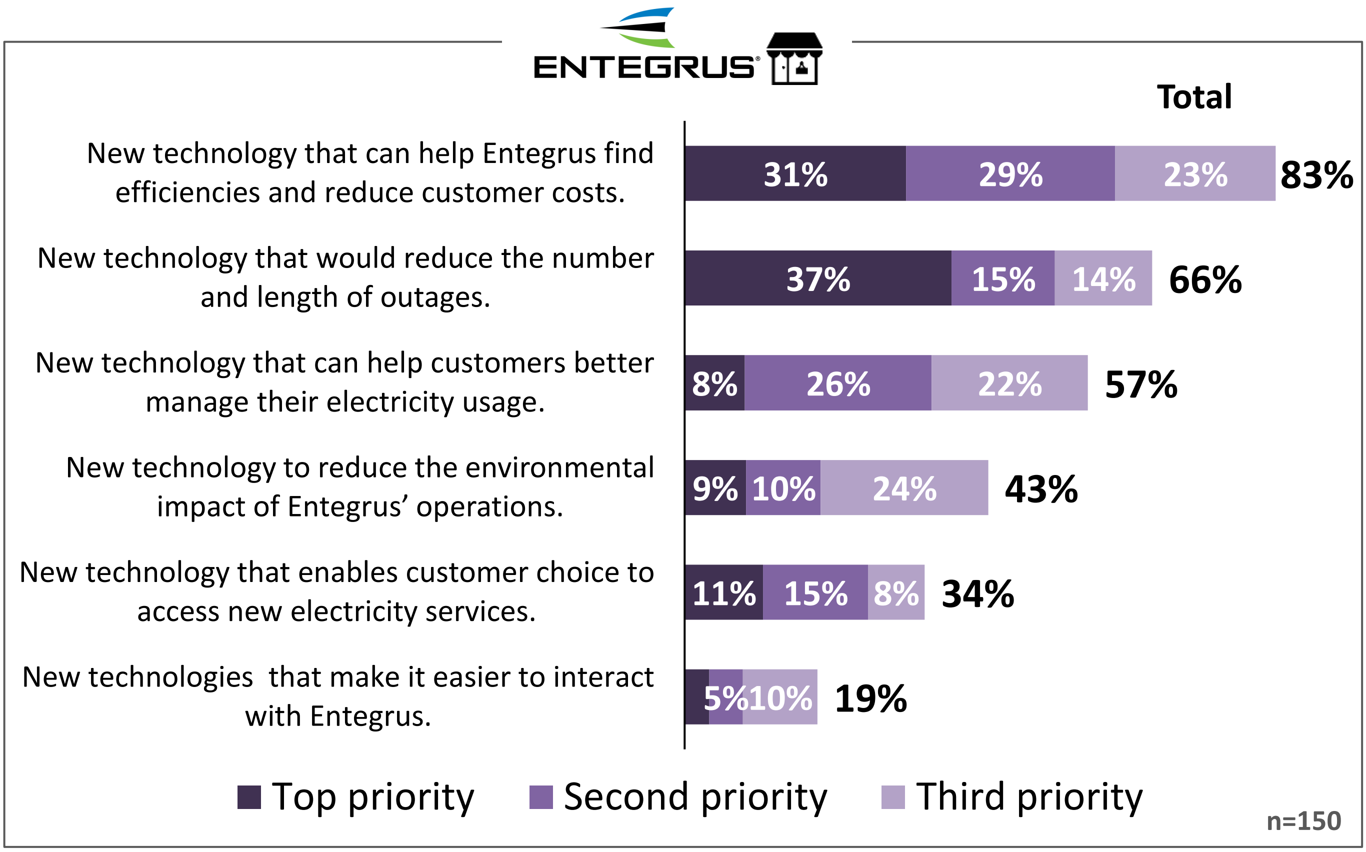
Region % who choose priority in their top 3	Legacy Entegrus	St. Thomas
New technology that can help Entegrus find efficiencies	85%	79%
New technology that would reduce the # and length of outages	73%	48%
New technology that can help customers better manage usage	55%	59%
New technology to reduce environmental impact	40%	48%
New technology that enables customer choice	30%	41%
New technologies that make it easier to interact with Entegrus	16%	25%

Online Workbook

Ranking Technology Priorities

Small Business

Q Thinking again about the things that Entegrus should be focusing on, please rank your top 3 technology priorities – where '1' would be the most important, '2' the second most important, and '3' the third most important.



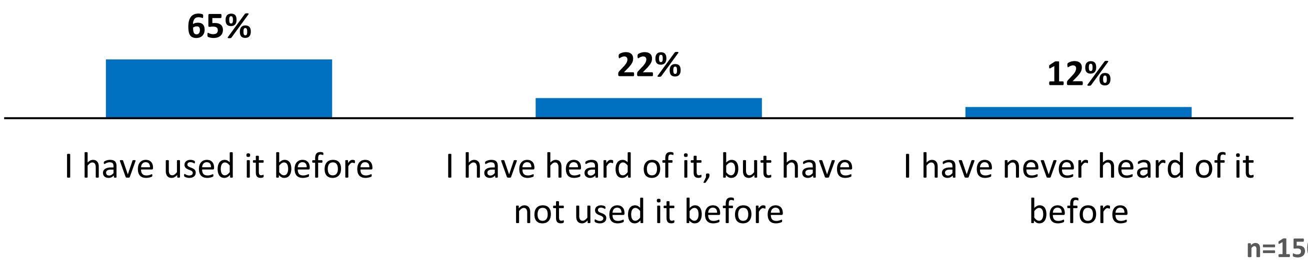
Bill impact on finances % who choose priority in their top 3	Significant impact	Impact	No impact
New technology that can help Entegrus find efficiencies	83%	76%	90%
New technology that would reduce the # and length of outages	68%	66%	63%
New technology that can help customers better manage usage	56%	59%	54%
New technology to reduce environmental impact	34%	49%	45%
New technology that enables customer choice	41%	33%	27%
New technologies that make it easier to interact with Entegrus	19%	17%	20%

Online Workbook

Entegrus' Digital Tools – The Entegrus.com Website

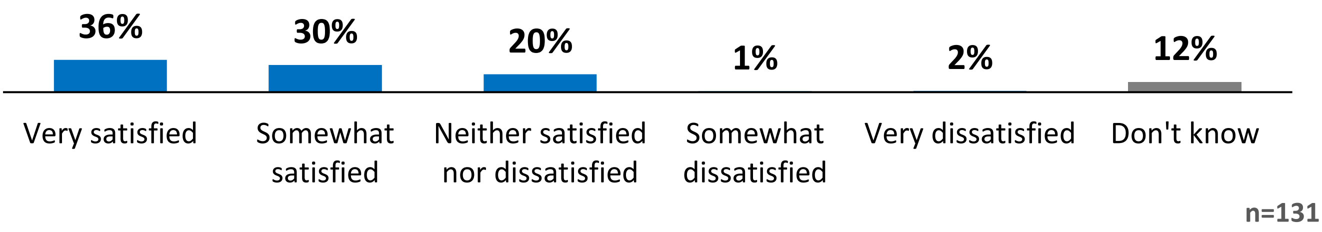
Q How familiar are you with the following digital tools that are offered by Entegrus?

The Entegrus.com website



	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No impact
Have used it	62%	72%	71%	68%	56%
Have heard of it, but not used it	26%	13%	19%	26%	22%
Have not heard of it	11%	15%	10%	6%	22%

Q Please indicate whether you are satisfied or dissatisfied with each of the following tools.



	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No impact
Satisfied (Very + Somewhat)	62%	75%	78%	58%	63%
Neutral	22%	15%	13%	28%	17%
Dissatisfied (Very + Somewhat)	4%	--	4%	2%	2%

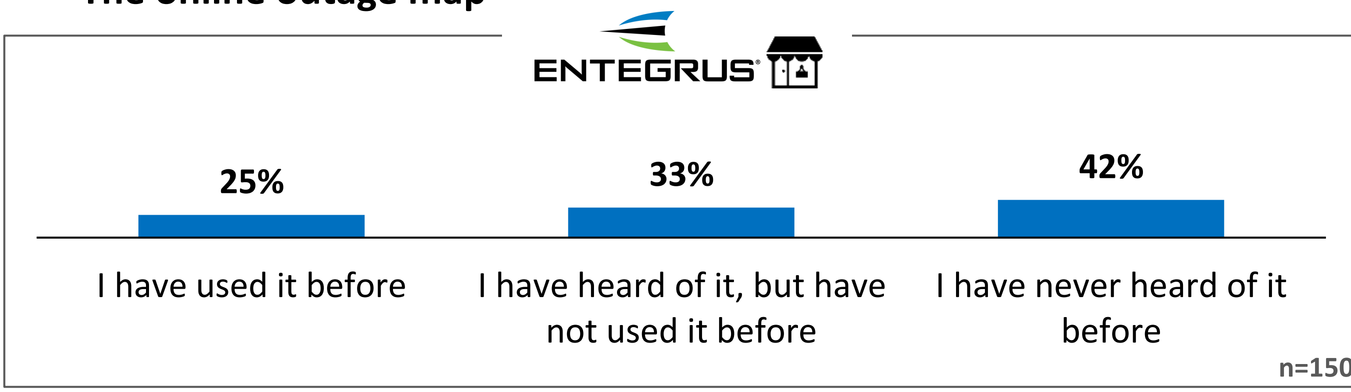
Online Workbook

Entegrus' Digital Tools – The Online Outage Map

Small Business

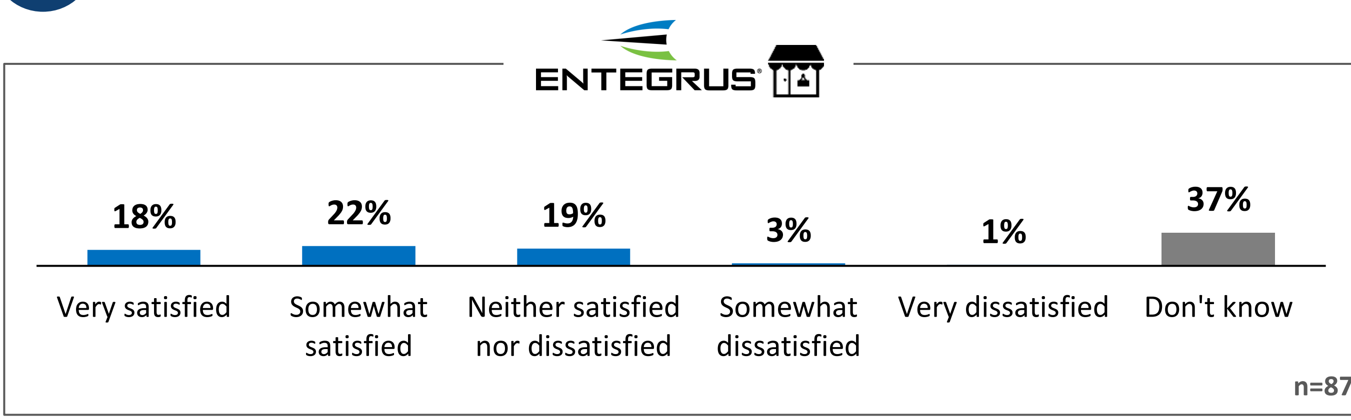
Q How familiar are you with the following digital tools that are offered by Entegrus?

The online outage map



	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No impact
Have used it	33%	7%	27%	32%	16%
Have heard of it, but not used it	32%	35%	44%	31%	26%
Have not heard of it	35%	58%	30%	37%	58%

Q Please indicate whether you are satisfied or dissatisfied with each of the following tools.



	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No impact
Satisfied (Very + Somewhat)	45%	21%	36%	39%	46%
Neutral	22%	9%	21%	25%	7%
Dissatisfied (Very + Somewhat)	3%	9%	2%	8%	--

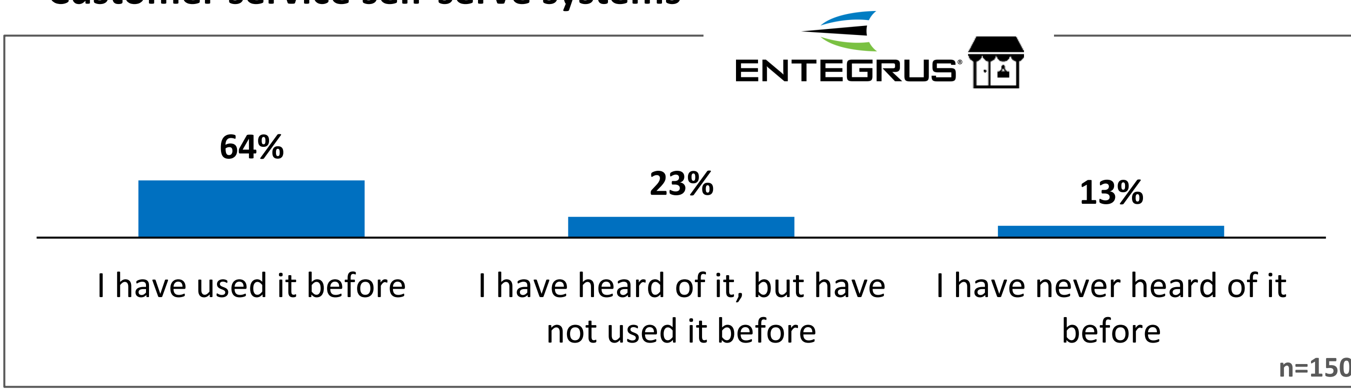
Online Workbook

Small Business

Entegrus' Digital Tools – Customer Service Self-Serve Systems

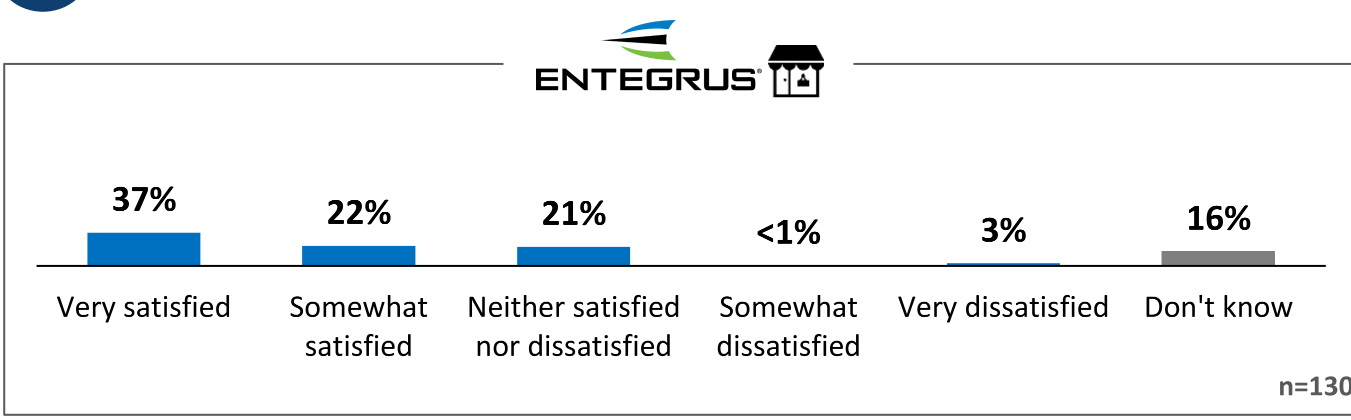
Q How familiar are you with the following digital tools that are offered by Entegrus?

Customer service self-serve systems



	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No impact
Have used it	65%	60%	67%	64%	60%
Have heard of it, but not used it	25%	19%	25%	26%	18%
Have not heard of it	10%	21%	8%	10%	22%

Q Please indicate whether you are satisfied or dissatisfied with each of the following tools.



	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No impact
Satisfied (Very + Somewhat)	59%	61%	58%	60%	59%
Neutral	21%	22%	19%	27%	16%
Dissatisfied (Very + Somewhat)	5%	--	4%	4%	2%

Online Workbook

Additional Digital Tools or Services

Q Are there any additional digital tools or services that you would like Entegrus to provide?

Additional Comments	%
Billing issues/payment options	1.9%
Better outage communication/text notifications	1.1%
Mobile app for outage communication and updates	1.1%
Improvements to website/more user friendly	0.5%
Other	0.6%
None	94.8%

Small Business Customers

Workbook Diagnostics

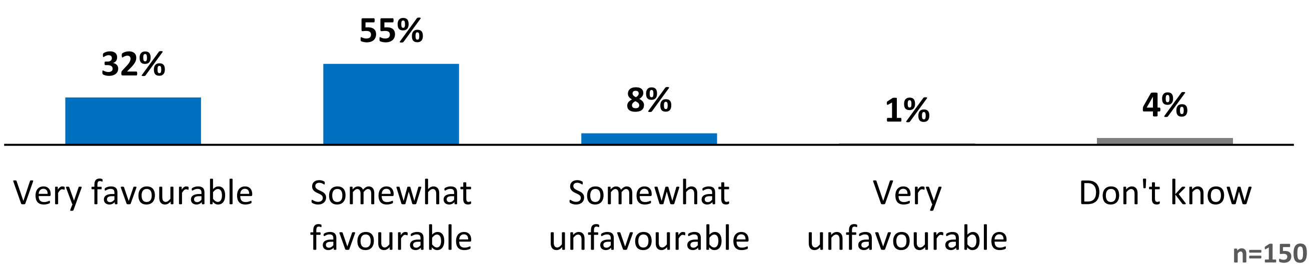
Online Workbook

Workbook Impression

Small Business

Q Overall, did you have a favourable or unfavourable impression of the customer engagement you just completed?

ENTEGRUS



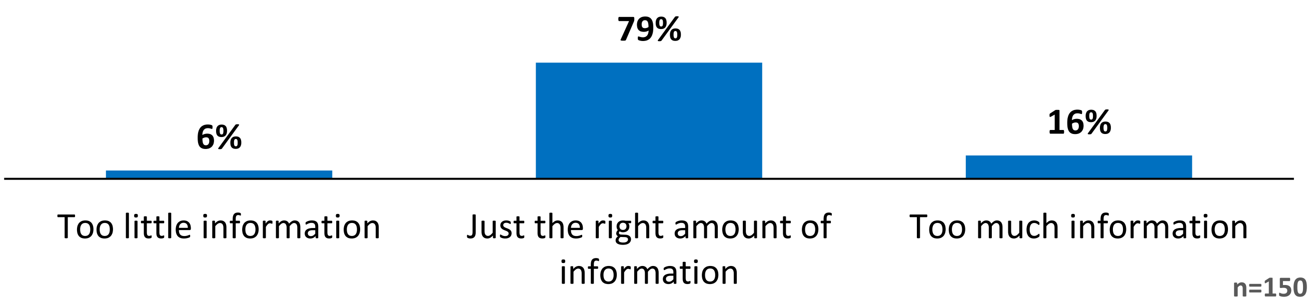
	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No Impact
Very favourable	32%	32%	26%	30%	40%
Somewhat favourable	55%	54%	60%	57%	47%
Somewhat unfavourable	6%	12%	10%	5%	9%
Very unfavourable	1%	--	--	1%	1%
Favourable (Very + Somewhat)	**87%**	**86%**	**87%**	**87%**	**87%**
Unfavourable (Very + Somewhat)	**7%**	**12%**	**10%**	**6%**	**10%**

Online Workbook
Amount of Information

Small Business

Q In this customer engagement, do you feel that Entegrus provided too much information, not enough, or just the right amount?

ENTEGRUS



n=150

	Region		Bill impact on finances		
	Legacy Entegrus	St. Thomas	Significant impact	Impact	No Impact
To little information	4%	10%	3%	8%	5%
Just the right amount	79%	77%	81%	79%	76%
Too much information	17%	13%	16%	13%	19%

Online Workbook

Content Missing from Engagement

Small Business

Q Was there any content missing that you would have liked to have seen included in this customer engagement?

Additional Comments	%
Transparency regarding operations and spending	2.7%
Survey is biased/don't trust it	1.3%
Survey is complicated/too long	0.7%
Reasons for outages/why some regions have more	0.6%
Breakdown/clear explanation of charges	0.5%
Plans to use/adapt to new technology	0.4%
Alternative/green energy plans	0.4%
None	93.3%

Online Workbook
Outstanding Questions

Q Is there anything that you would still like answered?

Additional Comments	%
Reduce costs/water and sewage charges	1.5%
Survey is biased/too long	1.3%
Transparency of operations, profits, and costs	1.1%
Information on grid updates, poles and cables	0.7%
Would like updates/findings of study	0.4%
Other	1.0%
None	94.0%

Commercial & Industrial Customers

Online Workbook Results

Online Workbook

Survey Design & Methodology

INNOVATIVE was engaged by Entegrus Powerlines Inc. to gather input on their proposed distribution system plan. Throughout this report, actual pages of the workbook that customers completed are included in the order that they were seen and are indicated by a watermark that says “workbook page”.

Field Dates & Workbook Delivery

The **Commercial & Industrial Online Workbook** was sent to all Entegrus C&I customers who have provided the utility with an email address. Customers had an opportunity to complete the workbook between **June 21st and July 20th, 2021**.

Each customer received a unique URL that could be linked back to their annual consumption, region and rate class.

In total, the C&I workbook was sent to **261** customers via e-blast from INNOVATIVE. Reminder emails were sent weekly to those who had not yet completed the workbook.

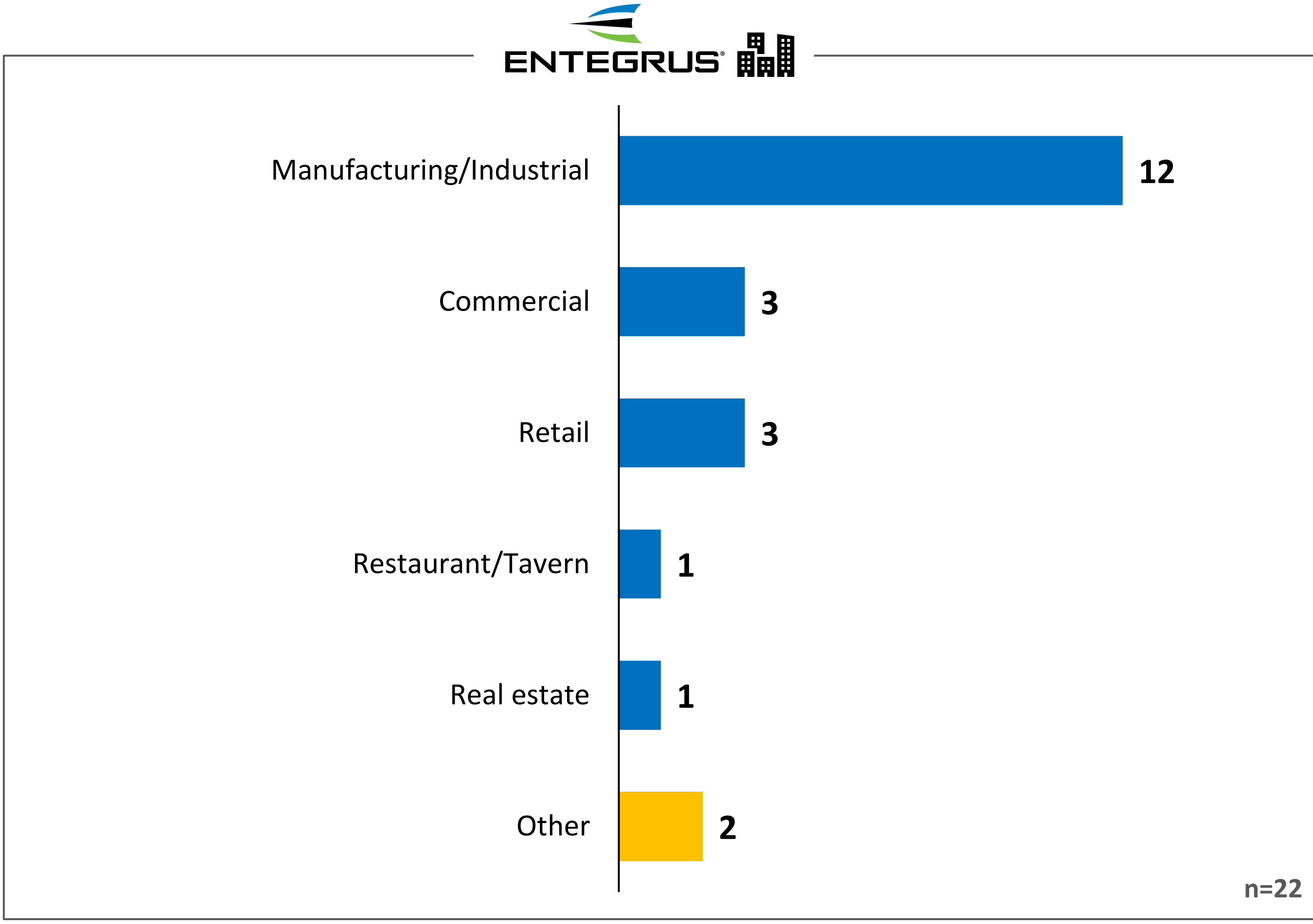
Residential Online Workbook Completes

A total of **22** (unweighted) Entegrus C&I customers completed the online workbook via a unique URL.

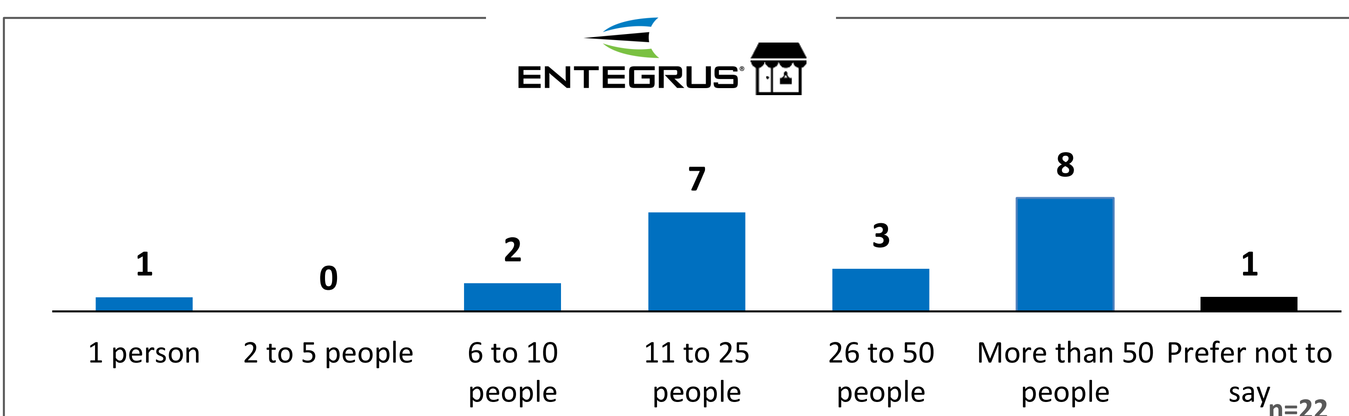
Sample Weighting

Due to the small sample size (n=22), commercial & industrial customer results are not weighted. Results should be interpreted as directional only.

Q Which of the following best describes the sector in which your business operates? Would you say…



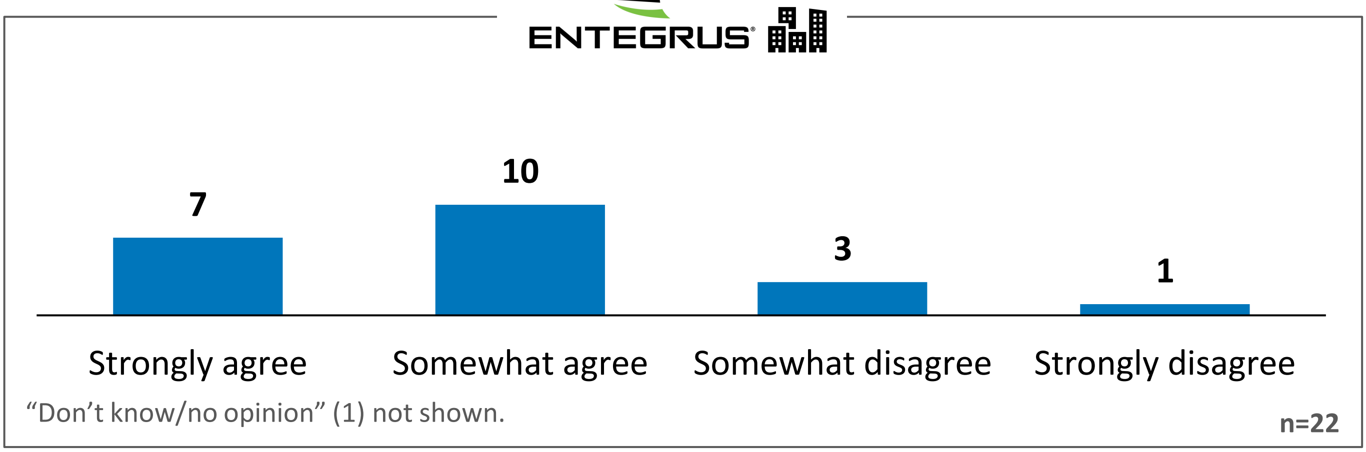
Q Including yourself, how many people work at your organization?



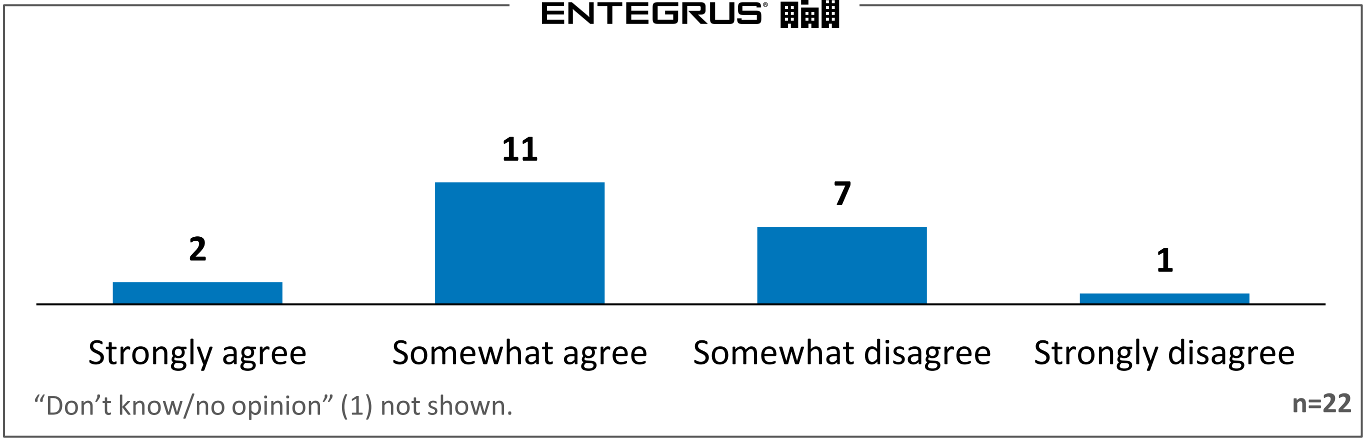
Online Workbook
Environmental Controls

Now we would like to shift the focus, and ask you some general questions about the electricity system in Ontario. To what extent do you agree or disagree with the following statements?

Q The cost of my organization's electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.



Q Customers are well served by the electricity system in Ontario.



Online Workbook

Commercial & Industrial

Planning for the Future: 2021-2025 Investment Plan

About this Customer Engagement

Welcome to Entegrus' customer engagement survey!

As Entegrus plans for the future, they need your input on choices that will impact the services you receive and the rates that you pay for the delivery of electricity.

- **Entegrus is currently in the process of developing its investment plan for 2021 to 2025.** This plan will determine the investments Entegrus makes in equipment and infrastructure, the services it provides, and the rates you pay.
- **Entegrus is now looking for your input on its draft plan** to ensure it is making spending decisions that matter to you, the customer.
- **Later this year, Entegrus will provide its investment plan** to the public regulator, the Ontario Energy Board (OEB) for its scrutiny.
- **Between now and 2025, Entegrus will execute its 2021 to 2025 investment plan,** ultimately, impacting the services you receive and the delivery of electricity throughout the communities that Entegrus serves.

This survey will take approximately 20-30 minutes to complete and can be done so at your convenience. Once you begin, your progress will be saved, and you can return to the customer engagement at any time.

All individual responses will be kept confidential. Innovative Research Group (INNOVATIVE), an independent research company, has been hired to gather your feedback.

Those who complete the questions that follow will be invited to enter a draw to win one of two (2) $500 prepaid VISA gift cards.

Electricity 101

Who is Entegrus?

Entegrus is a regulated electricity distributor that owns and operates distribution systems serving 17 communities in Southwestern Ontario, stretching between Wheatley (to the west), St. Thomas (to the east), Parkhill (to the north) and Lake Erie (to the south). The Entegrus service territory covers an area of approximately 5,600 square kilometres and the distance and time between Parkhill and Wheatley is about 170km. or a two-hour drive.

The utility's service territory today is a product of multiple mergers and acquisitions of previously independent distributors dating back to the late-1990s. The electrification of Southwestern Ontario dates back to the early 1900s. Most of the initial system expansion in the Entegrus communities occurred between 1950 and 1970. Some of the equipment in Entegrus' distribution system is more than 50 years old.

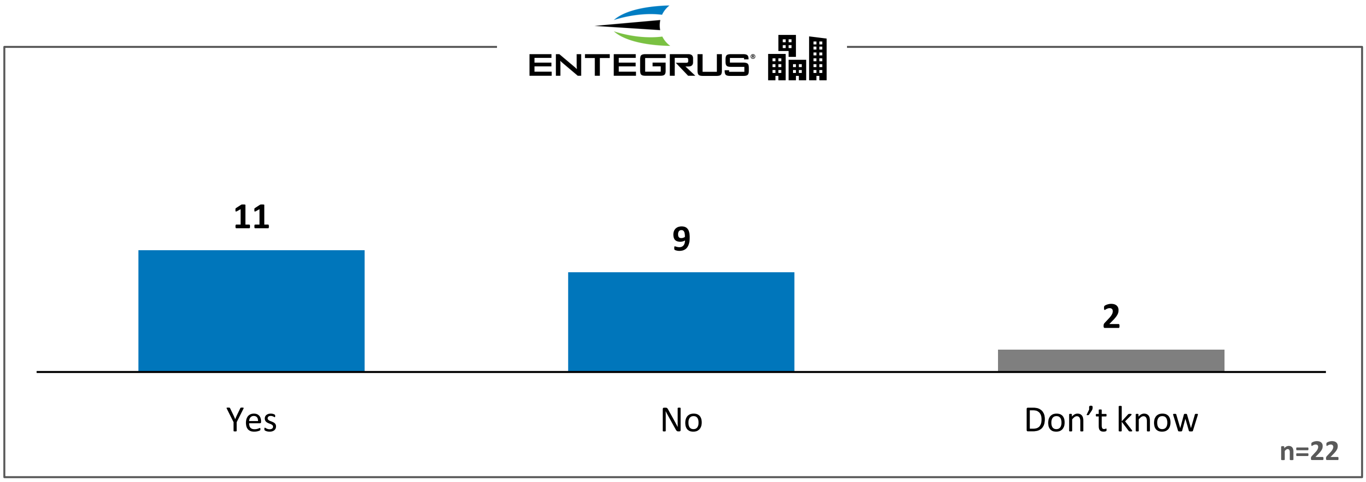
The most recent and significant addition to Entegrus' asset base is the amalgamation of Entegrus' assets with those of the former St. Thomas Energy, approved by the OEB on March 15, 2018.

Online Workbook

Familiarity with St.Thomas Merger

Commercial & Industrial

Q Had you heard of the Entegrus merger with St. Thomas Energy before this survey?



Electricity 101

What is Entegrus' role in Ontario's electricity system?

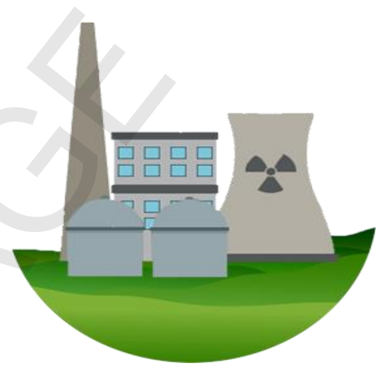
Ontario's electricity system is owned and operated by public, private and municipal corporations across the province. It is made up of three key components: **generation**, **transmission** and **distribution**.

Generation

Where electricity comes from

Ontario gets its electricity from a mix of energy sources. About half comes from nuclear power. The remainder comes from a mix of hydroelectric, natural gas, wind and solar.

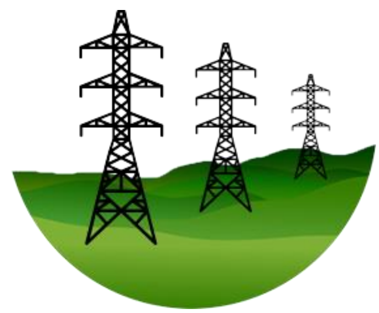
Ontario Power Generation, a government-owned company, generates almost half of Ontario's electricity. The other half comes from multiple generators who have contracts with the grid operator to provide power from a variety of sources.



Transmission

How electricity travels across Ontario

Once electricity is generated, it must be transported to urban and rural areas across the province. This happens by way of high voltage transmission lines that serve as highways for electricity. The province has more than 30,000 kilometres of transmission lines, most of which is owned and operated by Hydro One.

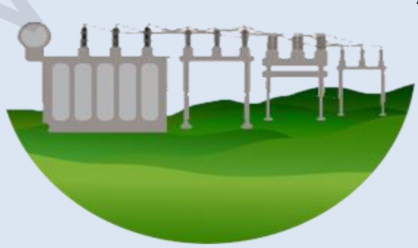


Local Distribution

How electricity is delivered to the end-consumer

Entegrus is responsible for the last step of the journey: distributing electricity to customers through its distribution system.

- Entegrus manages all aspects of the electricity distribution business throughout 17 communities in Southwestern Ontario and is regulated by the Ontario Energy Board (OEB).
- Entegrus is jointly owned by the Municipality of Chatham-Kent (72%), the Corporation of the City of St. Thomas (20%) and Corix Infrastructure Inc. (8%).
- Entegrus is entirely funded through the rates its customers pay and does <u>not</u> receive taxpayer money to fund its operations or its investments in the distribution system.

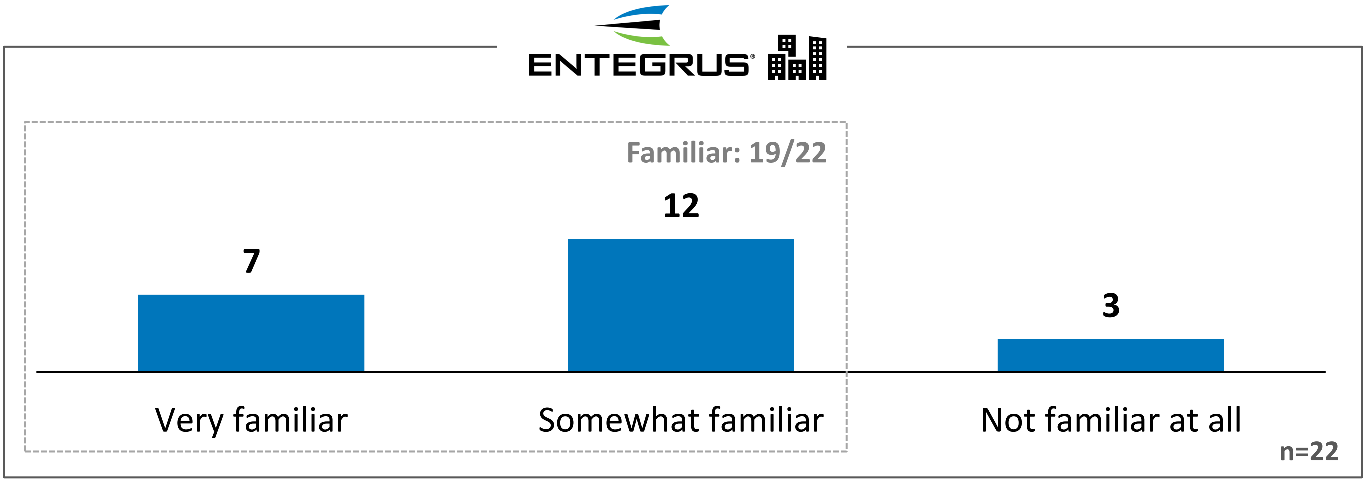


Online Workbook

Familiarity with Entegrus

Commercial & Industrial

Q How familiar are you with Entegrus, which operates the electricity distribution system in your community?



Online Workbook

Commercial & Industrial

Planning for the Future: 2021-2025 Investment Plan

Electricity 101

How much of my electricity bill goes to Entegrus?

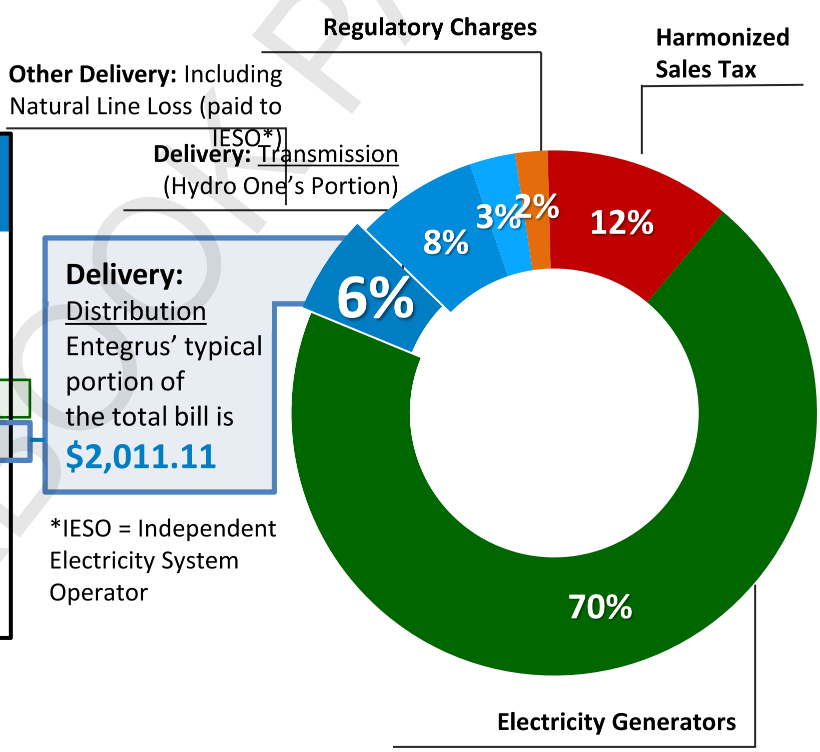
- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board (OEB), the provincial energy regulator.
- While **Entegrus** is responsible for collecting payment for the entire electricity bill – as well as water charges for many of its communities – Entegrus retains only a portion of the electricity delivery charge. The electricity delivery charge also includes Hydro One transmission costs and system losses.
- Distribution makes up about 6% of the typical business customer's bill in your rate class.
- The rest of your bill is passed onto provincial transmission companies, power generation companies, the provincial government and regulatory agencies.

Entegrus Sample Monthly Bill
(Based on 500 kW monthly demand)

Account Number:
000 000 000 000 0000

Meter Number:
00000000

Your Electricity Charges	
Electricity	22.230.00
Delivery	6,383.75
Regulatory Charges	661.38
Total Electricity Charges	**$29,275.12**
HST	3,805.77
Total Amount	**$33,080.89**



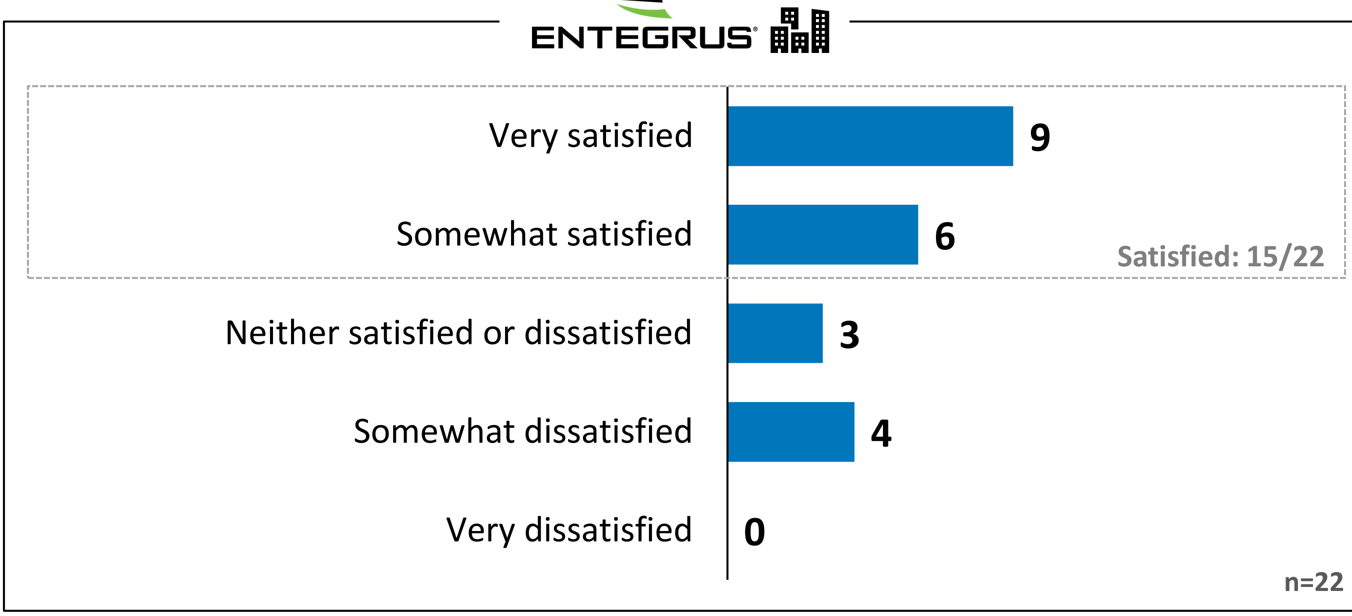
*IESO = Independent Electricity System Operator

Note: In the workbook, bill impacts differed based on rate zone (Entegrus main or St.Thomas). Entegrus main shown above.

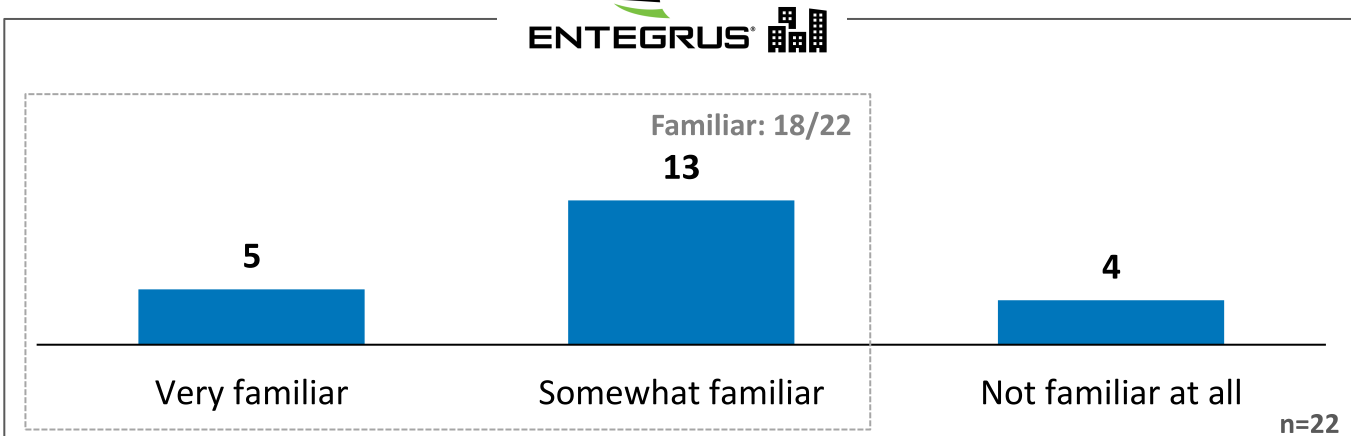
Online Workbook

Overall Satisfaction and Familiarity

Q Thinking specifically about the services provided to you and your community by Entegrus, overall, how satisfied or dissatisfied are you with the services that your organization receives?



Q Before this survey, how familiar were you with the amount of your organization's electricity bill that went to Entegrus?



Online Workbook

How Entegrus can Improve Services to Customers

Commercial & Industrial

Q Is there anything in particular you would like Entegrus to do to improve its services to your organization?

Additional Comments
“Increase the reliability of supply during storms. Far too often a power interruption occurs during a storm (even momentary) and it shuts down our production for approx. 1.5 hours. Then we need to get equipment back up and ready to run. Need more reliable supply without losses for eliminating revenue losses due to a small storm..”
“Reduce the rates, simplify the bill so the general consumer understands what they are paying for.”
“Reduced power blips”
“Smart metering”

Online Workbook
Planning for the Future: 2021-2025 Investment Plan

Commercial & Industrial

Entegrus Background

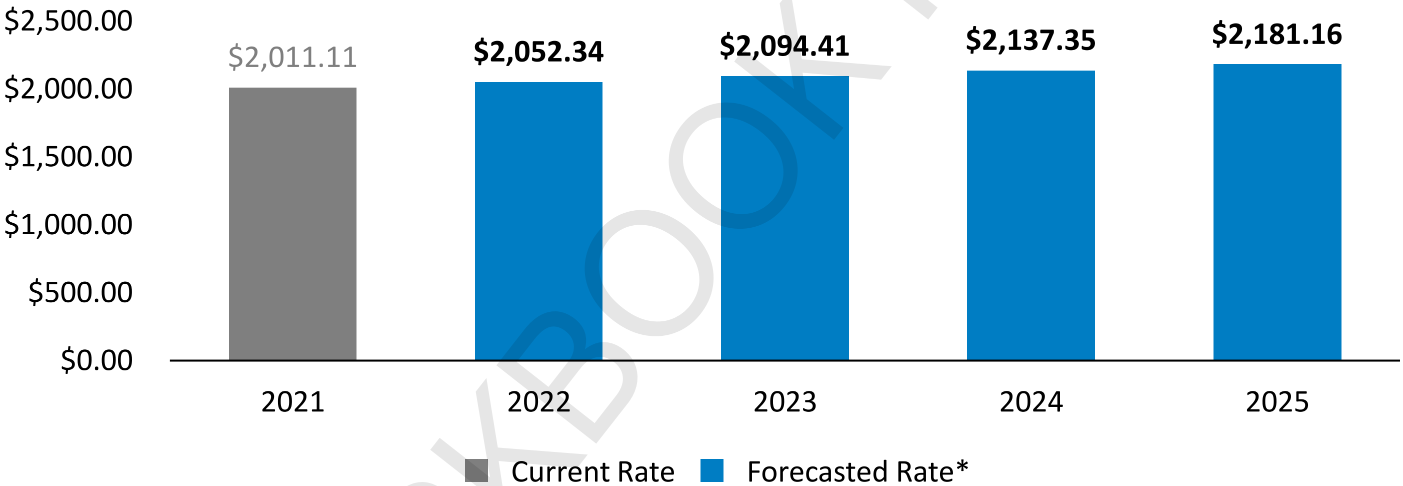
How much can you expect to pay over the next few years?

Prior to merging, both **Entegrus** and **St. Thomas Energy** had their rates set by the OEB, meaning, the amount they can charge customers for the delivery of electricity.

While the merger was finalized in April 2018, for the eight years that follow the OEB has limited your future rate increases to less than inflation. That means that each year Entegrus is permitted to increase rates to reflect inflation minus savings targets established by the OEB. This requires Entegrus to keep cost increases below inflation.

For a business customer like yourself, the distribution charge for the **typical bill is estimated to increase by approximately 2.05%** on average for the next five years (based on 2020 OEB inflation), until 2026.

Distribution Portion of the Bill per Month (2021-2025)



* These estimates are preliminary and are subject to your feedback as the investment plan is finalized.

Where does your money go?

Entegrus has two budgets; **operating and capital.** The operating budget covers recurring expenses, such as salaries, taxes, fuel costs, and rent. Until 2026, Entegrus cannot ask for any additional money for operating expenses.

This engagement is about the capital budget. This budget covers things like poles, wires, cables, transformers, meters, computers and programs, vehicles, and buildings.

Note: In the workbook, bill impacts differed based on rate zone (Entegrus main or St.Thomas). Entegrus main shown above.

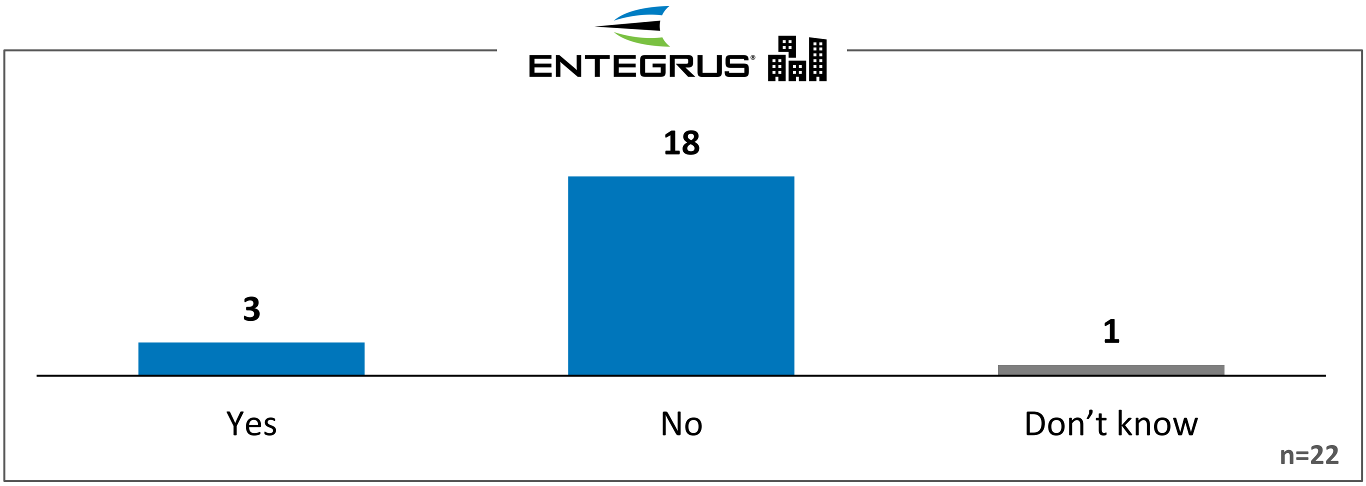
INNOVATIVE RESEARCH GROUP

Online Workbook

Familiarity with Bill Increase over Next 5 Years

Commercial & Industrial

Q Before this survey, were you aware that for a small business customer like yourself, the distribution charge for the typical bill is estimated to increase by approximately 2.05% on average for the next five years, until 2026?



Entegrus Background

How are rates staying below inflation?

Entegrus' 2021 to 2025 investment plan sets out to balance a stronger investment focus on reliability and unprecedented customer growth with an objective of keeping distribution rates affordable for customers.

Accordingly, while investment levels have increased above historic levels in 2019 and 2020 and will continue to remain at higher levels through 2025, there are no proposed incremental rate impacts arising from this investment plan for the period from 2021-2025.

In order to safeguard against reliability deterioration, Entegrus' shareholders have decided to spend above the currently approved rates with no added cost to customers from 2021-2025. These additional investments will address aging infrastructure to safeguard reliability and thereby also ensure a strong foundation to enable future customer investments in electric vehicles and customer-owned electricity generation.

Spending above current rates

As mentioned earlier, Entegrus is entirely funded through the rates its customers pay and does not receive taxpayer money to fund its operations or its investments in the distribution system.

That said, Entegrus shareholders have decided that the need for additional reliability investments cannot be put on hold, nor should customers be faced with incremental rate increases at this time. As such, over the 2018 to 2020 period, Entegrus invested an incremental $5.7 million in the distribution system beyond what was originally planned to address reliability and harmonize systems post-merger. For the 2021 to 2025 period, approximately $63 million will be invested in the distribution system, **including an estimated incremental $6.5 million to address reliability, at no additional cost to customers over that period.**

Finding internal cost savings

According to the latest data published by the Ontario Energy Board of approximately 60 electricity providers from across the province, Entegrus had the 15th lowest total cost per customer. That means Entegrus is among the most efficient electricity distributors in Ontario.

Benchmarking isn't the only way that Entegrus measures its operational efficiency. Entegrus is a member of the GridSmartCity Co-operative, an organization that brings together 15 Ontario LDCs to collaborate and share knowledge, skills and expertise – with some of the goals being increased efficiency and cost savings through economies of scale.

Cost saving benefits include negotiated group rates for services and group savings on the procurement of wood poles, cables, wires, and transformers.

Additionally, through its merger with St. Thomas Energy, Entegrus continues to see annual savings of approximately $1.4 million each year through shared operating, maintenance, and administrative costs.

Entegrus Background

What is this engagement about?

This customer engagement is about finding the right balance between the service you receive and the price you pay.

The point of this engagement is to allow customers like yourself to provide feedback on whether Entegrus planners have found the right balance or whether they should consider different options that better reflect your views.

As mentioned earlier, Entegrus' 2021 to 2025 investment plan sets out to balance a stronger investment focus on reliability and unprecedented customer growth with an objective of keeping distribution rates affordable for customers.

Affordability is at the core of Entegrus' plans.

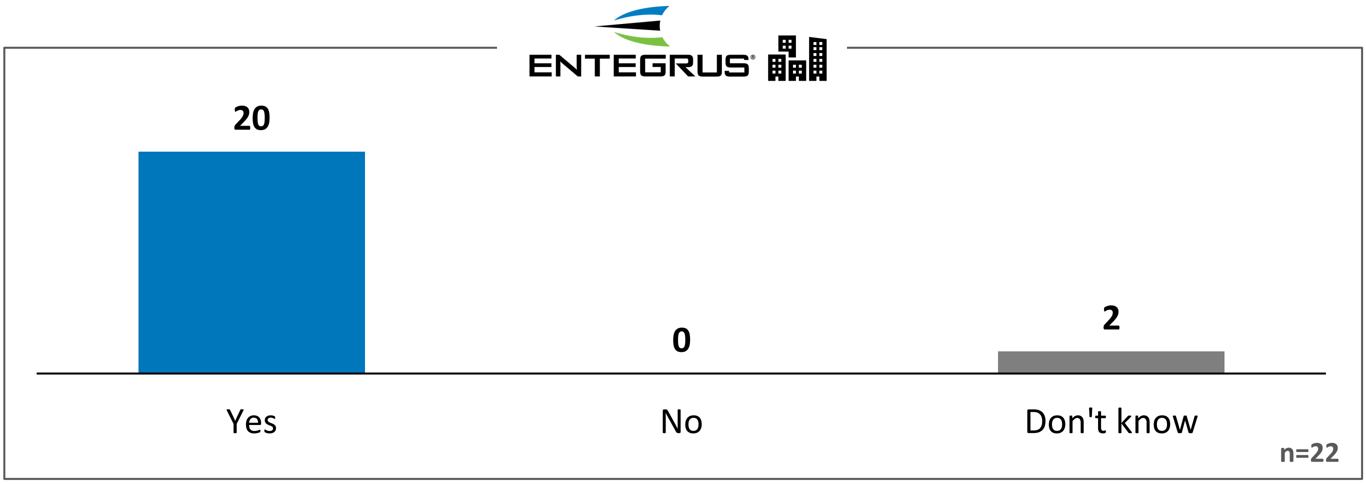
Before Entegrus finalizes its plans, it is coming to its customers with a final set of choices. For each choice, Entegrus has identified an option to stay within existing rates (including the incremental investments Entegrus is already planning). It has also identified options to increase investments where it will provide meaningful benefits to customers.

Online Workbook

Purpose of Customer Engagement

Commercial & Industrial

Q Do you feel that the purpose of this customer engagement is clear?



Entegrus Background

What are the key investment drivers for 2021 to 2025?

Entegrus has identified three primary investment drivers for the 2021 to 2025 period – **aging infrastructure (reliability), customer growth,** and **grid modernization**.

A damaged Entegrus distribution pole.

Aging Infrastructure: Recall, much of the initial economic expansion in Entegrus' service territory occurred between 1950 and 1970. That means parts of Entegrus' distribution system are now more than 50 years old.

Entegrus' 2021-2025 plan demonstrates a notable increased focus on replacing aging infrastructure. This is driven by the fact that portions of the distribution system have degraded beyond the expectation of the utility's 2016-2020 plans.

- This additional degradation became apparent in 2017 and 2018 when new technology and additional engineering staff enabled Entegrus to conduct a deeper system-wide infrastructure assessment, including resistograph pole testing.
- This assessment identified that the level of asset degradation was higher than originally forecast. Simultaneously, in 2018, customers began to experience an increase in power outages.

Overall, the additional work to replace aging infrastructure will mitigate reliability issues and provide a stronger distribution system foundation for later integration of future customer investments in electric vehicle and customer-owned electricity generation in the next planning cycle from 2026 to 2030.

Entegrus Background

What are the key investment drivers for 2021 to 2025?

Customer Growth: Even though many developers initially put projects on hold as a result of the COVID-19 pandemic, by the summer of 2020 Entegrus continued to experience unprecedented customer growth. High residential growth continues to occur in St. Thomas and other communities in the Entegrus northeast region including Strathroy and Mt. Brydges. Residential growth and significant levels of activity required to prepare the Entegrus distribution system to support fibre-to-the-home expansion by telecoms is also occurring in Chatham-Kent.

While customer growth remains high it is currently difficult to predict whether this trend will continue beyond 2021 given the circumstances of the pandemic.

A new subdivision located in St.Thomas

System Modernization: As described previously, the Entegrus service territory extends over an area of 5,600 square kilometres. Servicing each community requires significant travel. Being able to troubleshoot problems remotely reduces and in some cases eliminates the need to send a crew out for repairs.

While Entegrus' primary focuses are on reliability and servicing customer growth while keeping distribution rates affordable, the 2021 to 2025 plans do include focus on system modernization, including some automated distribution restoration technologies.

The plans also include further harmonization of legacy systems across the merged entity to help enable future investments in technology including electric vehicles and customer-owned electricity generation.

Online Workbook

Commercial & Industrial

Planning for the Future: 2021-2025 Investment Plan

Entegrus Background

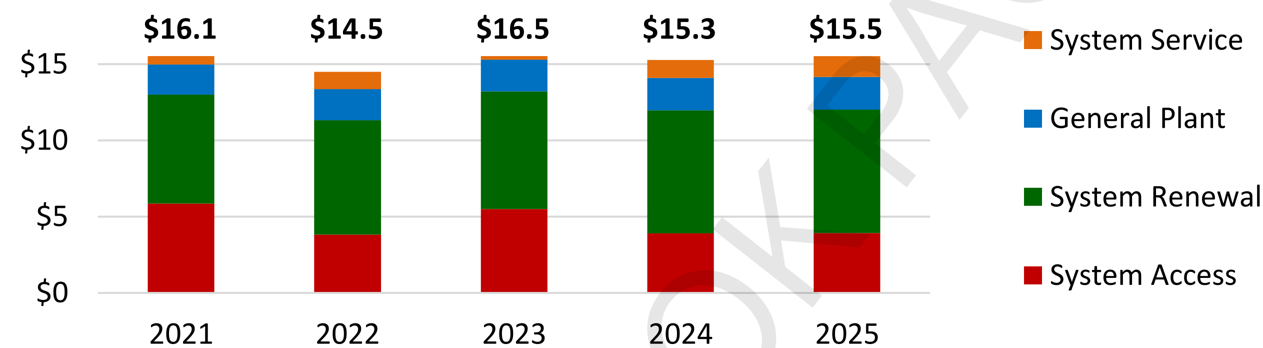
How does Entegrus plan future investments in the system?

Entegrus' **capital budget** covers items that have lasting benefits over many years such as investments in the core distribution system including poles, wires, cables, switches, and transformers.

Based on initial information and input from Entegrus' internal engineering and technical experts and emerging pressures on the distribution system, **Entegrus' draft capital budget is estimated to be $77.9 million over the five-year period between 2021 and 2025**.

Entegrus plans its capital investments in four categories.

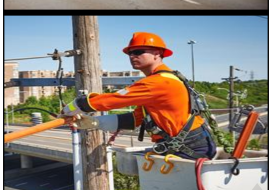
2021-2025 Forecasted Capital Investments (Millions)*



** These estimates are preliminary, and are subject to your feedback as the business plan is finalized.*

System Access ($23 Million, averaging $4.6 per year)

"Must do" investments for new subdivisions, new upgraded commercial and industrial services, and relocating assets based on road infrastructure needs. Entegrus is expected to recover close to 65% of these costs from developers, internet providers, and larger business customers.



System Renewal ($38.5 Million, averaging $7.7 per year)

Replacement of aged overhead wires, poles, and pole mounted transformers, underground cables and transformers and distribution station upgrades.

General Plant ($10.4 Million, averaging $2.1 per year)

These are investments needed to support the distribution system, such as tools, vehicles, buildings, and computers.

System Service ($6 Million, averaging $1.2 per year)

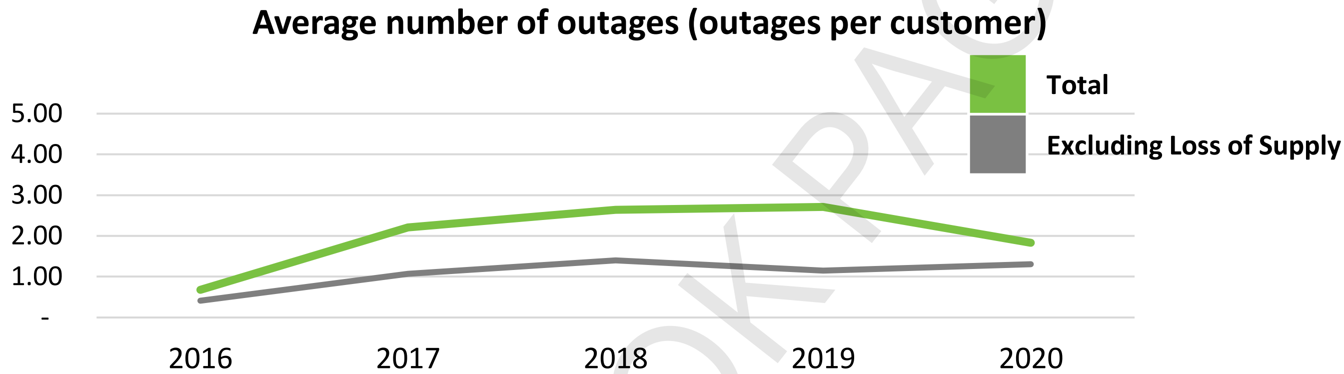
These investments consist of projects that address capacity constraints, improve system reliability and supply new growth.

Entegrus Background

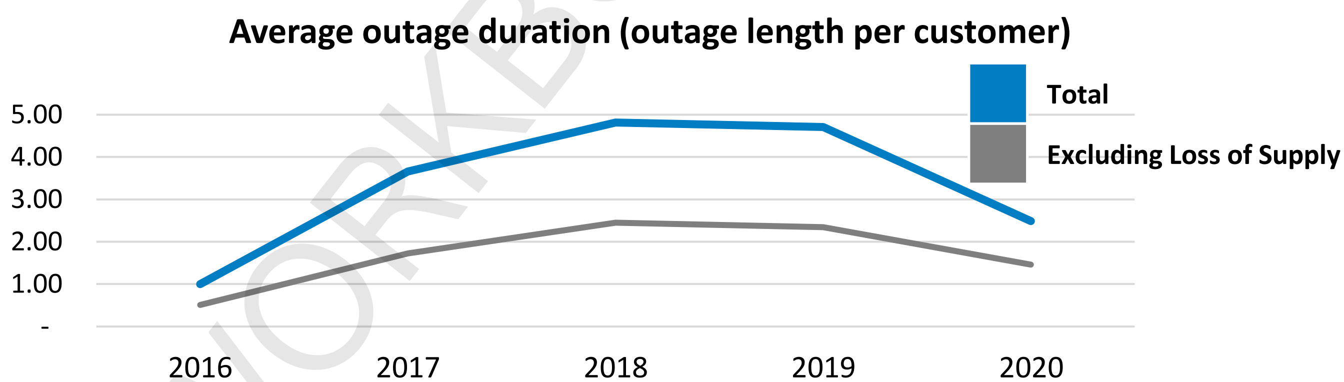
How does Entegrus' distribution system perform?

Entegrus tracks both the average number of power outages per customer and how long those interruptions last. Keep in mind that these are system averages, and your actual experience may be different. Some customers connected to newer lines may not experience any outages while others may experience more than the average number of outages each year.

Between 2016 and 2020, the typical Entegrus customer (excluding St. Thomas) experienced about two outages per year.



Over the same period, the average **duration** of an outage has been about 3.3 hours, some of which has been driven by loss of power supply due to significant weather events. Meaning when the power does go out, Entegrus is typically able to restore power in about three hours.



Loss of supply occurs when there is an interruption to the supply of electricity from the upstream electrical system operated by Hydro One. These failures are largely out of the control of Entegrus but there are investments that can be made to attempt to reduce the impacts of these outages including a more intelligent system that can automatically re-route power when one of these outages does occur. In fact, investments by Entegrus in automated switches have already avoided 18,000 customer outage hours between 2017 and 2020.

Note: St.Thomas outage statistics shown for St.Thomas customers

Entegrus Background

How does Entegrus' distribution system perform?

Recently, Entegrus, with the help of an independent third party, conducted a system-wide study to better understand the health of the system and the long-term implications on system reliability. This study concluded that the deterioration in Entegrus' reliability measures (illustrated above) required **timely and proactive intervention to maintain current levels of reliability** and start to slow, or halt, the reliability deterioration trend before it becomes irreversible.

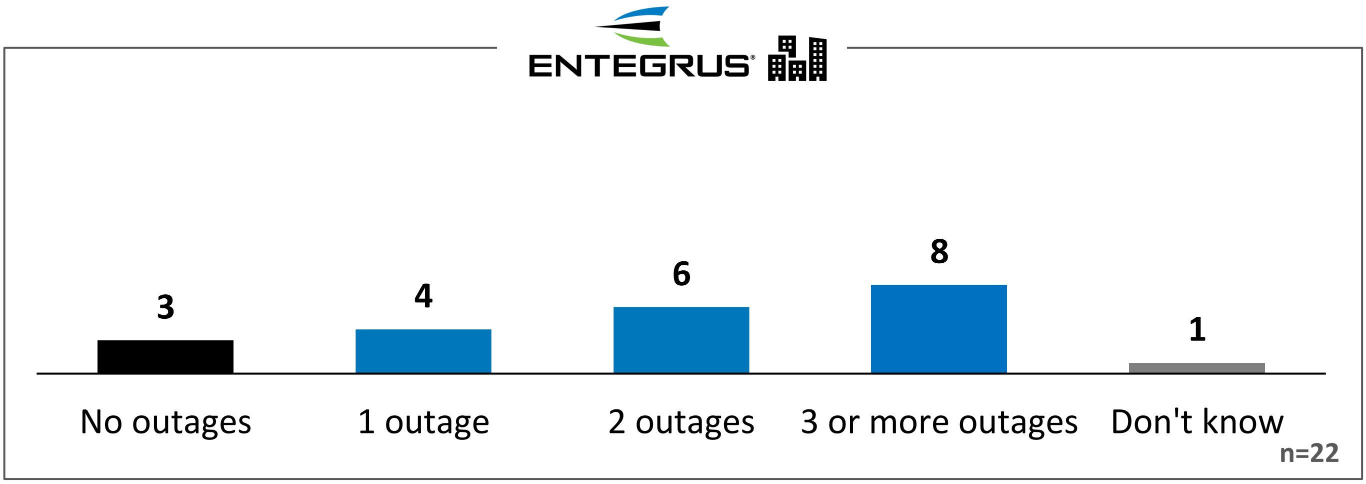
An Entegrus crew working to restore power during a winter storm.

Some of the effects of the proactive intervention undertaken in 2020 have already resulted in improvement; however, favourable weather and pandemic-related factors, such as fewer scheduled outages and less foreign interference (i.e. fewer vehicle accidents impacting the distribution system) contributed to the 2020 results.

Online Workbook

Number of Outages Experienced

Q Have you experienced any power outages at your business in the past 12 months which lasted longer than one minute?



Entegrus Background

What contributes to a power outage?

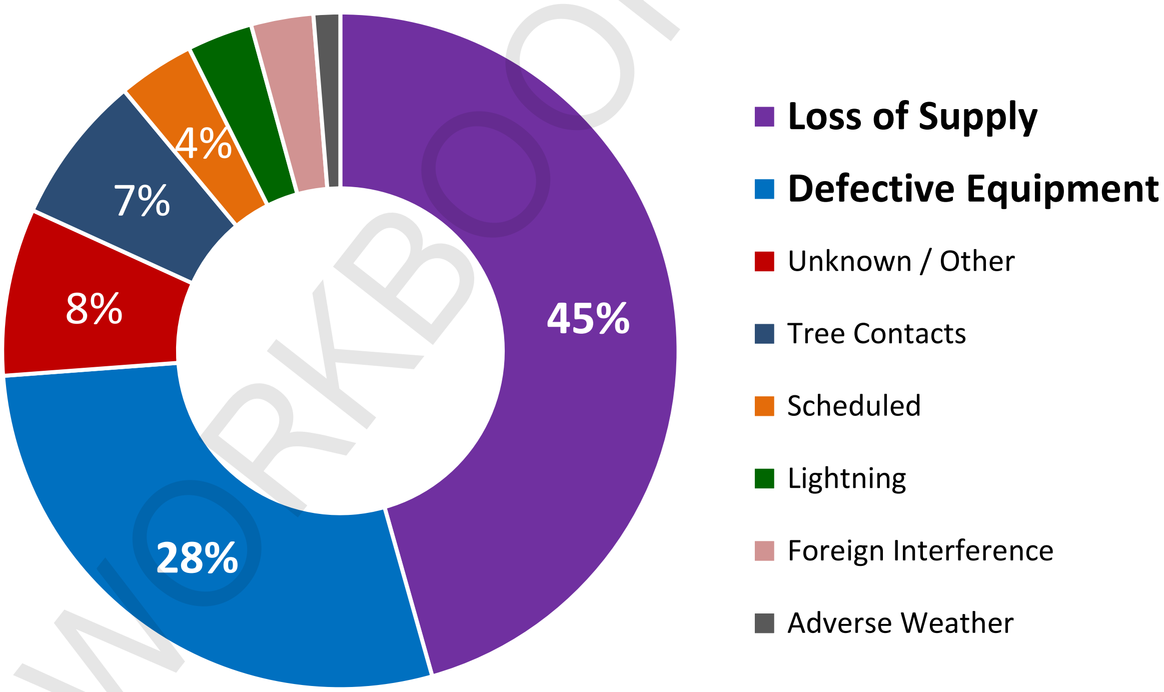
In order to provide feedback on Entegrus' plan, it's important to understand how the distribution system has performed in the past as well as what is expected in the future.

A core objective of Entegrus' 2021-2025 plan is to maintain reliability while making targeted improvements to those areas experiencing below average service.

In the Entegrus communities, the two primary contributors to outages account for 1-in-3 of all outages:

1. **Loss of supply** from the transmission system accounted for 45% of customer hours of interruption between 2016-2020. This is the single largest outage cause.
2. **Defective equipment** accounted for 28% of customer hours of interruption over the same period.

Customer Outage Duration (Hours) by Cause 2016-2020

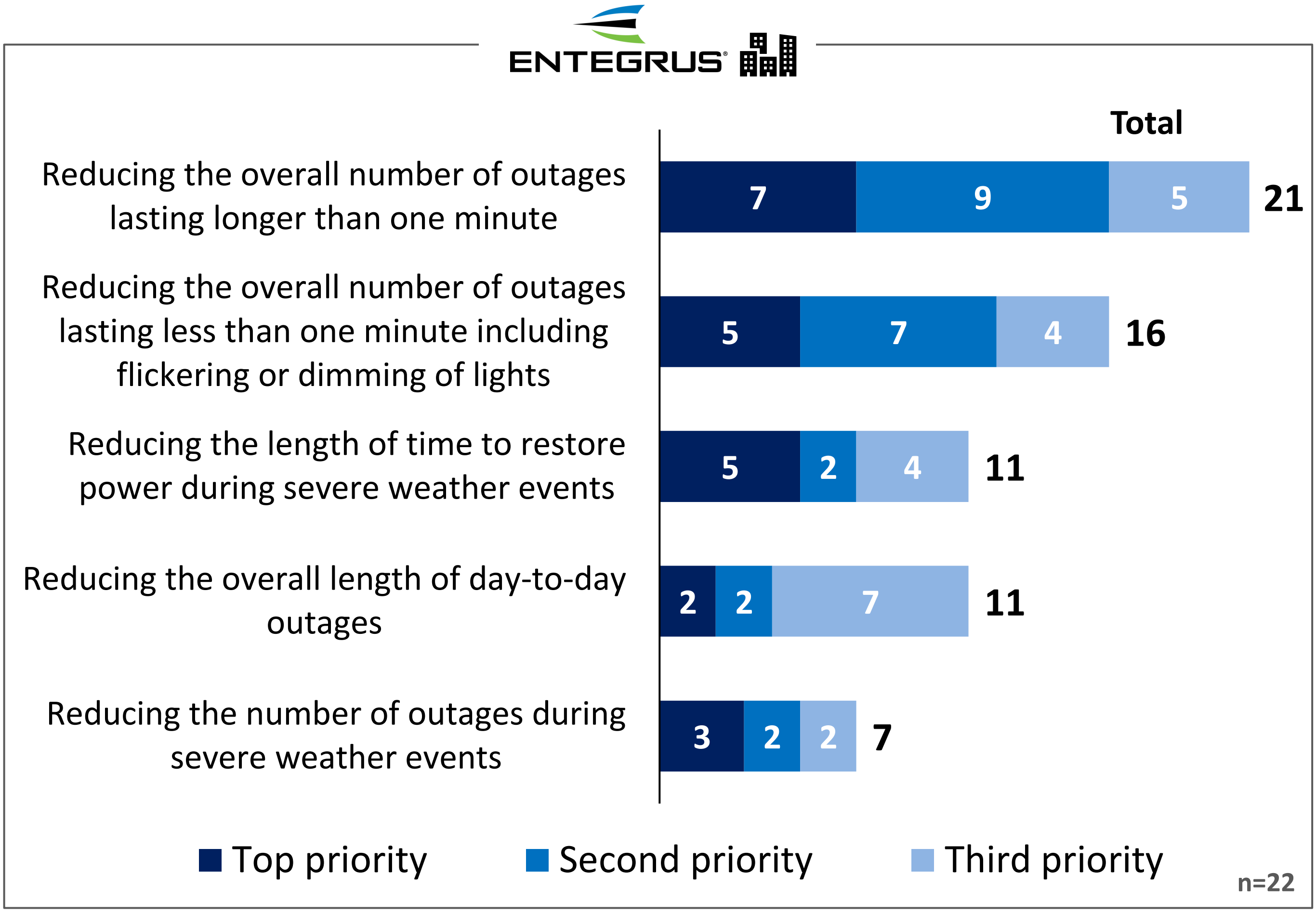


Note: St.Thomas outage statistics shown for St.Thomas customers

Online Workbook
Reliability Priorities

Commercial & Industrial

Q Among the following reliability outcomes, which are the most important to you? *While all of these priorities may be important to you, please rank your top 3 priorities – where '1' would be most important, '2' the second most important, and '3' the third most important.*



Entegrus Background

How can Entegrus improve the services you receive?

As previously mentioned, Entegrus has committed to the OEB to limit your future rate increases to less than inflation until 2026.

An Entegrus crew installing a new pole.

That said, as part of the OEB policies, there is an option for utilities to apply for additional rate increases for discrete projects that are prudent, needed and not supported by existing rates. However, as previously noted, Entegrus has decided to continue to make certain additional reliability investments without asking customers for rate increases at this time, to keep distribution rates affordable in 2021-2025.

Looking ahead, Entegrus has identified two projects that will help mitigate reliability issues related to degraded infrastructure and provide a stronger distribution system foundation for later integration of electric vehicle and customer-owned generation infrastructure investments in the next planning cycle from 2026 to 2030. Entegrus is looking for your thoughts to determine whether it should pursue these two projects, financing these on its own until 2026, with no additional charges to customers.

As noted above, Entegrus will only be asking for increases of less than inflation from customers for the next five years and any investments made now will not impact your rates until the next planning period between 2026 and 2030.

Line Modernization and Station Decommissioning

About 15% of Entegrus' customers are serviced by low voltage distribution systems. These low voltage lines were built in the 1950's, 1960's and 1970's and represent some of Entegrus' oldest distribution assets.

These low voltage lines have much less capacity than modern lines and are supported by stations that are required to deliver this lower voltage. These stations look like small houses, or in some cases, are fenced-in areas containing weatherized electrical equipment. During an outage, the modern lines cannot be used to restore power to the low voltage lines, because they don't operate at the same voltage levels.

Due to the limited capacity of the low voltage lines, they are not suited for smart grid technology or customer-owned electricity generation. As such, this equipment has become functionally outdated and the risk of equipment failure is increasing.

For the past 10 years, Entegrus has focused on converting these low voltage lines to the modern technology. When enough lines are converted, Entegrus can decommission and sell the land that contains the low voltage stations.

Investing in these projects offers three primary benefits:

A low voltage transformer station.

1. **Improved reliability through the new lines and transformers;**
2. **Increased capacity on each line to support customer growth, smart grid technology, and customer-owned electricity generation; and**
3. **Improved outage restoration from the enhanced back-up and availability of tie points at this higher voltage level.**

Entegrus currently has 19 of these stations supporting these low voltage lines still in use. To balance replacing other degraded assets and supporting customer growth, Entegrus planners are targeting the removal of 4 stations by 2025. At this pace, all of the low voltage lines would be replaced by modern lines and all the stations would be decommissioned beyond 2040.

However, because this equipment does not pose an urgent threat to reliability, if unforeseen distribution system priorities emerge over that period, it is the practice of Entegrus to divert resources away from these 4 lines modernization and station decommissioning projects to resolve more pressing priorities.

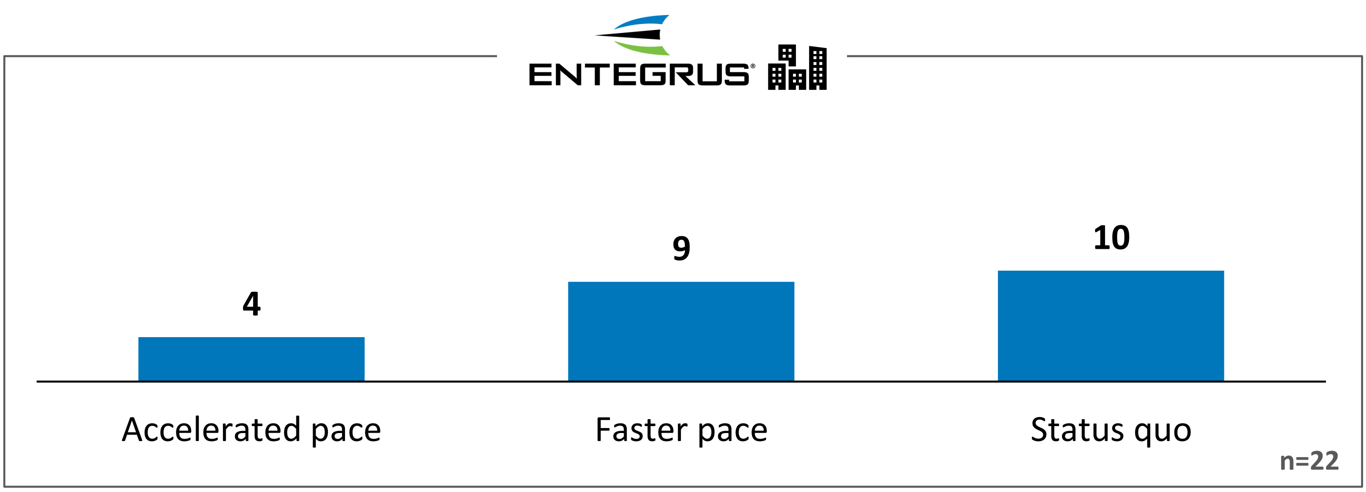
Online Workbook

Commercial & Industrial

Choice 1: Line Modernization and Station Decommissioning

Which of the following options do you prefer?

Option	Description	Expected Outcome
Accelerated Paced Line Modernization *<u>Additional</u> $40-$60 per month starting in 2026*	Line modernization to allow the removal of 6 low voltage Stations to occur from 2021-2025 regardless of other priorities.	• Complete line modernization of all low voltage equipment and Station decommissioning by 2035 • Reduce risk of deterioration of reliability • Avoid some Station maintenance costs.
Faster Paced Line Modernization *<u>Additional</u> $20-$30 per month starting in 2026*	Line modernization to allow the removal of 5 low voltage Stations to occur in 2021-2025 regardless of other priorities.	• Complete line modernization of all low voltage equipment and Station decommissioning by 2040 • Risk of deterioration of reliability continues • Escalating Station maintenance versus obsolescence.
Status Quo *Within current rates*	Continue to target line modernization to allow removal of 4 low voltage Stations, to occur in 2021-2025. Allow for diversion from this plan if other priorities emerge.	• Maintain low voltage Stations beyond 2040 • Higher risk of deterioration of reliability continues • Escalating Station maintenance versus obsolescence.
Additional Feedback (Optional)		



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Making Choices (2 of 2)

Implementing Smart Grid Technology

New technology has changed the way that Entegrus can manage and monitor the distribution system.

Intelligent (automated) switches

Intelligent (automated) switches allow Entegrus to automatically reroute power during outages and planned maintenance, reducing the length of time customers are without power and reducing reliance on crews travelling to the site to physically re-route power. When this automatic rerouting occurs, impacted neighbourhoods would experience an outage lasting less than one minute, rather than a lengthier interruption.

Entegrus has recently used automated switch technology to target more rural communities experiencing poor reliability due to loss of supply. These communities are served by two long lines from the provincial transmission system, and the technology allows the two lines to automatically back each other up when one line experiences an outage, eliminating the need for manual intervention.

However, Entegrus now sees an opportunity to roll this technology out in larger cities that have many interconnecting lines that can form “grids”. Doing so will offer multiple alternative paths for electricity to flow, bypassing the fault and avoiding potential widespread outages. Entegrus ran a successful pilot of intelligent switch technology on a single feeder line in Chatham in 2020.

Not only do these intelligent switches help reduce the length of time customers are without power, but they also help create a more integrated, advanced system that is better equipped to handle future technological advancements including electric vehicles and customer-owned electricity generation.

In its current draft plan, in order to afford to invest more dollars in replacement of poles and wires while limiting cost increases to customers, Entegrus plans to selectively install 6 more of these intelligent switches in 2021-2025. That said, there is a near term opportunity for a broad roll out of intelligent switches in the larger communities of Chatham and St. Thomas where there is the opportunity to increase connectivity by creating a medium or higher density of intelligent switches.

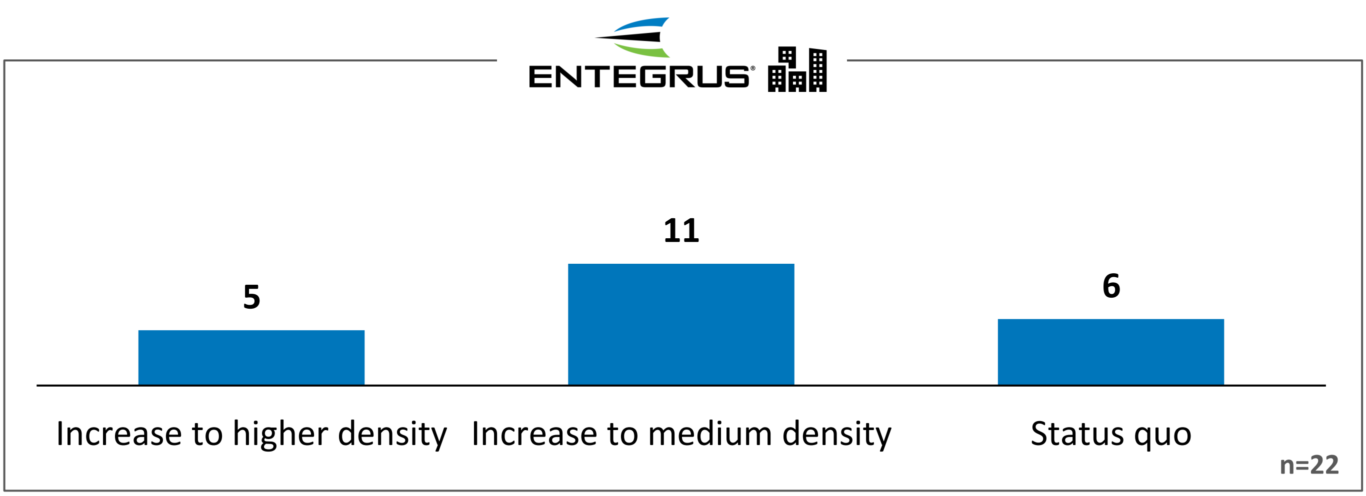
Online Workbook

Choice 2: Implementing Smart Grid Technology

Commercial & Industrial

Which of the following options do you prefer?

Option	Description	Expected Outcome
Increase to Higher Intelligent Switch Density in Chatham & St. Thomas *Additional $20-$40 per month starting in 2026*	Install an additional 18 switches in Chatham and an additional 10 switches in St. Thomas	Reduce outage duration by about 20% - 25% and outage frequency > 1 minute by about 30% - 40%
Increase to Medium Intelligent Switch Density in Chatham & St. Thomas *Additional $10-$20 per month starting in 2026*	Install an additional 11 switches in Chatham and an additional 6 switches in St. Thomas	Reduce outage duration by about 15% - 20% and outage frequency >1 minute by about 25% - 30%
Status Quo – Stay with Low Intelligent Switch Density in Chatham & St. Thomas *Within current rates*	No additional investment in intelligent switches beyond the few in the current plan.	Increased risk of potential deterioration of reliability in the medium term.
Additional Feedback (Optional)		



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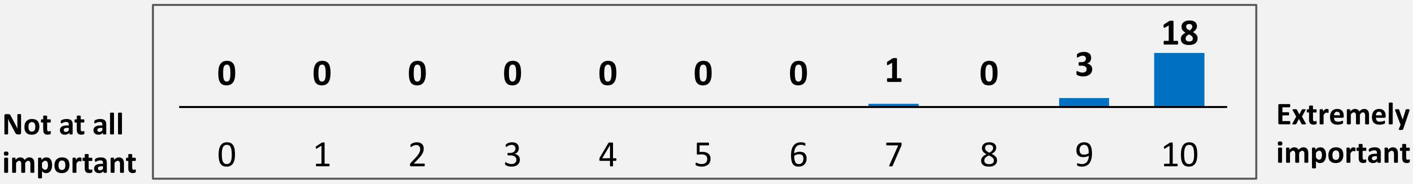
Online Workbook

Importance of Entegrus Priorities

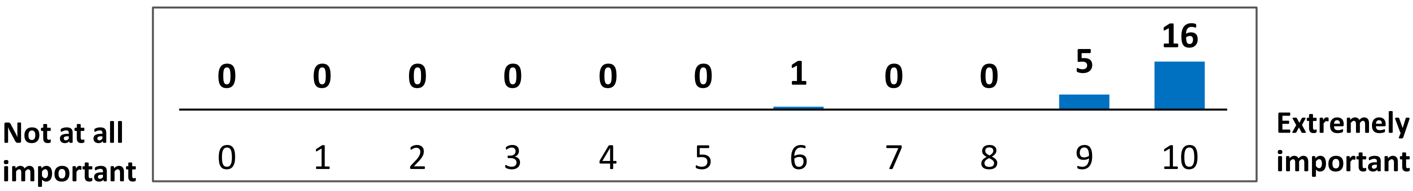
Commercial & Industrial

Q How importance are each of the following Entegrus priorities to you as a customer?

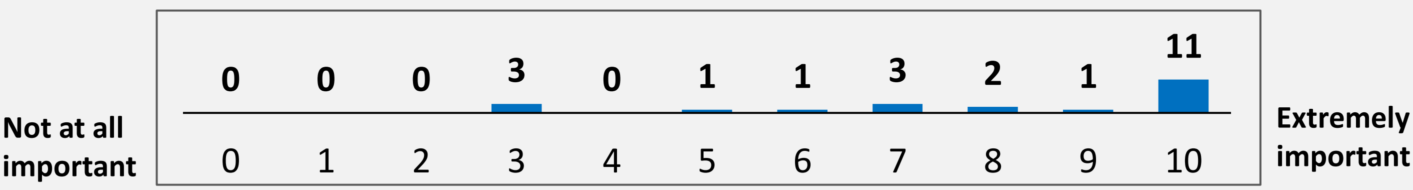
Ensuring reliable electrical service



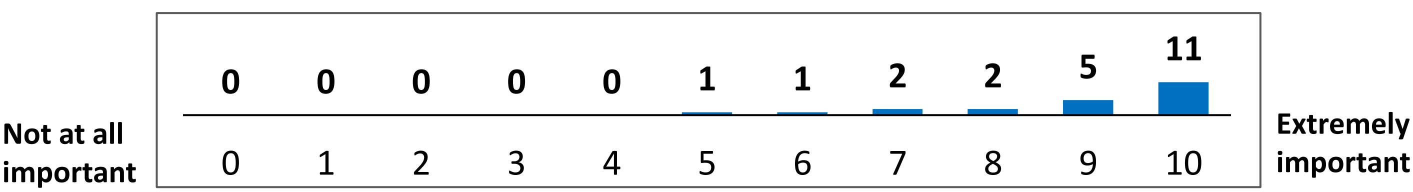
Delivering electricity at reasonable rates



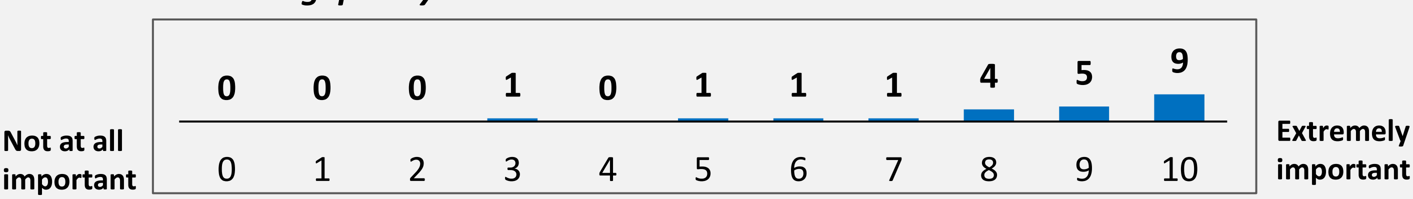
Helping customers with conservation and cost savings



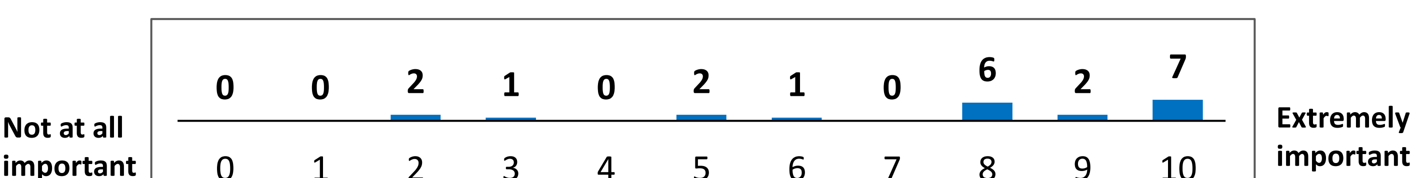
Ensuring the safety of electricity infrastructure



Providing quality customer service



Minimizing the impact on the environment



Note: “Don’t know” not shown.

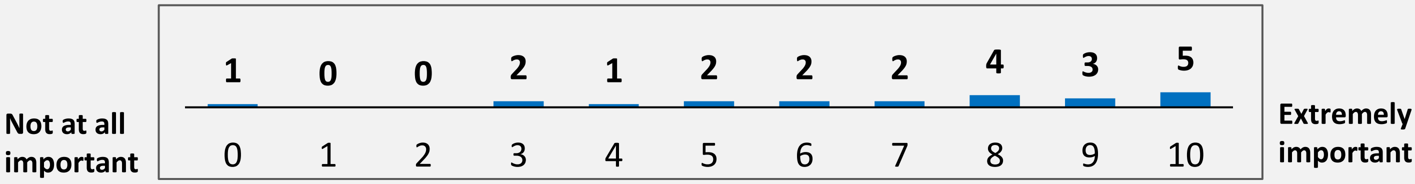
Online Workbook

Importance of Entegrus Priorities

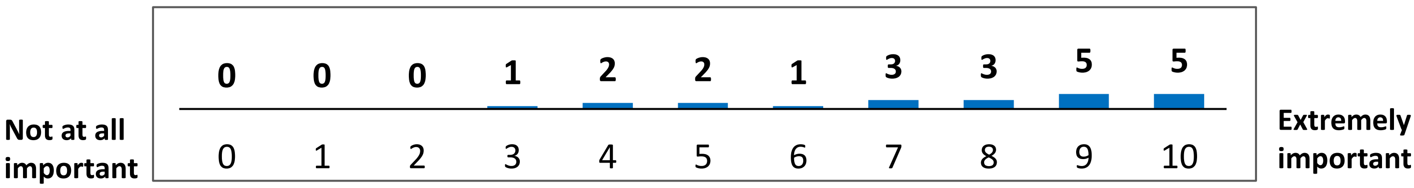
Commercial & Industrial

Q How importance are each of the following Entegrus priorities to you as a customer?

Enabling customer choice to access new electricity services



Proactively preparing for community growth



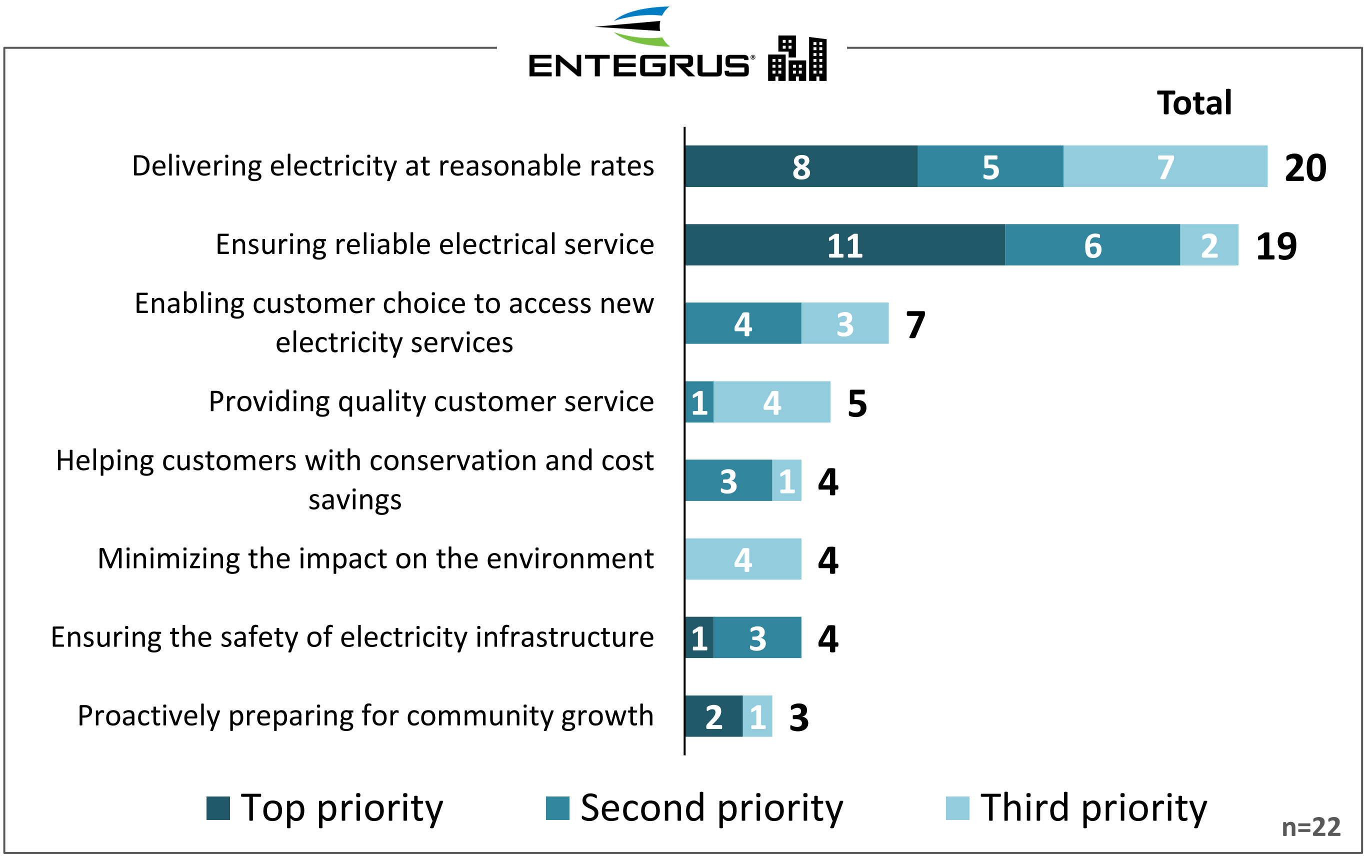
Note: "Don't know" not shown.

Online Workbook

Ranking Entegrus Priorities

Commercial & Industrial

Q Thinking again about the things that Entegrus should be focusing on, please rank your top 3 priorities – where '1' would be the most important, '2' the second most important, and '3' the third most important.



Online Workbook

Additional Entegrus Priorities

Q

The list above may not include all the outcomes that matter to you. Are there any other important priorities that Entegrus should be focusing on that weren't included in the list above?

Additional Comments
"Coming up with an electricity storage rate (presumably in the evening) to allow for optimal use of the distribution grid and encourage storage. I believe this rate should be nominal with the goal to balance the load and encourage storage."
"Reliable electrical supply - reducing the number of momentary or longer outages."

Online Workbook

Importance of Technology Priorities

Commercial & Industrial

Q How importance are each of the following investments in new technology that Entegrus could focus on?

New technology that would reduce the number and length of outages

Not at all important	0	1	2	3	4	5	6	7	8	9	10	Extremely important
	0	0	0	0	0	1	0	1	2	2	16	

New technology that can help Entegrus find efficiencies and reduce customer costs

Not at all important	0	1	2	3	4	5	6	7	8	9	10	Extremely important
	0	0	0	0	0	1	0	2	1	4	14	

New technology that can help customers better manage their electricity usage

Not at all important	0	1	2	3	4	5	6	7	8	9	10	Extremely important
	0	0	0	1	0	1	0	6	4	4	6	

New technology that enables customer choice to access new electricity services

Not at all important	0	1	2	3	4	5	6	7	8	9	10	Extremely important
	0	0	1	1	3	2	1	1	4	4	5	

New technologies that make it easier to interact with Entegrus

Not at all important	0	1	2	3	4	5	6	7	8	9	10	Extremely important
	1	1	0	2	0	1	6	3	3	1	4	

New technology to reduce the environmental impact of Entegrus' operations

Not at all important	0	1	2	3	4	5	6	7	8	9	10	Extremely important
	2	0	2	1	1	2	1	3	4	2	4	

Note: "Don't know" not shown.

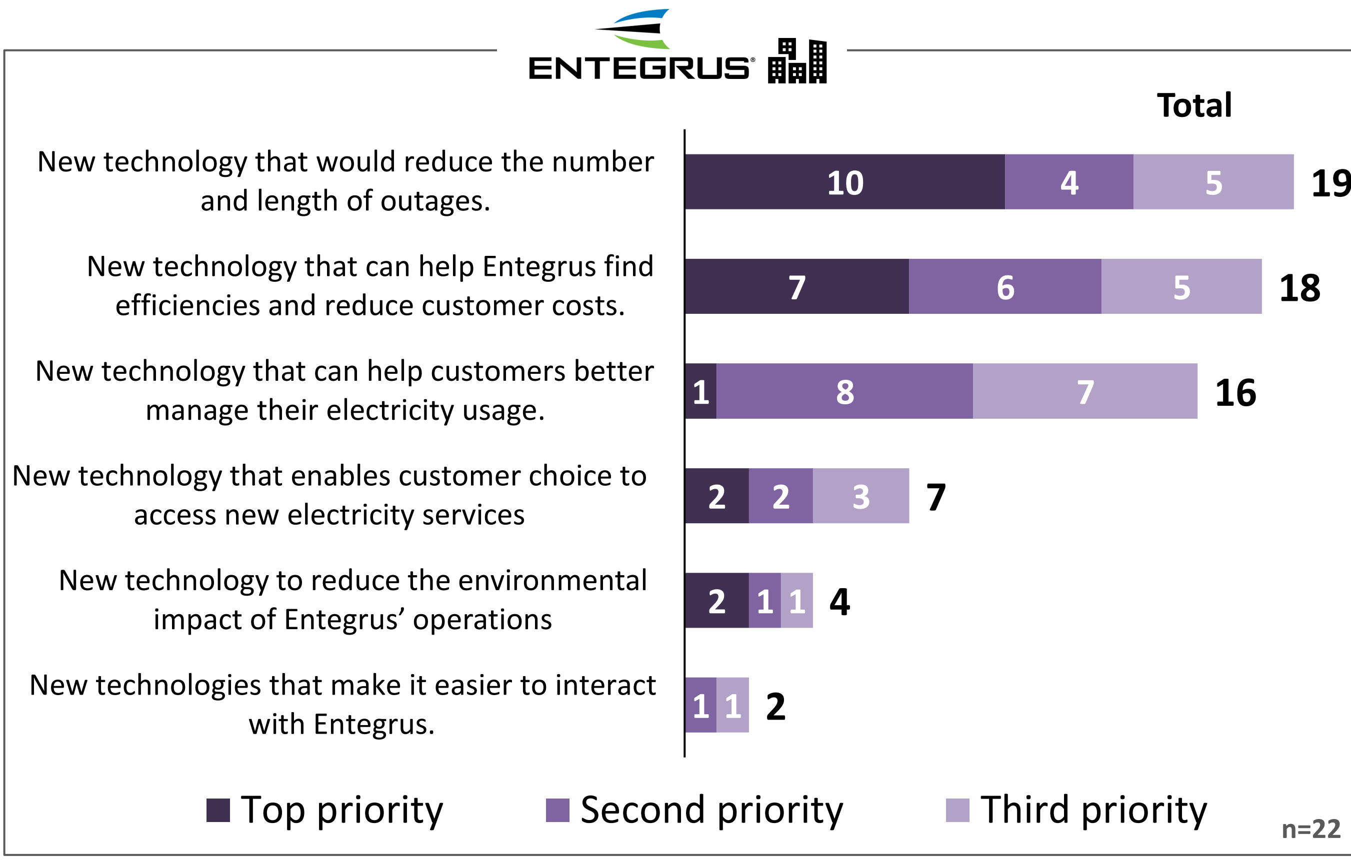
Online Workbook

Ranking Technology Priorities

Commercial & Industrial

Q

Thinking again about the things that Entegrus should be focusing on, please rank your top 3 technology priorities – where '1' would be the most important, '2' the second most important, and '3' the third most important.



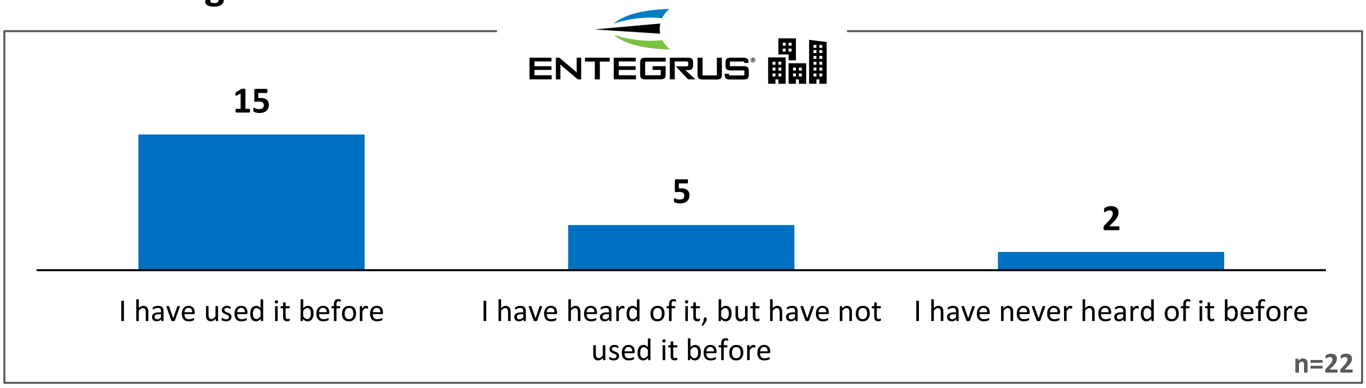
Online Workbook

Commercial & Industrial

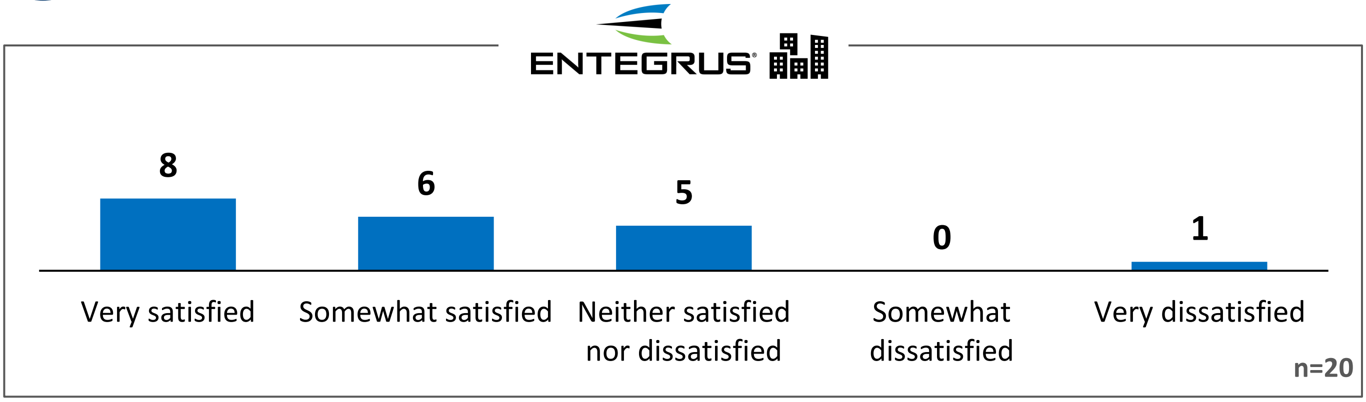
Entegrus' Digital Tools – The Entegrus.com Website

Q How familiar are you with the following digital tools that are offered by Entegrus?

The Entegrus.com website



Q Please indicate whether you are satisfied or dissatisfied with each of the following tools.



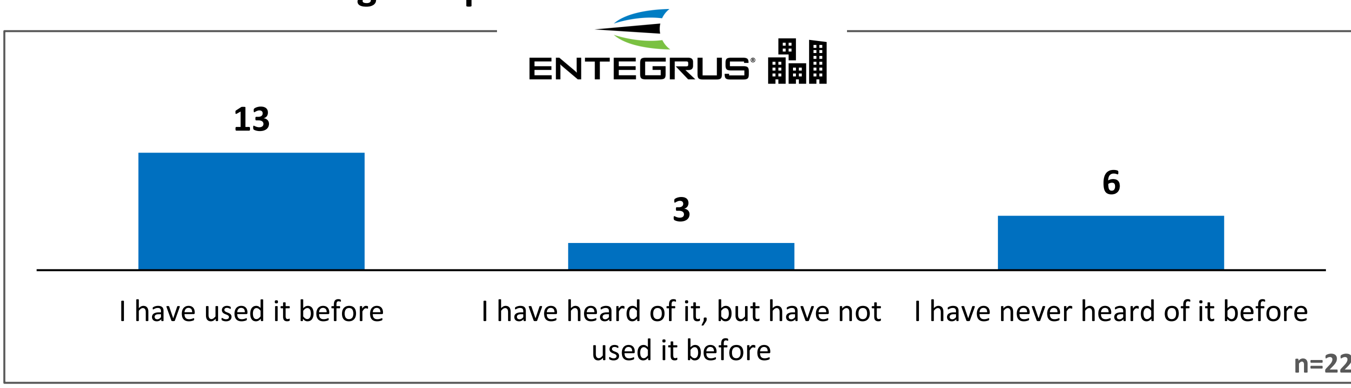
Online Workbook

Entegrus' Digital Tools – The Online Outage Map

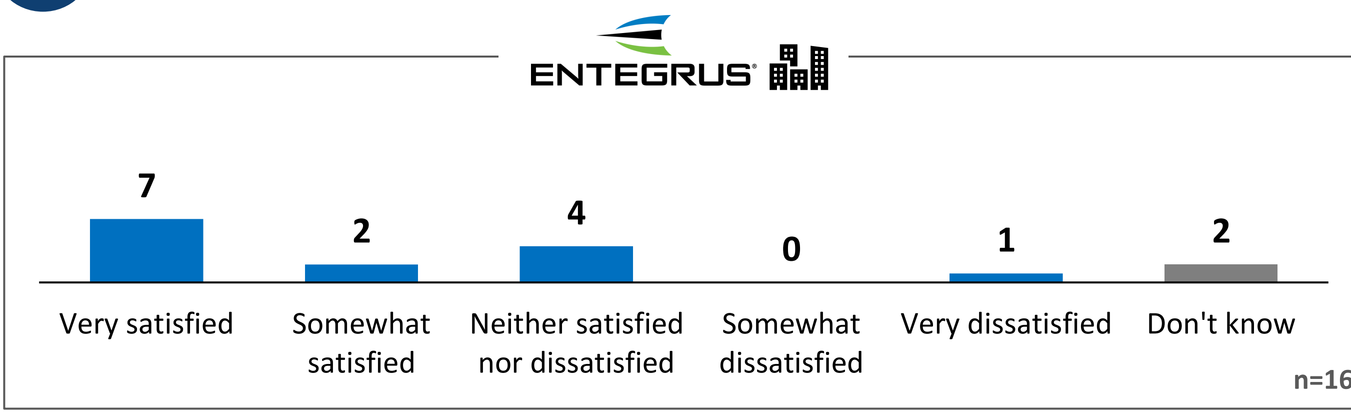
Commercial & Industrial

Q How familiar are you with the following digital tools that are offered by Entegrus?

The online outage map



Q Please indicate whether you are satisfied or dissatisfied with each of the following tools.



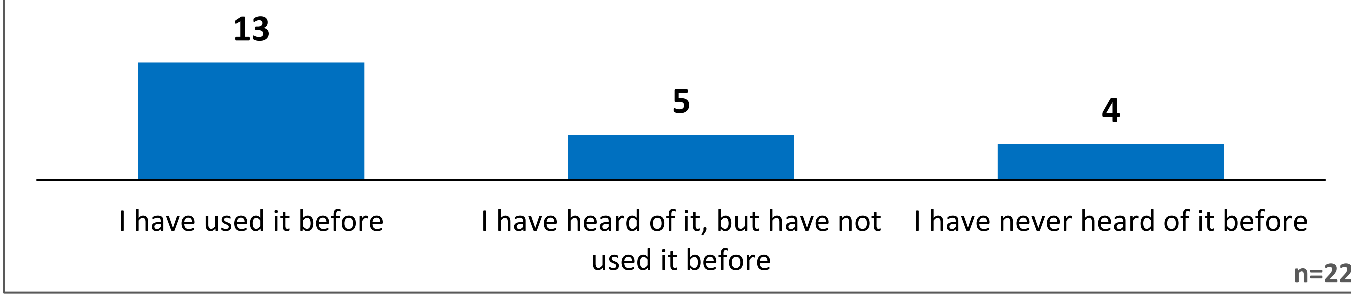
Online Workbook

Commercial & Industrial

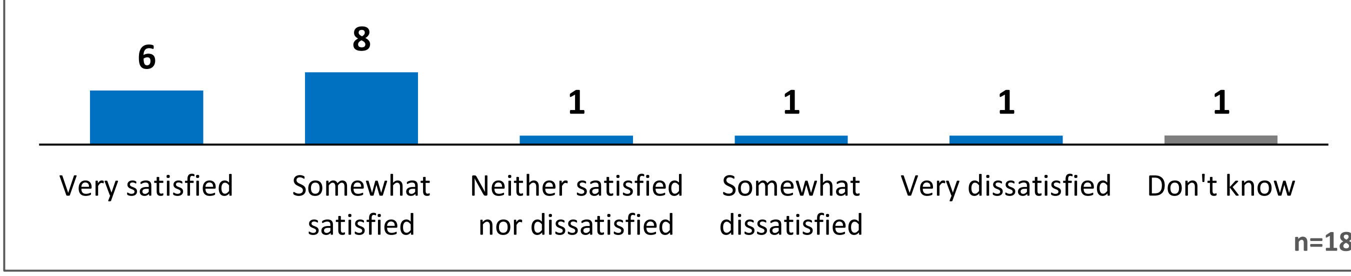
Entegrus' Digital Tools – Customer Service Self-Serve Programs

Q How familiar are you with the following digital tools that are offered by Entegrus?

Customer service self-serve programs



Q Please indicate whether you are satisfied or dissatisfied with each of the following tools.



Q Are there any additional digital tools or services that you would like Entegrus to provide?

Additional Comments
"Having a MyAccount portal along with a website is sufficient but MyAccount has features that do not work like, 'My Recent Usage'".

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Commercial & Industrial Customers

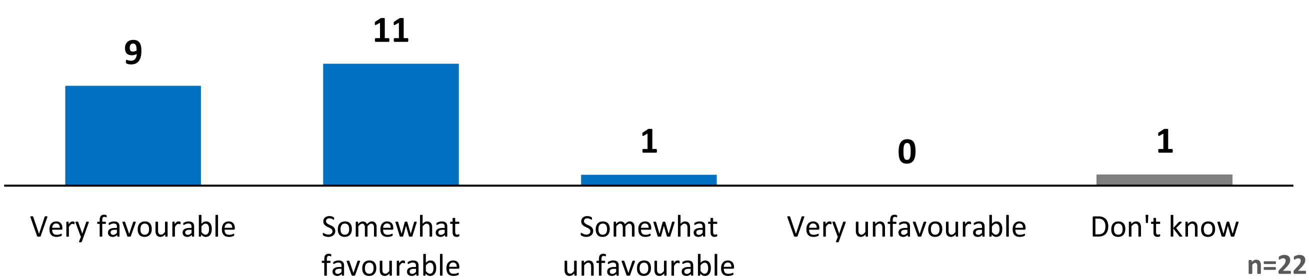
Workbook Diagnostics

Online Workbook

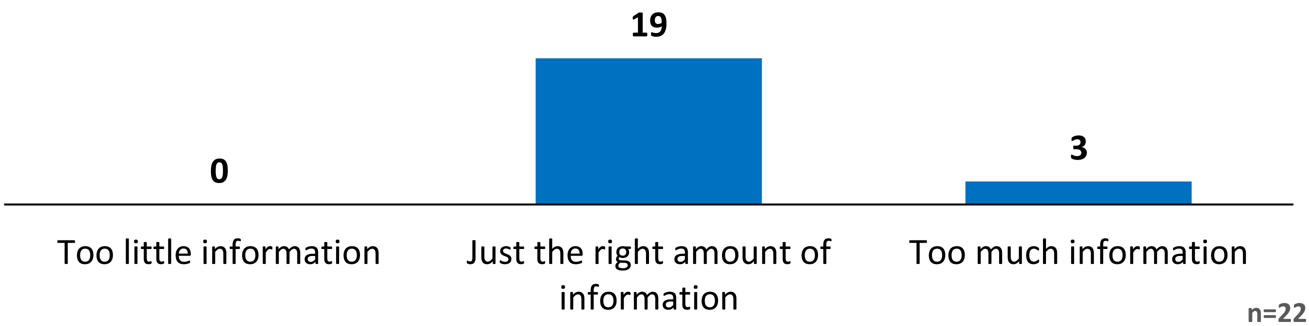
Workbook Diagnostics

Commercial & Industrial

Q Overall, did you have a favourable or unfavourable impression of the customer engagement you just completed?



Q In this customer engagement, do you feel that Entegrus provided too much information, not enough, or just the right amount?



Online Workbook

Content Missing from Engagement

Commercial & Industrial

Q Was there any content missing that you would have liked to have seen included in this customer engagement?

Additional Comments
"Given that you charge developers for new infrastructure such as poles and transformers, you should have not capital costs for new subdivisions or commercial/industrial areas. And it would have been prudent to have had a reserve fund study to be better understand and save for infrastructure replacement."
"Cost reductions – we have one of the highest costs of power in North America."
"As the economy moves away from carbon i would like to know what options exist through incentives or otherwise, to convert from gas to electricity. It is hard to do in a high priced electricity environment."

Q Is there anything that you would still like answered?

Additional Comments
"Why was Entegrus allowed to double charge us when we contracted our power from a third party?"
"Can Entegrus support a shift to electric vehicles in the upcoming decade? Or would significant changes/investments need to be made in order to accommodate a shift in individual transportation methods/preferences?"

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Building Understanding.

Personalized research to connect you and your audiences.

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Appendix 2.0

ENTEGRUS®

Customer Engagement

Residential and Small Business Online Workbook Layout

Low-Volume Workbook

June 2021

STRICTLY PROPRIETARY AND CONFIDENTIAL

About this Customer Engagement

Welcome to Entegrus' customer engagement survey!

As Entegrus plans for the future, they need your input on choices that will impact the services you receive and the rates that you pay for the delivery of electricity.

- **Entegrus is currently in the process of developing its investment plan for 2021 to 2025.** This plan will determine the investments Entegrus makes in equipment and infrastructure, the services it provides, and the rates you pay.
- **Entegrus is now looking for your input on its draft plan** to ensure it is making spending decisions that matter to you, the customer.
- **Later this year, Entegrus will provide its investment plan** to the public regulator, the Ontario Energy Board (OEB) for its scrutiny.
- **Between now and 2025, Entegrus will execute its 2021 to 2025 investment plan,** ultimately, impacting the services you receive and the delivery of electricity throughout the communities that Entegrus serves.

This survey will take approximately 20-30 minutes to complete and can be done so at your convenience. Once you begin, your progress will be saved, and you can return to the customer engagement at any time.

All individual responses will be kept confidential. Innovative Research Group (INNOVATIVE), an independent research company, has been hired to gather your feedback.

Those who complete the questions that follow will be invited to enter a draw to win one of two (2) $500 prepaid VISA gift cards.

About this Customer Engagement

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- **Between now and 2025, Entegrus will execute its 2021 to 2025 investment plan,** ultimately, impacting the services you receive and the delivery of electricity throughout the communities that Entegrus serves.

Note: The estimates throughout this survey are for illustrative purposes only, and may not reflect the actual size of your organization's monthly electricity bill.

For the purpose of this exercise, the estimates are based on a customer with an average monthly demand of 500 kW and average monthly consumption of 162,500 kWh.

This survey will take approximately 20-30 minutes to complete and can be done so at your convenience. Once you begin, your progress will be saved, and you can return to the customer engagement at any time.

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Entegrus Customer Engagement

Planning for the Future: 2021-2025 Investment Plan

About this Customer Engagement

Thank you for your interest in being a part of Entegrus' customer engagement.

If you are reading this on a smaller mobile device, you may want to consider accessing the survey from a tablet, desktop computer or laptop instead so that it is easier for you to read.

[OPEN LINK ONLY] Would you like to complete this survey on behalf of your business or organization, or your home?
◻ Business or organization ◻ Home
[OPEN LINK ONLY] Business or organization: In which of the following communities does your organization primarily operate from? **Home: In which of the following communities is your primary residence?** **[drop down]**
◻ Blenheim ◻ Bothwell ◻ Chatham ◻ Dresden ◻ Dutton ◻ Erieau ◻ Merlin ◻ Mount Brydges ◻ Newbury ◻ Parkhill ◻ Ridgetown ◻ St. Thomas ◻ Strathroy ◻ Thamesville ◻ Tilbury ◻ Wallaceburg ◻ Wheatley

Electricity 101

Who is Entegrus?

Entegrus is a regulated electricity distributor that owns and operates distribution systems serving 17 communities in Southwestern Ontario, stretching between Wheatley (to the west), St. Thomas (to the east), Parkhill (to the north) and Lake Erie (to the south). The Entegrus service territory covers an area of approximately 5,600 square kilometers and the distance and time between Parkhill and Wheatley is about 170km, or a two-hour drive.

The utility's service territory today is a product of multiple mergers and acquisitions of previously independent distributors dating back to the late-1990s. The electrification of Southwestern Ontario dates back to the early 1900s. Most of the initial system expansion in the Entegrus communities occurred between 1950 and 1970. Some of the equipment in Entegrus' distribution system is more than 50 years old.

The most recent and significant addition to Entegrus' asset base is the amalgamation of Entegrus' assets with those of the former St. Thomas Energy, approved by the OEB on March 15, 2018.

Had you heard of the Entegrus merger with St. Thomas Energy before this survey?
◻ Yes ◻ No ◻ Don't know

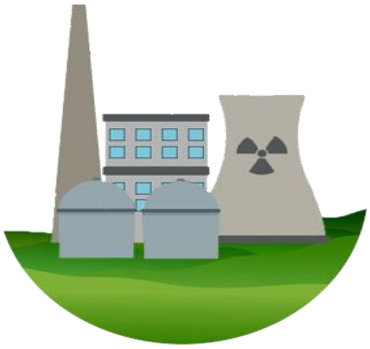
Electricity 101

What is Entegrus' role in Ontario's electricity system?

Ontario's electricity system is owned and operated by public, private and municipal corporations across the province. It is made up of three key components: **generation**, **transmission** and **distribution**.

Generation

Where electricity comes from

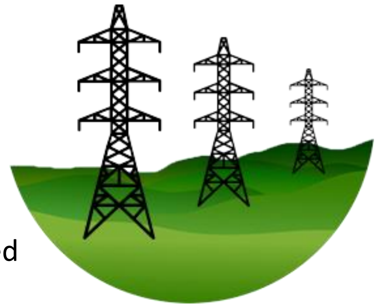


Ontario gets its electricity from a mix of energy sources. About half comes from nuclear power. The remainder comes from a mix of hydroelectric, natural gas, wind and solar.

Ontario Power Generation, a government-owned company, generates almost half of Ontario's electricity. The other half comes from multiple generators who have contracts with the grid operator to provide power from a variety of sources.

Transmission

How electricity travels across Ontario



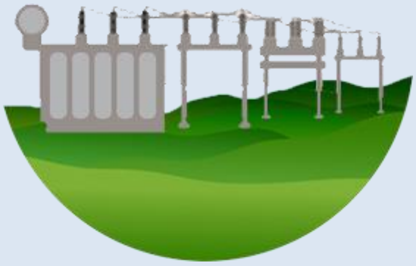
Once electricity is generated, it must be transported to urban and rural areas across the province. This happens by way of high voltage transmission lines that serve as highways for electricity. The province has more than 30,000 kilometres of transmission lines, most of which is owned and operated by Hydro One.

Local Distribution

How electricity is delivered to the end-consumer

Entegrus is responsible for the last step of the journey: distributing electricity to customers through its distribution system.

- Entegrus manages all aspects of the electricity distribution business throughout 17 communities in Southwestern Ontario and is regulated by the Ontario Energy Board (OEB).
- Entegrus is jointly owned by the Municipality of Chatham-Kent (72%), the Corporation of the City of St. Thomas (20%) and Corix Infrastructure Inc. (8%).
- Entegrus is entirely funded through the rates its customers pay and does not receive taxpayer money to fund its operations or its investments in the distribution system.



How familiar are you with Entegrus, which operates the electricity distribution system in your community?

☐ Very familiar
☐ Somewhat familiar
☐ Not familiar at all
☐ Don't know

Electricity 101

How much of my electricity bill goes to Entegrus?

- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board (OEB), the provincial energy regulator.
- While **Entegrus** is responsible for collecting payment for the entire electricity bill – as well as water charges for many of its communities – Entegrus retains only a portion of the electricity delivery charge. The electricity delivery charge also includes Hydro One transmission costs and system losses.
- Distribution makes up about 26% of the typical residential customer's bill.
- The rest of your bill is passed onto provincial transmission companies, power generation companies, the provincial government and regulatory agencies.

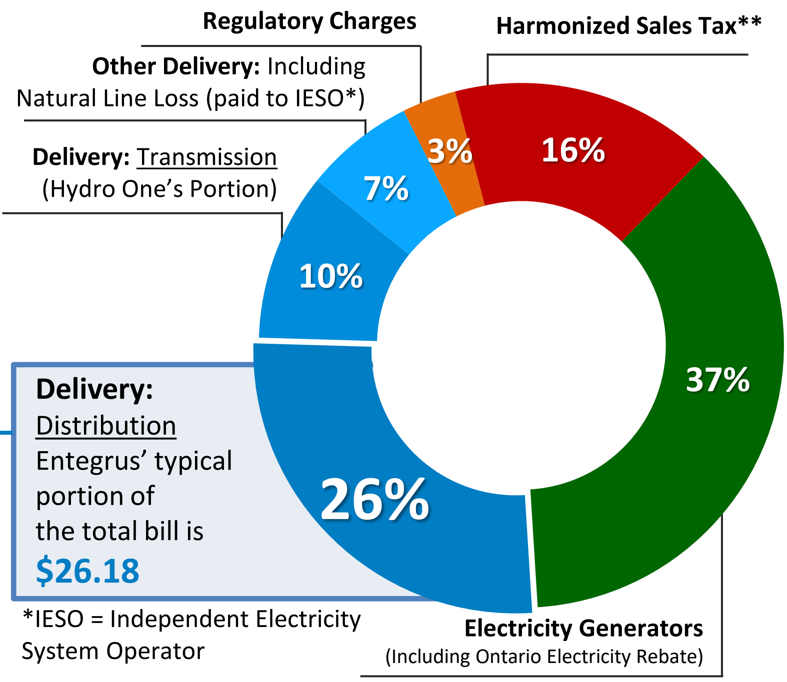
Entegrus Sample Monthly Bill
(Based on monthly usage of 750 kWh)

Account Number:
000 000 000 000 0000

Meter Number:
00000000

Your Electricity Charges

Electricity	
Off-Peak @ 8.2 ¢/kWh	**39.36**
Mid-Peak @ 11.3 ¢/kWh	**15.26**
On-Peak @ 17 ¢/kWh	**22.95**
Delivery	**43.13**
Regulatory Charges	**3.30**
Total Electricity Charges	**$123.99**
HST	**16.12**
Ontario Electricity Rebate	**(-$41.17)**
Total Amount	**$98.95**



** HST is calculated before applying the Ontario Electricity Rebate and is therefore above 13%.

Thinking specifically about the services provided to you and your community by Entegrus, overall, how satisfied or dissatisfied are you with the services that you receive?

□ Very satisfied
□ Somewhat satisfied
□ Neither satisfied nor dissatisfied
□ Somewhat dissatisfied
□ Very dissatisfied
□ Don't know

Before this survey, how familiar were you with the amount of your electricity bill that went to Entegrus?

□ Very familiar
□ Somewhat familiar
□ Not familiar
□ Don't know

Is there anything in particular you would like Entegrus to do to improve its services to you? [OPEN]

Entegrus Background

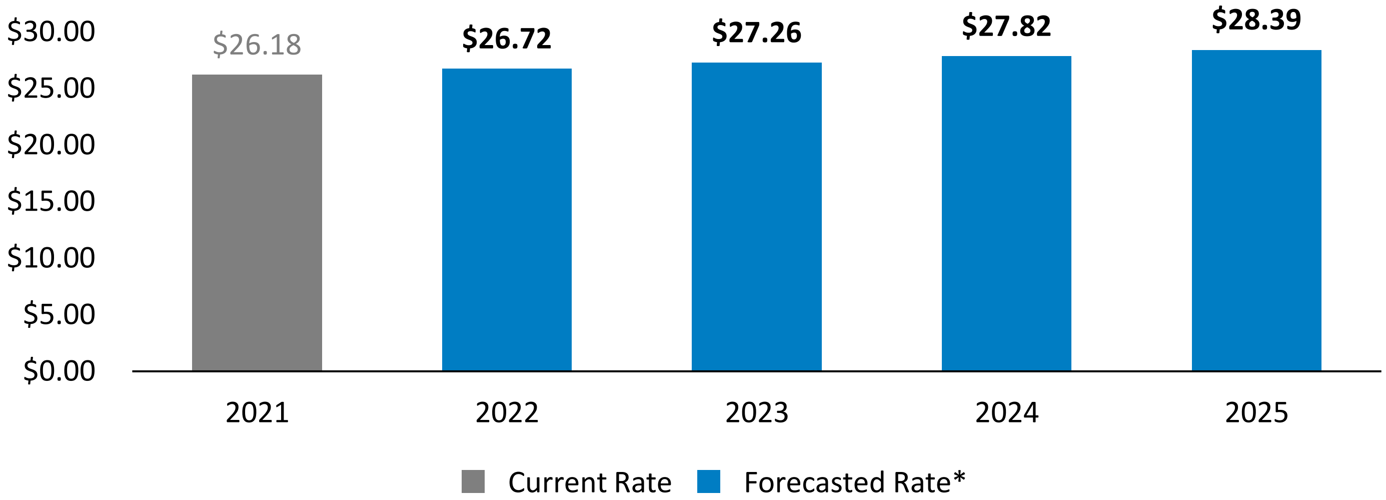
How much can you expect to pay over the next few years?

Prior to merging, both **Entegrus** and **St. Thomas Energy** had their rates set by the OEB, meaning the amount they can charge customers for the delivery of electricity.

While the merger was finalized in April 2018, for the eight years that follow the OEB has limited your future rate increases to less than inflation. That means that each year Entegrus is permitted to increase rates to reflect inflation minus savings targets established by the OEB. This requires Entegrus to keep cost increases below inflation.

For a residential customer like yourself, the distribution charge for the **typical bill is estimated to increase by approximately 2.05%** on average for the next five years (based on 2020 OEB inflation), until 2026.

Distribution Portion of the Bill per Month (2021-2025)



* These estimates are preliminary and are subject to your feedback as the investment plan is finalized.

Where does your money go?

Entegrus has two budgets; **operating and capital.** The operating budget covers recurring expenses, such as salaries, taxes, fuel costs, and rent. Until 2026, Entegrus cannot ask for any additional money for operating expenses.

This engagement is about the capital budget. This budget covers things like poles, wires, cables, transformers, meters, computers and programs, vehicles, and buildings.

Before this survey, were you aware that for a residential customer like yourself, the distribution charge for the typical bill is estimated to increase by approximately 2.05% on average for the next five years, until 2026?
☐ Yes ☐ No ☐ Don’t know

Electricity 101

How much of my electricity bill goes to Entegrus?

- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board (OEB), the provincial energy regulator.
- While **Entegrus** is responsible for collecting payment for the entire electricity bill – as well as water charges for many of its communities – Entegrus retains only a portion of the electricity delivery charge. The electricity delivery charge also includes Hydro One transmission costs and system losses.
- Distribution makes up about 28% of the typical residential customer's bill.
- The rest of your bill is passed onto provincial transmission companies, power generation companies, the provincial government and regulatory agencies.

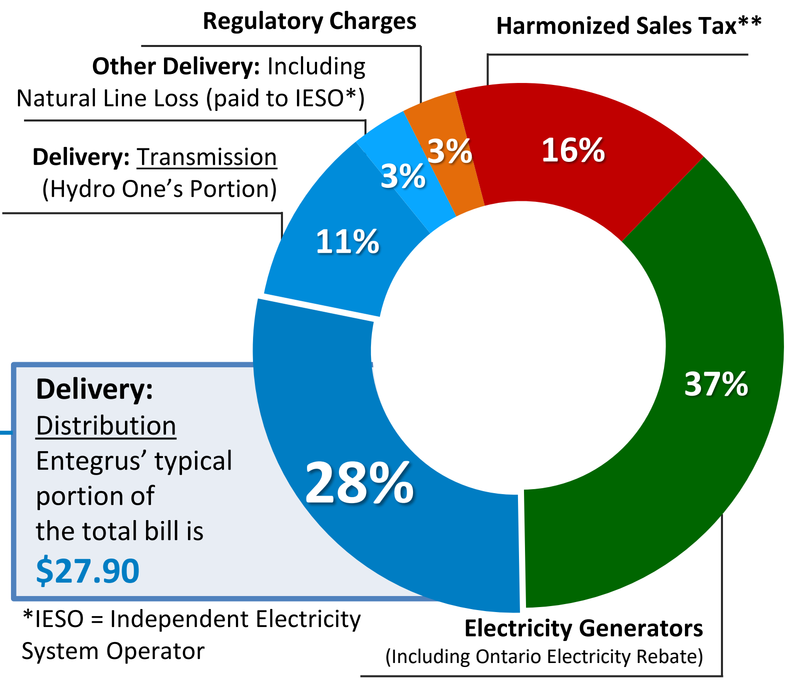
Entegrus Sample Monthly Bill
(Based on monthly usage of 750 kWh)

Account Number:
000 000 000 000 0000

Meter Number:
00000000

Your Electricity Charges

Electricity	
Off-Peak @ 8.2 ¢/kWh	39.36
Mid-Peak @ 11.3 ¢/kWh	15.26
On-Peak @ 17 ¢/kWh	22.95
Delivery	42.05
Regulatory Charges	3.29
Total Electricity Charges	**$122.90**
HST	15.98
Ontario Electricity Rebate	(-$40.80)
Total Amount	**$98.07**



*IESO = Independent Electricity System Operator

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Thinking specifically about the services provided to you and your community by Entegrus, overall, how satisfied or dissatisfied are you with the services that you receive?

- ☐ Very satisfied
- ☐ Somewhat satisfied
- ☐ Neither satisfied nor dissatisfied
- ☐ Somewhat dissatisfied
- ☐ Very dissatisfied
- ☐ Don't know

Before this survey, how familiar were you with the amount of your electricity bill that went to Entegrus?

- ☐ Very familiar
- ☐ Somewhat familiar
- ☐ Not familiar
- ☐ Don't know

Is there anything in particular you would like Entegrus to do to improve its services to you? [OPEN]

Entegrus Background

How much can you expect to pay over the next few years?

Prior to merging, both **Entegrus** and **St. Thomas Energy** had their rates set by the OEB, meaning, the amount they can charge customers for the delivery of electricity.

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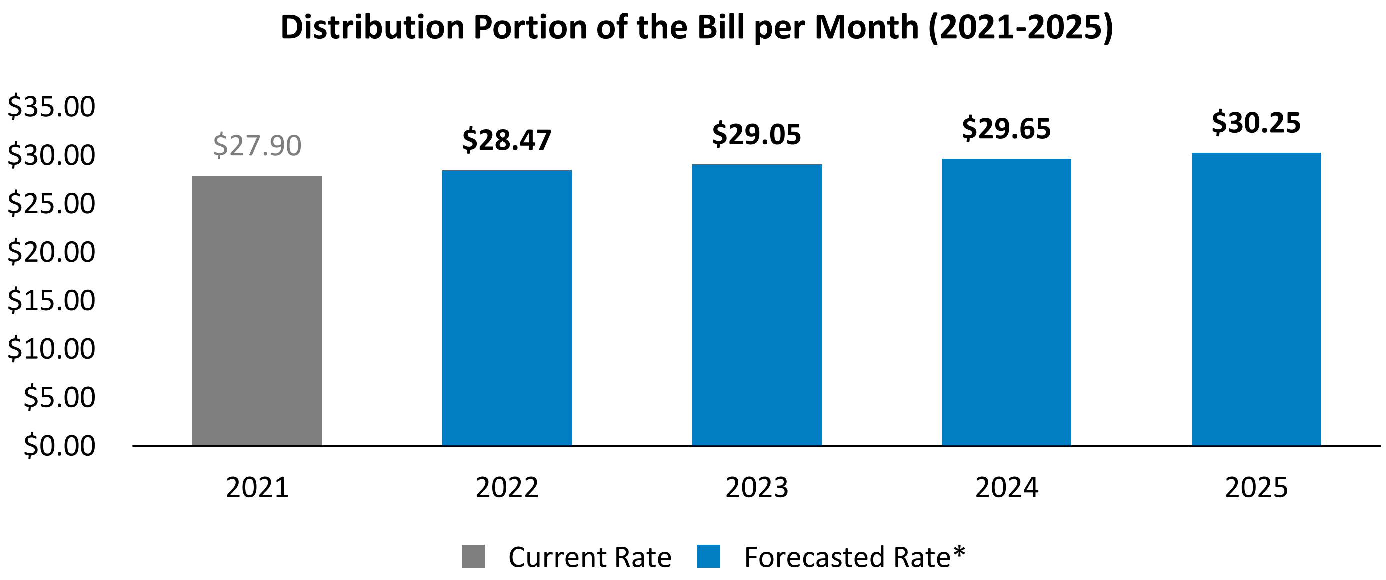
For a residential customer like yourself, the distribution charge for the **typical bill is estimated to increase by approximately 2.05%** on average for the next five years (based on 2020 OEB inflation), until 2026.



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This engagement is about the capital budget. This budget covers things like poles, wires, cables, transformers, meters, computers and programs, vehicles, and buildings.

Before this survey, were you aware that for a residential customer like yourself, the distribution charge for the typical bill is estimated to increase by approximately 2.05% on average for the next five years, until 2026?

- ☐ Yes
- ☐ No
- ☐ Don’t know

Electricity 101

How much of my electricity bill goes to Entegrus?

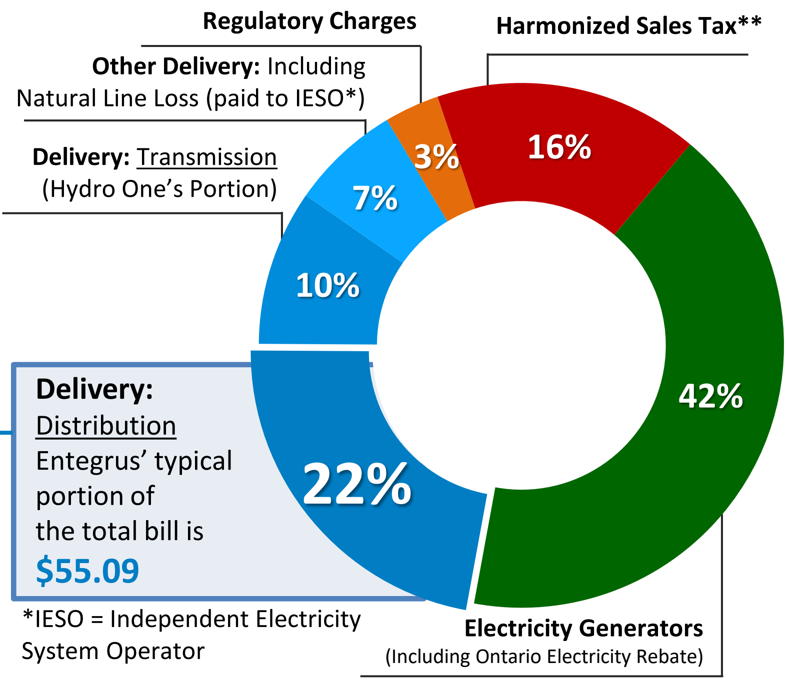
- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board (OEB), the provincial energy regulator.
- While **Entegrus** is responsible for collecting payment for the entire electricity bill – as well as water charges for many of its communities – Entegrus retains only a portion of the electricity delivery charge. The electricity delivery charge also includes Hydro One transmission costs and system losses.
- Distribution makes up about 22% of the typical small business customer's bill.
- The rest of your bill is passed onto provincial transmission companies, power generation companies, the provincial government and regulatory agencies.

Entegrus Sample Monthly Bill
(Based on monthly usage of 2,000 kWh)

Account Number:
000 000 000 000 0000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
Off-Peak @ 8.2 ¢/kWh	104.96
Mid-Peak @ 11.3 ¢/kWh	40.68
On-Peak @ 17 ¢/kWh	61.20
Delivery	95.58
Regulatory Charges	8.39
Total Electricity Charges	**$310.81**
HST	40.40
Ontario Electricity Rebate	(-$103.19)
Total Amount	**$248.02**



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Thinking specifically about the services provided to you and your community by Entegrus, overall, how satisfied or dissatisfied are you with the services that your organization receives?

- ☐ Very satisfied
- ☐ Somewhat satisfied
- ☐ Neither satisfied nor dissatisfied
- ☐ Somewhat dissatisfied
- ☐ Very dissatisfied
- ☐ Don't know

Before this survey, how familiar were you with the amount of your organization's electricity bill that went to Entegrus?

- ☐ Very familiar
- ☐ Somewhat familiar
- ☐ Not familiar
- ☐ Don't know

Is there anything in particular you would like Entegrus to do to improve its services to your organization? [OPEN]

Entegrus Background

How much can you expect to pay over the next few years?

Prior to merging, both **Entegrus** and **St. Thomas Energy** had their rates set by the OEB, meaning, the amount they can charge customers for the delivery of electricity.

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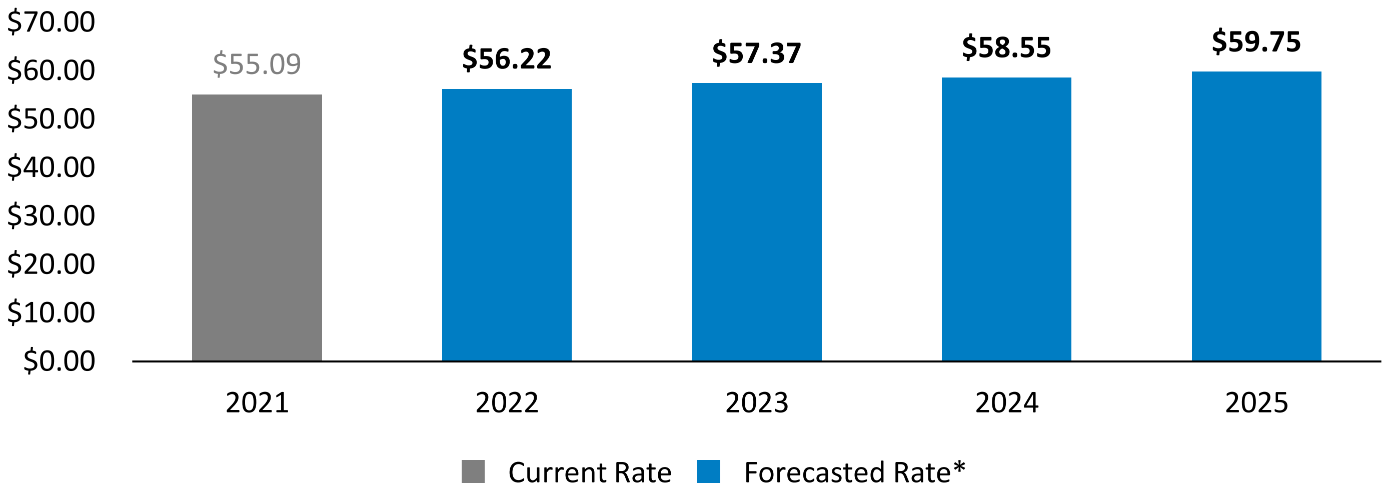
Distribution Portion of the Bill per Month (2021-2025)



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Before this survey, were you aware that for a small business customer like yourself, the distribution charge for the typical bill is estimated to increase by approximately 2.05% on average for the next five years, until 2026?

- ☐ Yes
- ☐ No
- ☐ Don't know

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How much of my electricity bill goes to Entegrus?

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- While **Entegrus** is responsible for collecting payment for the entire electricity bill – as well as water charges for many of its communities – Entegrus retains only a portion of the electricity delivery charge. The electricity delivery charge also includes Hydro One transmission costs and system losses.
- Distribution makes up about 25% of the typical small business customer's bill.
- The rest of your bill is passed onto provincial transmission companies, power generation companies, the provincial government and regulatory agencies.

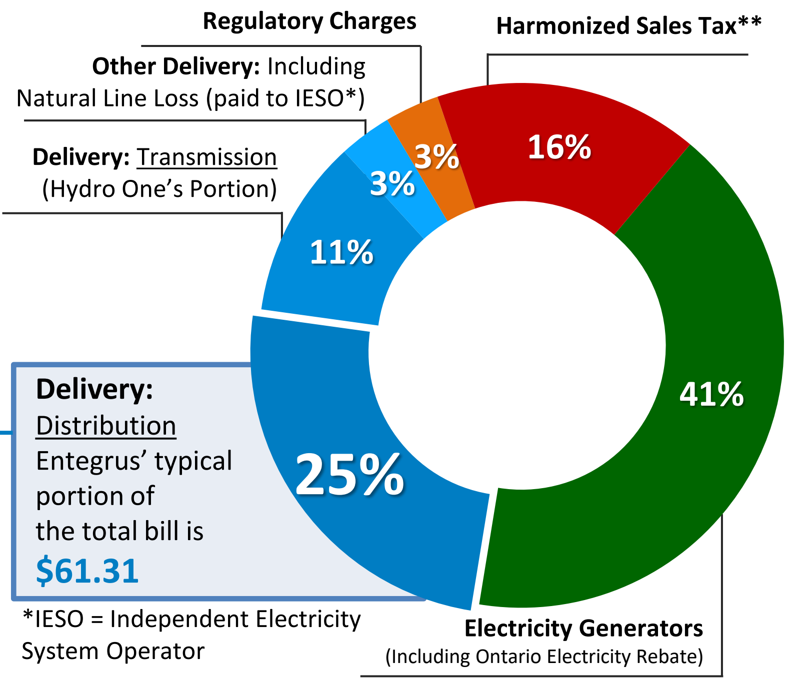
Entegrus Sample Monthly Bill
(Based on monthly usage of 2,000 kWh)

Account Number:
000 000 000 000 0000

Meter Number:
00000000

Your Electricity Charges

Electricity	
Off-Peak @ 8.2 ¢/kWh	104.96
Mid-Peak @ 11.3 ¢/kWh	40.68
On-Peak @ 17 ¢/kWh	61.20
Delivery	96.85
Regulatory Charges	22.36
Total Electricity Charges	**$326.04**
HST	42.39
Ontario Electricity Rebate	**(-$108.25)**
Total Amount	**$260.18**



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- ☐ Very satisfied
- ☐ Somewhat satisfied
- ☐ Neither satisfied nor dissatisfied
- ☐ Somewhat dissatisfied
- ☐ Very dissatisfied
- ☐ Don't know

Before this survey, how familiar were you with the amount of your organization's electricity bill that went to Entegrus?

- ☐ Very familiar
- ☐ Somewhat familiar
- ☐ Not familiar
- ☐ Don't know

Is there anything in particular you would like Entegrus to do to improve its services to your organization? [OPEN]

Entegrus Background

How much can you expect to pay over the next few years?

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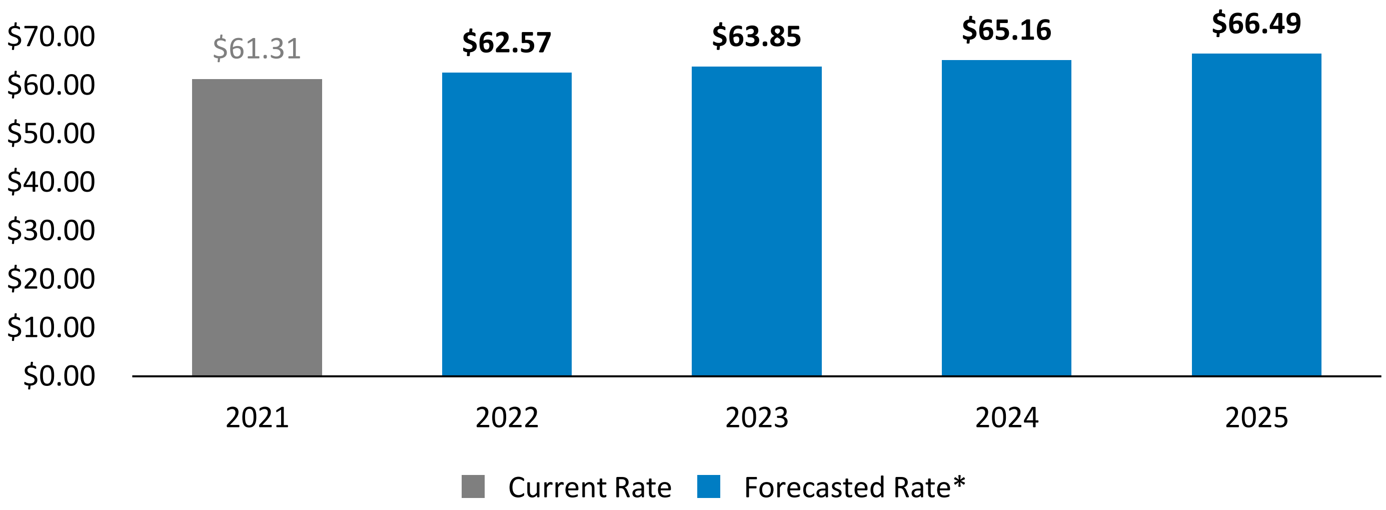

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- ☐ Yes
- ☐ No
- ☐ Don’t know

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How much of my electricity bill goes to Entegrus?

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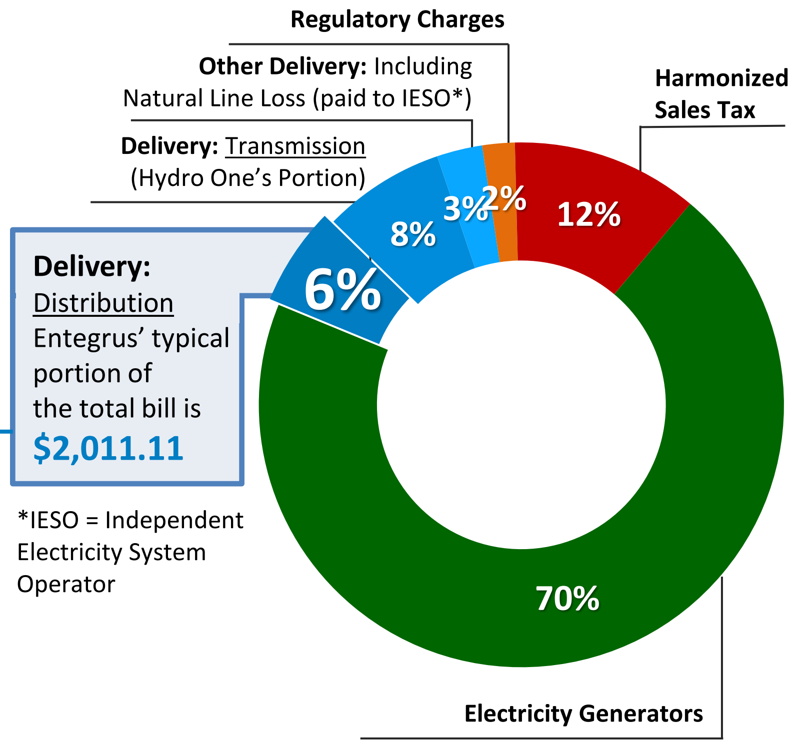
- While **Entegrus** is responsible for collecting payment for the entire electricity bill – as well as water charges for many of its communities – Entegrus retains only a portion of the electricity delivery charge. The electricity delivery charge also includes Hydro One transmission costs and system losses.
- Distribution makes up about 6% of the typical business customer's bill in your rate class.
- The rest of your bill is passed onto provincial transmission companies, power generation companies, the provincial government and regulatory agencies.

Entegrus Sample Monthly Bill
(Based on 500 kW monthly demand)

Account Number:
000 000 000 000 0000

Meter Number:
00000000

Your Electricity Charges	
Electricity	22.230.00
Delivery	6,383.75
Regulatory Charges	661.38
Total Electricity Charges	**$29,275.12**
HST	3,805.77
Total Amount	**$33,080.89**



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Entegrus Background

How much can you expect to pay over the next few years?

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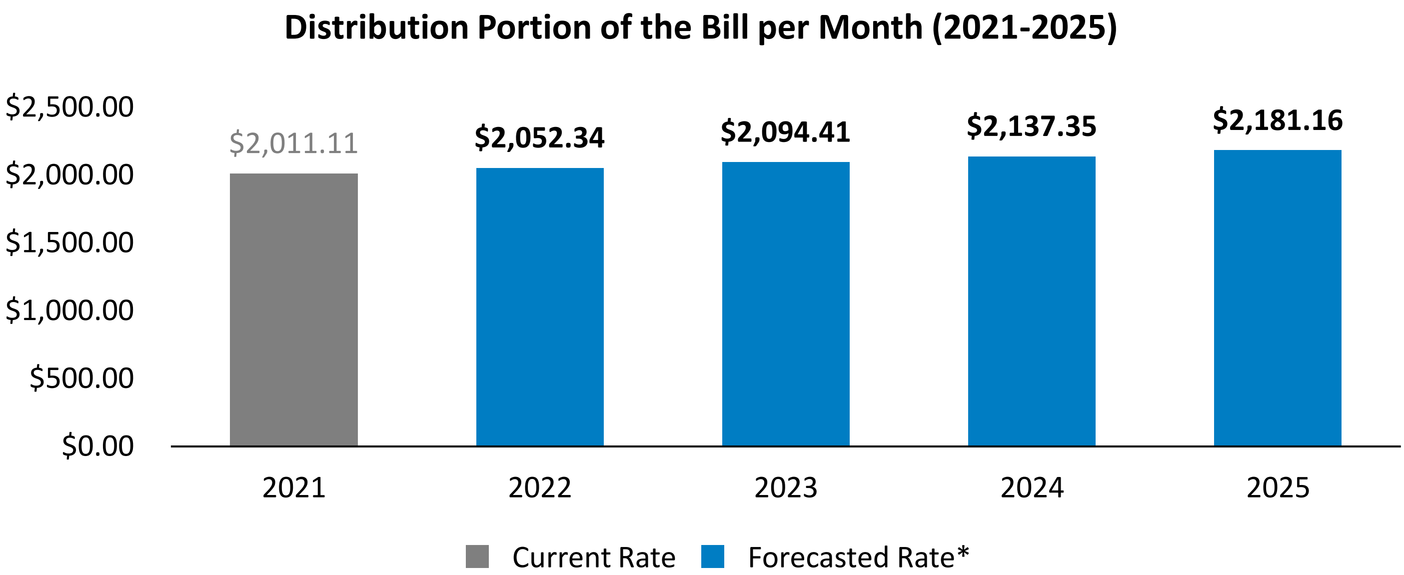

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- ☐ Yes
- ☐ No
- ☐ Don’t know

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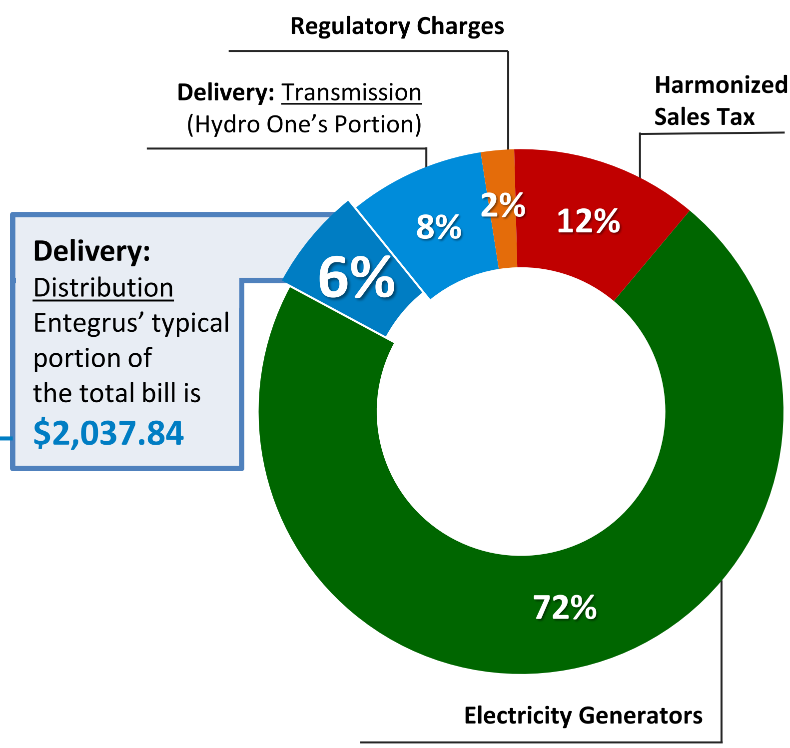
Entegrus Sample Monthly Bill
(Based on 500 kW monthly demand)

Account Number:
000 000 000 000 0000

Meter Number:
00000000

Your Electricity Charges	
Electricity	22.230.00
Delivery	5,665.73
Regulatory Charges	658.91
Total Electricity Charges	**$28,554.64**
HST	3,712.10
Total Amount	**$32,266.74**



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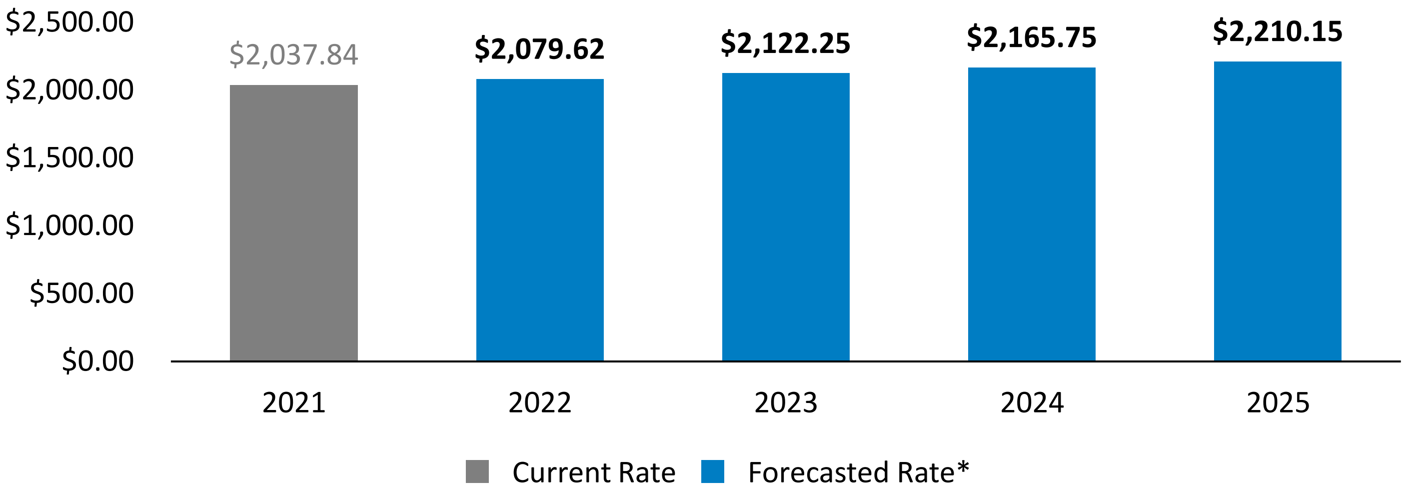
Distribution Portion of the Bill per Month (2021-2025)



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- ☐ Yes
- ☐ No
- ☐ Don't know

Entegrus Background

How are rates staying below inflation?

Entegrus' 2021 to 2025 investment plan sets out to balance a stronger investment focus on reliability and unprecedented customer growth with an objective of keeping distribution rates affordable for customers.

Accordingly, while investment levels have increased above historic levels in 2019 and 2020 and will continue to remain at higher levels through 2025, there are no proposed incremental rate impacts arising from this investment plan for the period from 2021-2025.

In order to safeguard against reliability deterioration, Entegrus' shareholders have decided to spend above the currently approved rates with no added cost to customers from 2021-2025. These additional investments will address aging infrastructure to safeguard reliability and thereby also ensure a strong foundation to enable future customer investments in electric vehicles and customer-owned electricity generation.

Spending above current rates

As mentioned earlier, Entegrus is entirely funded through the rates its customers pay and does not receive taxpayer money to fund its operations or its investments in the distribution system.

That said, Entegrus shareholders have decided that the need for additional reliability investments cannot be put on hold, nor should customers be faced with incremental rate increases at this time. As such, over the 2018 to 2020 period, Entegrus invested an incremental $5.7 million in the distribution system beyond what was originally planned to address reliability and harmonize systems post-merger. For the 2021 to 2025 period, approximately $63 million will be invested in the distribution system, **including an estimated incremental $6.5 million to address reliability, at no additional cost to customers over that period.**

Finding internal cost savings

According to the latest data published by the Ontario Energy Board of approximately 60 electricity providers from across the province, Entegrus had the 15th lowest total cost per customer. That means Entegrus is among the most efficient electricity distributors in Ontario.

GridSmartCity®
renewing energy

Benchmarking isn't the only way that Entegrus measures its operational efficiency. Entegrus is a member of the GridSmartCity Co-operative, an organization that brings together 15 Ontario LDCs to collaborate and share knowledge, skills and expertise – with some of the goals being increased efficiency and cost savings through economies of scale.

Cost saving benefits include negotiated group rates for services and group savings on the procurement of wood poles, cables, wires, and transformers.

Additionally, through its merger with St. Thomas Energy, Entegrus continues to see annual savings of approximately $1.4 million each year through shared operating, maintenance, and administrative costs.

Entegrus Background

What is this engagement about?

This customer engagement is about finding the right balance between the service you receive and the price you pay.

The point of this engagement is to allow customers like yourself to provide feedback on whether Entegrus planners have found the right balance or whether they should consider different options that better reflect your views.

As mentioned earlier, Entegrus' 2021 to 2025 investment plan sets out to balance a stronger investment focus on reliability and unprecedented customer growth with an objective of keeping distribution rates affordable for customers.

Affordability is at the core of Entegrus' plans.

Before Entegrus finalizes its plans, it is coming to its customers with a final set of choices. For each choice, Entegrus has identified an option to stay within existing rates (including the incremental investments Entegrus is already planning). It has also identified options to increase investments where it will provide meaningful benefits to customers.

Do you feel that the purpose of this customer engagement is clear?
◻ Yes ◻ No ◻ Don't know

Entegrus Background

What are the key investment drivers for 2021 to 2025?

Entegrus has identified three primary investment drivers for the 2021 to 2025 period – **aging infrastructure (reliability), customer growth,** and **grid modernization**.


A damaged Entegrus distribution pole.

Aging Infrastructure: Recall, much of the initial economic expansion in Entegrus' service territory occurred between 1950 and 1970. That means parts of Entegrus' distribution system are now more than 50 years old.

Entegrus' 2021-2025 plan demonstrates a notable increased focus on replacing aging infrastructure. This is driven by the fact that portions of the distribution system have degraded beyond the expectation of the utility's 2016-2020 plans.

- This additional degradation became apparent in 2017 and 2018 when new technology and additional engineering staff enabled Entegrus to conduct a deeper system-wide infrastructure assessment, including resistograph pole testing.
- This assessment identified that the level of asset degradation was higher than originally forecast. Simultaneously, in 2018, customers began to experience an increase in power outages.

Overall, the additional work to replace aging infrastructure will mitigate reliability issues and provide a stronger distribution system foundation for later integration of future customer investments in electric vehicle and customer-owned electricity generation in the next planning cycle from 2026 to 2030.

Entegrus Background

What are the key investment drivers for 2021 to 2025?

Customer Growth: Even though many developers initially put projects on hold as a result of the COVID-19 pandemic, by the summer of 2020 Entegrus continued to experience unprecedented customer growth. High residential growth continues to occur in St. Thomas and other communities in the Entegrus northeast region including Strathroy and Mt. Brydges. Residential growth and significant levels of activity required to prepare the Entegrus distribution system to support fibre-to-the-home expansion by telecoms is also occurring in Chatham-Kent.

While customer growth remains high it is currently difficult to predict whether this trend will continue beyond 2021 given the circumstances of the pandemic.

A new subdivision located in St.Thomas

System Modernization: As described previously, the Entegrus service territory extends over an area of 5,600 square kilometres. Servicing each community requires significant travel. Being able to troubleshoot problems remotely reduces and in some cases eliminates the need to send a crew out for repairs.

While Entegrus' primary focuses are on reliability and servicing customer growth while keeping distribution rates affordable, the 2021 to 2025 plans do include focus on system modernization, including some automated distribution restoration technologies.

The plans also include further harmonization of legacy systems across the merged entity to help enable future investments in technology including electric vehicles and customer-owned electricity generation.

Entegrus Background

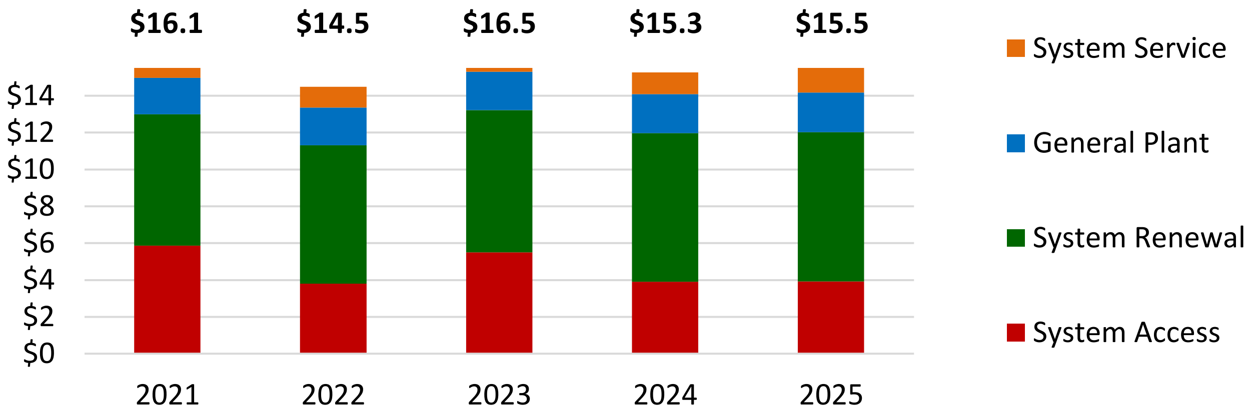
How does Entegrus plan future investments in the system?

Entegrus' **capital budget** covers items that have lasting benefits over many years such as investments in the core distribution system including poles, wires, cables, switches, and transformers.

Based on initial information and input from Entegrus' internal engineering and technical experts and emerging pressures on the distribution system, **Entegrus' draft capital budget is estimated to be $77.9 million over the five-year period between 2021 and 2025**.

Entegrus plans its capital investments in four categories.

2021-2025 Forecasted Capital Investments (Millions)*



** These estimates are preliminary, and are subject to your feedback as the business plan is finalized.*

System Access ($23 Million, averaging $4.6 per year)

"Must do" investments for new subdivisions, new upgraded commercial and industrial services, and relocating assets based on road infrastructure needs. Entegrus is expected to recover close to 65% of these costs from developers, internet providers, and larger business customers.

System Renewal ($38.5 Million, averaging $7.7 per year)

Replacement of aged overhead wires, poles, and pole mounted transformers, underground cables and transformers and distribution station upgrades.

General Plant ($10.4 Million, averaging $2.1 per year)

These are investments needed to support the distribution system, such as tools, vehicles, buildings, and computers.

System Service ($6 Million, averaging $1.2 per year)

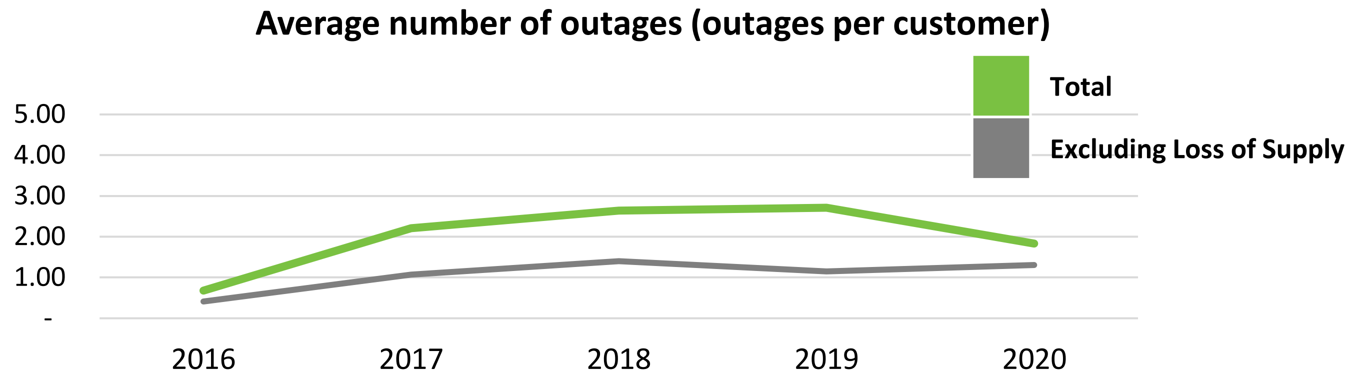
These investments consist of projects that address capacity constraints, improve system reliability and supply new growth.

Entegrus Background

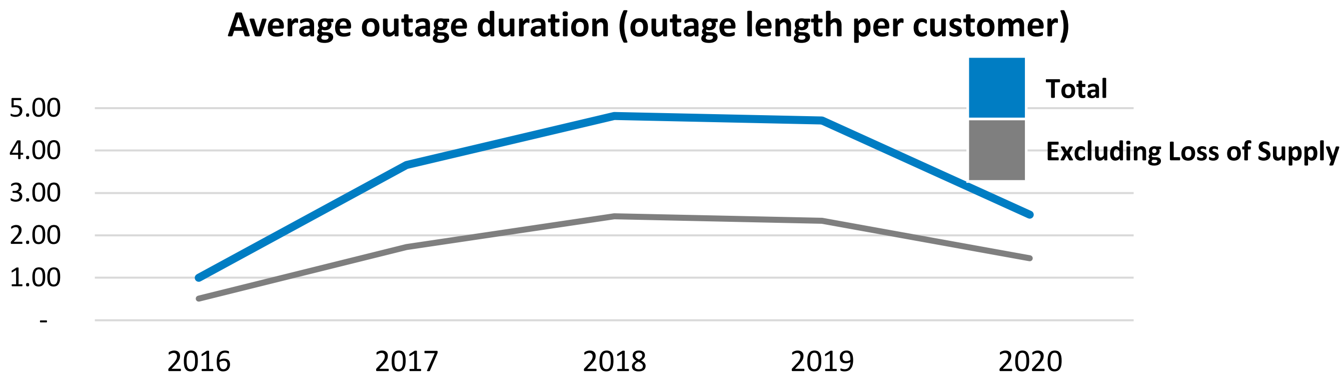
How does Entegrus' distribution system perform?

Entegrus tracks both the average number of power outages per customer and how long those interruptions last. Keep in mind that these are system averages, and your actual experience may be different. Some customers connected to newer lines may not experience any outages while others may experience more than the average number of outages each year.

Between 2016 and 2020, the typical Entegrus customer (excluding St. Thomas) experienced about two outages per year.



Over the same period, the average **duration** of an outage has been about 3.3 hours, some of which has been driven by loss of power supply due to significant weather events. Meaning when the power does go out, Entegrus is typically able to restore power in about three hours.



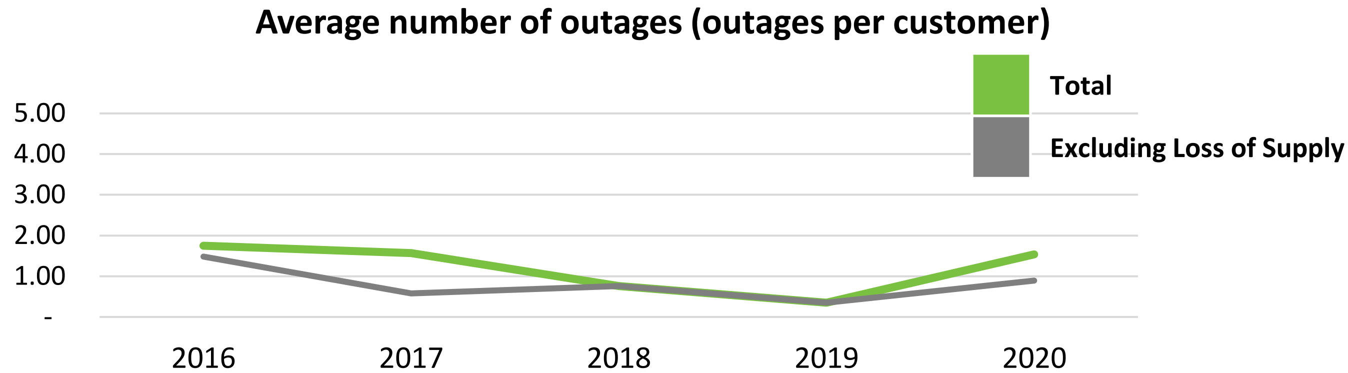
Loss of supply occurs when there is an interruption to the supply of electricity from the upstream electrical system operated by Hydro One. These failures are largely out of the control of Entegrus but there are investments that can be made to attempt to reduce the impacts of these outages including a more intelligent system that can automatically re-route power when one of these outages does occur. In fact, investments by Entegrus in automated switches have already avoided 18,000 customer outage hours between 2017 and 2020.

Entegrus Background

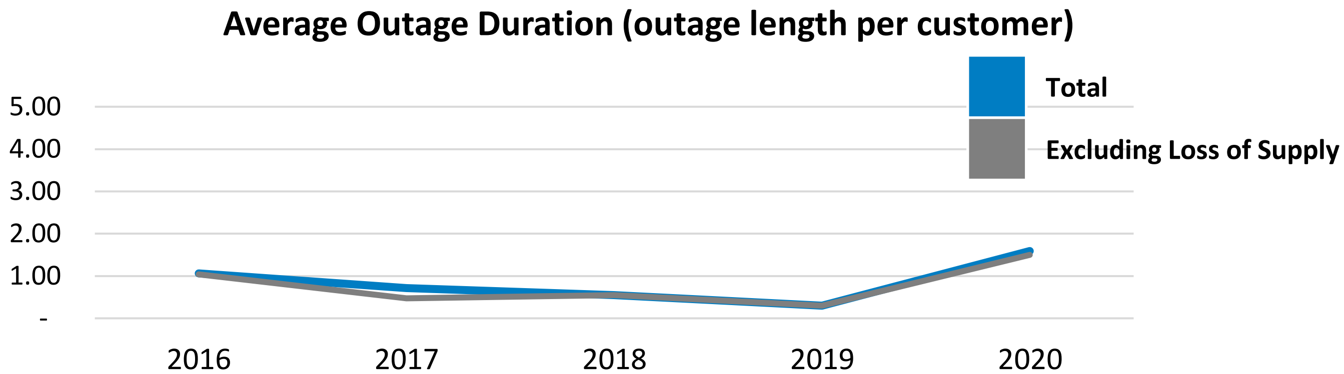
How does Entegrus' distribution system perform?

Entegrus tracks both the average number of power outages per customer and how long those interruptions last. Keep in mind that these are system averages, and your actual experience may be different. Some customers connected to newer lines may not experience any outages while others may experience more than the average number of outages each year.

Between 2016 and 2020, the typical Entegrus customer in St. Thomas experienced about one outage per year.



Over the same period, the average **duration** of an outage has been about 0.8 hours. Meaning when the power does go out, Entegrus is typically able to restore power in less than one hour.



Loss of supply occurs when there is an interruption to the supply of electricity from the upstream electrical system operated by Hydro One. These failures are largely out of the control of Entegrus but there are investments that can be made to attempt to reduce the impacts of these outages including a more intelligent system that can automatically re-route power when one of these outages does occur.

Entegrus Background

How does Entegrus' distribution system perform?

Recently, Entegrus, with the help of an independent third party, conducted a system-wide study to better understand the health of the system and the long-term implications on system reliability. This study concluded that the deterioration in Entegrus' reliability measures (illustrated above) required **timely and proactive intervention to maintain current levels of reliability** and start to slow, or halt, the reliability deterioration trend before it becomes irreversible.

An Entegrus crew working to restore power during a winter storm.

Some of the effects of the proactive intervention undertaken in 2020 have already resulted in improvement; however, favourable weather and pandemic-related factors, such as fewer scheduled outages and less foreign interference (i.e. fewer vehicle accidents impacting the distribution system) contributed to the 2020 results.

Have you experienced any power outages [at home/at your business] in the past 12 months which lasted longer than one minute?

- ☐ No outages
- ☐ 1 outage
- ☐ 2 outages
- ☐ 3 or more outages
- ☐ Don't know

Entegrus Background

What contributes to a power outage?

In order to provide feedback on Entegrus' plan, it's important to understand how the distribution system has performed in the past as well as what is expected in the future.

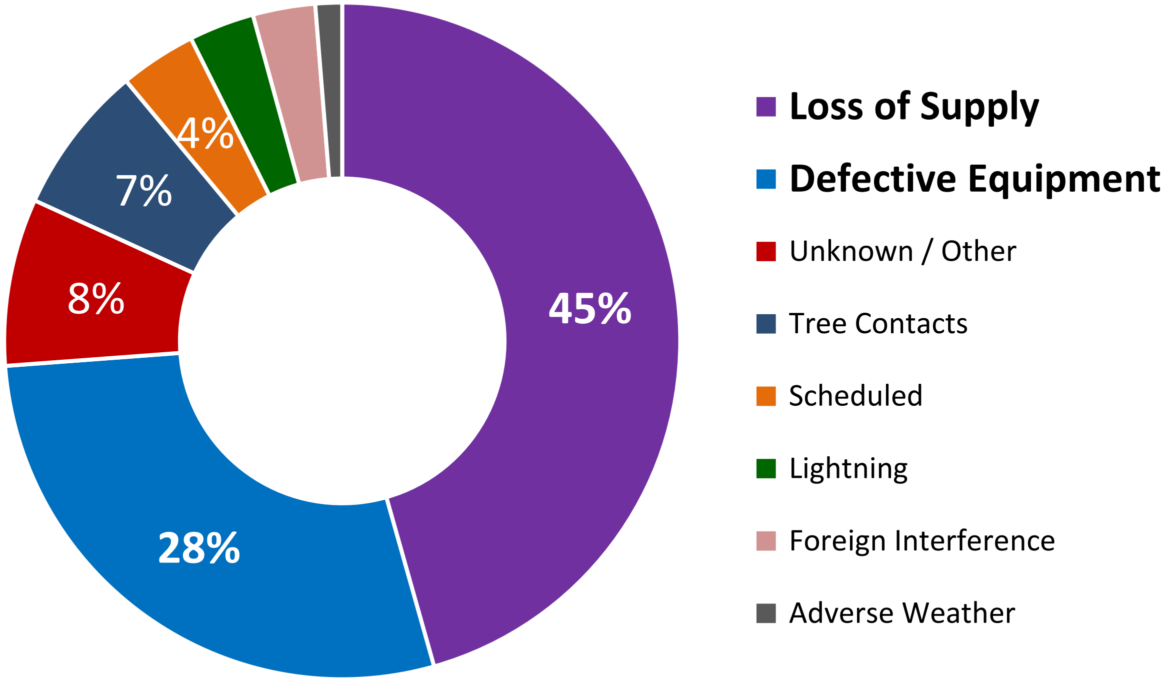
A core objective of Entegrus' 2021-2025 plan is to maintain reliability while making targeted improvements to those areas experiencing below average service.

In the Entegrus communities, the two primary contributors to outages account for 1-in-3 of all outages:

1. **Loss of supply** from the transmission system accounted for 45% of customer hours of interruption between 2016-2020. This is the single largest outage cause.

2. **Defective equipment** accounted for 28% of customer hours of interruption over the same period.

Customer Outage Duration (Hours) by Cause 2016-2020



Among the following reliability outcomes, which are most important to you?
While all of these priorities may be important to you, please rank your top 3 priorities – where "1" would be most important, "2" the second most important, and "3" the third most important.

Reliability Priority Areas	Ranking
Reducing the overall number of outages lasting longer than one minute	
Reducing the overall length of day-to-day outages	
Reducing the number of outages during severe weather events (e.g. ice storms, windstorms, and thunderstorms)	
Reducing the length of time to restore power during severe weather events (e.g. ice storms, windstorms, and thunderstorms)	
Reducing the overall number of outages lasting less than one minute including flickering or dimming of lights	

Entegrus Background

What contributes to a power outage?

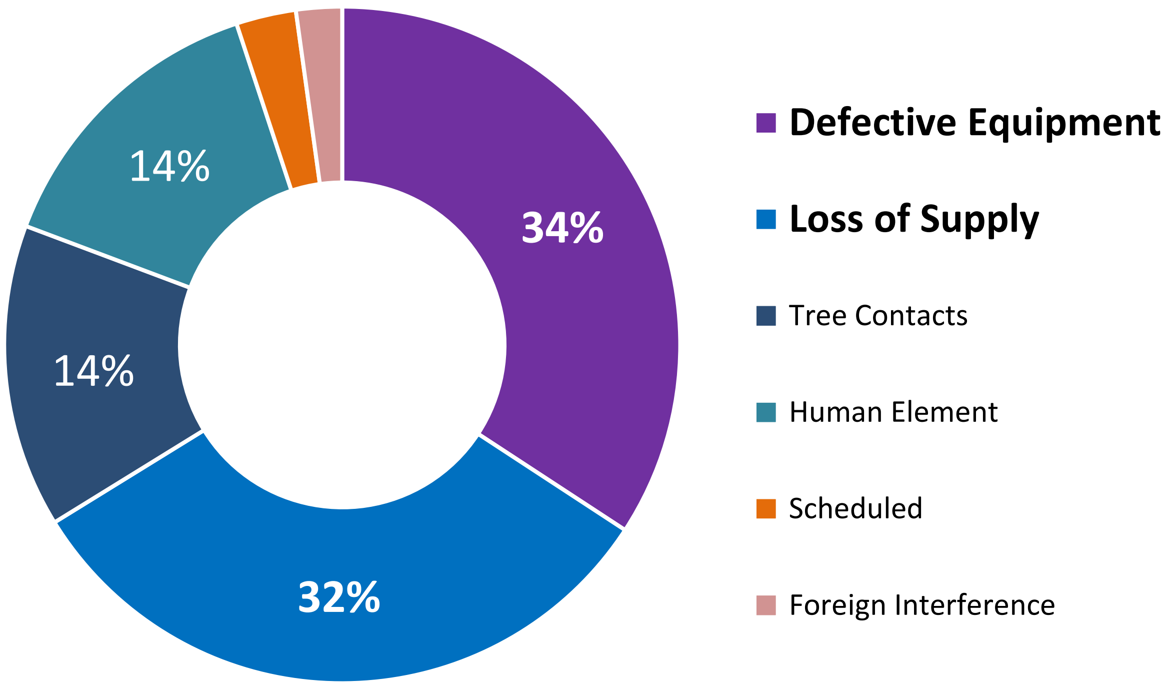
In order to provide feedback on Entegrus' plan, it's important to understand how the distribution system has performed in the past as well as what is expected in the future.

A core objective of Entegrus' 2021-2025 plan is to maintain reliability while making targeted improvements to those areas experiencing below average service.

In St. Thomas, the two primary contributors to outages account for 1-in-3 of all outages:

1. **Defective equipment** accounted for 34% of customer hours of interruption over the same period.
2. **Loss of supply** from the transmission system accounted for 32% of customer hours of interruption between 2016-2020.

Customer Outage Duration (Hours) by Cause 2016-2020



Among the following reliability outcomes, which are most important to you?
While all of these priorities may be important to you, please rank your top 3 priorities – where "1" would be most important, "2" the second most important, and "3" the third most important.

Reliability Priority Areas	Ranking
Reducing the overall number of outages lasting longer than one minute	
Reducing the overall length of day-to-day outages	
Reducing the number of outages during severe weather events (e.g. ice storms, windstorms, and thunderstorms)	
Reducing the length of time to restore power during severe weather events (e.g. ice storms, windstorms, and thunderstorms)	
Reducing the overall number of outages lasting less than one minute including flickering or dimming of lights	

Entegrus Background

How can Entegrus improve the services you receive?

As previously mentioned, Entegrus has committed to the OEB to limit your future rate increases to less than inflation until 2026.

An Entegrus crew installing a new pole.

That said, as part of the OEB policies, there is an option for utilities to apply for additional rate increases for discrete projects that are prudent, needed and not supported by existing rates. However, as previously noted, Entegrus has decided to continue to make certain additional reliability investments without asking customers for rate increases at this time, to keep distribution rates affordable in 2021-2025.

Looking ahead, Entegrus has identified two projects that will help mitigate reliability issues related to degraded infrastructure and provide a stronger distribution system foundation for later integration of electric vehicle and customer-owned generation infrastructure investments in the next planning cycle from 2026 to 2030. Entegrus is looking for your thoughts to determine whether it should pursue these two projects, financing these on its own until 2026, with no additional charges to customers.

As noted above, Entegrus will only be asking for increases of less than inflation from customers for the next five years and any investments made now will not impact your rates until the next planning period between 2026 and 2030.

Making Choices (1 of 2)

Line Modernization and Station Decommissioning

About 15% of Entegrus' customers are serviced by low voltage distribution systems. These low voltage lines were built in the 1950's, 1960's and 1970's and represent some of Entegrus' oldest distribution assets.

A low voltage transformer station.

These low voltage lines have much less capacity than modern lines and are supported by stations that are required to deliver this lower voltage. These stations look like small houses, or in some cases, are fenced-in areas containing weatherized electrical equipment. During an outage, the modern lines cannot be used to restore power to the low voltage lines, because they don't operate at the same voltage levels.

Due to the limited capacity of the low voltage lines, they are not suited for smart grid technology or customer-owned electricity generation. As such, this equipment has become functionally outdated and the risk of equipment failure is increasing.

For the past 10 years, Entegrus has focused on converting these low voltage lines to the modern technology. When enough lines are converted, Entegrus can decommission and sell the land that contains the low voltage stations.

Investing in these projects offers three primary benefits:

1. **Improved reliability through the new lines and transformers;**
2. **Increased capacity on each line to support customer growth, smart grid technology, and customer-owned electricity generation; and**
3. **Improved outage restoration from the enhanced back-up and availability of tie points at this higher voltage level.**

Entegrus currently has 19 of these stations supporting these low voltage lines still in use. To balance replacing other degraded assets and supporting customer growth, Entegrus planners are targeting the removal of 4 stations by 2025. At this pace, all of the low voltage lines would be replaced by modern lines and all the stations would be decommissioned beyond 2040.

However, because this equipment does not pose an urgent threat to reliability, if unforeseen distribution system priorities emerge over that period, it is the practice of Entegrus to divert resources away from these 4 lines modernization and station decommissioning projects to resolve more pressing priorities.

Which of the following options do you prefer?

Option	Description	Expected Outcome
Accelerated Paced Line Modernization *Additional $0.50 - $0.70 per month starting in 2026*	Line modernization to allow the removal of 6 low voltage Stations to occur from 2021-2025 regardless of other priorities.	• Complete line modernization of all low voltage equipment and Station decommissioning by 2035 • Reduce risk of deterioration of reliability • Avoid some Station maintenance costs
Faster Paced Line Modernization *Additional $0.25 - $0.35 per month starting in 2026*	Line modernization to allow the removal of 5 low voltage Stations to occur in 2021-2025 regardless of other priorities.	• Complete line modernization of all low voltage equipment and Station decommissioning by 2040 • Risk of deterioration of reliability continues • Escalating Station maintenance versus obsolescence
Status Quo *Within current rates*	Continue to target line modernization to allow removal of 4 low voltage Stations, to occur in 2021-2025. Allow for diversion from this plan if other priorities emerge.	• Maintain low voltage Stations beyond 2040 • Higher risk of deterioration of reliability continues • Escalating Station maintenance versus obsolescence.
Additional Feedback (Optional)		

Making Choices (2 of 2)

Implementing Smart Grid Technology

New technology has changed the way that Entegrus can manage and monitor the distribution system.

Intelligent (automated) switches

Intelligent (automated) switches allow Entegrus to automatically reroute power during outages and planned maintenance, reducing the length of time customers are without power and reducing reliance on crews travelling to the site to physically re-route power. When this automatic rerouting occurs, impacted neighbourhoods would experience an outage lasting less than one minute, rather than a lengthier interruption.

Entegrus has recently used automated switch technology to target more rural communities experiencing poor reliability due to loss of supply. These communities are served by two long lines from the provincial transmission system, and the technology allows the two lines to automatically back each other up when one line experiences an outage, eliminating the need for manual intervention.

However, Entegrus now sees an opportunity to roll this technology out in larger cities that have many interconnecting lines that can form “grids”. Doing so will offer multiple alternative paths for electricity to flow, bypassing the fault and avoiding potential widespread outages. Entegrus ran a successful pilot of intelligent switch technology on a single feeder line in Chatham in 2020.

Not only do these intelligent switches help reduce the length of time customers are without power, but they also help create a more integrated, advanced system that is better equipped to handle future technological advancements including electric vehicles and customer-owned electricity generation.

In its current draft plan, in order to afford to invest more dollars in replacement of poles and wires while limiting cost increases to customers, Entegrus plans to selectively install 6 more of these intelligent switches in 2021-2025. That said, there is a near term opportunity for a broad roll out of intelligent switches in the larger communities of Chatham and St. Thomas where there is the opportunity to increase connectivity by creating a medium or higher density of intelligent switches.

Which of the following options do you prefer?

Option	Description	Expected Outcome
Increase to Higher Intelligent Switch Density in Chatham & St. Thomas *Additional $0.40- $0.70 per month starting in 2026*	Install an additional 18 switches in Chatham and an additional 10 switches in St. Thomas	Reduce outage duration by about 20% - 25% and outage frequency longer than 1 minute by about 30% - 40%
Increase to Medium Intelligent Switch Density in Chatham & St. Thomas *Additional $0.20 - $0.35 per month starting in 2026*	Install an additional 11 switches in Chatham and an additional 6 switches in St. Thomas	Reduce outage duration by about 15% - 20% and outage frequency longer than 1 minute by about 25% - 30%
Status Quo – Stay with Low Intelligent Switch Density in Chatham & St. Thomas *Within current rates*	No additional investment in intelligent switches beyond the few in the current plan.	Increased risk of potential deterioration of reliability in the medium term.

Additional Feedback (Optional)

Planning for the Future Beyond 2025

What priorities matter most to you?

Now we are going to shift focus and talk about the future of Entegrus' distribution system beyond 2025. Through previous customer research and contacts, several outcomes were identified by customers as priorities for Entegrus moving forward. We would like to check that list with you to ensure it is complete. We also want to understand the priorities you give to different outcomes.

How important are each of the following Entegrus priorities to you as a customer? *Please indicate by sliding the bars below.*

Priority Areas		
Delivering electricity at reasonable rates	Not at all important 0 — Extremely Important 10	○ Don't know
Ensuring reliable electrical service	Not at all important 0 — Extremely Important 10	○ Don't know
Providing quality customer service	Not at all important 0 — Extremely Important 10	○ Don't know
Helping customers with conservation and cost savings	Not at all important 0 — Extremely Important 10	○ Don't know
Proactively preparing for community growth	Not at all important 0 — Extremely Important 10	○ Don't know
Ensuring the safety of electricity infrastructure	Not at all important 0 — Extremely Important 10	○ Don't know
Enabling customer choice to access new electricity services (e.g. electricity storage and distributed generation, such as solar panels)	Not at all important 0 — Extremely Important 10	○ Don't know
Minimizing the impact on the environment	Not at all important 0 — Extremely Important 10	○ Don't know

Planning for the Future Beyond 2025

What priorities matter most to you?

Thinking again about the things that Entegrus should be focusing on, please rank your top 3 priorities—where “1” would be the most important, “2” the second most important, and “3” the third most important.

Priority Areas	Ranking
Delivering electricity at reasonable rates	
Ensuring reliable electrical service	
Providing quality customer service	
Helping customers with conservation and cost savings	
Proactively preparing for community growth	
Ensuring the safety of electricity infrastructure	
Enabling customer choice to access new electricity services (e.g. electricity storage and distributed generation, such as solar panels)	
Minimizing the impact on the environment	

The list above may not include all the outcomes that matter to you. Are there any other important priorities that Entegrus should be focusing on that weren’t included in the list above? [OPEN]

Planning for the Future Beyond 2025

What technology do you prioritize?

As technology continues to evolve, Entegrus wants to make sure it is investing in the areas that customers care about. Investments in technology can address a range of issues, including reliability, efficiency, customer service, Entegrus' impact on the environment, new service offerings, and tools to manage electricity usage.

How important are each of the following investments in new technology that Entegrus could focus on?

Priority Areas	
New technology that would reduce the number and length of outages.	Not at all important 0 — Extremely Important 10 ○ Don't know
New technologies, such as apps, online services and social media that make it easier to interact with Entegrus.	Not at all important 0 — Extremely Important 10 ○ Don't know
New technology to reduce the environmental impact of Entegrus' operations (e.g. reduce carbon emissions, electrify Entegrus' fleet).	Not at all important 0 — Extremely Important 10 ○ Don't know
New technology that enables customer choice to access new electricity services (e.g. electricity storage, power walls and distributed generation, such as solar panels).	Not at all important 0 — Extremely Important 10 ○ Don't know
New technology that can help customers better manage their electricity usage.	Not at all important 0 — Extremely Important 10 ○ Don't know
New technology that can help Entegrus find efficiencies and reduce customer costs.	Not at all important 0 — Extremely Important 10 ○ Don't know

Planning for the Future Beyond 2025

What technology priorities matter most to you?

Thinking again about the things that Entegrus should be focusing on, please rank your top 3 technology priorities—where “1” would be the most important, “2” the second most important, and “3” the third most important.

Priority Areas	Ranking
New technology that would reduce the number and length of outages.	
New technologies, such as apps, online services and social media that make it easier to interact with Entegrus.	
New technology to reduce the environmental impact of Entegrus’ operations (e.g. reduce carbon emissions, electrify Entegrus’ fleet).	
New technology that enables customer choice to access new electricity services (e.g. electricity storage, power walls and distributed generation, such as solar panels).	
New technology that can help customers better manage their electricity usage.	
New technology that can help Entegrus find efficiencies and reduce customer costs.	

Entegrus' Digital Tools

Have you used Entegrus' digital tools?

Now we are going to shift topics and talk about the digital tools currently offered by Entegrus.

How familiar are you with the following digital tools that are offered by Entegrus?
☐ I have used it before ☐ I have heard of it, but have not used it before ☐ I have never heard of it before

- **The Entegrus.com website**
- **The Entegrus online outage map**
- **Customer service self-serve systems (i.e. online forms, MyAccount, etc.)**

Please indicate whether you are satisfied or dissatisfied with each of the following tools.
☐ Very satisfied ☐ Somewhat satisfied ☐ Neither satisfied nor dissatisfied ☐ Somewhat dissatisfied ☐ Very dissatisfied ☐ Don't know

- **The Entegrus.com website**
- **The Entegrus online outage map**
- **Customer service self-serve systems (i.e. online forms, MyAccount, etc.)**

Are there any additional digital tools or services that you would like Entegrus to provide? [OPEN]
☐ None

Now we would like to shift the focus, and ask you some general questions about the electricity system in Ontario.

To what extent do you agree or disagree with the following statements?

The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.

□ Strongly agree
□ Somewhat agree
□ Somewhat disagree
□ Strongly disagree
□ Don’t know/No opinion

Customers are well served by the electricity system in Ontario.

□ Strongly agree
□ Somewhat agree
□ Somewhat disagree
□ Strongly disagree
□ Don’t know/No opinion

Now we would like to shift the focus, and ask you some general questions about the electricity system in Ontario.

To what extent do you agree or disagree with the following statements?

The cost of my organization's electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.

- ☐ Strongly agree
- ☐ Somewhat agree
- ☐ Somewhat disagree
- ☐ Strongly disagree
- ☐ Don't know/No opinion

Customers are well served by the electricity system in Ontario.

- ☐ Strongly agree
- ☐ Somewhat agree
- ☐ Somewhat disagree
- ☐ Strongly disagree
- ☐ Don't know/No opinion

About you

More about you

The following questions are for statistical purposes only. This information is used to segment and group similar people together when the survey results are analysed.

Do you identify as…

- ☐ A man
- ☐ A woman
- ☐ Prefer to self-describe **[SPECIFY]**
- ☐ Prefer not to say

What age category do you fall into?

- ☐ Under 18
- ☐ 18-24
- ☐ 25-34
- ☐ 35-44
- ☐ 45-54
- ☐ 55-64
- ☐ 65-74
- ☐ 75 or older
- ☐ Prefer not to say

Including yourself, how many people live in your household?

- ☐ Single person household
- ☐ 2 people
- ☐ 3 people
- ☐ 4 people
- ☐ 5 people
- ☐ 6 people
- ☐ 7 of more people
- ☐ Prefer not to say

Which of the following categories best describes the total annual income, after taxes, of all the members of your household?

- ☐ Less than $28,000
- ☐ $28,000 to less than $39,000
- ☐ $39,000 to less than $48,000
- ☐ $48,000 to less than $52,000
- ☐ $52,000 or more
- ☐ Prefer not to say

About you

More about your organization

The following questions are for statistical purposes only. This information is used to segment and group similar people together when the survey results are analysed.

Which of the following best describes the sector in which your business operates? Would you say…

- ☐ Commercial
- ☐ Manufacturing/Industrial
- ☐ Data Centre
- ☐ Hospitality
- ☐ Restaurant/Tavern
- ☐ Retail
- ☐ Warehouse
- ☐ Real estate
- ☐ Other [please specify]

Including yourself, how many people work at your organization?

- ☐ 1 person
- ☐ 2 to 5 people
- ☐ 6 to 10 people
- ☐ 11 to 25 people
- ☐ 26 to 50 people
- ☐ More than 50 people
- ☐ Prefer not to say

Final Thoughts

Feedback on Entegrus' customer engagement

These last few questions are about the customer engagement that you just completed. In order to do better in the future, Entegrus wants to understand whether this new way of collecting customer feedback has worked or not.

Overall, did you have a favourable or unfavourable impression of the customer engagement you just completed?

- ☐ Very favourable
- ☐ Somewhat favourable
- ☐ Somewhat unfavourable
- ☐ Very unfavourable
- ☐ Don't know

In this customer engagement, do you feel that Entegrus provided too much information, not enough, or just the right amount?

- ☐ Too little information
- ☐ Just the right amount of information
- ☐ Too much information

Was there any content missing that you would have liked to have seen included in this customer engagement? (OPEN)

- ☐ None

Is there anything that you would still like answered?

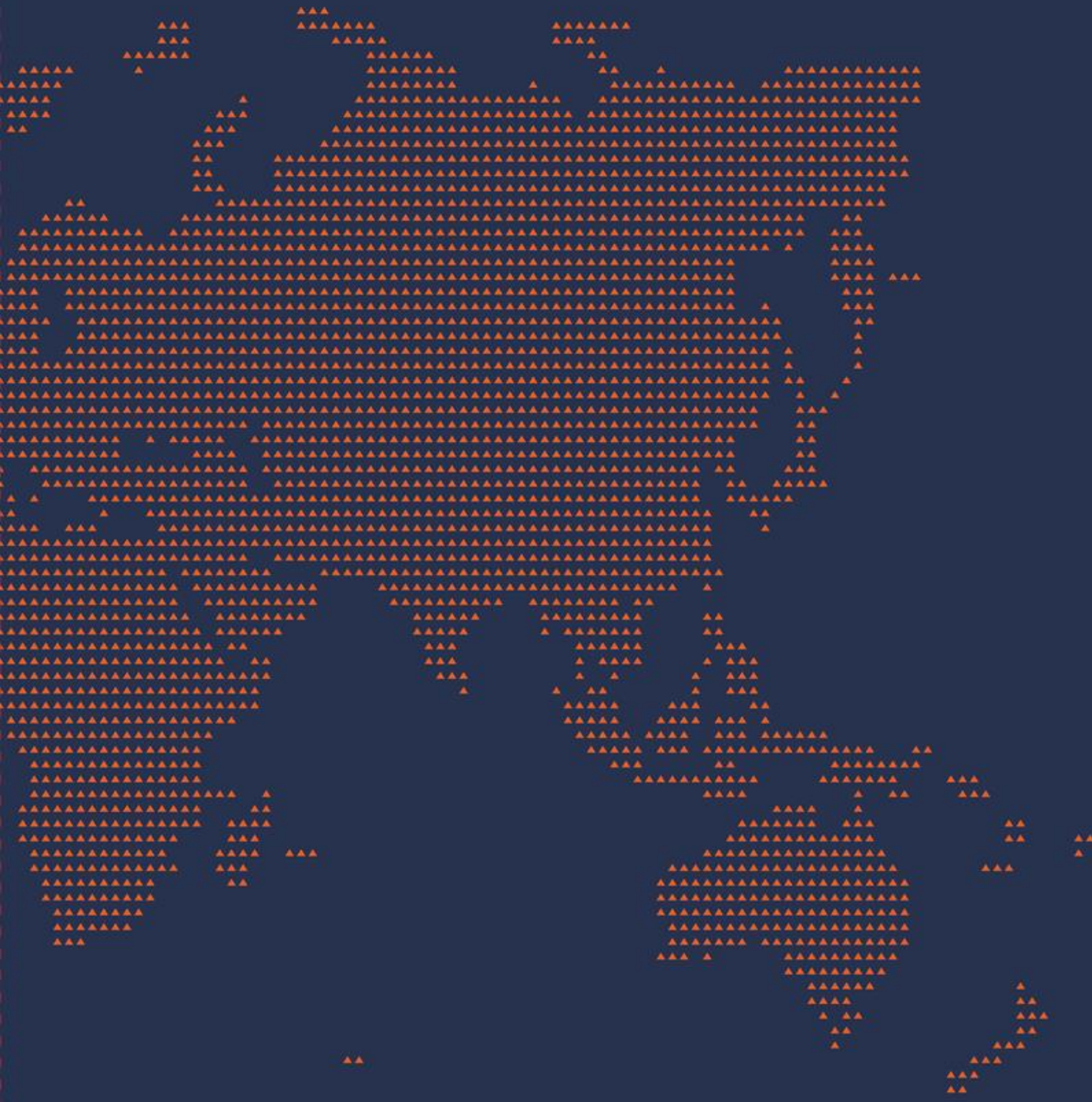
- ☐ None

ATTACHMENT C

September 2021 Asset Condition Assessment, Prepared by METSCO

METSCO

MAKING IT POSSIBLE



ASSET CONDITION ASSESSMENT FINAL DRAFT REPORT 2021

Prepared by

Project Number: P-19-217

Wednesday, September 8, 2021

METSCO Energy Solutions

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Project ID:	P-19-217

Revision	Date	Author	Description	Signature
1.0	March 2020	D. Balashov	Preliminary ACA framework with data collection recommendations.	
2.0	July 2020	D. Balashov	Initial release for review.	
3.0	08 September 2021	D. Lizak	Final release.	

Disclaimer

This report was prepared by METSCO Energy Solutions Inc. ("METSCO") for the sole benefit of Entegrus Powerlines Inc. ("Entegrus" or the Client), in accordance with the terms of the METSCO proposal and the Client Agreement.

Some of the information and statements contained in the Asset Condition Assessment ("ACA") are comprised of or are based on, assumptions, estimates, forecasts and predictions and projections made by METSCO and Entegrus. In addition, some of the information and statements in the ACA are based on actions that Entegrus currently intends it will take in the future. As circumstances change, assumptions and estimates may prove to be obsolete, events may not occur as forecasted, predicted, or projected, and Entegrus may at a later date decide to take different actions to those it currently intends to take.

Except for any statutory liability which cannot be excluded, METSCO and Entegrus will not be liable, whether in contract, tort (including negligence), equity or otherwise, to compensate or indemnify any person for any loss, injury or damage arising directly or indirectly from any person using or relying on any content of the ACA.

Executive Summary

Context of the Study

Entegrus Powerlines Inc ("Entegrus") is an electricity distributor operating a system that delivers electricity to approximately 59,000 customers across 17 communities in Southwestern Ontario, including Chatham, St. Thomas, Strathroy, Parkhill, Wallaceburg, Wheatley and others. Entegrus engaged METSCO Energy Solutions to prepare an Asset Condition Assessment ("ACA") study for the assets comprising its distribution system. The ACA is one of the key inputs for the preparation of Entegrus' five-year Distribution System Plan ("DSP"), developed in accordance with the filing requirements enacted by the Ontario Energy Board ("OEB").

Scope of the Study

METSCO's work included interviews with Entegrus subject matter experts to define the Health Indices appropriate for the asset types, review, consolidation and analysis of the utility's data sets, calculation of the Health Index values based on the available data, and preparation of the final document. METSCO assessed asset health for the following major asset classes:

- Wood Poles
- Concrete Poles
- Steel Poles
- Overhead Primary Conductors
- Underground Primary Cables
- Distribution Pole Mounted Transformers
- Distribution Pad Mounted Transformers
- Distribution Submersible Transformers
- Distribution Overhead Switches
- Station Power Transformers
- Station Switchgears
- Station Circuit Breakers
- Station Battery Systems
- Station Yards

All asset condition data used in the study are maintained by Entegrus as part of its regular asset management practices and collected in the course of inspection and testing activities that to METSCO's knowledge, are compliant with the Distribution System Code (DSC) requirements. METSCO received Entegrus' data between December of 2019 to May of 2020. As such, the most recent data available for the study reflects the 2019 inspections season.

Methodology and Findings

For all asset classes that underwent assessment, METSCO used a consistent scale of asset health from Very Good to Very Poor. The numerical Health Index ("HI") corresponding to each condition category serves as an indicator of an asset's remaining life, expressed as a percentage. Table presents the HI ranges corresponding to each condition score, along with their corresponding implications as to the follow-up actions required by the asset manager at Entegrus.

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

Health Index Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of ageing or minor deterioration of a limited number of components	Normal Maintenance
[70-85)	Good	Significant Deterioration of some components	Normal Maintenance
[50-70)	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
[30-50)	Poor	Widespread serious deterioration	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
[0-30)	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

Using this scale, METSCO calculated health information scores for every asset class in the scope of its assessment using a standard methodology, adapted to this engagement based on data availability and other relevant considerations. The assessment of the health of each asset class is made up of available and relevant "condition parameters" – individual characteristics of the state of degradation of an asset's components – each with its own sub-scale of assessment, and a weighting contribution that represents the percentage in the overall score.

The results of our assessment are presented as either Health Indices ("HI"), or "One- or Two-Parameter Evaluations" – depending on the number of relevant data parameters available for each asset class. To qualify for the definition of a Health Index, an asset class must have at least three recorded condition parameters available. When less than three parameters are available, the health of an asset class is presented as a One- or Two-Parameter Assessment, as appropriate. The distinction between a "Health Index" and a "Parameter Assessment" reflects only the number of available data parameters, and should not be interpreted as indicative of superior or inferior analytical rigour and/or weight that can be put on one set of results relative to another. As we discuss later in this document, the number of condition parameters collected per asset class is often a matter of strategy, which represents a trade-off made by a utility between incremental near/medium-term planning insights and additional costs to obtain them. This consideration is clearly reflected in Entegrus' approach to asset condition parameter collection across different asset classes.

Overall Results by Asset Class

METSCO's methodology for each asset class is described in more detail in Section 3 and Section 4. The consolidated results of the Asset Condition Assessment are summarized in Figure 0-1.

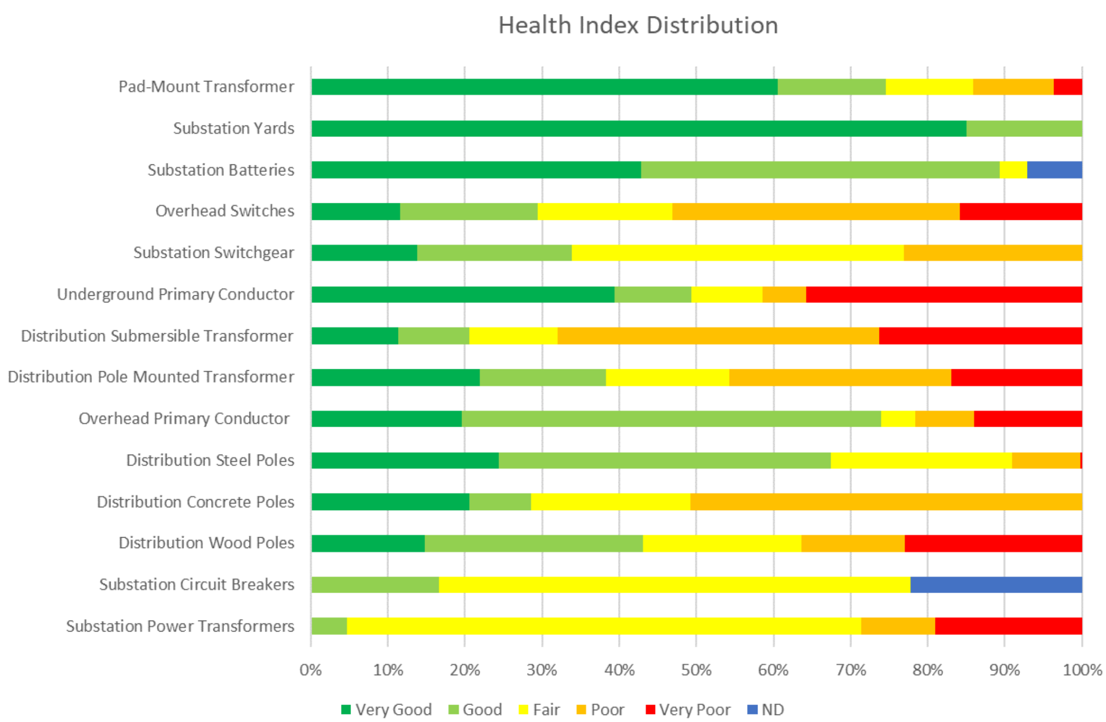


Figure 0-1: Health Index Results

As Figure 0-1 indicates, several Entegrus asset classes exhibit a significant degree of deterioration based on the results of the ACA. Most notable among them are the underground primary conductors, submersible underground transformers, and wood poles.

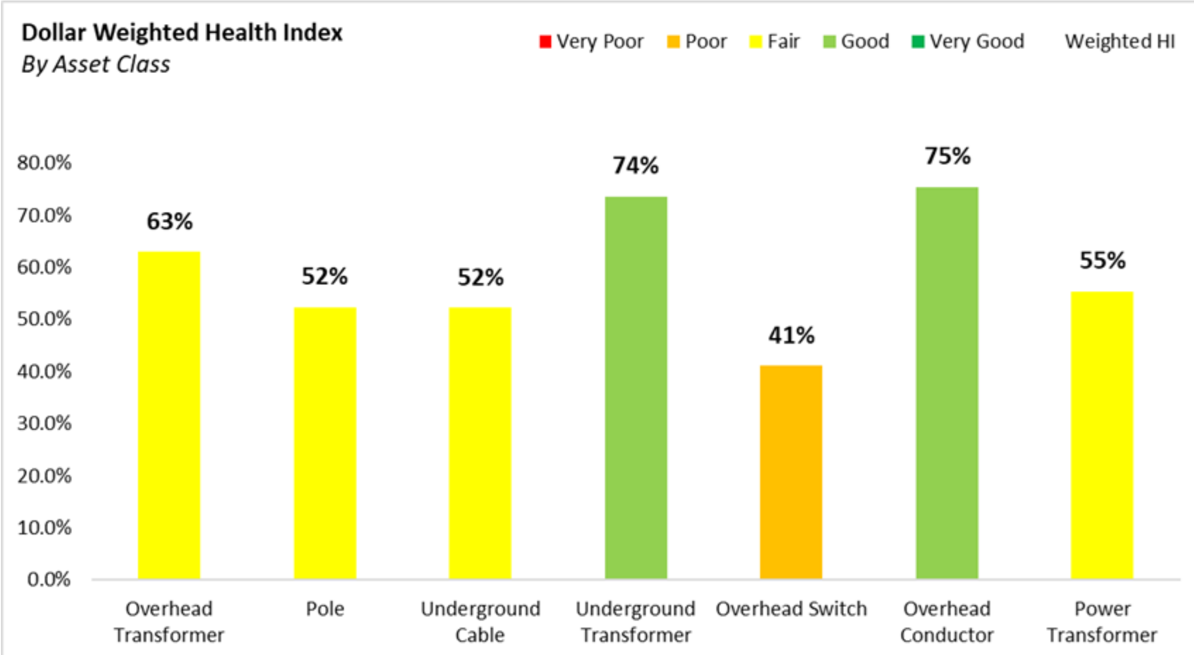
Table 0- presents the numerical Health Index summary for each asset class. The distribution of Health Indices is based on the total population count of a given asset class. For each asset class, the following details are listed: total population, average Health Index, average Data Availability Index ("DAI"), and the Health Index / Parameter Assessment distribution. A DAI is a percentage of condition parameter data available for an asset or asset class, as measured against the condition parameters considered in the Health Index Formulation. A DAI of 100% for an asset indicates that data was available for all assets and all condition parameters in an asset class. DAI is also calculated for individual condition parameters used in the Health Index Formulation.

Table 0-2: Asset Condition Assessment Overall results

Asset Class	Population	Health Index Distribution (%)						Average Health Index	Average DAI
		Very Good	Good	Fair	Poor	Very Poor	No Data		
Distribution									
Distribution Wood Pole	20446	14.78%	28.25%	20.57%	13.40%	23.00%		51.98%	100.00%
Overhead Primary Conductor (m)	460302.1	19.56%	54.37%	4.51%	7.61%	13.95%		75.60%	77.00%
Underground Primary Cable (m)	388214.23	39.35%	9.95%	9.31%	5.65%	35.74%		60.00%	100.00%
Pole-Mount Transformer	3250	21.88%	16.37%	15.97%	28.83%	16.95%		58.40%	95.00%
Pad-Mount Transformer	2300	60.57%	14.04%	11.22%	10.52%	3.65%		80.24%	95.00%
Submersible Transformer	194	11.34%	9.28%	11.34%	41.75%	26.29%		48.20%	88.00%
Overhead Switch	736	11.55%	17.93%	17.39%	37.23%	15.90%		60.00%	100.00%
Distribution Steel Poles	928	24.35%	43.10%	23.49%	8.84%	0.22%		77.50%	100.00%
Distribution Concrete Poles	63	20.63%	7.94%	20.63%	50.79%	0.00%		60.00%	100.00%
Station									
Power Transformer	21	0.00%	4.76%	66.67%	9.52%	19.05%		55.25%	96.14%
Circuit Breakers	20	0.00%	16.67%	61.11%	0.00%	0.00%	22.22%	68.00%	74.00%
Switchgear	65	13.85%	20.00%	43.08%	23.08%	0.00%		60.00%	100.00%
Batteries	28	42.86%	46.43%	3.57%	0.00%	0.00%	7.14%	85.00%	91.00%
Station Yards	20	85.00%	15.00%	0.00%	0.00%	0.00%		97.00%	100.00%

Replacement Value Dollar-Weighted Composite Health Index Results

As we have done in several of our more recent ACA reports, in addition to asset class-based HI results presentation, METSCO has also calculated several alternative means of presenting the results of our assessment of Entegrus' asset health. These alternative "lenses" factor in the replacement costs of individual assets – to present the calculated HI results as average scores, weighted by the replacement values of all assets under consideration in our analysis, and sometimes grouped in ways other than by asset class. This way of presenting the ACA results introduces the dimensions of economics and operations management, thereby conveying additional insights to the utility and its stakeholders.



Error! Reference source not found. presents the dollar-weighted average asset health score f or a core subset of assets covered in this ACA study. Unlike the individual health distributions for each asset class presented in Figure 0-1 and Table 0-1, the above Figure 0-2 represents an average health score for the entire asset class, with the overall asset class health score (expressed in % and colours consistent with the earlier diagrams) being reflective of the replacement value of individual units with health scores corresponding to each of the five asset health cohorts. We relied on Entegrus' average asset replacement unit costs as the costing source data for this analysis.

The concluding part of Section 4 presents several other alternative presentations of the Dollar-Weighted HI and our discussion of the associated implications for Entegrus' asset intervention strategy in 2021-2025.

Entegrus' Current Health Index Maturity and Continuous Improvement

Impact of the Recent Merger

Entegrus is a post-merger utility, having amalgamated its former assets and service territory with those of the former St. Thomas Energy Inc. ("STEI") in 2018. The data we relied on in conducting this ACA study reflects the completion of the 2019 inspection season or two years of integrated operations. Considering that most assets undergo inspections on a three-year cycle, some of the reported results reflect those of the pre-merger utilities. However, given our understanding of the pre- and post-amalgamation asset management due diligence activities that Entegrus undertook, we have confidence that the utility is aware of any potentially major issues associated with the legacy STEI plant. Overall, given that the former STEI generally collected and recorded similar types of data to Entegrus, we encountered no significant issues in establishing common Health Indices / Health Parameter Assessments between the two asset sub-populations.

As the merger consolidation work progresses, we encourage Entegrus to ensure that inspections conducted by members of the two former utilities, follow consistent frames of reference as to the threshold signs of deterioration or damage that would signify imminent failure and/or provide other reasons to suggest near-term intervention. While signs of degradation are generally well understood, in our experience there may be cultural differences at how one organization defines the signs of "inspection-based failure" relative to another.

Data Collection Practices

We have verified that Entegrus meets the minimum inspection requirements prescribed in the Distribution System Code for all asset classes this study explores. However, as discussed further in Sections 3 and 4, the amount of asset health data Entegrus collects varies significantly across its asset classes. While it regularly conducts multiple empirical tests on major substation equipment like transformers and circuit breakers and conducts multi-point visual assessments of line infrastructure (including IR scanning where applicable), Entegrus employs an exception-based reporting approach towards most of its line assets, whereby inspecting personnel only generate asset-specific condition records when they discover an issue indicative of imminent failure (and thus requiring near-term intervention via maintenance or replacement).

An implication of the exception-based reporting approach from the perspective of Health Index generation is that for most of its line assets, Entegrus possesses relatively few types of recorded asset-specific data aside from the year of installation, asset type/make/rating and (where relevant) historical equipment loading levels. However, another critical (and positive) implication of exception-based reporting is the comparatively low cost of inspections due to the time and effort saved in generating and analyzing physical inspection records for each asset.

Accordingly, Entegrus' approach to line asset inspection data management reflects an important trade-off between the amount of asset health data available for near-term asset intervention planning, and the avoided OM&A costs that benefit its ratepayers. Although the resulting line infrastructure Health Assessments (grounded largely in asset age and loading data) incorporate less empirical tests than could be available, they are nevertheless comparable with those of other Ontario distributors of Entegrus' size. Importantly, the analytical insights available from the asset health-related information that Entegrus does possess, still enable it to maintain an objective and data-driven outlook on the anticipated scope and magnitude of degradation across its system in the near-to-medium term. Given that it does perform substantial empirical tests on critical station assets the failure of which could result in major reactive costs (investments that seem to be paying off given the assessed condition of these assets), we see Entegrus' overall asset condition data collection strategy as highly pragmatic, nuanced and well-suited for a utility in its operating circumstances.

We also see clear motivation to continuously improve the amount of data insights generated through its inspection practices, while remaining consistent with its overall cost management strategy. The examples of recent pilots with Supervised Machine Learning algorithms to predict the scores of wood pole drill tests (which METSCO assisted Entegrus in), and a small-scale cable testing pilot are both a testament to Entegrus' emphasis on continuous improvement in the sphere of Asset Management, balanced by its entrepreneurial drive to manage the financial impact of these improvement activities.

Notwithstanding the above commentary, and consistent with our typical approach to ACA studies, Section 5 of this report lists several incremental enhancements to asset-class specific data collection practices that we see as consistent with Entegrus' overall strategy and potentially worthwhile exploring in the future. In providing these recommendations, METSCO is cognizant of the fact that regulated utilities are facing cost constraints across numerous facets of their operations, while contending with the effects of ageing infrastructure, changing climate, evolving customer needs, and many other priorities. This is even more so the case for Entegrus, that is expected to remain in the Deferred Rebasing period for the entire 2021-2025 DSP Forecast Period following the recent merger. As such, adoption of any incremental enhancement to the existing asset data collection practices must be grounded in management's assessment of the incremental value of such enhancements, relative to the opportunity cost of advancements elsewhere in the utility's operations.

Asset Interventions over the 2021-2025 Period

METSCO understands that Entegrus expects to remain in the deferred rebasing period for the entirety of its next DSP planning horizon, during which it is reasonable to expect that its capital budget is unlikely to differ from the historical levels. When comparing the volume of assets that received a Very Poor health score to Entegrus' historical System Renewal expenditure levels, we do not expect it to be practical for the utility to target eliminating all Very Poor assets over the 5-year plan period (as we have recommended in other ACAs). Instead, we suggest that Entegrus attempt to set its asset replacement targets by identifying the clusters of Very Poor assets concentrated in particularly critical / vulnerable parts of the system, as determined by the utility's System Renewal planning activities.

With respect to proactive investments in voltage conversion, we suggest that Entegrus consider prioritizing the combinations of the lowest substation transformer / circuit breaker health scores and the line facilities downstream from these stations. In incorporating this approach into its planning process, the utility stands to ensure that the worst-condition station assets are more likely to be removed from service sooner – avoiding the impact of them reaching end of life before the downstream feeders undergo voltage conversion.

Finally, and recognizing the likelihood of capital investment constraints in a deferred rebasing period, METSCO encourages Entegrus to begin proactively addressing its population of aged underground cables at a greater rate than we understand has been the case in recent years. While age is the only asset data criterion available for our analysis, this is typically the case for distribution utilities given the costs of cable testing work. In any case, a significant portion of Entegrus' population of cables has long surpassed the bound of expected end of life – particularly in the case of the population of direct-buried TRXLPE cables. While large-scale proactive renewal may not be economically feasible, we suggest that Entegrus consider exploring limited-scale cable testing as a means of gaining a modicum of incremental insights regarding the state of its underground equipment. At the same time, Entegrus can attempt to gain additional insights into the relative health of its cable population by cable type or geographic location through moderate adjustments to its equipment failure data collection practices, which can then enable the asset managers to make additional inferences as to the relative state of various underground cable sub-populations. Finally, a variation of randomized testing approach, similar to the strategy deployed with wood pole drill testing may also present a potentially viable approach.

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1 Introduction

METSCO Energy Solutions Inc. ("METSCO") is an engineering and management consulting firm specializing in work with electric and natural gas utilities. As a part of our Asset Management ("AM") consulting practice we have conducted numerous Asset Condition Assessments ("ACAs") commissioned by utilities, regulators, private sector power consumers and financial institutions. Aside from the practical experience in conducting the ACA studies, METSCO's engineers made significant contributions to the development and refinement of Health Index methodologies across multiple asset classes through field work and a variety of R&D activities. METSCO's collective record of experience in the area of asset management for electricity transmission and distribution utilities is among the most extensive in the world, with our AM frameworks gaining acceptance across multiple regulatory jurisdictions.

Entegrus Powerlines Inc ("Entegrus") is an electricity distributor operating within the Southwestern Ontario region. Entegrus engaged METSCO to prepare a comprehensive ACA study for the assets comprising its distribution system, following a 2018 amalgamation with the former St. Thomas Energy Inc. ("STEI"). The ACA is expected to serve as one of the key inputs for the preparation of Entegrus' five-year Distribution System Plan to be submitted to the Ontario Energy Board ("OEB"). The study's primary objective is to generate and report on the health of Entegrus' assets in a consistent and data driven way, using the latest objective information and asset health index frameworks accepted in the industry. The ACA results are an input required to assist in future planning and prioritization of asset renewal investments. A key supplementary objective of this report is to explore potential enhancements to Entegrus' asset condition data gathering practices as a part of continuous improvement work.

A dedicated ACA methodology is applied to each major asset class covered in this report. The adoption of the ACA methodology requires identifying end-of-life criteria for various components associated with each asset type, followed by periodic asset inspections and recording of asset data – to identify the assets most at risk at reaching the end-of-life criteria over the relevant planning horizon. Where asset condition information is not recorded, other objective data such as asset age, make, or wear and tear sustained in operation can be used as proxies of condition, based on industry-accepted conversion scales. Each asset health criterion represents a factor that is influential, to a specific degree, in determining an asset's (or its component's) condition relative to its potential failure. These components and tests are weighted based on their importance in determining the assets' end-of-life, using METSCO's algorithms refined over time and tested in multiple regulatory proceedings.

This report covers the following major asset classes:

- Distribution Poles (Wood, Concrete and Steel)
- Overhead Primary Conductors
- Underground Primary Cables
- Distribution Pole Mount Transformers
- Distribution Pad Mount Transformers
- Distribution Submersible Transformers
- Distribution Overhead Switches
- Station Power Transformers
- Station Switchgears
- Station Circuit Breakers
- Station Battery Systems
- Station Yards

All the asset condition and demographic data METSCO used in its work is maintained by Entegrus as part of its regular asset management activities. METSCO received Entegrus' data for the current condition assessment between December of 2019 and May of 2020.

This report is organized into six sections including this introductory section:

- Section 2 summarizes the PAS-55 and ISO 55000/55001/55002 standards and discusses how the ACA fits into the overall asset management framework.
- Section 3 describes the asset Health Index calculation methodology used by METSCO, and addresses some of the common issues related to assumptions and data availability issues.
- Section 4 provides the Condition Assessment methodology framework and assessment for each of the identified asset classes.
- Section 5 summarizes METSCO's recommendations for Entegrus on data collection improvements for continuous improvement efforts for the ACA.
- Finally, Section 6 summarizes METSCO's concluding remarks.

Having had the benefit of completing second Entegrus ACA in a row, METSCO commends Entegrus on the notable improvements to the availability, consistency, and verifiability of asset data relative to the ACA we completed ahead of the 2015-2020 DSP filing. As was the case with the last ACA, it is our hope that the observations and recommendations contained in this report help the utility plan and execute further continuous improvement activities.

2 Context of the ACA within AM Planning

An ACA is a critical step in developing an objectively informed asset replacement strategy. An ACA study involves collection, consolidation, and utilization of the results within an organizational AM framework for the purposes of objectively quantifying and managing the risks of its asset portfolio. The level of degradation of an asset, its configuration within the system, and its corresponding likelihood of failure feed directly into the risk evaluation process, which identifies asset candidates for intervention (i.e., replacement or refurbishment). Assets are then grouped into program and project scopes that are evaluated and prioritized.

The ACA framework is designed to provide utilities with insights into the current state of an organization's asset base, the risks associated with anticipated degradation, and approaches to managing this degradation within the current AM framework, while ensuring that the organization extracts the expected value out of the asset base.

International Asset Management Standards

The following paragraphs serve as a brief introduction to the ISO group of technical standards as they apply to Asset Management in an electric utility.

One of the most widely recognized industry standards for AM Planning is the ISO 5500X group of standards (which captures 55000, 55001 and 55002). According to these standards, each business entity finds itself at one of the three main stages along the Asset Management journey:

1. Exploratory stage - entities looking to establish and set up an AM system;
2. Advancement stage - entities looking to realize more value from an asset base; and
3. Continuous Improvement stage - those looking to assess and progressively enhance an asset management system already in place for avenues of improvement.

Given that AM is a continuous journey, ISO 5500X remains continuously relevant within an organization, providing an objective, evidence-based framework against which the organizations can assess the managerial decisions relating to their purpose, operating context, and financial constraints over the different stages of their existence.[1]

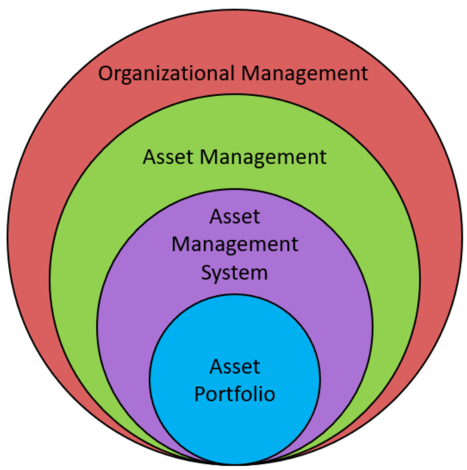
An asset is any item or entity that has a value to the organization. This value can be actual or potential, expressed in either a monetary or other manner valuable to an organization (including intangible outcomes like public safety). The primary job of an asset manager is to extract the maximum amount of value out of the group of assets in their care. Asset managers accomplish these objectives by way of tools and processes that are collectively known as the Asset Management System or Framework. Figure 2-1 displays the key

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

elements of such a framework expressed as a hierarchy of organizational systems. An asset portfolio, containing all known information regarding the assets, sits as the fundamental core of an organization. Around the asset portfolio, the AM System represents a set of interacting elements that establish the policy, objectives, and processes that help the organization achieve the objectives associated with preserving their assets in a working order to extract the intended value from them. The AM system is, in turn, embedded within the system AM practices – coordinated practical activities guided by the principles and processes defined in the AM System to realize the maximum value from the asset portfolio. Finally, the Organizational Management layer provides for an informed and consistent execution of the policies and processes underlying an AM System.[1]

The ACA framework is among the AM tools or procedures that enables Asset Managers to turn the known condition information into actionable insights based on the level of deterioration identified through inspections, testing and their subsequent analysis.

Figure 2-1: The relationship between key elements of an Asset Management System[1]



Role of an ACA within the AM Process

A well-executed AM strategy hinges on an organization's ability to be continuously aware of the state of its assets by way of regular data collection and analysis procedures. This includes but is not limited to the following activities: collection and storage of technical specifications, retaining data on historical asset performance, developing frameworks for projecting future asset behaviour and degradation, maintaining information on configuration of assets relative to other elements of the system. To accomplish these objectives, AM systems seek to develop techniques and procedures by which data can be most efficiently extracted from the field and stored and retrieved when necessary to generate analytical insights. In general, with more asset data on hand, better and more informed decisions can be made to realize greater benefits and reduce the risk across the asset portfolio managed by an organization.[2] However, as with all incremental business activities, the cost of collecting or analysing new data must be commensurate in value to the expected benefits extracted from actionable insights that the new data generates.

As a scientific and managerial discipline, Asset Management is fundamentally concerned with evaluating the opportunities for potential asset interventions (replacement or refurbishment) from a risk-based perspective – that is the product of probability and impact of events that asset interventions seek to prevent – relative to other potential intervention candidates that can be performed at comparable cost. Accordingly, Asset Management is about optimally allocating an organization's scarce capital resources across potential opportunities to reduce the risk inherent in the degradation of its assets through intervention activities that comprise AM operations and procedures. The role of an ACA study is to quantify the condition of each asset in a manner that serves to indicate its extent of degradation and failure probability.

Continuous Improvement in the AM Process

AM processes are ideally integrated throughout the entire organization. This requires a well-documented AM framework that also includes a clear and compelling expression of the organization's values in relation to how it intends to manage its assets. As a future-state goal, utilities and other organizations alike should strive to document their AM guiding principles within a Strategic Asset Management Plan ("SAMP"). The SAMP should be shared between all relevant agents (executive leadership, technical experts, operations and maintenance staff, or finance decision-makers) and updated on a regular basis, in order to capture the most current AM practices being implemented (including the trade-offs made in the process). Just as the asset base performance is subject to an in-depth review, the AM process and system should be reviewed with the same rigor.[1]

Asset Management should be regarded as a fluid process. Adopting a framework and an idealized set of practices does not bind the organization or restrict its agency. With time, the goal of any AM system is to continually improve and realize benefits within the organization through better management of its asset portfolio (including the insights regarding effectiveness and value for money of the AM processes themselves). Continually improved asset data and data collection procedures, updated SAMPs, and further integration into all aspects of an organization's activities as it grows and changes over time should be the goal of any AM framework. [1]

[2] ISO 55002 – Asset management – Management systems – Guidelines for the application of ISO 55001

3 Asset Health Index Calculation Methodology

3.1 METSCO's Project Execution

METSCO's execution path in completing an ACA study constitutes a four-phase procedure:

1. *Initial information gathering*: including initial interviews with Entegrus staff to investigate system configuration and the prominence of certain asset classes, establish the range of available condition data sources, and confirm the key assumptions regarding these factors with subject matter experts.

2. *Database construction and data verification* – activities to construct a single database of demographic and condition-related information for each asset class using the provided data sources. This includes consolidation of Entegrus' asset inspection records, databases containing results of technical tests performed by staff and contractors, and other pertinent information contained in the Geographic Information System ("GIS").

3. *HI and Data Availability Index ("DAI") calculation* – upon confirming the integrity of its condition dataset along with the accuracy of assumptions made in its preparation, METSCO calculated the Health Indices and DAI for all asset classes. This also involved a number of verification steps with Entegrus' SMEs to ensure that METSCO correctly interpreted the data records and was aware of the reasoning for any exceptions.

4. *Results Reporting* – the final phase of the project scope was the creation of the ACA report and sharing of the results with the Entegrus staff and Senior Management.

3.2 Data Sources

Since the completion of METSCO's last ACA study for Entegrus in 2015, the utility took significant steps to centralize and enhance the quality and consistency of its condition and demographic data for all asset classes examined in our study. Having designated its GIS platform as a formal Asset Registry, Entegrus has put into place the data collection and verification processes that have significantly enhanced the input data retrieval and initial review process. Another notable improvement relative to the 2015 ACA was the completeness of data records for most asset classes, which led to substantially higher Data Availability Indices.

In addition to the inspection, testing and demographic data contained in the GIS, Entegrus provided METSCO with historical operating data stored in other relevant IT/OT systems – most notably the loading information for transformers and the outage records from its Responder Outage Management System (OMS).

3.3 Asset Condition Assessment Methodologies

Prior to completing an ACA, a Health Index methodology needs to be selected for the current entity. The four most common methodologies that can be employed to assess the condition of the system assets include:

1. *Additive models* – asset degradation factors and scores are used to independently calculate a score for each individual asset, with the HI representing a weighted average of all individual scores from 0 to 100;
2. *Gateway models* – select parameters deemed to be most impactful on the asset's overall functionality act as "gates" to drive the overall condition of an asset, by effectively "deflating" the scores of other (less impactful) components;
3. *Subtractive models* – consider that a relatively Poor condition for any of several major assets within a broader system of assets could act as a sufficient justification to drive investments into the entire system; and
4. *Multiplicative models* – a HI that dynamically shifts the calculation towards specific degradation factors, if they are a leading indicator to show that an asset is failing.

The additive and gateway models are typically used for assessing individual assets, whereas the subtractive and multiplicative models are typically used for aggregate and composite system-level assessments. The latter models are still in an early stage and require extensive refinement and validation to confirm their applicability. The gateway model assigns gates to criteria or asset subcomponents which are difficult or expensive to replace and maintain, and/or are known to be a major cause of asset malfunctioning. This methodology is commonly used in conjunction with the additive model for major assets such as wood poles, where a "gate" score will act to reduce the HI due to a low recorded score for a given criterion. For example, if the remaining strength of a wood pole is less than 60%, the final HI for that asset is halved.

Most distribution utilities employ an additive model with select gateway model elements. METSCO selected this approach when conducting the ACA, which is in alignment with most of Entegrus' peer utilities.

It is also important to note that in cases where a utility does not possess at least three different asset health parameters for a given asset class, we refer to the resulting health calculation as a One- or Two-Parameter Health Assessment rather than a Health Index. This distinction in nomenclature is entirely a function of reporting clarity rather than a commentary on sufficiency of information to make observations about health of a given asset class. In METSCO's view, an *index* is a product of multiple inputs, and as such, it is not an appropriate term to describe a result of an assessment based on a single data input or even a pair of inputs.

Notwithstanding the above distinction, METSCO emphasizes that a higher number of inputs does not necessarily equate to higher quality or value of the health assessment. Like any economic activities, condition data collection, storage and analysis have cost implications, often in the form of OM&A expenditures that are passed on to ratepayers on a dollar-for-dollar basis. Accordingly, a decision to collect and keep track of any incremental data parameter across a population of assets carries significant cost implications for a utility and its customers.

3.4 Overview of the Selected Methodology

3.4.1 Condition Parameters

To calculate an HI (or a one-/two-parameter health assessment) for a given asset class, formulations are developed based on available condition parameters that can be expected to contribute to the degradation and eventual failure of that type of an asset. A weight is assigned to each condition parameter to indicate the amount of influence the condition has on the overall health of the asset relative to others. **Error! Reference source not found.** e xemplifies an HI formulation table.

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

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

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

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

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

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

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

Figure 3-1: HI Formulation Components

Condition parameters of an asset are characteristic properties that are used to derive the overall HI. Condition parameters are specific and uniquely graded for each asset class. Additionally, some condition parameters can be comprised of sub-condition parameters. For example, the oil quality condition parameter for a station power transformer is based on multiple sub-condition parameters like the acidity of oil, its interfacial tension, dielectric strength, and water content.

The scale used to determine an asset's score for a condition parameter is called the "condition indicator". Each condition parameter is ranked from A to E, with each rank corresponding to a numerical grade. In the above example, a condition score of 4 represents the best grade, whereas a condition score of 0 represents the worst grade.

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

3.4.2 Use of Age as a Condition Parameter

Some industry participants question the appropriateness of including age as a potential condition parameter for calculating asset HI values. At the core of the argument against the use of age in calculating asset condition is the notion that age implies a linear degradation path for an asset that does not always match the actual experience in the field.

While some assets lose their structural integrity faster than would be expected with the passage of time, others, such as those with limited exposure to natural environmental factors, or those that benefitted from regular predictive and corrective maintenance, may retain their original condition for a longer period of time than age-based degradation would imply. In recognition of the argument as to the limitations of age-based condition scoring, METSCO attempts to limit the instances where it relies on only age as a parameter explicitly used in the HI formulation.

In some cases, however, the limited number of condition parameters available for calculation of asset health makes age the only viable proxy for condition degradation. In other cases, such as when assessing condition of complex equipment containing a number of internal mechanical components that degrade with continuous operation and the state of which cannot be assessed without destructive testing, age represents an important component of asset health calculation irrespective of the number of other factors that may be available for analysis.

In the specific case of Entegrus, age is one of or the only available condition parameters for several line infrastructure asset classes, and as such – a dominant determinant of the reported condition, based on the appropriate formulation that translates calendar age into a specific condition score. While having additional asset condition data where age is the only available metric would enable Entegrus to derive additional and/or more precise insights about the state of their plant, a decision to collect more asset health information is a strategic tradeoff that utilities' management should make on balance of all costs and benefits including the opportunity cost of work elsewhere on the system foregone and/or deferred to enable data collection, and the expected benefits associated with newly collected data. In lieu of other available data, and given Entegrus' current asset management strategy where a large portion of line assets are managed on a Run to Failure basis, age makes up a reasonable proxy for condition of assets within the same asset class relative to one another. Ad Entegrus' Asset Management strategy evolves (e.g. such as once all substations have been taken out of service and more inspection / testing funding becomes available), we expect that Entegrus may consider expanding the scope of line equipment testing, beyond some of the pilot projects already ongoing and noted in this report. To inform Entegrus' thinking about the potential parameters that it can consider in the future, Section 5 includes our recommendations on a limited number of asset health parameters that in our view could be the most impactful, if collected.

3.4.3 Implications of Entegrus' Current Approach to Asset Data Collection

To be worthwhile of the incremental cost and effort, the collection and analysis of any new asset health data must give the utility confidence that the benefits of the resulting insights can lead to commensurate value gains. In cases where available spending levels limit the amount of inspection / testing work a utility can perform in a given year, management must prioritize among asset classes where more information is advisable, and those where lack of medium-longer-term planning precision can be a tolerable risk. In our interviews with Entegrus, we have confirmed that the utility's management applies this reasoning to the scoping of its inspection activities and setting of the associated budgets.

This approach is evident in practice when considering the relative number of testing and inspection data parameters available for Entegrus' major substation assets, where the utility collects substantially more condition data than it does for its linear infrastructure. METSCO understands that this trade-off is in part informed by Entegrus' strategy to phase out the substation assets as the voltage conversion work makes them redundant. For this strategy to yield long term shareholder and ratepayer value, voltage conversion must be completed before the major station equipment fails in service and warrants reactive replacement. This, in turn, means that it is critical for Entegrus to identify any material changes in the health of its station assets as early as possible, to ensure that voltage conversion activities and/or station preventative maintenance work can take place in time to avoid in-service failure and costly reactive replacement of the asset class slated for wholesale retirement.

Importantly, the relative lack of linear infrastructure health data *records* does not correspond to a lack of diligence in asset management. In the case of Entegrus (and multiple other Ontario distributors) it continues to rely on an Exception-Based approach to equipment deficiency reporting for overhead and underground line assets. This approach entails making a specific record of an asset's health parameters only when inspection reveals deficiencies indicative of imminent failure and/or other potential hazards requiring near-term rectification (e.g. safety issues or significant vegetation encroachments). Relying on data drawn from the Exception Records, Entegrus creates work orders to rectify the identified issues in the near term (prioritizing them based on relative urgency and other relevant operating factors).

Accordingly, while the Exception-Based asset health reporting approach does not generate records that could be used to generate Health Indices for an entire population of assets, it relies on modern multi-point inspection methodologies and relies on testing tools like IR scan guns where appropriate. As such, this approach ensures that all assets are inspected in accordance with the DSC requirements, all imminent issues are addressed in a timely manner, while managing the utility's overall inspection and testing budget. Inherent in this approach is an implicit trade-off between the precision of asset intervention planning over a medium/longer term and the rate impact of inspection work. Considering that Entegrus' asset management approach for line infrastructure has largely relied on a Run to Failure approach (with an important exception of Voltage Conversion work), METSCO sees the current approach to asset inspection and asset data record keeping as a reasonable exercise of management's discretion.

3.4.4 Entegrus' Work to Extract Additional Insights: The Pole Testing Predictive Analytics Pilot

It is worth noting that Entegrus is exploring innovative ways to draw new insights about the health of its distribution line assets using experimental, cost-conscious approaches. A recent notable example of such an approach is a pilot attempting to predict the results of the wood pole drill test using a Machine Learning algorithm, based on a small sample of actual drilled results.

Starting in 2016, Entegrus began drill testing small, randomly selected samples of poles representative of different geographic parts of its system and different age tranches. Randomly assigned drill tests that cover different age cohorts and regions of the population can be used to draw inferences about the population, and if possible, specific units that have not been drilled. Entegrus passed the drill test sample results to METSCO at the start of the ACA exercise to evaluate whether and how the results could be used to supplement the wood pole condition analysis.

METSCO explored several statistical approaches, ranging from simple age-based linear extrapolation to more advanced Machine Learning techniques such as Statistical Bootstrapping with Replacement Technique and the K Nearest Neighbours (KNN) Algorithm. While the fact that the poles were selected for drilling using random sampling would enable Entegrus to extrapolate these results to the population at large, this would be insufficient for the purposes of asset Health Index calculation, where each asset receives an individual score based on the available parameters. Accordingly, METSCO did not pursue statistical extrapolation, and instead selected the KNN algorithm as the preferred means to attempt predicting the internal integrity of the individual wood poles that have not been drill tested.

The KNN is a supervised Machine Learning algorithm that predicts a parameter unknown for a subset of a population (in this case - an untested pole's remaining strength grade) by initially exploring statistical relationships between other known parameters and the remaining strength of those poles that were actually drill-tested. In the case of our analysis, other available parameters that METSCO hypothesized could be predictive of a wood pole's remaining strength were pole height, type of wood, town of installation, and geographic coordinates. While pole age data is also available, we chose not to include it into our predictive analysis since age was already going to feature prominently in the poles' health score.

Rather than relying on extrapolation based on statistical sampling techniques, the algorithm works to identify the best data "matches" between the tested and untested poles on the basis of known parameters for both subsets, and then assigns the predicted test result on the basis of "dataspace proximity" between the poles with available drill test data and those where prediction is sought. In other words, the algorithm learns the likelihood of a given pole receiving a remaining strength drill test grade between A and E based on other known (independent) variables within the subset where drill test results exist, and then predicts the missing drill test results the data relationships it has explored earlier.

To test the accuracy of the KNN approach, we "held back" a portion of the poles sample where the drill test results were available and then used the algorithm trained on the remainder of the known sample to predict the remaining strength results for this test subset where they were actually known. The algorithm's overall resulting accuracy in assigning poles to a given remaining strength score was around 83% across all grades. While this result may sound somewhat encouraging, it is influenced by the mix of results across Remaining Strength grades within the full subset of poles that were drill tested.

As can be expected from a population of utility poles, the majority of units in a random subset that was tested received an "A" grade, indicating a healthy pole. As such, the result of an "A" was most likely to be correctly predicted during our accuracy testing verification step, since most of the poles in our held back accuracy verification subset were also graded as "A". A more telling statistic for our purposes was the accuracy with which the algorithm accurately predicted the poles with an "E" grade. Based on our accuracy verification test run, this crucial aspect of the algorithm's overall predictive accuracy was low – at approximately 12%. Given this result, it appears that the independent predictive variables available to the

KNN algorithm were insufficient to derive sufficiently nuanced results to predict the poles that would fail the Remaining Strength test. Accordingly, METSCO and Entegrus agreed that the algorithm's predictive accuracy was insufficient to warrant including its results into the Wood Pole HI formulation for the purposes of this ACA.

Despite the conclusions of the current pilot, METSCO commends Entegrus for managerial creativity and determination to explore opportunities to obtain cost efficient asset health insights by using modern data science techniques. We understand that Entegrus intends to continue exploring other creative opportunities to expand its knowledge of asset health with the help of modern technology and data science. We wholeheartedly endorse this commitment to managerial innovation in the asset management space.

Final Health Index Formulation

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

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

Where *i* corresponds to the condition parameter number, and the HI is a percentage representing the remaining life of the asset.

A gating approach is used for condition parameters that have a significant influence on the health of an asset. If the condition parameter that has been flagged as a gating parameter is below a pre-defined threshold value, the overall HI is reduced by 50%. This approach enables utilities to efficiently flag severely degraded assets through identification of condition parameters acknowledged to be critical indicators of overall asset health.

3.4.5 Health Index Results

METSCO's assessment of asset condition uses a consistent five-point scale along the expected degradation path for every asset, ranging from Very Good to Very Poor. To assign each asset into one of the categories, METSCO constructs an HI formulation for each asset class, which captures information on individual degradation factors contributing to that asset's declining condition over time.

Condition scores assigned to each degradation factor are also expressed as numerical or letter grades along with pre-defined scales. The final HI – expressed as a value between 0% and 100% - is a weighted sum of scores of individual degradation factors, with each of the five condition categories (Very Good, Good, Fair, Poor, Very Poor) corresponding to a numerical band. For example, the condition score of Very Good indicates assets with HI values between 100% and 85%, whereas assets found to be in a Very Poor condition score are those with calculated HI values between 0% and 30%. Generating an HI provides a succinct measure of the long-term health of an asset. **Error! Reference source not found.** presents the HI ranges with the corresponding asset condition, its description as well as implications for asset intervention prior to failure.

Table 3-1: HI Ranges and Corresponding Asset Condition

HI Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of aging or minor deterioration of a limited number of components	Normal Maintenance
[70-85)	Good	Significant Deterioration of some components	Normal Maintenance
[50-70)	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
[30-50)	Poor	Widespread serious deterioration	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
[0-30)	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

3.5 Data Availability Index

To put the calculation of HI values into the context of available data, METSCO supplemented its HI findings with the calculation of the DAI: a measure of the availability of the condition parameter data for a specific asset weighted by each condition parameter to the HI score. The DAI is calculated by dividing the sum of the weights of the condition parameters available to the total weight of the condition parameters used in the HI formulation for the asset class. The formula is given by:

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

Where *i* corresponds to the condition parameter number and *α* is the availability of coefficient (=1 when data available =0 when data unavailable)

An asset with all condition parameter data available will have a DAI value of 100%, independent of the asset's HI score. Assets with a high DAI will correlate to HI scores that describe the asset condition with a high degree of confidence. For distribution assets – typified by relatively large asset populations – if the DAI for an asset is less than 70%, a valid HI cannot be calculated. The subset of distribution assets without a valid HI are assigned an extrapolated HI value using the valid HI results for assets within the same asset class and ten-year age band. Similarly for station assets – typified by relatively small asset populations – if the DAI for an asset is less than 65%, a valid HI cannot be calculated. HI results for station assets are not extrapolated due to the small populations and higher complexity of equipment (and thus potential asset health issues).

4 Asset Condition Assessment Results

This section presents the current Health Index formulation for each asset class, the calculated scores for Health Indices, as well as the data available to perform the study.

4.1 Station Assets

4.1.1 Power Transformer

Table 4-1: Power Transformer Health Index Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Insulation Power Factor	10	A,B,C,D,E	4,3,2,1,0	40
Dissolved Gas Analysis (DGA)	10	A,B,C,D,E	4,3,2,1,0	40
Insulation Moisture Content	10	A,B,C,D,E	4,3,2,1,0	40
Service Age	6	A,B,C,D,E	4,3,2,1,0	24
Load History	2	A,B,C,D,E	4,3,2,1,0	8
Oil Quality	8	A,C,E	4,2,0	32
Overall Condition	6	A,B,C,D,E	4,3,2,1,0	24
Bushing Condition	5	A,B,C,D,E	4,3,2,1,0	20
Oil Levels	1	A,B,C,D,E	4,3,2,1,0	4
Oil Leaks	1	A,B,C,D,E	4,3,2,1,0	4
			Total Score	**236**

Power transformers in the distribution system are housed within municipal stations. They are used to step down the voltage within the distribution system to supply end users. Computing the Health Index of a transformer requires developing end-of-life criteria for its various components. **Error! Reference source not found.** summarizes the methodology to g enerate the Health Index for oil type power transformers. The Health Index score for a power transformer is composed of ten condition parameters. Of these ten, dissolved gas analysis, insulation power factor, insulation moisture content and oil quality are determined by quantitative testing results, with each parameter carrying a weight of eight or ten. Each of these parameters represents an aspect of a power transformer with a direct impact on the operational health of the asset. In addition, loading history and visual inspection results were used to calculate the Health Index Score.

By performing the dissolved gas analysis ("DGA"), it is possible to identify the precursor conditions of internal faults such as arcing, partial discharge, low-energy sparking, severe overloading, and overheating in the insulating medium. Insulation power factor measurements are an important source of data to monitor transformer and bushing conditions. Lower scores for one or a combination of these condition parameters strongly indicate progressed degradation of the asset, hence their larger weights. Oil leaks and overall condition of components are collected by visual inspection and serve as indicators of the total health of the asset.

Although load history is not a test, it holds value as an input for the Health Index algorithm. The peak loading information dating from 2015-2019 was used for the analysis. The rate of insulation degradation is directly related to the operating temperature which is directly related to transformer loading levels. The peak loading level of the transformers is expressed in a percentage of the nameplate rating. Entegrus collects the substation load history monthly, recording the monthly peak for each month.

Entegrus owns 21 substation power transformers within its service territory. Age was known for all the power transformers in the system. As noted earlier in this report, the utility expects to decommission all of its substations and their individual components as the progressive voltage conversion work makes the individual stations' voltage step-down function redundant.

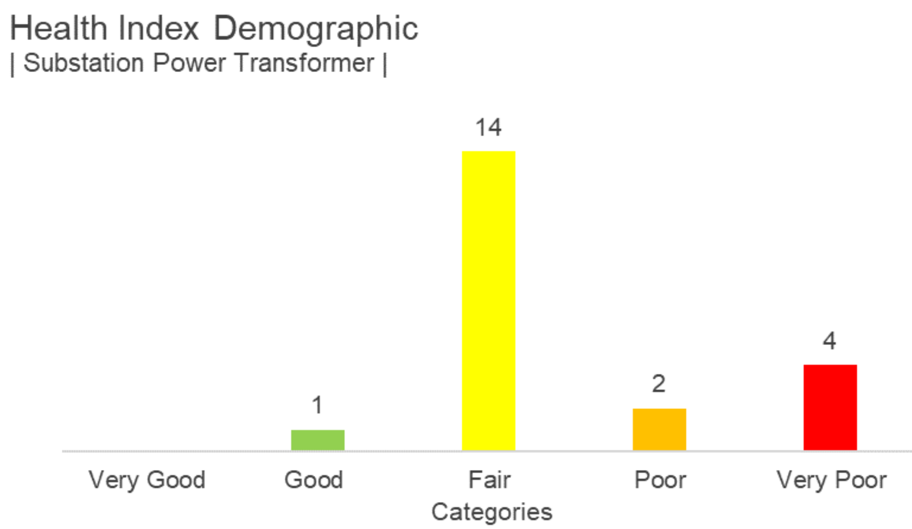


Figure 4-1: Power Transformers Health Index Demographic

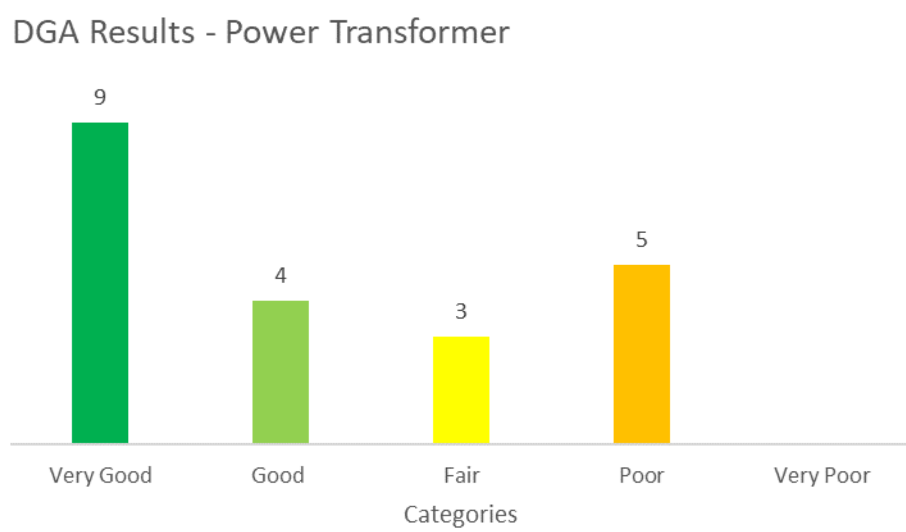


Figure 4-2: Power Transformers DGA Analysis Results

The Health Index distribution for in-service power transformers leveraged from the substation assessment is presented in **Error! Reference source not found.**. Entegrus' power t ransformer inspections, test results and loading history were used to calculate the Health Index based on the criteria provided in **Error! Reference source not found.**. The power t ransformers assessed are all quite old with none being below 40 years of age. This is a contributing factor in the results of the health index calculation and can explain why the condition of the transformers range from good to very poor with the majority of the population falling in the fair category. The average health index for power transformers is 55%.

Error! Reference source not found. illustrates the DGA analysis results for the power t ransformers. DGA tests can be a leading indicator as to how the power transformer's internal condition is before experiencing unfavorable results. The figure is presented to show there are five power transformers tested that have a Poor DGA result. These power transformers and the respective outcome of DGA results can support Entegrus' prioritization methods for the voltage conversion and eventual decommissioning of substations. It cannot be guaranteed the internal oil of each power transformer will remain as is for years to come, or if it will continue to degrade to a point the utility is required to intervene. Intervention methods that address the quality of oil include oil reclamation, transformer drying, asset renewal, or asset retirement (i.e. decommissioning). Since station transformer renewal is not consistent with Entegrus' strategy for this asset class, and the timing of decommissioning through voltage conversions depends on a number of factors aside from transformer health, METSCO advises Entegrus to contemplate additional preventative maintenance on units in concern. Transformer Drying may be one such method given the evidence of moisture present in the Oil Analysis. However, prior to engaging in this (relatively costly) activity, Entegrus may wish to explore additional testing on the units in the Very Poor / Poor condition, such as the Dielectric Frequency (DFR) test, which costs substantially less than drying and may reveal that the more expensive preventative practices are not required on some or all of the units of concern. Moving forward, it is advised Entegrus should track and trend the DGA results over each year and to be aware the possible impact of degraded power transformers can have on their voltage conversion/decommissioning strategy.

Table 4-2: Power Transformers condition parameters data availability

Condition Parameters	% of assets
Service Age	100%
Oil Quality	100%
Insulation Power Factor	100%
Visual Inspection – Bushing Condition	67%
Overall Condition	95%
Oil Leaks	95%
Oil Level	95%
Insulation Moisture Content	100%
DGA	100%
Load History	100%

The average DAI for oil type power transformer data is 97%. **Error! Reference source not f ound.** presents the DAI of individual condition parameters used for the power transformer HI framework.

4.1.2 Circuit Breakers

Table 4-3: Circuit Breaker Health Index Algorithm

Condition Parameter	Type	Weight	Ranking	Numerical Grade	Max Score
Overall Condition	All	4	A,C,E	4,2,0	16
Control & Operating Mechanism	All	2	A,C,E	4,2,0	8
Arch Chutes	Air	3	A,E	4,0	12
Insulation Resistance Test	All	4	A,B,C,D,E	4,3,2,1,0	16
Contact Resistance	Oil	4	A,B,D,E	4,3,1,0	16
	Air	2	A,B,D,E	4,3,1,0	8
				Total Score (Air/Oil)	**60/56**

Station circuit breakers are a critical substation asset and are the primary protective device for maintaining public safety and protecting other station equipment. Breakers work with station relays, to open either in a fault situation or as directed by the operations center or automation.

Breaker degradation occurs primarily through physical processes, such as by way of corrosion, accumulation of debris on insulators, or due to operations under load. In general, the more load passing through the asset when the breaker operates the more wear and tear it sustains.

Several types of breakers are available, with the primary difference being the medium used to break up the current – including traditional oil breakers or vacuum bottle insulated with SF6 gas or solid dielectric insulation. Table 4-3 above provides the health index algorithm for station batteries.

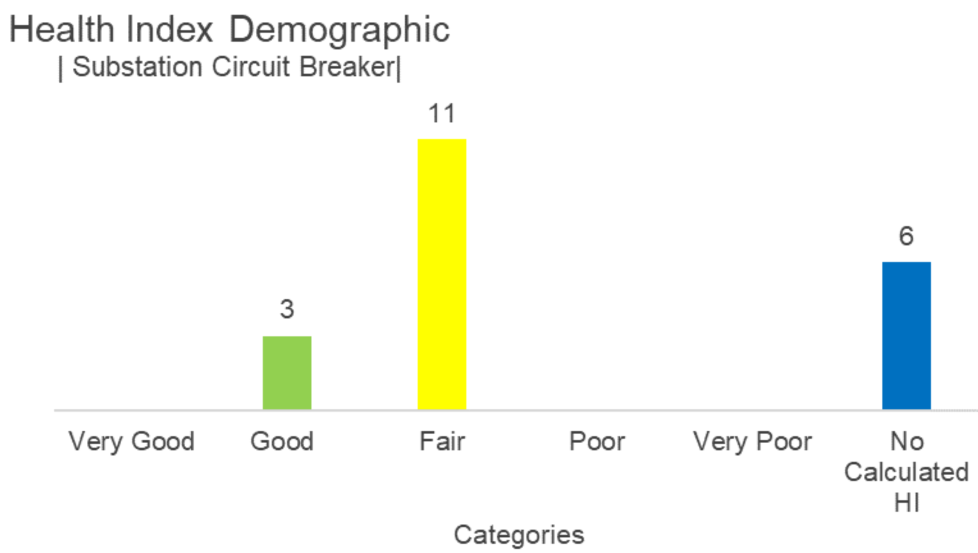


Figure 4-3: Substation Circuit Breaker Health Index Demographic

The above Figure 4-3 presents the results of METSCO's Asset Condition Assessment for the Substation Circuit Breaker asset class. 55% of circuit breakers assessed fall in the Fair category resulting in an average HI score of 66% across all assets. The six assets scored in No Calculated HI are due to a lack of data availability resulting in unreliable Health Index scores.

Table 4-4: Circuit Breakers Condition Parameters Data Availability

Condition Parameter	Type	% of assets
Overall Condition	All	100%
Control & Operating Mechanism	All	100%
Arch Chutes	Air	93%
Insulation Resistance Test	All	100%
Contact Resistance	Air	71%

The average DAI for circuit breakers is 93% (excluding assets with no HI). **Error! Reference source not found.** presents the DAI of individual condition parameters used for the Circuit Breakers HI framework.

4.1.3 Switchgear

Table 4-5: Switchgears Health Index Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	5	A,B,C,D,E	4,3,2,1,0	20
			Total Score	**20**

Station switchgear consists of breakers, fuses, and switches that control and regulate the current flowing through the distribution system. During a fault, the switchgear isolates and clears the faults downstream. It is also used to de-energize equipment during maintenance and testing. A "one-parameter assessment" was used for Switchgear due to having less than three available condition parameters as highlighted in Table 4-5. Appendix A provides grading tables for each condition parameter. Entegrus owns 65 station switchgears within its service territory. Age was known for the total population of Entegrus' in-service station switchgear units.

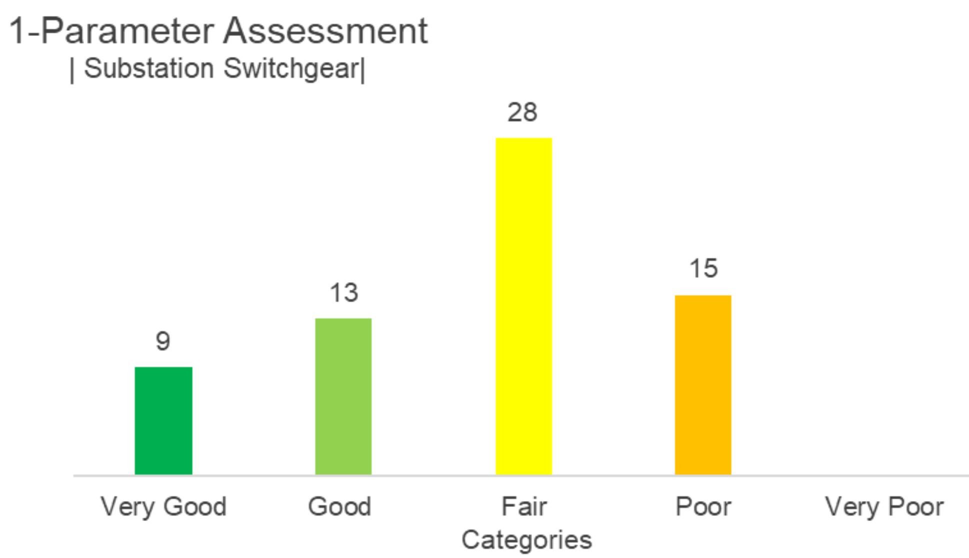


Figure 4-4: Switchgears Health Index Demographic

Entegrus' nameplate information was used to calculate the one-parameter assessment based on the criteria provided in **Error! Reference source not found.**. The overall one-parameter assessment distribution for the station switchgears leveraged from the substation assessment is presented in **Error! Reference source not found.**. 34% of the asset class is in Very Good or Good condition, with 43% of the station switchgears in Fair condition. The average age for Switchgears is 26 years, corresponding to an average condition score of Fair.

Table 4-6: Primary Station Switchgears Condition Parameters Data Availability

Condition Parameter	% of Assets with Data
Service Age	100%

The DAI for switchgear data is 100%. **Error! Reference source not found.** presents the DAI o f individual condition parameters used for the switchgear HI framework.

4.1.4 Station Batteries

Table 4-7: Station Batteries Health Index Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	4	A,B,C,D,E	4,3,2,1,0	16
Battery Condition	2	A,C,E	4,2,0	8
Charger Condition	2	A,C,E	4,2,0	8
Post Condition	2	A,C,E	4,2,0	8
			Total Score	**40**

The purpose of substation batteries is to supply control power used in operating critical devices such as protection relays, trip coils and circuit breakers. Batteries are carefully sized to store adequate energy for system operation during an AC power failure.

Both the electrodes and electrolyte in control batteries undergo aging with repeated charge and discharge cycles, which result in a gradual reduction of battery storage capacity. The end of life is reached when the battery is no longer able to retain adequate charge for required functions. Battery chargers can experience component failures, but these can be easily replaced, resulting in instances of chargers frequently outlasting the battery units.

Table 4-7 above provides the health index algorithm for station batteries. The below Figure 4-5 presents the results of METSCO's Asset Condition Assessment for the Substation Batteries asset class.

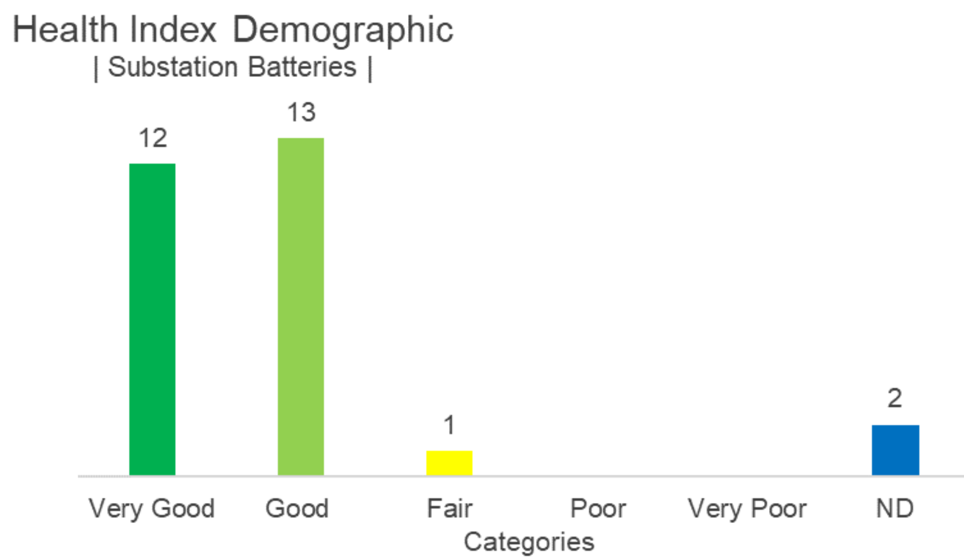


Figure 4-5: Station Batteries Health Index Demographic

Of the 28 station batteries considered in this assessment 89% fall in the Very Good or Good categories with an average HI score of 85%.

Table 4-8: Station Batteries condition parameters data availability

Condition Parameter	% of assets
Service Age	92.0%
Battery Condition	89.0%
Charger Condition	89.0%
Post Condition	89.0%

The average DAI for station batteries is 91%. **Error! Reference source not found.** presents t he DAI of individual condition parameters used for the Station Batteries HI framework.

4.1.5 Substation Yards

Substation yards in this assessment refer to fenced off enclosures surrounding substation outdoor equipment and service buildings. The combined Health Index includes the general condition of the station fences, gates, and presence of yard vegetation. Table 4-9summarizes the methodlgy used in calculating the Health Index for Station Yards.

Table 4-9: Station Yards Health Index Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Station Fence Condition	4	A,B,C,D,E	4,3,2,1,0	16
Station Gate Condition	4	A,B,C,D,E	4,3,2,1,0	16
Weed Problem Condition	2	A,B,C,D,E	4,3,2,1,0	8
			Total Score	**24**

Entegrus' station asset visual inspection records are the main input of the Health Index formulation. Appendix A provides grading tables for each condition parameter.

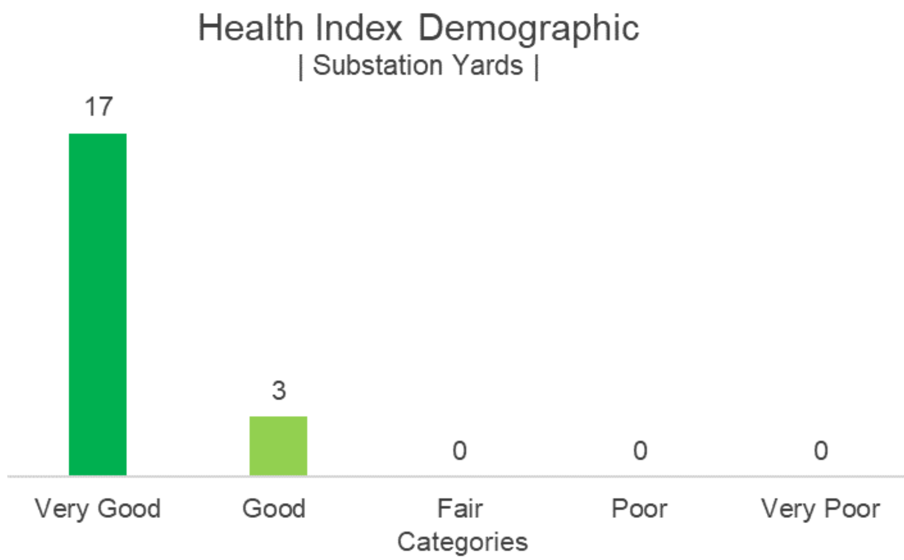


Figure 4-6: Substation Yards Health Index Demographic

The above Figure 4-6 presents the results of METSCO's Asset Condition Assessment for the Substation Yards asset class. Entegrus owns 20 stations within its service territory considered in this assessment. The average Health Index for station yards is 97%.

Table 4-10: Station Yards Condition Parameters Data Availability

Condition Parameter	% of assets
Station Fence Condition	100%
Station Gate Condition	100%
Weed Problem Condition	100%

The DAI across the station yard asset class is 100%. Table 4-10 presents the DAI of individual condition parameters used for the station yard HI framework.

4.2 Distribution Assets

4.2.1 Distribution Poles

Table 4-11: Distribution Pole One-Parameter Assessment Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	15	A,B,C,D,E	4,3,2,1,0	60
			Total Score	**168**

Overhead poles are an integral part of any distribution system. They support the overhead distribution equipment such overhead transformers, switches, reclosers, and streetlights. Pole failures are also among the most consequential events from the perspective of public safety. Entegrus' system includes Wood Poles, Steel Poles and Concrete Poles, with the latter two types constituting a relatively minor portion of all units. The only asset health parameter available for all three types of poles is asset age. Accordingly, the One-Parameter Health Assessment for Entegrus' distribution poles is a function of these units' age, as translated into condition score using a conversion approach described in Appendix A.

4.2.1.1 Wood Poles

Entegrus owns 20,446 distribution wood poles within its service territory. Wood, being a natural material, has degradation processes that are different from other assets in distribution systems. The most critical degradation process for wood poles involves biological and environmental mechanisms such as fungal decay, wildlife damage and effects of weather which can impact the mechanical strength of the pole. Any loss in the strength of the pole can present additional safety and environmental risks to the public and to Entegrus.

The installation date is unknown for approximately 18% of the total in-service population. In order to consider assets with unknown ages, METSCO used a best-fit age extrapolation method.

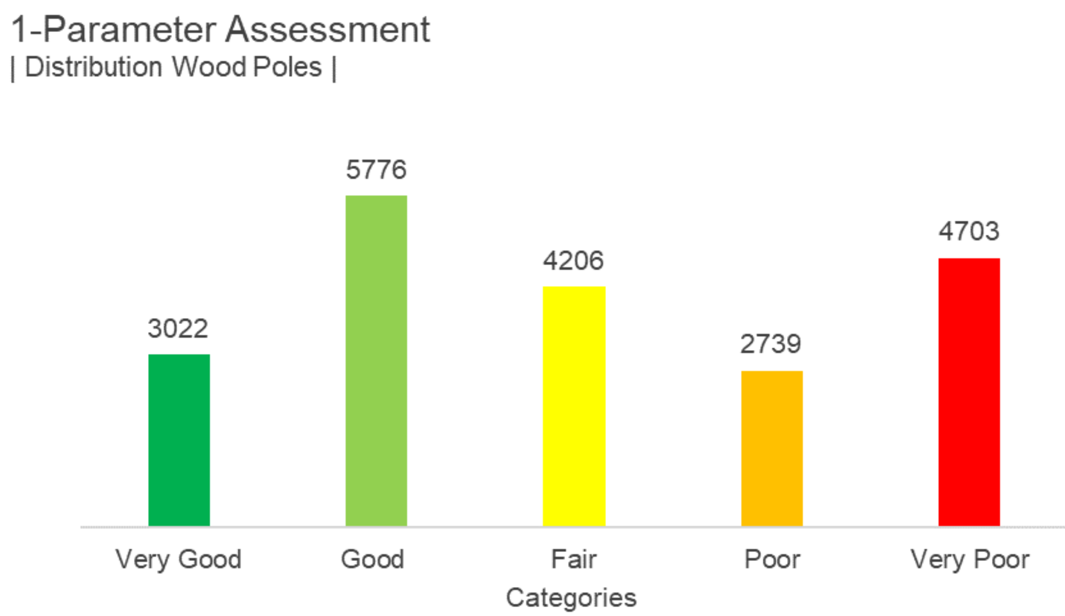


Figure 4-7: Distribution Wood Poles Health Index Demographic

The above Figure 4-7 presents the results of METSCO's Asset Condition Assessment for the Wood Poles asset class. Entegrus' pole maintenance and nameplate data were used to calculate the one-parameter assessment based on the criteria provided in **Error! Reference source not found.**. Poles are inspected on a 3-year cycle. As noted in Section 3, Entegrus collects a limited number of drill testing results on a small random sample of its wood poles every year. The units that fail the Remaining Strength drill test are captured in a dedicated database and are replaced in order of relative priority.

Entegrus and METSCO attempted to use the random sample pole testing results to use in a Machine Learning algorithm that would predict the remaining strength pole test failure based on other independent variables. These included pole height, wood type, geographic coordinates, and town of installation (to represent potential impact of legacy AM practices by multiple predecessor utilities that now comprise Entegrus). Based on the results of the pilot described in Section 3, Entegrus and METSCO agreed that the algorithm-predicted results were not sufficiently accurate at this time to be used as a dedicated component of a wood pole health index. Notwithstanding the pilot's results, METSCO commends Entegrus for managerial creativity in attempting to drive additional asset health insights using advanced data science techniques. As we discuss in our recommendations, we hope that Entegrus continues this innovative work as its AM function matures further.

A valid one-parameter assessment was calculated for 100% of the distribution of wood poles. The distribution of scores can been seen for wood poles in Figure 4-7.

Table 4-12: Distribution Wood Poles condition parameters data availability

Condition Parameter	% of assets
Service Age	100%

**Note: Extrapolated service age included*

The average DAI across the wood pole asset class is 100% as shown in Table 4-12.

4.2.1.2 Steel Poles

Entegrus owns 928 distribution steel poles within its service territory. The installation date is known for the entirety of its in-service population.

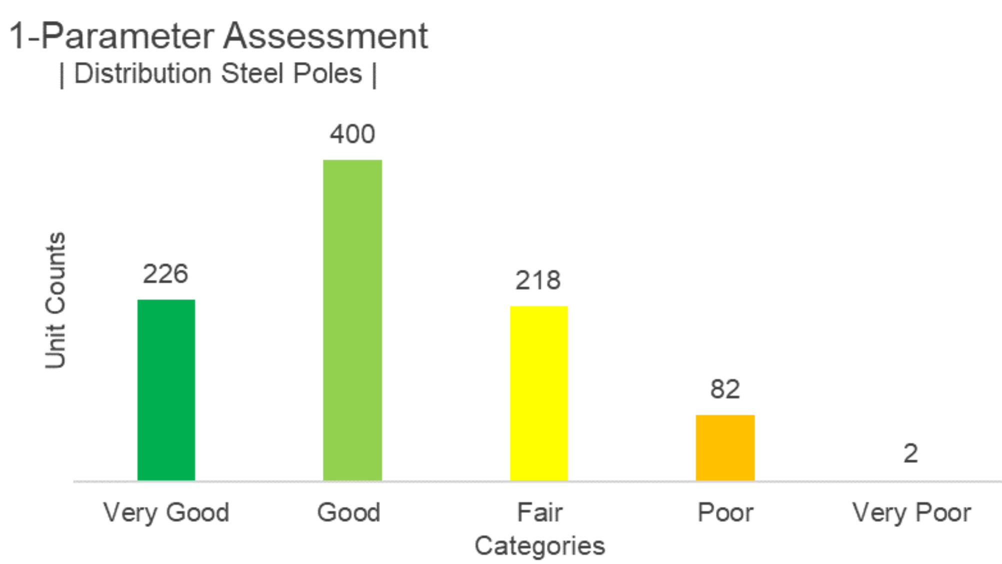


Figure 4-8: Distribution Steel Poles Health Index Demographic

The above Figure 4-8 presents the results of METSCO's Asset Condition Assessment for the Steel Poles asset class. Entegrus' pole maintenance and nameplate data were used to calculate the one-parameter assessment based on the criteria provided in Table 4-11. Poles are inspected on a 3-year cycle.

A valid one-parameter assessment was calculated for 100% of the distribution of steel poles. The one-parameter assessment distribution for steel poles can be seen in Figure 4-8. It is evident that most steel poles fall in the Very Good or Good category and make up over 67% of the distribution. The average age of steel poles is 23 years resulting in an average condition score of Good across the asset class.

We understand that Entegrus has now implemented a policy whereby it will not install new steel or concrete poles (or replace the existing ones with equivalents once they reach end of life), save for the situations where affected customers specifically request these materials and pay for the difference in cost from the appropriately sized wood poles. Accordingly, we do not expect the utility to consider collecting any additional condition data points for this asset class.

Table 4-13: Distribution Steel Poles Condition Parameters Data Availability

Condition Parameter	% of assets
Service Age	100%

The average DAI across the steel pole asset class is 100% as shown in Table 4-12 presents the DAI of individual condition parameters used for the steel pole health results.

4.2.1.3 Concrete Poles

Entegrus owns 63 distribution concrete poles within its service territory. The installation dates are known for 100% of in-service units.

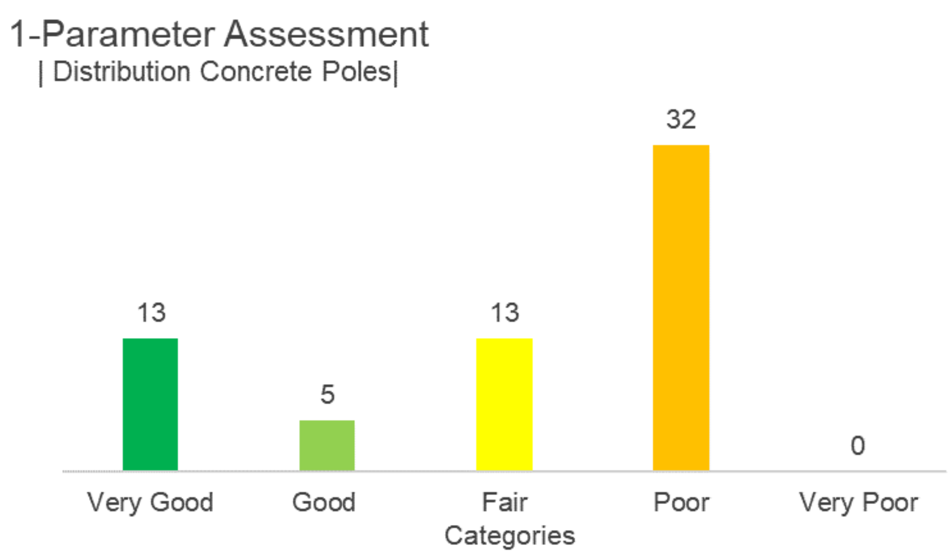


Figure 4-9: Distribution Concrete Poles Health Index Demographic

The above Figure 4-9 presents the results of METSCO's Asset Condition Assessment for the Concrete Poles asset class. A valid one-parameter assessment was calculated for 100% of the distribution of concrete poles with age representing the health parameter used. Nearly 60% of concrete distribution poles have an age of 30 years or higher, which explains why the distribution is skewed towards Poor units. The average age of concrete poles is about 33 years, resulting in an average condition score of Fair across the asset class.

As with the steel poles, Entegrus' recently adopted standard calls for any concrete poles undergoing replacement due to end of life or other reasons (e.g. plant relocations) to be replaced by wood poles of the appropriate size, aside from the case where individual customers specifically request the installation of concrete poles and pay for the difference in costs. Considering that this asset subclass is being phased out from Entegrus' system, we expect that no other parameters beyond age will be collected in the future, and the units will be replaced based on recommendations of cyclical inspections or other relevant operational considerations.

Table 4-14: Distribution Concrete Poles Condition Parameters Data Availability

Condition Parameter	% of assets
Service Age	100%

The average DAI across the concrete pole asset class is 100%.

4.2.2 Overhead Primary Conductor

Table 4-15: Overhead Primary Conductor Two-Parameter Assessment Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	5	A,B,C,D,E	4,3,2,1,0	20
Small Conductor Risk	5	A,E	4,0	20
			Total Score	**40**

Overhead primary conductors transmit electricity from substations to customer premises and are supported by service poles. The Health Index formulation for overhead primary conductors is summarized in Table 4-15. Due to having less than 3 condition parameters available, this assessment is labeled a "two-parameter health assessment". Appendix A provides grading tables for each condition parameter.

Although laboratory tests are available to determine the tensile strength and assess the remaining useful life of conductors, distribution line conductors are rarely tested given the cost considerations involved. As such, these tests are typically reserved for larger and more expensive transmission conductors. An appropriate proxy for the tensile strength of the conductor and to determine the remaining life of the asset is the use of service age. In addition to age, an undersized conductor risk (applicable to the largely obsolete #2-#6 copper conductors) is the additional condition parameter used to evaluate the HI of overhead conductors. Undersized conductors carrying large loads can result in sub-optimal system operation due to high line losses and are susceptible to frequent breakdowns.

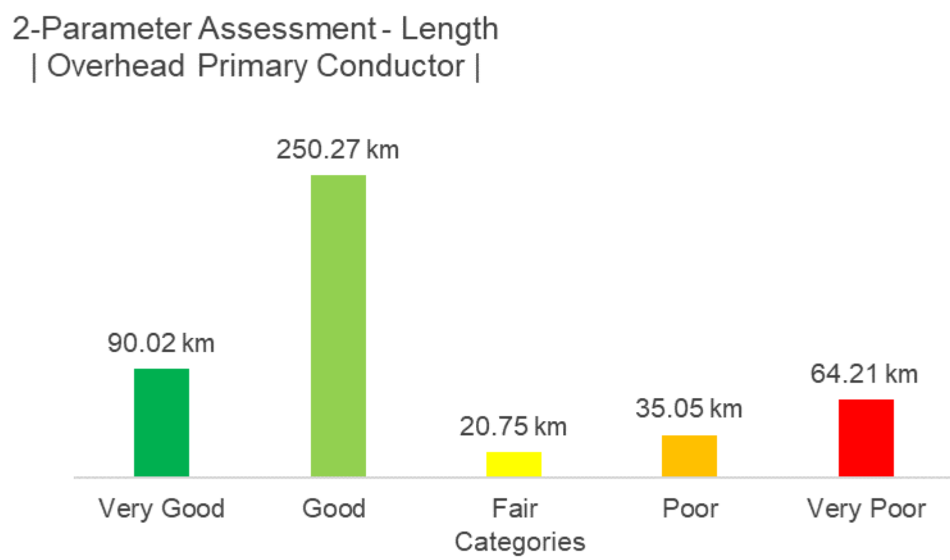


Figure 4-10 Overhead Primary Conductor Health Index Demographic

The above Figure 4-10 presents the results of METSCO's Asset Condition Assessment for the Overhead Primary Conductor asset class. Entegrus owns roughly 460.3 km of overhead primary conductor within its service territory. The installation date was unknown for approximately 2% of both 1-phase and 3-phase conductors and was extrapolated by the average age of distribution wood poles on the same distribution feeder to show an approximate representation of the age distribution. The applied assumption for the service age of assets was used in the two-parameter assessment calculation and was confirmed with Entegrus. Figure 4-10 illustrates the overall Health Index for overhead primary conductors.

A valid two-parameter assessment was calculated for 100% of the conductors, using the extrapolated age results. Most of the primary conductors are in Very Good and Good condition with less than 11% in Poor and Very Poor condition. The average Health Index for overhead primary conductors is 75.6%.

Table 4-16: Overhead Primary Conductor condition parameters data availability

Condition Parameter	% of Assets with Data
Service Age*	100%
Small Conductor Risk	54%

**Note: Extrapolated service age included*

The average DAI across the overhead primary conductor asset class is 77%. Table 4-16 presents the DAI of individual condition parameters used for the overhead primary conductors HI framework.

4.2.3 Underground Primary Cable

Like overhead conductors, underground cables also transmit electricity within the electrical distribution system, however, they are located below ground. Compared to overhead lines, they are less susceptible to weather fluctuations, external contacts such as tree branches and vegetation and are in general affected by fewer outage types. However, distribution underground cables are more expensive and are one of the more challenging assets in electricity systems from a condition assessment and asset management viewpoint. Several test techniques, such as partial discharge (PD) and water tree diagnostic testing have become available over recent years to identify the condition and performance of the asset class. Some tests can be destructive to the asset and hence are used less frequently. Accordingly, the preference is given to non-destructive testing such as Hi-Pot testing. In the absence of these tests, a sampling methodology can be executed to determine the general condition of the asset. Rather than doing tests for 100% of the system, a sampling approach can be taken where specific portions of cable are tested and those results are extrapolated over the entire system.

Entegrus owns approximately 388.2 km of underground primary cable within its service territory. The installation date was unknown for less than 1% of cable segments for both 1-phase and 3-phase cables and was extrapolated by the average age of cables on the same distribution feeder to show an approximate representation of the age distribution. The age distribution of underground primary cables were sorted in age bands specific to the insulating technology used in the cables. The applied assumption for the service age of assets was used in the one-parameter assessment calculation and was confirmed with Entegrus.

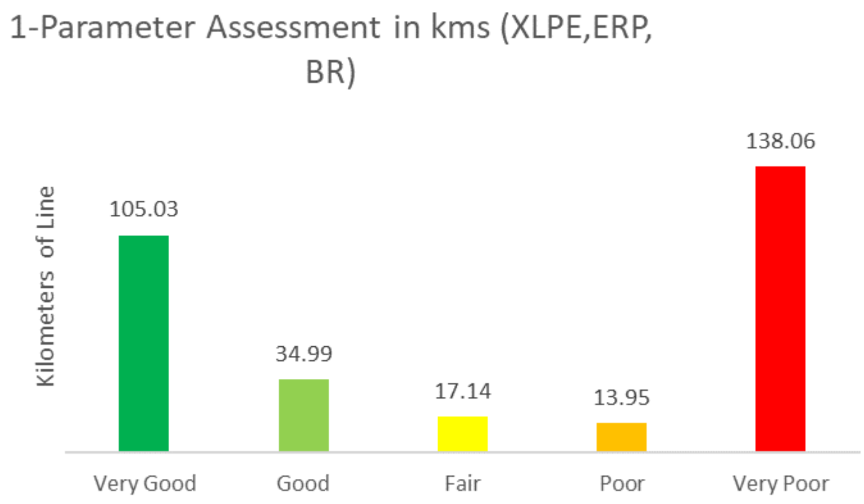


Figure 4-11: Underground Primary Cable Health Index Demographic (XLPE, ERP, BR)

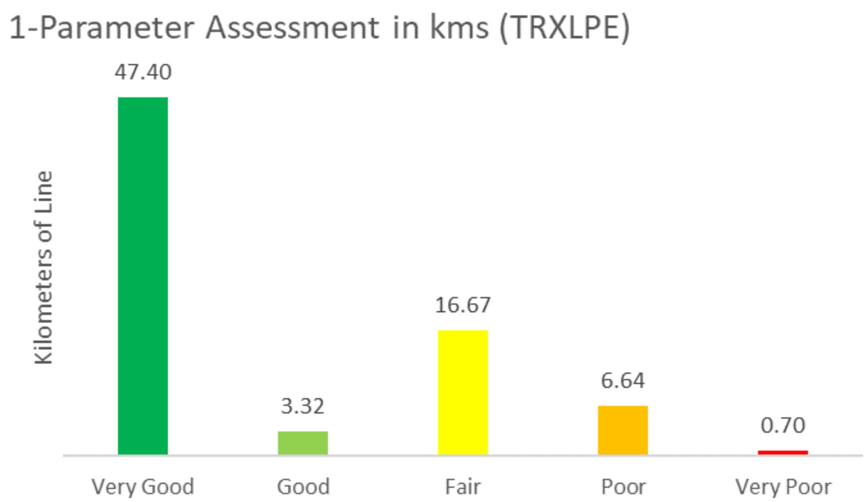


Figure 4-12: Underground Primary Cable Health Index Demographic (TRXLPE)

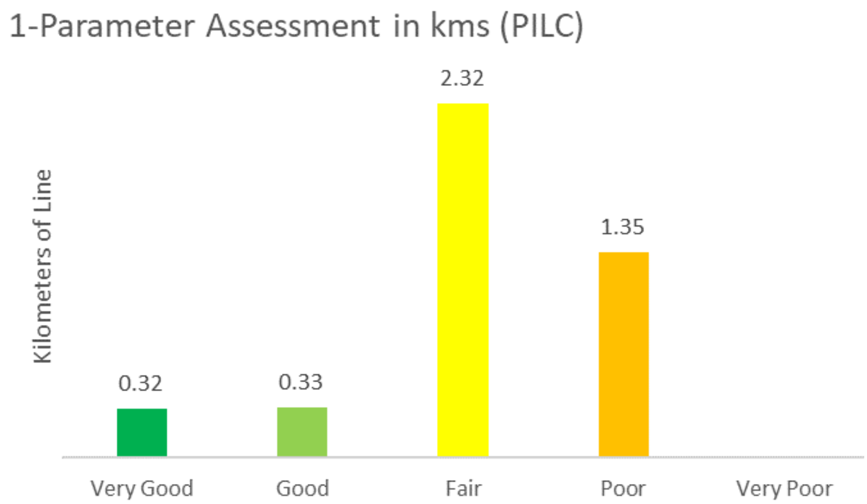


Figure 4-13: Underground Primary Cable Health Index Demographic (PILC)

The overall one-parameter assessment for underground primary cable is illustrated in the above figures. The 3 categories used to sort age bands based on insulation type are *TRXLPE*, *PILC* and *XLPE, ERP, BR*. Most of the underground primary cables are in Very Good to Fair range excluding a large number of Very Poor assets for XLPE, ERP and BR insulation types. The number of cable segments for all cable types were examined in their respective health bands and then averaged. Due to this offsetting distribution of Very Good and Very Poor cable segments, the average Health Index for underground primary cables falls in the Fair category.

Table 4-17: Underground Primary Cables condition parameters data availability

Condition Parameter	% of Assets with Data
Service Age*	100%

**Note: Extrapolated service age included*

The average DAI across the underground primary cable asset class is 100% with service age being the sole parameter. Table 4-17

4.2.4 Distribution Overhead (Pole-Mount) Transformer

Table 4-18: Pole-Mount Transformer Health Index Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Peak Loading	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	**24**

Overhead (pole-mount) transformers are installed on service poles to step down power from the medium voltage distribution system to the final voltage rating for customer use. The Health Index for pole-mount transformers is calculated by considering a combination of asset health degradation criteria summarized in Table 4-18. Each condition parameter represents a factor critical in determining the asset's condition relative to a potential failure to occur.

In addition to service age, another condition parameter available is the historical peak loading experienced by the transformer, as drawn from the utility's smart metering data. Load unbalances or high peak loading degrades transformer insulation over time and ultimately reduces the remaining useful life of a distribution transformer. In general, the useful life of a transformer is determined by its insulation condition which is largely affected by transformer loading, temperature, and presence of oxygen and moisture in the oil. While this data is not captured in inspection records for all units, Entegrus inspection crews also conduct IR scans for this asset class to identify the hot spots indicative of imminent failure.

Entegrus owns 3250 pole mount transformers within its service territory. The installation date is unknown for 2% of the asset population. Proportional age extrapolation was performed in order to assign age values to these assets that make up the unknown age population.

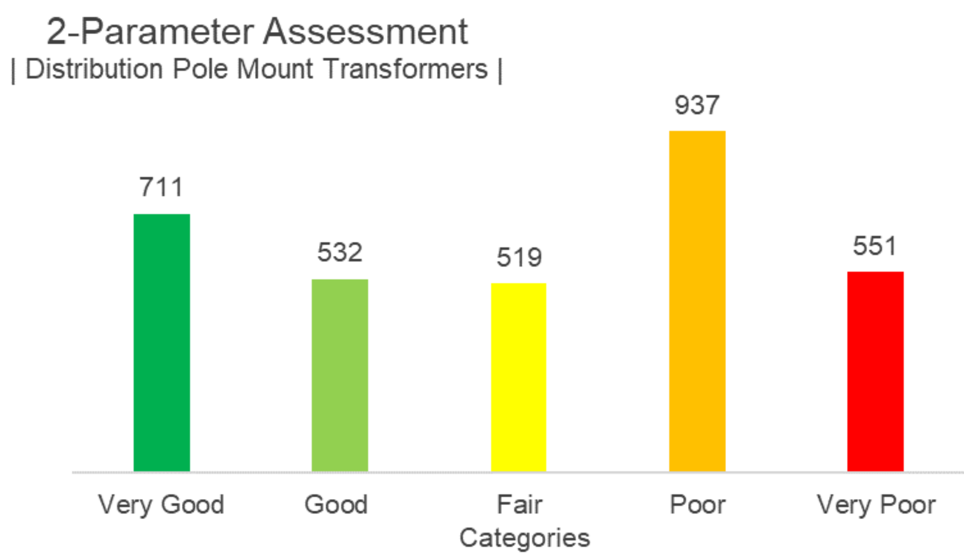


Figure 4-14: Pole-Mount Transformers Health Index Demographic

The above Figure 4-14 presents the results of METSCO's Asset Condition Assessment for the Pole-Mount Transformers asset class. Entegrus' transformer nameplate information and operating loading data were used to calculate the two-parameter assessment based on the criteria provided in Table 4-18. The average Health Index of the overhead distribution transformers is 58.4%.

Table 4-19: Pole-Mount Transformers condition parameters data availability

Condition Parameter	% of Assets with Data
Service Age*	100%
Peak Loading	95%

**Note: Extrapolated service age included*

The average DAI for the condition parameters for pole-mount transformers is 95%. Table 4-19 presents the DAI of individual condition parameters used for the overhead distribution transformer HI framework.

4.2.5 Distribution Underground Transformer

Distribution underground transformers are utilized for similar functionalities as pole-mount transformers. They step down power from the medium voltage distribution system to the final utilization voltage for the customer, however, they are located below ground or on ground level. Two types of underground distribution transformers are assessed within this report:

- Pad-Mount transformer
- Submersible transformer

Table 4-20: Pad Mount & Submersible Transformer Health Index Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Transformer Age	3	A,B,C,D,E	4,3,2,1,0	12
Peak loading	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	**24**

The two-parameter assessment for underground distribution transformers is calculated by considering a combination of end-of-life criteria summarized in Table 4-20. Each condition parameter represents a factor critical in determining the asset's condition relative to a potential failure to occur. Appendix A provides grading tables for each condition parameter.

In general, the useful life of a transformer is determined by its insulation condition which is largely affected by transformer loading, temperature, and presence of oxygen and moisture in the oil.

Entegrus owns 2300 pad mount transformers and 194 submersible transformers within its service territory.

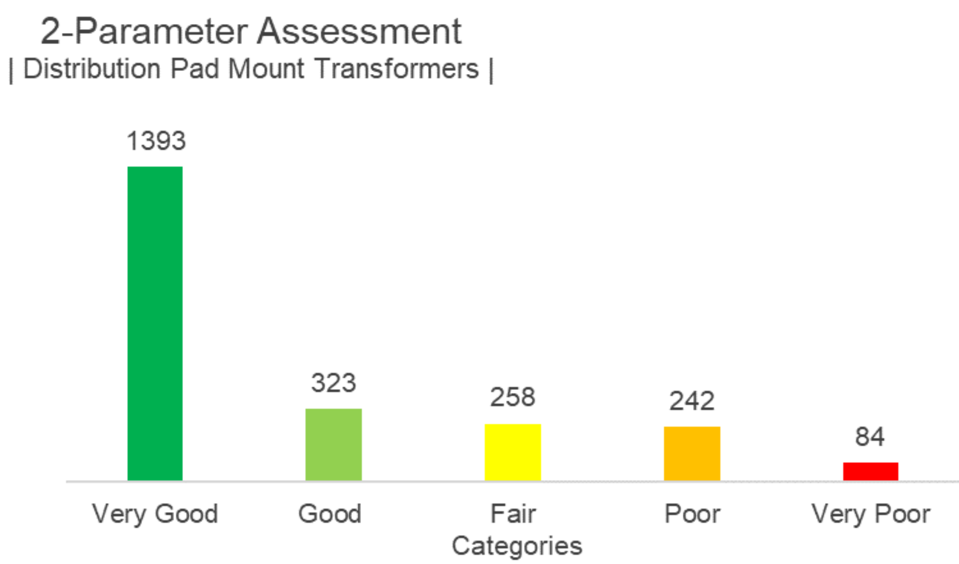


Figure 4-15: Pad-mount Transformers Health Index Demographic

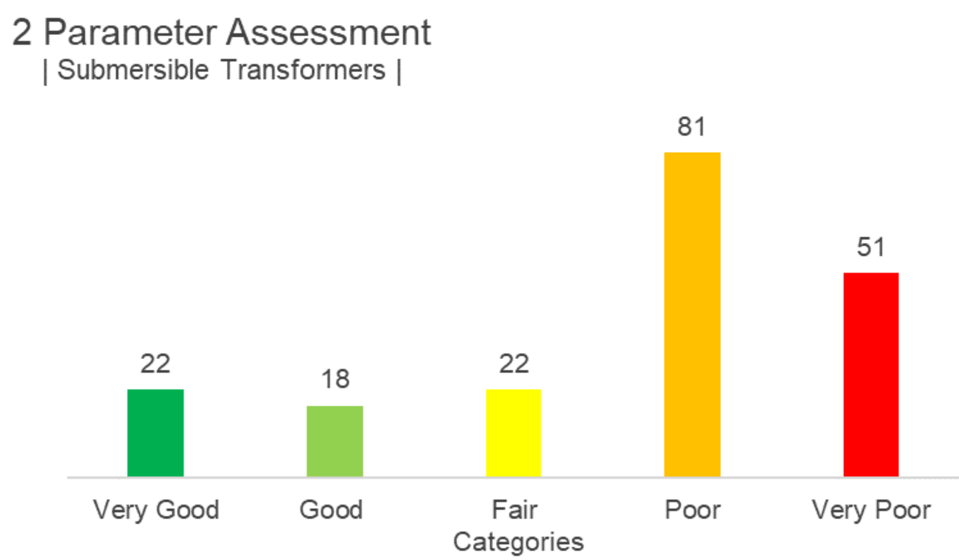


Figure 4-16: Submersible Transformers Health Index Demographic

The above Figures 4-15 and 4-16 present the results of METSCO's Asset Condition Assessment for the Pad-Mount and Submersible Transformer asset classes respectively. Entegrus' nameplate information, and operating loading data were leveraged in calculating the two-parameter assessment based on the criteria provided in Table 4-20. Approximately 18% of the underground distribution transformers within Entegrus' service territory have peak loading percentage of 100% or greater which can pose operating restrictions and impact the condition of the assets. A valid Health Index was calculated for 100% of both pad-mount and vault transformers. Most of the pad-mount transformers are in Very Good or

Good condition. The average Health Index of the pad-mount and vault transformers are 80.2% and 48.2%, respectively.

Table 4-21: Underground Transformers Condition Parameters Data Availability

Condition Parameter	% of Assets with Data	
	Pad-Mount Tx	Submersible Tx
Transformer Age*	100%	100%
Peak Loading	89.6%	77.3%

**Note: Extrapolated service age included*

The class-average DAI for pad-mount and submersible transformer data is 95% and 89% respectively. Table 4-21 presents the DAI of individual condition parameters used for the underground distribution transformers HI framework.

4.2.6 Distribution Overhead Switch

Table 4-22: Distribution Overhead Switch Health Index Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	4	A,B,C,D,E	4,3,2,1,0	16
			Total Score	**16**

Entegrus' distribution overhead switch types include fused cutout and load break switches mounted on its distribution poles. Load break switches are operated to sectionalize the circuit during a restoration procedure by breaking all three phases of load with a single operation. These switches are operated either manually or from Entegrus' control room where remote/automatic operability is enabled via SCADA or other technologies.

Fused cutout switches are a combination of a switch and a fuse and provide over-current protection during overload conditions or short circuits. The "one-parameter assessment" for switches is calculated by considering a combination of end-of-life criteria summarized in Table 4-22. Each condition parameter represents a factor critical in determining the asset's condition relative to a potential failure to occur. Appendix A provides the grading tables for each condition parameter.

Entegrus owns 736 overhead switches within its service territory with 4% of assets having unknown age values. For assets with unknown installation dates, the assumption made was to use the average distribution pole age on the same feeder as a proxy. The applied assumption for the service age of assets was used in the one-parameter assessment calculation and was confirmed with Entegrus.

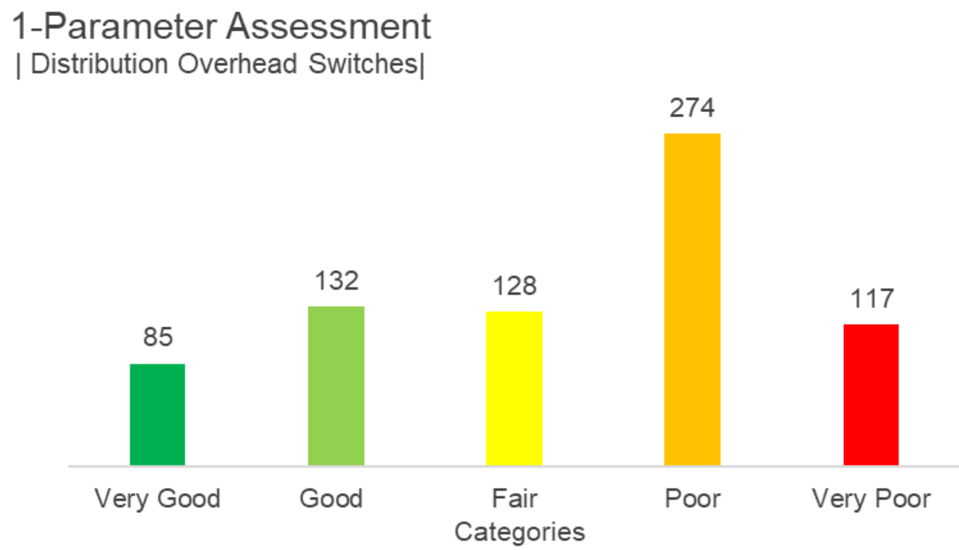


Figure 4-17: Overhead Switches Health Index Demographic

The above Figure 4-17 presents the results of METSCO's Asset Condition Assessment for the Overhead Switches asset class. Entegrus' nameplate information was used to calculate the one-parameter assessment based on the criteria provided in Table 4-22. More than 70% of the switches are in Fair or lower conditions. The average age of overhead switches is roughly 26 years resulting in an average score of Fair among assets.

Table 4-23: Distribution Overhead Switches condition parameters data availability

Condition Parameter	% of Assets with Data
Service Age*	100%

** Note: Extrapolated service age included*

The average DAI for overhead switch data is 100%. Table 4-23 presents the DAI of individual condition parameters used for the overhead switch HI framework.

4.3 Replacement Value-Weighted Average Health Index

The preceding sections provide asset class health distributions across individual health categories from Very Good to Very Poor, consistent with a traditional manner of ACA results presentation. In addition to these results that are most relevant to the engineering / asset management professionals, METSCO is increasingly utilizing another complimentary form of presenting the ACA results, which also caters to the utilities' finance and strategy functions. This alternative means of presentation entails producing weighted average Health Index results segmented by asset class, voltage, subsystem, geographic location, or asset criticality level (among others), where Asset Replacement Value (in dollars) is used for the purposes of weighting the HI scores from individual assets. METSCO believes that the resulting replacement-value weighted average health indices enable utilities to make additional strategic insights that may always be apparent when presented through a more traditional approach.

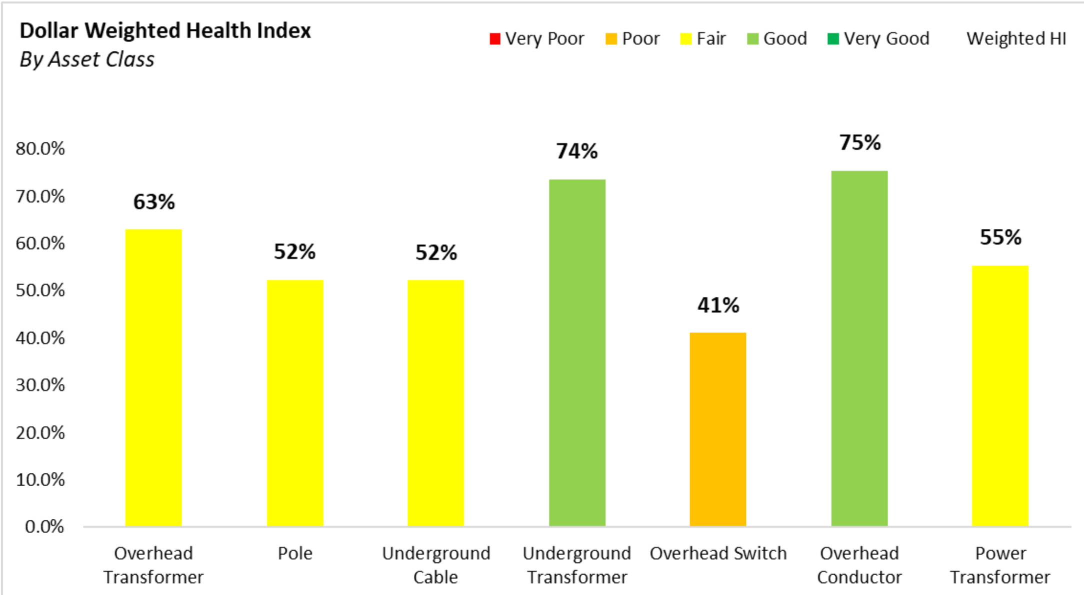


Figure 4-18: Replacement Value-Weighted Average Asset Health by Asset Class

Figure 4-18 presents average ACA results for a subset of major asset classes examined in this study. In producing this and other dollar-weighted asset health results, METSCO relied on a set of average asset unit costs Entegrus uses for the purposes of investment planning. The relatively higher health of Overhead Conductors is a function of their longer expected service lives relative to most other overhead assets, while the relatively higher health of Underground Transformers is in part the result of Entegrus' concerted effort to phase out its population of aged submersible transformers over the past decade.

Figure 4-19 presents the health results for the same select asset classes as the preceding Figure 4-18, with the assets being grouped according to service voltage of the feeders they are installed on (with stations being their own distinct category given their function of stepping down voltages). As this figure illustrates, the assets with the worst calculated health results on Entegrus' system, predominantly reside on the lower-voltage 2.4-13.8-kV feeders that the utility is actively attempting to renew and convert to a standard 27.6 kV voltage. The 27.6-kV voltage assets are (more appropriately for a mature utility) on average in a Fair health category, consistent with a more balanced distribution of newer and older equipment.

The substations equipment is on average in the higher end of the Fair condition grade, which is consistent with the more extensive testing and maintenance activities that Entegrus employs towards these assets. Keeping the substations in good operating condition up to the time when all downstream feeders are converted to the new higher-voltage standard is a key component of Entegrus' long-term capital productivity strategy.

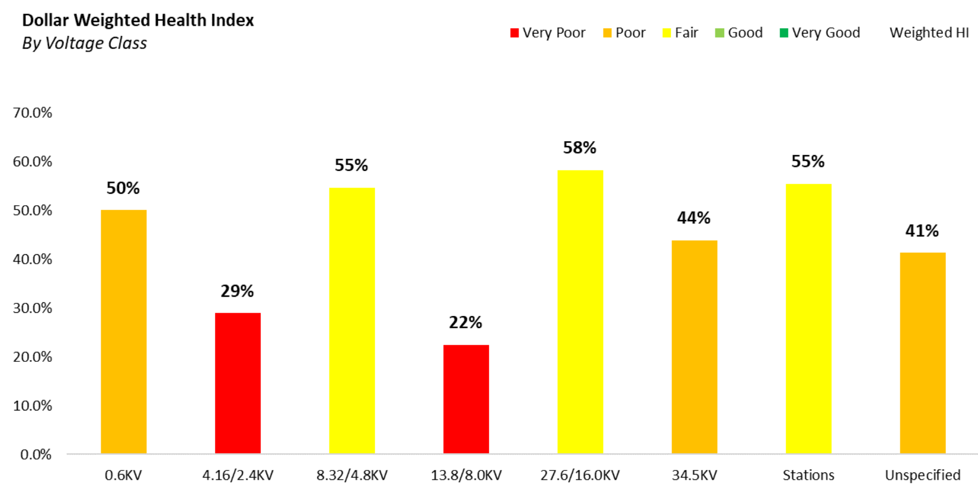


Figure 4-19: Average Asset Health by Voltage Class

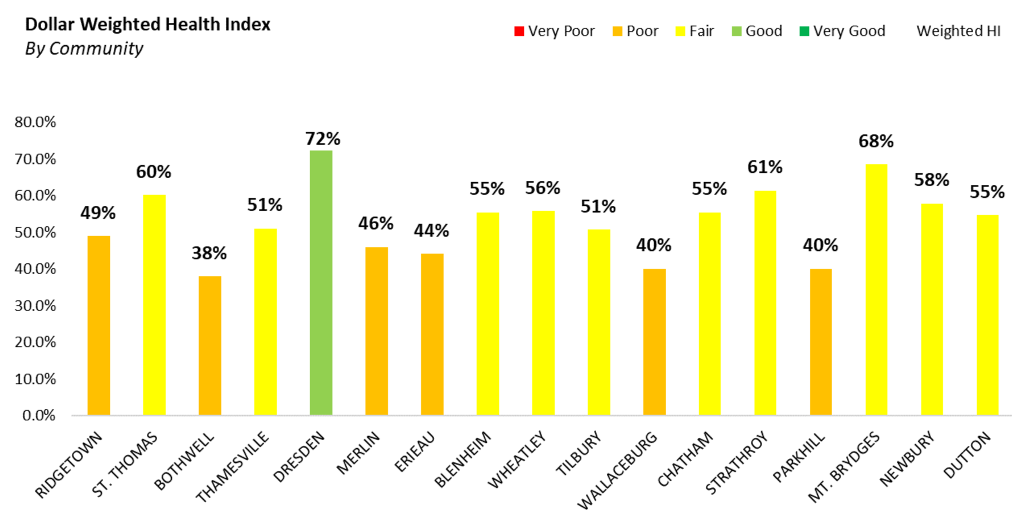


Figure 4-20: Average Asset Health by Community

Finally, Figure 4-20 groups the average asset health by individual communities that Entegrus serves (once again using replacement costs as a weighting factor). As can be seen from the diagram, Entegrus' three largest communities of Chatham, St. Thomas and Strathroy are in a relatively stable zone of "Fair" average health, with some of the smaller communities having average asset health in the Poor group (largely owing to the presence of low-voltage assets in what are relatively small municipal asset populations overall). Entegrus has confirmed that the materially better average condition for the community of

Dresden is a function of its small size and a relatively comprehensive pole replacement program that it recently benefitted from.

When considering asset health results across these different lenses of presentation, it appears that Entegrus' focus on voltage conversion as a major part of its System Renewal program is well justified by the available asset information. Similarly, given the relatively good condition of its substation assets, it appears that the utility's strategy to phase them out without having to replace them (as it completes the downstream voltage conversion work), can lead to material capital efficiencies, provided the volumes of conversion work keep up over the coming years.

METSCO hopes that these additional means of presenting the ACA results assist Entegrus' management in a variety of internal and external endeavors including strategic planning, stakeholder engagement, and shareholder communications, among others.

5 Recommendations

5.1 Asset Data Management Enhancements

Since METSCO's last ACA performed for Entegrus ahead of its 2016 rebasing application, the utility has taken decisive steps to enhance its asset data management processes. Having designated its GIS system as the formal Asset Registry, Entegrus took significant efforts to identify and rectify the missing data and verify the accuracy of the historical information where practicable. The utility also standardized the asset inspection data capturing and reporting from the field and appears to have robust accountability frameworks in place to ensure quality, consistency and regularity of asset inspection, testing, and modification data flow from the field. These positive developments took a concerted effort on the part of the utility's management for which they should be commended. From a practical perspective, these investments in asset data management also streamlined METSCO's data analysis work underlying this ACA.

Considering the above-noted enhancements, METSCO has only two relatively modest recommendations with respect to this dimension of ACA-related work:

1a) *Ensure inspections reflect consistency between legacy STEI and Entegrus field crews* – while Entegrus will likely continue relying on exception-based asset data reporting for the bulk of its line assets, it is nevertheless critical to ensure that all crews conducting inspections have consistent references as to what constitutes the threshold of defect / degradation that warrants completing an Exception Report. In METSCO's experience, it is not uncommon that field crews of neighbouring utilities, or even crews of the same utility operating in different regions may have materially different expectations as to what constitutes an asset defect or failure vs. severe (but acceptable) degradation.

To ensure consistency in asset health data generation post-amalgamation, METSCO suggests that Entegrus' AM staff conduct periodic spot checks of the assets identified for near-term intervention – particularly within its northern operations region – which is now served by a combination of Entegrus and former STEI crews. Even if no material deviations are identified by way of these periodic spot checks, Entegrus may benefit from developing a formal "Asset Health Look Book" with pictures of various types of asset deficiencies and the guidance on the appropriate means of classifying them and taking further actions.

1b) *Archive (or clearly separate the location of or reference to) historical GIS asset data kept on hand* – consistent with good data management practices, Entegrus' GIS functionality keeps track of the previous (historical) asset data, even after newer information has been added. While this practice can help resolve a number of potential situations where past record verification can help, in several instances during our project, Entegrus staff provided us with more dated asset information than what was available. While all these instances were quickly identified and rectified without material impact on the final results, it suggests that there may be opportunities for a clearer separation (by way of references, data storage locations etc.) between the latest data and all previous versions. We expect that this is a relatively minor adjustment that Entegrus may already be making following the instances that led us to making this recommendation.

5.2 Health Index Enhancements

In a departure from a typical practice in our ACA reports, METSCO is not recommending any specific incremental additional types of asset inspection and/or testing data that Entegrus should consider collecting across its asset base in the coming years. We do so for several important reasons. First, Entegrus finds itself in a post-amalgamation deferred rebasing period where it will remain until 2026. Given the operating and capital funding constraints associated with prolonged gaps between rebasing applications (potentially further exacerbated by the impact of the COVID-19 pandemic), it is, in METSCO's opinion, unreasonable to expect that Entegrus may find itself in a position to consider collecting / recording additional asset data points that could help it construct more advanced asset health index formulations.

Instead of recommending that Entegrus consider collecting any additional asset condition parameters across its asset base at this time, and in light of this ACA's findings regarding the portions of certain line asset classes in the Poor and Very Poor categories, METSCO suggests that Entegrus dedicate available resources to active System Renewal work, to the extent permissible by and other operating priorities. As we allude to throughout this report, METSCO believes that a decision to pursue collection of any incremental asset health data points must be based on a reasonable expectation that the anticipated value gain is commensurate to the opportunity cost of pursuing new data collection. On balance of our understanding of Entegrus' regulatory commitments, the asset health insights already available from this ACA, and the upcoming investment priorities outside of the System Renewal work, METSCO believes that the current opportunity cost of pursuing any new asset health data collection is prohibitive.

In our assessment, Entegrus already collects an appropriate amount of empirical information on its core substation assets health to enable it to execute its strategy of phasing out the substations as the voltage conversion work makes them. Given the current health of the substation assets, and Entegrus' additional efforts to avoid connecting any new larger loads to the low-voltage systems downstream of substations, we believe that the utility is in a position to execute this strategy successfully using the inspection and testing data it currently collects.

As to the line assets, where asset health data continues to rely on age to a significant degree, instead of recommending any new HI parameters system-wide, we instead suggest that Entegrus focus its efforts on further refining its understanding of the assets in the Poor / Very Poor categories and use any resulting insights to drive its specific asset intervention decisions in the near-term and inform the longer-term AM strategy more broadly.

Using the results our replacement value dollar-weighted asset health analysis by voltage class, it appears that Entegrus' current focus on low-voltage circuit conversion is well warranted. However, given the overhead asset counts in the Poor / Very Poor category across the remaining low-voltage circuits, Entegrus should consider finding cost-effective ways to further stratify these condition cohorts in the coming years. We make this recommendation as it does not appear feasible for Entegrus to remove all Very Poor assets from its service territory over the next five years, given its historical replacement rates and other upcoming priorities such as major System Service investments. Among the practical ways of obtaining further insights within the Poor/ Very Poor asset classifications are the following:

2a) Focus the Random Wood Pole Sampling Work – as noted earlier in this report, Entegrus has made commendable efforts on conducting random Drill Test sampling work across its Wood Pole population. While we were unable to use the results of this work to construct a sufficiently robust predictive algorithm across the asset base, METSCO suggests that Entegrus may consider focusing its random sampling efforts specifically within the sub-population of poles in the Poor / Very Poor health cohort. Doing so can help identify any potential "hot spots" of particularly deteriorated units, and may enable Entegrus staff identify some more nuanced factors that can serve to enhance the accuracy of predictive Remaining Strength algorithms deployed on a pilot basis.

A potential alternative means of focusing the limited budget for drill testing currently available, would involve directing them on pole subsegments assessed in a particular threshold condition grade – such as poles assessed to be on the verge between Poor and Very Poor or Fair and Poor. This type of more focused marginal condition analysis can provide planners with a more nuanced view on the anticipated pace of pole degradation beyond the immediate term.

2b) Draw Additional Insights from Outage Reporting – while some informal records of assets that fail in service are available, Entegrus as a whole does not currently have a formal program for collecting sub-cause code information for outages assigned a Defective Equipment Cause Code. METSCO recommends that Entegrus explore augmenting its outage investigation and reporting protocols to capture specific asset types / models / IDs where outages are caused by equipment failure or malfunction. The data generated by way of these process adjustments can help Entegrus planners identify potential trends regarding the equipment types, locations, or other relevant characteristics of failing assets that can also be used as inputs into the near-term intervention planning.

2c) Leverage Opportunities for Cable Inspections – we understand that the configuration of the majority of Entegrus' underground circuits makes field cable testing a complex and costly endeavor. However, we do expect the utility to access some cables through a combination of both reactive and proactive work in the coming years. We encourage Entegrus to explore opportunities to assess the condition samples of cables taken from the field (particularly where replacement was proactive to enabled voltage conversion), and record the location, type, number/extent of splicing, and other pertinent information during reactive underground restoration work. Proactive cable testing remains advisable (e.g. Partial Discharge (PD) or Concentric Neutral Corrosion) and could be valuable using a similar a variation of a test targeting approach suggested in the Recommendation *2a)* above. Entegrus may also consider exploring online PD testing that does not require an outage, but produces less definitive results. In any case, we suggest using every suitable opportunity to gain additional datapoints as to the current state of its underground cables, such as those noted above.

In providing these recommendations METSCO, is attempting to take a nuanced and pragmatic outlook on Entegrus' current operational environment – rather than offering continuous improvement recommendations anchored in industry best practices – that are typically reflective of utilities operating at different scale and circumstances. METSCO remains a strong proponent of evidence-based Asset Management, grounded in maximum available depth and diversity of information sources. However, as we continue building our own experience and expertise within the AM domain, our increasing appreciation of the economics of asset data collection in the regulated utilities domain is resulting in a more balanced outlook as to the pace and scale of desirable asset data collection practices.

6 Conclusion

The preceding report highlights a number of improvements on the part of Entegrus' Asset Management staff that demonstrate their commitment to continuous improvement and pragmatic approach to asset decision-making based on a clear sense of strategic trade-offs.

Among the notable successes since the last ACA are the improvements in asset data management that significantly simplified the effort of data review and analysis underlying METSCO's work. Looking at specific asset classes, it appears that Entegrus' strategic commitment to phasing out its population of submersible transformers is having a positive impact on the overall health of the underground transformer population. Similarly, the focus on condition monitoring of major substation equipment appears to be paying off given the current HI results – notwithstanding the advanced age of many station transformer units in particular.

At the same time the observed condition of certain line asset classes – most notably overhead poles and underground cables – suggests that higher replacement volumes and creative cost-effective approaches to gain further insights about the relative state of individual assets in the Poor and Very Poor categories appear desirable. Unlike most of our other ACAs, we are not suggesting that Entegrus incorporate any condition parameters. Instead, we recommend that that maximum feasible resources be dedicated to active System Renewal work, while any incremental (and invariably focused) insights regarding the asset base's health come from modest enhancements to the existing practices – to maximize the value of information that becomes available from time to time through normal operations.

The complexity of Entegrus' service territory and the impact of the COVID-19 pandemic make this challenge more formidable still. However, having observed the focus and managerial creativity with which Entegrus approached its Asset Management function over the past five years, METSCO is confident that the utility will continue making prudent investment decisions that benefit its customers and shareholder alike.

This concludes our Asset Condition Assessment report. METSCO thanks the Entegrus management team for the opportunity to conduct this study and the professional support shown to our staff throughout the project's duration.

7 Appendix A – Condition Parameters Grading Tables

7.1 Power Transformers

Table 7-1: Criteria for DGA Results

Gas Condition	Gas Generation Rate		
	Low	Low to High	High
Condition 1	A	A	B
Condition 2	B	B	C
Condition 3	C	C	D
Condition 4	D	D	E

Table 7-2: Criteria for Load History

Condition Rating	Corresponding Condition
A	$LS \geq 3.5$
B	$2.5 \leq LS < 3.5$
C	$1.5 \leq LS < 2.5$
D	$0.5 \leq LS < 1.5$
E	$LS < 0.5$

Table 7-3: Criteria for Insulation Power Factor

Condition Rating	Corresponding Condition
A	$PF_{MAX} < 0.5$
B	$0.5 \leq PF_{MAX} < 1$
C	$1 \leq PF_{MAX} < 1.5$
D	$1.5 \leq PF_{MAX} < 2$
E	$PF_{MAX} \geq 2$

Table 7-4: Criteria for Oil Quality Tests

Test	Station Transformer Voltage Class	Grade
	U ≤ 69 kV	
Acid Number	≤0.05	A
	0.05-0.20	C
	≥0.20	E
IFT [mN/m]	≥30	A
	25-30	C
	≤25	E
Dielectric Strength [kV]	>23 (1mm gap) >40 (2 mm gap)	A
	≤40	E
Water Content [ppm]	<35	A
	≥35	E

Table 7-5: Criteria for Service Age

Condition Rating	Corresponding Condition
A	Less than 20 years
B	20 to 40 years
C	40 to 60 years
D	More than 60 years
E	-

Table 7-6: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 - 0.5% Moisture
B	0.5 - 1% Moisture
C	1 - 1.5% Moisture
D	1.5
E	>2% Moisture

Table 7-7: Criteria for Visual Inspection field (Bushing Condition/Overall Condition/Oil Leaks/Oil Levels)

Condition Rating	Visual Inspection (Ent)	Visual Inspection (Met)
A	No rust on tank/radiator, no damage to bushings, no sign of oil leaks, forced air cooling fully functional	Bushings are not broken and are free of chips, radial cracks, flashover burns, copper splash, and copper wash. Cementing and fasteners are secure.
B	Only one of the following defects: minor rust, or minor cracks in bushings or minor oil leak	Bushings are not broken, but minor chips and cracks are visible. Cementing and fasteners are secure.
C	Two or more of the above indicated defects present but do not impact safe operation	Bushings are not broken; however, major chips and some flashover burns and copper splash are visible. Cementing and fasteners are secure.
D	Tank/radiator badly rusted or major damage to bushing or major oil leak	Bushings are broken or cementing and fasteners are not secure.
E	Two or more of the above indicated defects or the cooling fans do not work	Bushings, cementing, or fasteners are broken/damaged beyond repair.

7.2 Circuit Breakers

Table 7-8: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	All conditions marked as Satisfactory
C	One Not Satisfactory parameter
E	More than one Not Satisfactory parameter

Table 7-9: Criteria for Control & Operating Mechanisms

Condition Rating	Corresponding Condition
A	All conditions marked as Satisfactory
C	One Not Satisfactory parameter
E	More than one Not Satisfactory parameter

Table 7-10: Criteria for Arc Chutes

Condition Rating	Corresponding Condition
A	Condition marked as Satisfactory
E	Condition marked as Not Satisfactory

Table 7-11: Criteria for Coil Signature

Condition Rating	Corresponding Condition
A	All conditions marked as Satisfactory
E	One or more conditions marked as Not Satisfactory

Table 7-12: Criteria for Insulation Resistance

Condition Rating	Corresponding Condition
A	>2500 GOhms
B	1000-2500 GOhms
C	500-1000 GOhms
D	100-500 GOhms
E	<100 GOhms

Table 7-13: Criteria for Contact Resistance

Condition Rating	Corresponding Condition
A	0-1%
B	1-3%
D	3-5%
E	>5%

7.3 Switchgear

Table 7-14: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Over 40 years

7.4 Station Batteries

Table 7-15: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 5 years
B	6 to 10 years
C	11 to 15 years
D	16 to 20 years
E	Over 20 years

Table 7-16: Criteria for Battery Condition

Condition Rating	Corresponding Condition
A	Good
C	Fair
E	Poor

Table 7-17: Criteria for Post Condition

Condition Rating	Corresponding Condition
A	Good
C	Fair
E	Poor

Table 7-18: Criteria for Charger Condition

Condition Rating	Corresponding Condition
A	Good
C	Fair
E	Poor

7.5 Substation Yards

Table 7-19: Criteria for Station Fence Condition

Condition Rating	Corresponding Condition
A	Very Good
B	Good
C	Fair
D	Poor
E	Very Poor

Table 7-20: Criteria for Station Gate Condition

Condition Rating	Corresponding Condition
A	Very Good
B	Good
C	Fair
D	Poor
E	Very Poor

Table 7-21: Criteria for Weed Problem Condition

Condition Rating	Corresponding Condition
A	Very Good
B	Good
C	Fair
D	Poor
E	Very Poor

7.6 Distribution Poles

7.6.1 Wood Poles

Table 7-22: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 50 years
E	Over 50 years

7.6.2 Steel Poles

Table 7-23: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 60 years
E	Over 60 years

7.6.3 Concrete Poles

Table 7-24: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 50 years
E	Over 50 years

7.7 Overhead Primary Conductor

Table 7-25: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 30 years
C	31 to 50 years
D	51 to 70 years
E	Over 70 years

Table 7-26: Criteria for Small Risk Conductor

Condition Rating	Corresponding Condition
A	Absence of small-sized conductors
E	Presence of small-sized conductors (#4 to #6 copper)

7.8 Underground Primary Cable

7.8.1 XLPE, EPR and BR Insulation Type

Table 7-27: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 15 years
C	16 to 20 years
D	21 to 25 years
E	Over 25 years

7.8.2 TRXLPE Insulation Type

Table 7-28: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 20 years
B	21 to 30 years
C	31 to 40 years
D	41 to 50 years
E	Over 50 years

7.8.3 PILC Insulation Type

Table 7-29: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 15 years
B	16 to 30 years
C	31 to 45 years
D	46 to 65 years
E	Over 65 years

7.9 Distribution Overhead (Pole-Mount) Transformer

Table 7-30: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Over 40 years

Table 7-31: Criteria for Peak Loading

Condition Rating	Component Condition
A	Peak load of less than 50% of its rating
B	Peak load of 50% to 75% of its rating
C	Peak load of 75% to 100% of its rating
D	Peak load of 100% to 125% of its rating
E	Peak load of greater than 125% of its rating

7.10 Distribution Underground Transformer

Table 7-32: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Over 40 years

Table 7-33: Criteria for Peak Loading

Condition Rating	Component Condition
A	Peak load of less than 50% of its rating
B	Peak load of 50% to 75% of its rating
C	Peak load of 75% to 100% of its rating
D	Peak load of 100% to 125% of its rating
E	Peak load of greater than 125% of its rating

7.11 Distribution Overhead Switch

Table 7-34: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Over 40 years

8 Appendix B – METSCO Company Profile

METSCO Energy Solutions Inc. is a Canadian corporation which started its operations on the market in 2006. METSCO is engaged in the business of providing consulting and project management services to electricity generating, transmission, and distribution companies, major industrial and commercial users of electricity, as well as municipalities and constructors on lighting services, asset management, and construction audits. Our head office is located in Toronto, ON and our western office is located in Calgary, AB. Through our network of associates, we provide consulting services to power sector clients around the world. A small subset of our major clients is shown in the figure below.

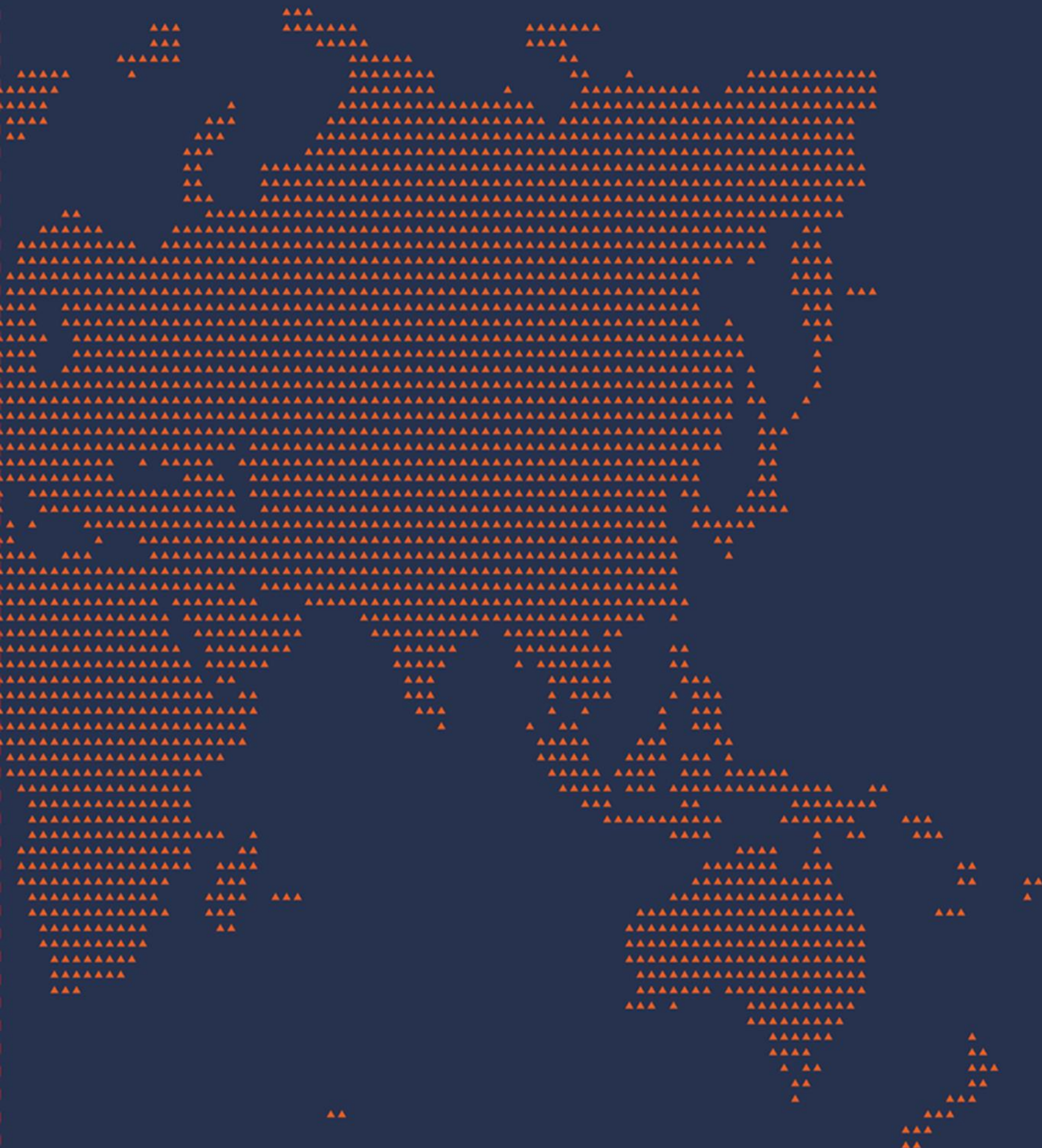
Figure 8-1: METSCO Clients

METSCO has been leading the industry in Asset Condition Assessment and Asset Management practices for over 10 years. Our founders are the pioneers of the first-ever Health Index methodology for power equipment in North America as well as the most robust high voltage risk-based analytics on the market today. METSCO has since completed hundreds of asset condition assessments, asset management plans, and asset management framework implementations. Our collective record of experience in these areas is the largest in the world, with ours being the only practice with widespread acceptance across regulatory jurisdictions. METSCO has worked with over 100 different utilities through its tenure, and as such, has been exposed and introduced to practices and unique challenges from a variety of entities, environments, and geographies. When a client chooses METSCO to work on improving Asset Management practices, it is choosing the industry-leading standard, rigorously tested and refined on a continued basis. Our experts have developed, supported, managed, led and sat on stand defending their own DSPs as utility staff giving METSCO the qualified experts to provide its service to Entegrus.

In addition to our work in the area of asset health assessments and lifecycle enhancement, our services span a broad common utility issue area, including planning and asset management, design, construction supervision, project management, commissioning, troubleshooting operating problems, investigating asset failures and providing training and technology transfer.

Our founders and leaders are pioneers in their respective fields. The fundamental electrical utility-grade engineering services we provide include:

- Power sector process engineering and improvement
- Fixed Asset Investment Planning – development of economic investment plans
- Regulatory Proceeding Support
- Power System Planning and Studies – identifying system constraints
- Smart Grid Development – from planning to implementation of leading technologies
- Asset Performance and Asset Management
- Distribution and Transmission System Design
- Mentoring, Training, and Technical Resource Development
- Health Index Validation and Development
- Business Case Development
- Owners Engineering Services
- Risk Modeling – Asset Lifecycle and Risk Assessment



ATTACHMENT D

London Area Region Scoping Assessment Report, May 2015

LONDON AREA REGION
SCOPING ASSESSMENT OUTCOME REPORT

ieso
Independent Electricity System Operator

Scoping Assessment Outcome Report Summary			
Region:	London and surrounding areas		
Start Date	May 5, 2015	**End Date**	August 28, 2015[1]

1. Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board's ("OEB" or "Board") Regional Planning process. The Board endorsed the Planning Process Working Group's Report to the Board in May 2013 and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013.

The first stage in the regional planning process, the Needs Assessment, was carried out by the Study Team lead by Hydro One Networks Inc. ("Hydro One") for the London Area. The final Needs Assessment report[2] was issued on April 3, 2015 and concluded that some needs in the region may require regional coordination, and these needs should be reviewed further under the IESO-led Scoping Assessment process.

The IESO, in collaboration with the Regional Participants, further reviewed the needs identified, in combination with information collected as part of the Needs Screening, and information on potential wires and non-wires alternatives, to assess and determine the best planning approach for the whole or parts of the region: an integrated regional resource plan ("IRRP"), a regional infrastructure plan ("RIP") or that regional coordination is not required and the planning can simply be done between the Transmitter and its customers.

This Scoping Assessment report:

- Defines the sub-regions for needs requiring regional coordination as identified in the Needs Screening report;
- Determines the appropriate regional planning approach and scope for each sub-region with identified needs requiring regional coordination;
- Establishes a Terms of Reference in the case where an IRRP and/or wires planning is the recommended approach for the sub-region(s);
- Establishes a working group for each sub-region recommended for an IRRP or wires planning.

[1] As per city of London's request, the public comment period has been extended. The end date is adjusted accordingly.
[2] The Needs Assessment report for the London region can be found at http://www.hydroone.com/RegionalPlanning/LondonArea/Documents/Needs%20Assessment%20Report%20-%20London%20Region%20-%20April%202,%202015.pdf

2. Team

The Scoping Assessment was carried out with the following Regional Participants:

- Independent Electricity System Operator ("IESO")
- Hydro One Networks Inc. ("Hydro One Transmission")
- Hydro One Networks Inc. ("Hydro One Distribution")
- Entegrus Power Lines
- Erie Thames Power Lines Corporation
- London Hydro Inc.
- St. Thomas Energy Inc.
- Tillsonburg Hydro Inc.
- Woodstock Hydro Services Inc.

3. Categories of Needs, Analysis and Results

I. Overview of the Regional Electricity System

The London Area is located in South-western Ontario and includes all or part of the following Counties, and Cities: Oxford County, Middlesex County, Elgin County, Norfolk County, the City of Woodstock, the City of London, and the City of St. Thomas. For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries.

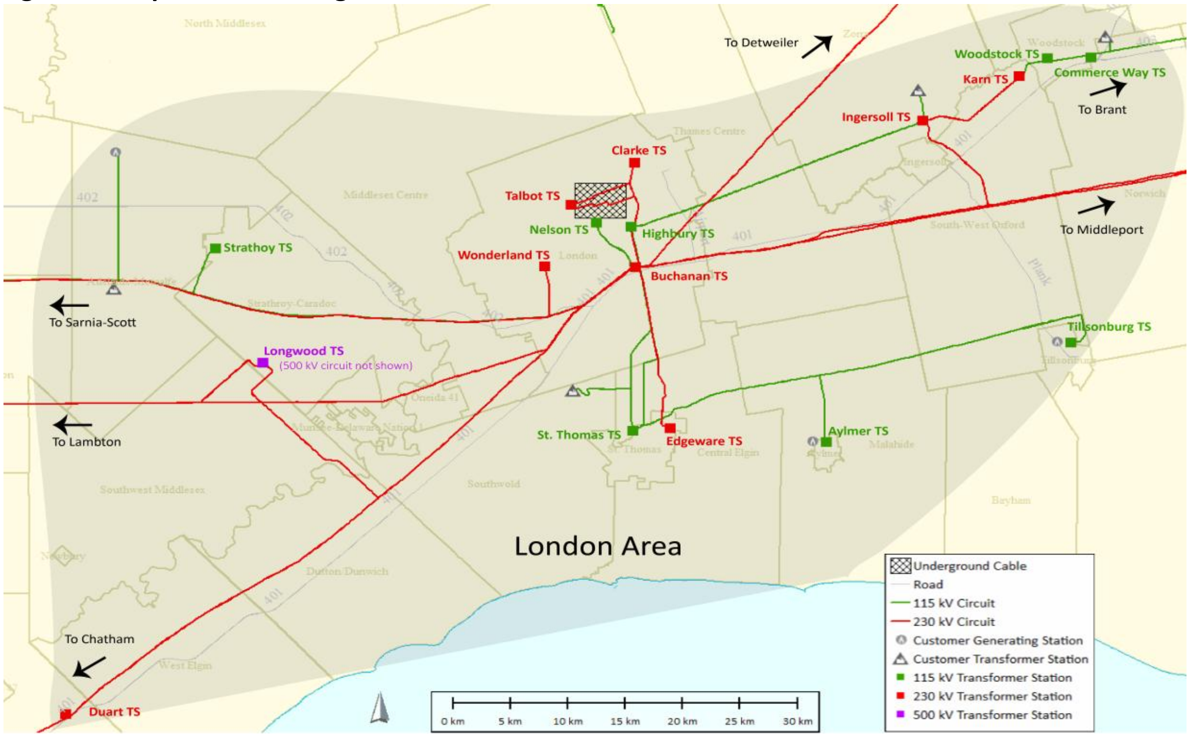
The region also includes the following First Nations:

- Chippewas of the Thames
- Oneida Nation of the Thames
- Munsee-Delaware Nation

The electricity infrastructure supplying the London Area region is shown in Figure 1. The region is supplied from 115 kV and 230 kV transmission lines and stations that connect at the Buchanan and Longwood transformer stations ("TS"). The 500/230 kV auto-transformers at Longwood TS and the 230/115 kV auto-transformers at Buchanan TS and Karn TS provide the major source of supply to the area. Figure 2 shows the electricity infrastructure in the region in a single line diagram.

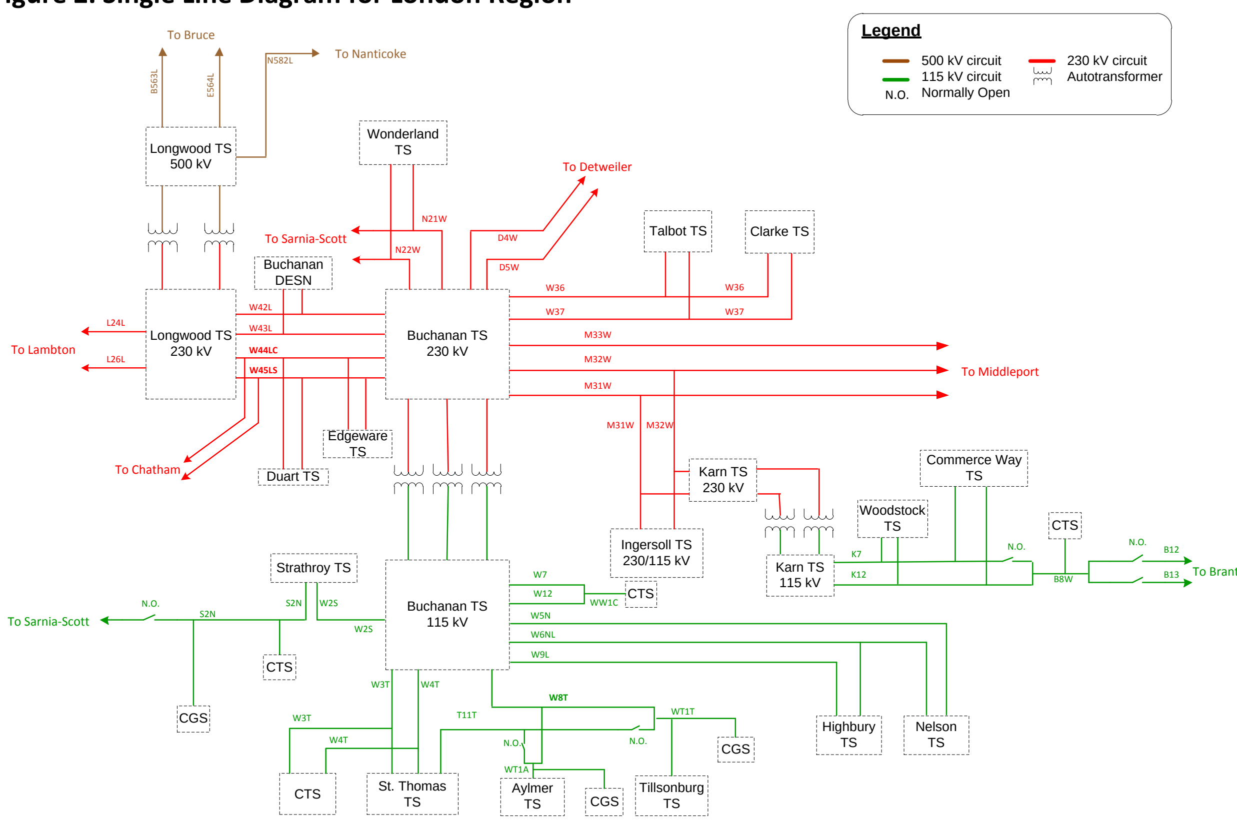
The region is summer-peaking (i.e., electricity demand is highest during the summer months) and had a peak demand of approximately 1250 MW in 2014. The region is characterized by gradual forecast growth with demand in some pockets slightly exceeding the supply capacity of the infrastructure.

Figure 1. Map of London Region



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

Figure 2. Single Line Diagram for London Region



II. Results from Need Screening Studies

Hydro One's Needs Assessment report identified the following needs in the London Area, based on a 10-year demand forecast.

CAPACITY

Line Capacity

- The single 115 kV circuit W8T, which supplies Aylmer TS and Tillsonburg TS from Buchanan TS, is expected to reach its thermal capacity in the medium-term.

No other capacity needs were identified for the 230 kV and 115 kV transmission lines serving the area.

Station Capacity

- Four stations[3] in the London region have exceeded or are expected to exceed their supply capacity over the study period: Aylmer TS, Strathroy TS, Tillsonburg TS and Wonderland TS.

LOAD RESTORATION

Hydro One's Needs Screening identified potential restoration needs[4] and this study confirms these needs as follows:

Circuits	Load Restoration Criterion not met
M31W+M32W[5]	4 hours
W36 + W37	30 min and 4 hours

AGING INFRASTRUCTURE / REPLACEMENT PLANS

The following infrastructure is expected to reach its end-of-life or is the subject of sustainment activities within the study period.

Equipment	Estimated Completion Date
Aylmer TS- undergoing end of life plan	2019
Nelson TS DESN[6] - undergoing end of life replacements	2018
Strathroy TS[7]- one transformer is to be replaced within the next five years	2017

[3] Hydro One's Need Screening report listed six stations with capacity limitations. Subsequent to the Needs Assessment, it has been clarified that no station capacity needs at Clarke TS and Talbot TS.

[4] Hydro One' s need screening identified potential restoration concerns for loss of N21/22W exceeding 150 MW due to loss of Wonderland TS, Modeland TS and Wanstead TS (based on the new SIA). However, both Modeland TS and Wanstead TS are out of the scope of this region and will be considered as part of Group 3 regional planning.

[5] The load restoration criterion not met on M31/32W refers to the loss of the Ingersoll tap that would result in losing Ingersoll TS, and Commerce Way TS, Woodstock TS and CTS following the loss of the autos at Karn TS.

[6] Nelson TS is undergoing end of life replacement and will be redeveloped at 27.6 kV instead of the previous 13.8 kV. This project is underway between Hydro One and London Hydro.

OTHER

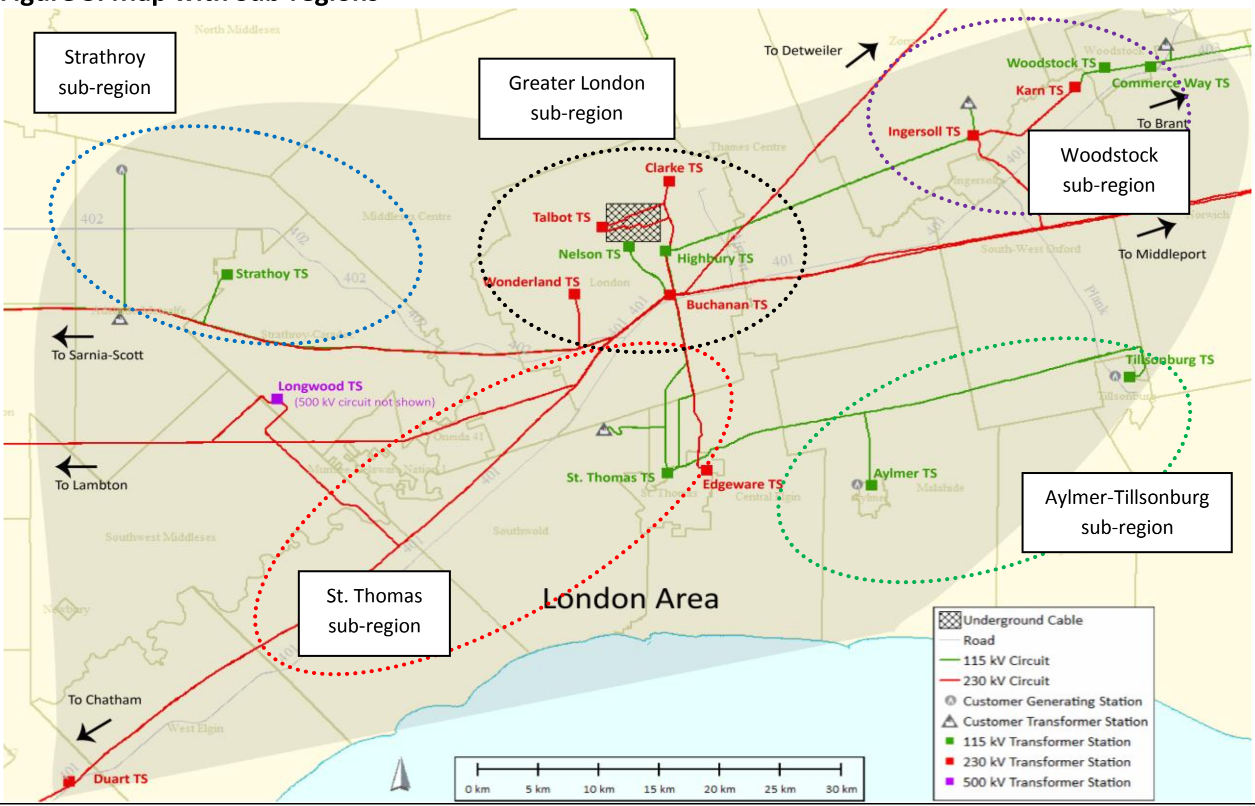
- Historical data shows that Buchanan DESN power factor may be below criteria under peak load conditions.
- IESO operations identified that under peak conditions if Buchanan TS 115 kV capacitors are in service, it is a challenge to place additional 230 kV capacitors in service.
- A number of 230 kV circuits in the region were identified to be overloaded under certain high generation conditions.

III. Analysis of Needs

a. Identification of Sub-Regions

The Regional Participants have identified five sub-regions in the London Area based on electrical supply and service boundaries that require consideration as part of this Scoping Assessment as shown in Figure3.

Figure 3. Map with Sub-regions



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[7] The end of life activities at Strathroy TS were provided by Hydro One after the Needs Screening report was finalized.

1. Greater London Sub-Region

In 2014, the Greater London area reached peak electricity demand of approximately 740 MW. Going forward, typical electricity demand growth is forecasted for this area.

This sub-region includes the following infrastructure:

- Stations—Buchanan DESN, Clarke TS, Highbury TS, Nelson TS, Talbot TS, Wonderland TS
- Transmission circuits—W36/37, N21/22W, W5N/W6NL/W9L
- 230/115 kV auto-transformers at Buchanan TS

Customers in this sub-region are supplied by London Hydro and Hydro One Distribution.

The needs in this sub-region include addressing transformation capacity limitation at the Wonderland transformer station[8] and meeting load restoration criteria on circuits W36/37 that supply over 350 MW of load.

While both capacity and load restoration needs have been identified in this sub-region, wires and non-wires options must be considered. In addition, the decisions made in this area will have broad impacts, involving multiple LDCs and relevant ratepayers. Therefore, the Regional Participants propose that this sub-region be studied through the IRRP process.

2. Aylmer-Tillsonburg Sub-Region

In 2014, this sub-region reached peak electricity demand of approximately 108 MW. Going forward, typical load growth is forecast for this area.

This sub-region includes the following infrastructure:

- Stations—Aylmer TS, Tillsonburg TS
- Transmission circuits—115 kV circuits: W8T, WT1T, WT1A, T11T

Customers in this sub-region are supplied by Erie Thames Powerlines, Tillsonburg Hydro and Hydro One Distribution.

The needs in this sub-region include addressing overloaded transformers at Aylmer TS and Tillsonburg TS, voltage issues at Tillsonburg TS, and thermal overloading on the circuit W8T that supplies both these stations as identified in Hydro One's Needs Screening.

The transformation capacity need at Aylmer is planned to be addressed by an end of life replacement of Aylmer TS (this process was already underway by Hydro One Networks prior to the start of this scoping assessment).

[8] Subsequent to the Needs Assessment, contracts have been executed for the refurbishment of Nelson TS at 27.6kV and for 18MW of generation under CHPSOP. This is estimated to provide additional 70MVA of transformation capacity for the area.

As the end of life plan at Aylmer TS is a wires solution and is already under way, other needs including the voltage decline at Tillsonburg TS and the need for capacity on the 115 kV circuit W8T could be more efficiently addressed by way of a combined wires plan that considers all three needs in the area. Therefore, the Regional Participants recommend that the needs within this sub-region be addressed as part of a Hydro One led wires planning.

3. Strathroy Sub-Region
In 2014, this sub-region reached peak electricity demand of approximately 63 MW. Going forward, typical load growth is forecast for this area.

This sub-region includes the following infrastructure:

- Stations—Strathroy TS
- Transmission circuits—W2S, S2N

Customers in this sub-region are supplied by Entegrus and Hydro One Distribution.

Hydro One's Needs Assessment report indicated that Strathroy TS is forecasted to exceed its station capacity. Based on Hydro One's information, there is a sustainment plan to replace T2 which is approaching end of life. Therefore, it is recommended that the capacity needs in this sub-region are best addressed as local planning between the relevant LDCs and Hydro One Transmission.

4. Woodstock Sub-Region
In 2014, this sub-region reached peak electricity demand of approximately 170 MW. Going forward, typical load growth is forecast for this area.

This sub-region includes the following infrastructure:

- Stations— Ingersoll TS, Woodstock TS and Commerceway TS, KarnTS
- Transmission circuits—M31/32W, K7/K12, B8W

Customers in this sub-region are supplied by Woodstock Hydro and Hydro One Distribution.

The need in this area is to meet restoration criteria for the loss of double circuits M31/32W, specifically the Ingersoll tap that would result in a loss of approximately 180 MW of load. To meet the ORTAC criteria, which requires the amount of load in excess of 150 MW to be restored within approximately 4 hours, there is a need for a plan to restore approximately 30 MW of load within 4 hours for this sub-region.

As load restoration is the only need in this area, the Regional Participants agreed that this does not require regional coordination and can be addressed through local planning involving Hydro One transmission and the affected LDCs.

5. St. Thomas Sub-Region
In 2014, this sub-region reached peak electricity demand of approximately 107 MW. Going forward, typical load growth is forecast for this area.

This sub-region includes the following infrastructure:
- Stations— Edgeware TS, St. Thomas TS
- Transmission circuits—W3/4T, W44LC, W45LS

Customers in this sub-region are supplied by St. Thomas Energy Inc., London Hydro and Hydro One Distribution.

No needs have been identified in this sub-region, thus no further regional planning is recommended for this sub-region.

b. Other findings

i. Operational Items

The Regional Participants agree that the following needs do not require regional coordination and can be addressed between Hydro One Networks and the relevant LDC (s), or Hydro One Networks and the IESO as required:
- Low power factor at Buchanan DESN
- Switching in of 230 kV capacitor banks and 115 kV capacitor banks at Buchanan TS

ii. Bulk System

The 230 kV circuits W44LC, W45LS, N21/22W are bulk system assets and connect the generation from Sarnia to the rest of Southwestern Ontario. It was noted that under high transfer conditions from west to east and/or high generation conditions, these circuits may become overloaded. Although this may create some congestion, this is not expected to create any local or global reliability concerns. The IESO will continue to monitor the congestion on these circuits.

4. Conclusion

The Scoping Assessment concludes that:

- An IRRP be undertaken to address the needs identified in the Greater London sub-region
- Wires planning led by Hydro One Networks to address the needs identified in the Aylmer-Tillsonburg sub-region. Ultimately the wires plan will be part of the RIP for the London Area region.
- Additional needs identified in the Needs Assessment will be addressed through other processes as follows:
  - Strathroy sub-region- local planning by Hydro One Networks and LDC(s)
  - M31/32W restoration needs - local planning by Hydro One Networks and LDC(s)
  - Low power factor at Buchanan DESN— to be coordinated between Hydro One Networks and LDC(s)
  - Switching in 230 kV and 115 kV capacitor banks at Buchanan TS - to be coordinated between Hydro One Networks and IESO

The draft Terms of Reference for the Greater London sub-region IRRP and the Aylmer-Tillsonburg sub-region wires planning are attached. The draft Terms of Reference will be finalized once the studies are kicked off.

Greater London IRRP Terms of Reference

1. Introduction and Background

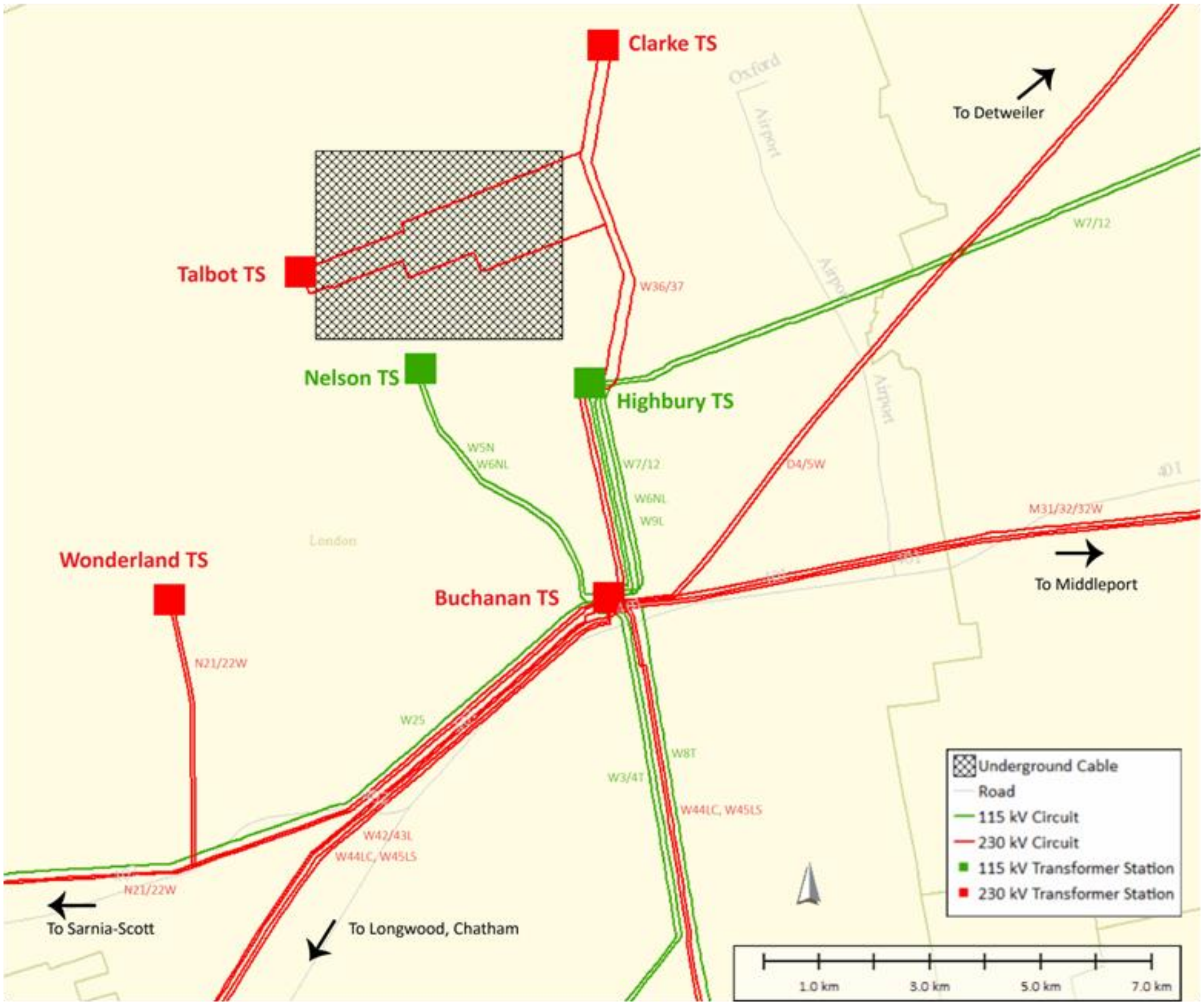
These Terms of Reference (ToR) establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables and timelines for an Integrated Regional Resource Plan of the Greater London sub-region (to be referred to as the Greater London IRRP).

Based on the potential for demand growth within this sub-region, limits on the capability of the transmission capacity supplying the area, and opportunities for coordinating demand and supply options, an integrated regional resource planning approach is recommended.

Greater London sub-region

The Greater London sub-region is a summer-peaking area that includes the City of London, and customers in surrounding municipalities supplied from Buchanan DESN, Clarke, Highbury, Nelson, Talbot, and Wonderland transformer stations (TS). The approximate geographical boundaries of the sub-region are shown in Figure 1.

Figure 1. Greater London Sub-Region



Source: IESO

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

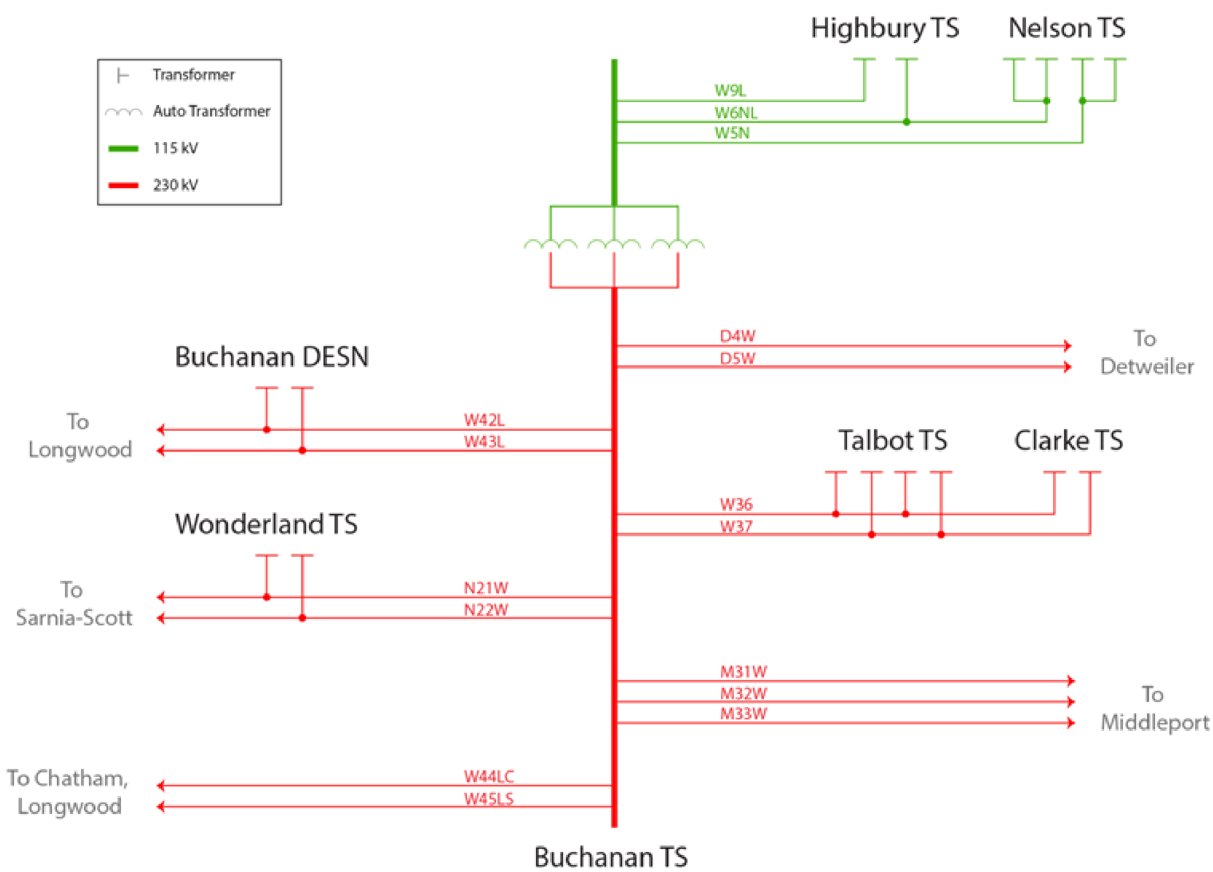
The sub-region includes all or part of the following municipalities:

- City of London
- London Township
- Nissouri Township
- Perth South Township
- Delaware Township
- Dorchester North Township

Greater London Electricity System

The electricity system supplying the Greater London sub-region is shown in Figure 2.

Figure 2. Greater London Electricity System



Source: IESO

2. Objectives

1. To assess the adequacy of electricity supply to customers in the Greater London sub-region over the next 20 years.
2. To coordinate customer-driven electricity needs with major asset renewal needs, and develop a flexible, comprehensive, integrated electricity plan for the Greater London sub-region.
3. To develop an implementation plan, while maintaining flexibility in order to accommodate changes in key assumptions over time.

3. Scope

This IRRP will develop and recommend an integrated plan to meet the needs of the Greater London sub-region. The plan is a joint initiative involving London Hydro, Hydro One Distribution, Hydro One

Transmission, and the IESO, and will incorporate input from community engagement. The plan will integrate forecast electricity demand growth, conservation and demand management (“CDM”) in the area with transmission and distribution system capability, end-of-life of major facilities in the area, relevant community plans, other bulk system developments, and FIT and other generation uptake through province-wide programs, and will develop an integrated plan to address needs.

This IRRP will address regional needs in the Greater London area, including capacity, security, reliability and relevant end of life consideration of assets. The following existing infrastructure and assumptions are included in the scope of this study:

- Stations—Buchanan DESN, Clarke TS, Highbury TS, Talbot TS, Wonderland TS
- Transmission circuits—W36/37, N21/22W, W5N/W6NL/W9L
- 230/115 kV auto-transformers at Buchanan TS
- Nelson TS is assumed to be redeveloped with low side voltage at 27.6 kV and will be considered as an option of providing load transfer relief to other stations once redeveloped

The Greater London IRRP will:

- Prepare a 20-year electricity demand forecast and establish needs over this timeframe.
- Examine the Load Meeting Capability and reliability of the existing transmission system supplying the Greater London sub-region, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices.
- Establish feasible integrated alternatives to address remaining needs, including a mix of CDM, generation, transmission and distribution facilities, and other electricity system initiatives in order to address the needs of the Greater London sub-region.
- Evaluate options using decision-making criteria including but not limited to: technical feasibility, economics, reliability performance, environmental and social factors.

4. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data
    - Historical coincident peak demand information for the sub-region
    - Historical weather correction, median and extreme conditions
    - Gross peak demand forecast scenarios by sub-region, TS, etc.
    - Coincident peak demand data including transmission-connected customers
    - Identified potential future load customers

- Conservation and Demand Management
    - LDC CDM plans
    - Incorporation of verified LDC results and progression towards OEB targets, and any other CDM programs/opportunities in the area
    - Long-term conservation initiative

- Conservation potential studies, if available
- Potential for CDM at transmission-connected customers' facilities

- Local resources
  - Existing local generation, including distributed generation ("DG"), district energy, customer-based generation, Non-Utility Generators and hydroelectric facilities as applicable
  - Existing or committed renewable generation from Feed-in-Tariff ("FIT") and non-FIT procurements
  - Future district energy plans, combined heat and power, energy storage, or other generation proposals

- Relevant local plans, as applicable
  - LDC Distribution System Plans
  - Community Energy Plans and Municipal Energy Plans

- Criteria, codes and other requirements
  - Ontario Resource and Transmission Assessment Criteria ("ORTAC")
    - Supply capability
    - Load security
    - Load restoration requirements
  - NERC and NPCC reliability criteria, as applicable
  - OEB Transmission System Code
  - OEB Distribution System Code
  - Reliability considerations, such as the frequency and duration of interruptions to customers
  - Other applicable requirements

- Existing system capability
  - Transmission line ratings as per Hydro One transmission records
  - System capability as per current IESO PSS/E base cases
  - Transformer station ratings (10-day LTR) as per asset owner
  - Load transfer capability
  - Technical and operating characteristics of local generation

- Bulk System considerations to be applied to the existing area network
  - Buchanan auto transformer capability
  - NPLIP interface flow assumptions

- End-of-life asset considerations/sustainment plans
  - Transmission assets
  - Distribution assets

- Other considerations, as applicable

5. Working Group

The core Working Group will consist of planning representative/s from the following organizations:

- Independent Electricity System Operator *(Team Lead for IRRP)*
- Hydro One Transmission
- London Hydro
- Hydro One Distribution

Authority and Funding

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

5. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended to and adopted by the provincial government to enhance the regional planning and siting processes in 2013. These recommendations were subsequently referenced in the 2013 Long Term Energy Plan. As such, the Working Group is committed to conducting plan-level engagement throughout the development of the Greater London IRRP.

The first step in engagement will consist of meetings with municipalities, First Nation communities within the planning area, and those who may have an interest in the planning area, and the Métis Nation of Ontario; with the purpose of discussing regional planning, the development of the Greater London plan, and integrated solutions.

Typically this will be followed by the establishment of a Local Advisory Committee for local community members to provide input and recommendations throughout the planning process, including information on local priorities and ideas on the design of community engagement strategies. Broad community engagement will be conducted to obtain public input in the development of the plan.

6. Activities, Timeline and Primary Accountability

	Activity	Lead Responsibility	Deliverable(s)	Timeframe
1	**Prepare Terms of Reference considering stakeholder input**	*IESO*	- Finalized Terms of Reference	Q3 2015
2	**Develop the Planning Forecast for the sub-region**		- Long-term planning forecast scenarios	Q3 2015
	- Establish historical coincident peak demand information	*IESO*		
	- Establish historical weather correction, median and extreme conditions	*IESO*		
	- Establish gross peak demand forecast	*LDCs*		
	- Establish existing, committed and potential DG	*IESO*		
	- Establish near- and long-term conservation forecast based on LDC CDM plans and LTEP target	*IESO*		
	- Develop planning forecast scenarios - including the impacts of CDM, DG and extreme weather conditions	*IESO*		
3	**Provide information on load transfer capabilities under normal and emergency conditions**	*LDCs*	- Load transfer capabilities under normal and emergency conditions	Q3 2015
4	**Provide and review relevant community plans, if applicable**	*LDCs First Nations and IESO*	- Relevant community plans	Q3 2015
5	**Complete system studies to identify needs** - Obtain PSS/E base case - Include bulk system assumptions as identified in Key Assumptions - Apply reliability criteria as defined in ORTAC to demand forecast scenarios - Confirm and refine the need(s) and timing/load levels	*IESO, Hydro One Transmission*	- Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q4 2015
6	**Develop Options and Alternatives**		- Develop flexible planning options for forecast scenarios	Q1 2016
	Identify solutions requiring immediate implementation and prepare hand-off letters to responsible parties (if applicable)	*IESO*		
	Develop conservation options	*IESO and LDCs*		
	Develop local generation options	*IESO and LDCs*		
	Develop transmission and/or distribution options including maximizing existing infrastructure capability	*IESO, Hydro One Transmission and LDCs*		
	Develop options involving other electricity initiatives (e.g., smart grid, storage)	*IESO/ LDCs with support as needed*		
	Develop portfolios of integrated alternatives	*All*		

	Technical comparison and evaluation	*All*		
7	**Plan and Undertake Community & Stakeholder Engagement**		- Community and Stakeholder Engagement Plan - Input from local communities, First Nation communities, and Métis Nation of Ontario	
	- Establish engagement subcommittee of the Working Group	*All*		Q3 2015
	- Early engagement with local municipalities and First Nation communities within study area, First Nation communities who may have an interest in the study area, and the Métis Nation of Ontario	*All*		Q3- Q4 2015
	- Establish Local Advisory Committee and develop broader community engagement plan with LAC input	*All*		Q4 2015
	- Develop communications materials	*All*		Q1-Q2 2016
	- Undertake community and stakeholder engagement	*All*		
	- Summarize input and incorporate feedback	*All*		
8	**Develop long-term recommendations and implementation plan based on community and stakeholder input**	*IESO*	- Implementation plan - Monitoring activities and identification of decision triggers - Hand-off letters - Procedures for annual review	Q3 2016
9	**Prepare the IRRP report detailing the recommended near, medium and long-term plan for approval by all parties**	*IESO*	- IRRP report	Q4 2016

Regional Infrastructure Planning – Scope for Aylmer-Tillsonburg Sub-Region
2015–07–13

1. Needs Identified during Needs Assessment

The primary supply to the Town of Alymer and Town of Tillsonburg is from a single-circuit 115 kV line, W8T, emanating from Buchanan TS, a distance of about 57 km. Two transformer stations, namely Alymer TS (15 MVA) and Tillsonburg TS (83 MVA), are connected to this radial circuit and they step the 115 kV transmission voltage level down to the lower distribution voltages for serving customers in the area. Based on the latest load forecast prepared as part of the London Area Needs Assessment (NA) in 2014, the supply capability of W8T is expected to be exceeded in the medium term (2019 – 2023). Additionally, inadequate voltages on this circuit will worsen with load growth. Further, loss of one of the two transformers at Aylmer TS and Tillsonburg TS would result in overloading the remaining transformer.

There are also two existing renewable generators directly connected to this 115 kV system. Currently, ability to connect additional generation sources is restricted due to the thermal constraint on W8T. There is a need to address the supply capacity limitations of the 115 kV transmission system to adequately supply the load in this area.

A schematic diagram of the existing facilities is provided in Figure 1.

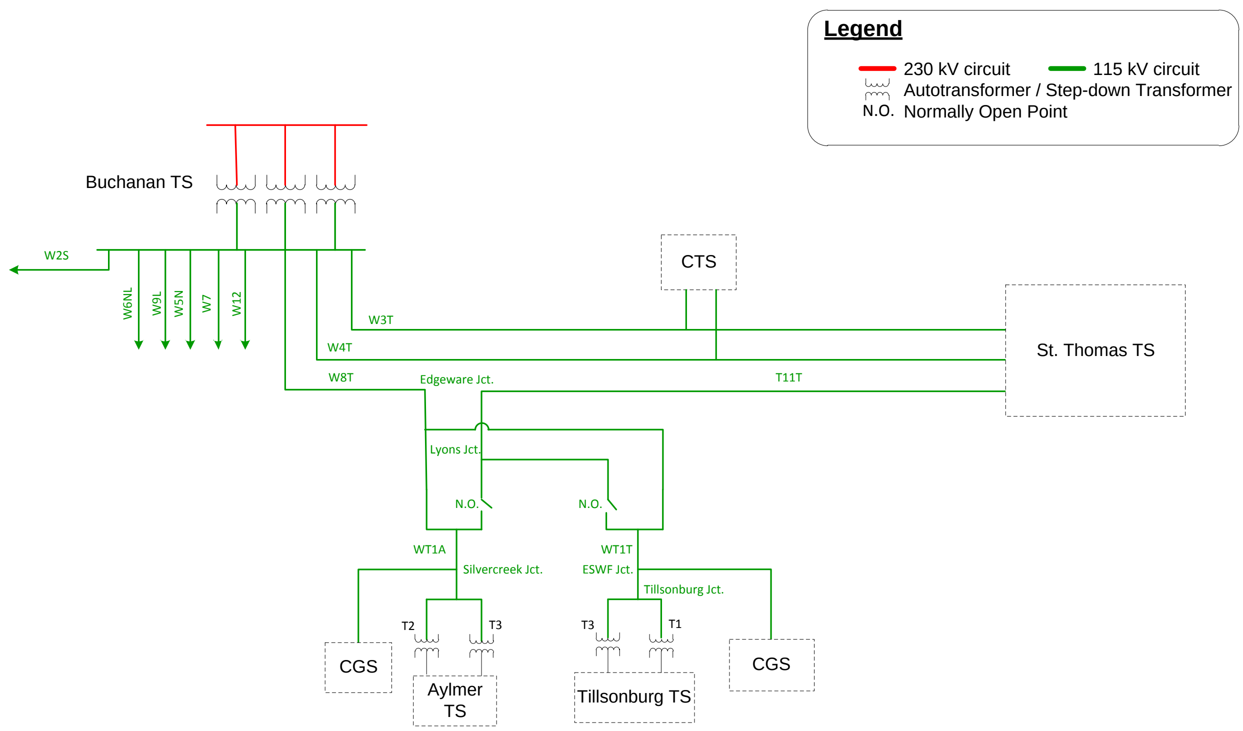


Figure 1 – Schematic diagram of the existing facilities in Aylmer-Tillsonburg sub-region

2. Alymer-Tillsonburg Sub-region Study Scope

The scope of this study is to develop alternatives to address

1. Supply capability limitation (590A) of 115 kV transmission line (W8T) over the study period
2. Supply capability limitation of Transformer Stations capacity at Alymer TS (15 MVA) and Tillsonburg TS (83 MVA),

As identified in the Scoping Assessment, Hydro One Transmission will initiate and undertake the wires planning work and along with the LDCs within this sub-region to address the above needs. The wires planning will review factors such as:

- the load forecast used in the IRRP and/or NA,
- transmission and distribution system capability along with any other relevant updates with respect to local plans,
- CDM, renewable and non-renewable generation development and
- other electricity system and local drivers that may impact the needs and alternatives under consideration.

3. Study Team

The study team will consist of planning representative/s from the following organizations:

-Hydro One Transmission
-IESO
-Erie Thames Power Lines
-Tillsonburg Hydro
-Hydro One Distribution

4. Activities, Primary Accountability and Timeline for Wires Planning

Activity	Primary Accountability	Timeline
Organize and lead study team	Hydro One (Transmission)	Q3 2015
Trigger start of wires planning	Hydro One (Transmission)	Day 0 - 30
Review and reaffirm load forecast	LDCs	
Review and reaffirm CDM and DG for study period	IESO	
Provide any relevant distribution load transfer capabilities under normal and emergency conditions	LDCs	
Perform relevant system studies to identify supply capabilities	Hydro One (Transmission)	Day 31-90
Review and reaffirm regional needs	Study Team	
Generate alternatives to address needs.	Study Team	Day 91-150
Compare and evaluate alternatives • TX alternatives • DX alternatives (in lieu of TX alternatives) • Relevant DX investments	Study Team	
Recommend preferred alternative(s)	Study Team	
Complete Study Report	Hydro One (Transmission)	Day 150-180

5. Deliverable

The deliverable will be a report that summarizes the additional planning assessments and analysis, identifies the potential transmission and/or distribution options and their associated costs, and recommends the preferred overall approach to address the two needs above. The report will ultimately form part of the Regional Infrastructure Plan for the London Area and could be used to support transmission and/or regulatory applications.

ATTACHMENT E

Local Planning Report: Chatham-Kent/Lambton/Sarnia, June 2017

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

LOCAL PLANNING REPORT

Kent TS Transformation Capacity
Region: Chatham-Kent/Lambton/Sarnia

Date: June 28th, 2017
Revision: Final

Prepared by: Kent Sub-region Local Planning Study Team

Organizations
Hydro One Networks Inc. (Lead Transmitter)
Hydro One Networks Inc. (Distribution)
Entegrus Inc.

Disclaimer

This Local Planning Report was prepared for the purpose of developing wires-only options and recommending a preferred solution(s) to address the local needs identified in the Needs Assessment (NA) report for the Chatham-Kent/Lambton/Sarnia Region that do not require further coordinated regional planning. The preferred solution(s) that have been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Local Planning Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the Local Planning Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Local Planning Report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Local Planning Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

LOCAL PLANNING EXECUTIVE SUMMARY

REGION	Chatham-Kent/Lambton/Sarnia (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	January 11, 2017	**END DATE**	June 28, 2017

1. INTRODUCTION

The purpose of this Local Planning (LP) report is to develop wires-only options and recommend a preferred solution that will address the local needs identified in the Needs Assessment (NA) report for the Chatham-Kent/Lambton/Sarnia Region dated June 12, 2016. The development of the LP report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

Based on Section 6 of the NA report, the study team recommended that coordinated regional planning is not required to address the identified needs in the Chatham-Kent/Lambton/Sarnia Region. It concluded that thermal overloading at Kent TS T3/T4 is local in nature and this need will be addressed by wires options through local planning led by Hydro One with participation of the impacted LDCs.

2. LOCAL NEEDS ADDRESSED IN THIS REPORT

Based on the historical load Kent TS T3/T4 has already exceeded its 10-Day Limited Time Rating (LTR). This report is developed to address the transformation capacity requirement at Kent TS.

3. FINDINGS

Based on the load forecast and transfer capability information, there is sufficient transfer capability in the existing distribution system to lower the loading on Kent TS T3 to within its LTR following loss of T4.

See Section 4 for further details.

4. CONCLUSION

The local planning study team agreed that no action is required at this time.

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1 Introduction

The Needs Assessment (NA) for Chatham-Kent/Lambton/Sarnia ("Region") was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. The NA report can be found on Hydro One's Regional Planning website. The study team identified Kent TS T3/T4 transformation capacity need in the Region over the next 10 years (2016 to 2025) and recommended that it should be further assessed through the Local Planning (LP) process.

1.1 Geographical Area and Existing Supply Network

Kent Transformer Station ("TS") is a transmission substation that is located in the Municipality of Chatham-Kent in Southwestern Ontario and supplies the surrounding mainly-rural areas, including Chatham, Dover, Raleigh, Harwich, Howard and Orford. Kent TS is supplied by the 230 kV double circuit line L28C/L29C, from Lambton TS to Chatham SS. There are four transformers at Kent TS that take 230 kV and step it down to supply low voltage feeders at 27.6 kV. The four transformers are connected into two "Dual Element Spot Network" or DESN structures which provide redundancy in the form of duplication for most station components. The two larger transformers, namely T1 and T2, are rated at 75/100/125MVA and are connected in "Bermondsey" configuration. The two smaller transformers, T3 and T4, are rated at 25/33/42 MVA and are connected in "Jones" configuration. The simplified schematic of Kent TS is shown in Figure 1.

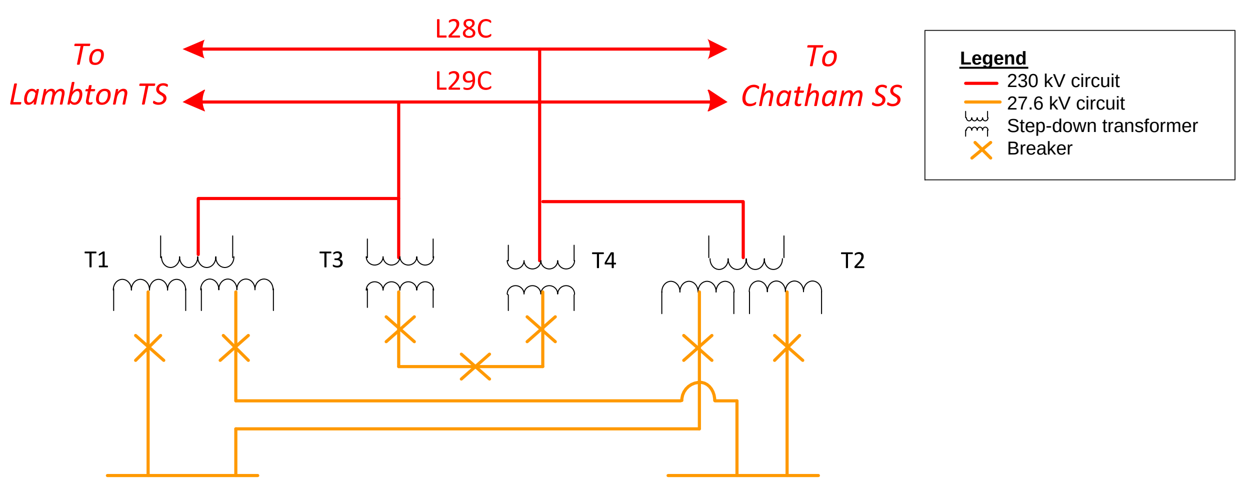


Figure 1 Schematic of Kent TS

Electricity distribution services to customers in the Kent sub-region is provided by Entegrus and Hydro One Distribution at the 27.6 kV level.

2 Load Forecast

To access the need at Kent TS, Entegrus Inc. (Entegrus) and Hydro One Distribution provided summer peak gross load forecasts for 2017 – 2026. Conservation and demand management ("CDM") programs and distributed generation ("DG") in the distribution network that are either currently in place or foreseen by the IESO were deducted from the gross forecast. The remaining forecast, also known as net load forecast, is summarized in Table 1.

Transformer Station	DESN ID	Customer Data	Summer Peak Load (MW)												
			Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
			2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Kent TS	*T1/T2*	Gross Load				117.0	119.5	122.2	124.9	127.5	130.1	132.8	135.5	138.0	140.6
		DG & CDM				4.4	5.8	7.1	8.3	9.2	10.1	10.8	11.7	13.3	15.3
		Net Load Forecast	**84**	**91**	**84**	**113**	**114**	**116**	**117**	**119**	**121**	**122**	**124**	**125**	**126**
	T3/T4	Gross Load				59.9	60.2	60.7	61.2	61.5	61.8	62.0	62.2	62.4	62.7
		DG & CDM				2.0	2.8	3.5	4.2	4.7	5.2	5.6	6.1	6.9	7.5
		Net Load Forecast	**60**	**52**	**60**	**58**	**58**	**58**	**57**	**57**	**57**	**57**	**57**	**56**	**56**

Table 1 Non-coincident net load forecast (MW)

3 Methodology and Assessment

The IESO Ontario Resource and Transmission Assessment Criteria ("ORTAC") outlines the supply reliability planning requirements to ensure loading on transmission network does not exceed equipment ratings under both normal and contingency operating conditions. For transformer, in the event where one of the two transformers in a substation suffers an outage, namely a (N – 1) event, loading of the remaining transformer should not exceed its 10 – day limited time rating ("LTR"). This is based on the assumption that transformer could be forced out of service at any time leaving the remaining transformer to carry all of the load. The supply capability of a DESN station is determined by its most limiting element. Presently, the summer 10 – Day LTR of T4 is slightly higher than that of T3. At the time of this assessment, the summer 10 – Day LTR for Kent TS T3 is 59 MVA[1] (or 54 MW at 0.9 power factor).

Figure 2 shows the comparison of expected load at Kent DESNs against the respective supply capability. With increasing CDM contributions over the study period, the overload at Kent T3/T4

[1] 10 – Day LTR of 59 MVA is rated at 30 °C ambitent temperature

is expected to decline from 6 MW to 2 MW.

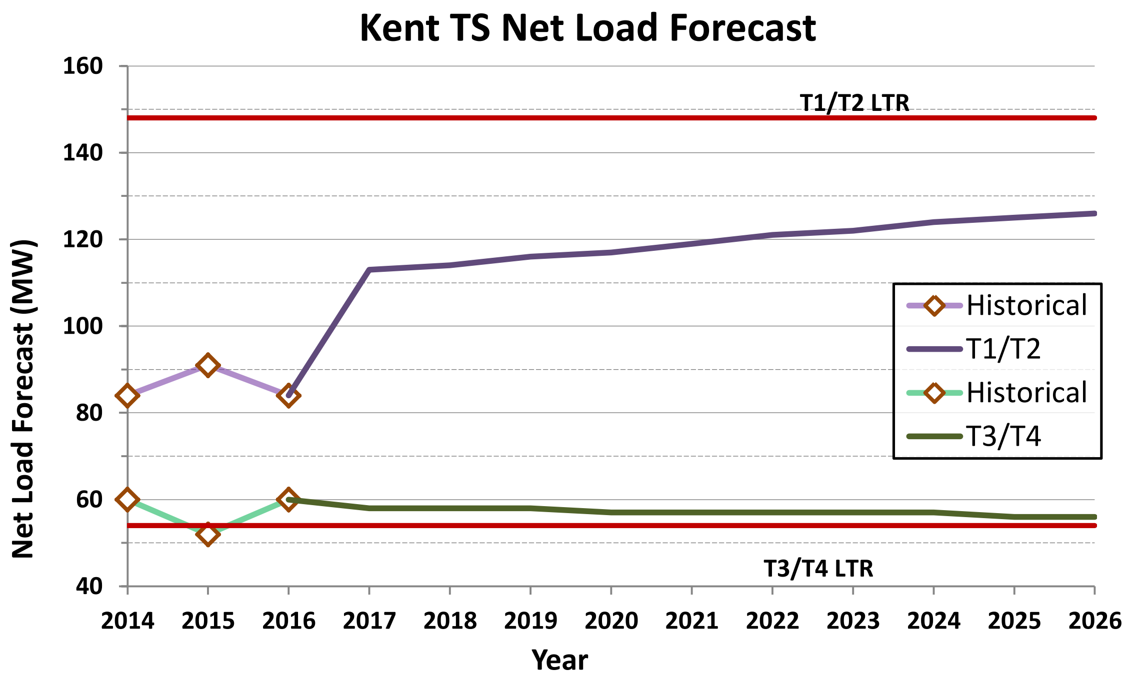


Figure 2: Kent TS Net Load Forecast

4 Findings

Currently, Kent T1 and T2 have the same summer 10 – day LTR of 155 MVA (or 148 MW at 0.95 power factor[2]) and as shown in Figure 2, loading at this pair of transformer is expected to remain below the Kent T1/T2 summer 10 – day LTR throughout the study period. In the event of Kent TS transformer T4 suffers an outage, Entegrus has confirmed there is existing transfer capability to transfer all of its load at Kent TS T3/T4 DESN to Kent TS T1/T2 DESN. In doing so, loading at Kent T3 can be brought back to below its LTR while supply to customers will remain uninterrupted.

5 Conclusion

Based on the information provided in this report, there is sufficient transfer capability on the existing system to mitigate the potential transformer overload at Kent TS over the ten year study period from 2017 to 2026. Therefore Hydro One Distribution, Entegrus Inc. and Hydro One Transmission agreed that no further action is required at this time. The next Regional Planning process is expected to initiate again within the next 5 years. The load forecast shall be examined at that point again and necessary steps shall be taken to address potential upcoming needs. The study team will monitor and track the loading at Kent TS and reconvene should unforeseen needs emerge prior to the next regional planning cycle.

[2] There are two existing low-voltage capacitor banks connected to Kent T1/T2 DESN; therefore, higher power factor is assumed.

6 References

[1] Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

[2] IESO Ontario Resource and Transmission Assessment Criteria (ORTAC)

[3] Chatham-Lambton-Sarnia Needs Assessment Report – June 12, 2016

Appendix A – List of Acronyms

Acronym	Description
DESN	Dual Element Spot Network
DSC	Distribution System Code
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Planning
LTR	Limited Time Rating
MW	Megawatt
NA	Needs Assessment
OEB	Ontario Energy Board
PPWG	Planning Process Working Group
TS	Transformer Station
TSC	Transmission System Code

ATTACHMENT F

Greater Bruce/Huron Region Scoping Assessment, September 2019

Greater Bruce/Huron Region Scoping Assessment Report

Contents

Greater Bruce/Huron Region Participants

Company
Independent Electricity System Operator
Hydro One Networks Inc. (Transmission)
Hydro One Networks Inc. (Distribution)
Festival Hydro
Entegrus Powerlines Inc.
ERTH Power
Wellington North Power Inc.
Westario Power Inc.

Scoping Assessment Outcome Report Summary

Region:	Greater Bruce/Huron		
Start Date	Jun 26, 2019	**End Date**	September 19, 2019[1]

1. Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board (OEB)'s regional planning process. The Board endorsed the Planning Process Working Group's Report to the Board in May 2013 and formalized the process and timelines through changes to the Transmission System Code and Distribution System Code in August 2013.

The first cycle of regional planning for the Greater Bruce/Huron region was completed in August 2017. Needs were identified in the near- to medium-term time frames, and a number of solutions were recommended to address them.

The second cycle of the regional planning process for the Greater Bruce/Huron region was triggered in April 2019. The Needs Assessment (NA) is the first step in the regional planning process and was carried out by the study team led by Hydro One Networks Inc. (Hydro One). The needs identified in the resulting report, issued on May 31, 2019, identified a number of needs. These needs are inputs to the scoping process to determine the planning process required.

During the Scoping Assessment process, regional participants reviewed the nature and timing of known needs to determine the most appropriate planning approach going forward, as well as the best geographic grouping of the needs in order to efficiently facilitate further studies. The planning approaches considered include:

- An Integrated Regional Resource Plan (IRRP), where regional coordination is needed and there is a potential for wide range of options including both wires and non-wires options;
- A Regional Infrastructure Plan (RIP), which considers wires-only options; and
- A local plan undertaken by the transmitter and the affected local distribution company (LDC), where no further regional coordination is needed.

This report:

- Lists the needs requiring more comprehensive planning and regional coordination;
- Reassesses the areas that need to be studied and the geographic grouping of needs;
- Determines the appropriate regional planning approach and scope for each sub-region where a need for regional coordination or more comprehensive planning is identified;
- Creates terms of reference for an IRRP if one is required; and
- Establishes the composition of the Working Group for the IRRP.

[1] Updated September 17, 2020

2. Team

The Scoping Assessment was carried out by a study team of the following Regional Participants:

- Independent Electricity System Operator
- Hydro One Networks Inc. (Transmission)
- Hydro One Networks Inc. (Distribution)
- Festival Hydro Inc.
- Entegrus Powerlines Inc.
- ERTH Power
- Wellington North Power Inc.
- Westario Power Inc.

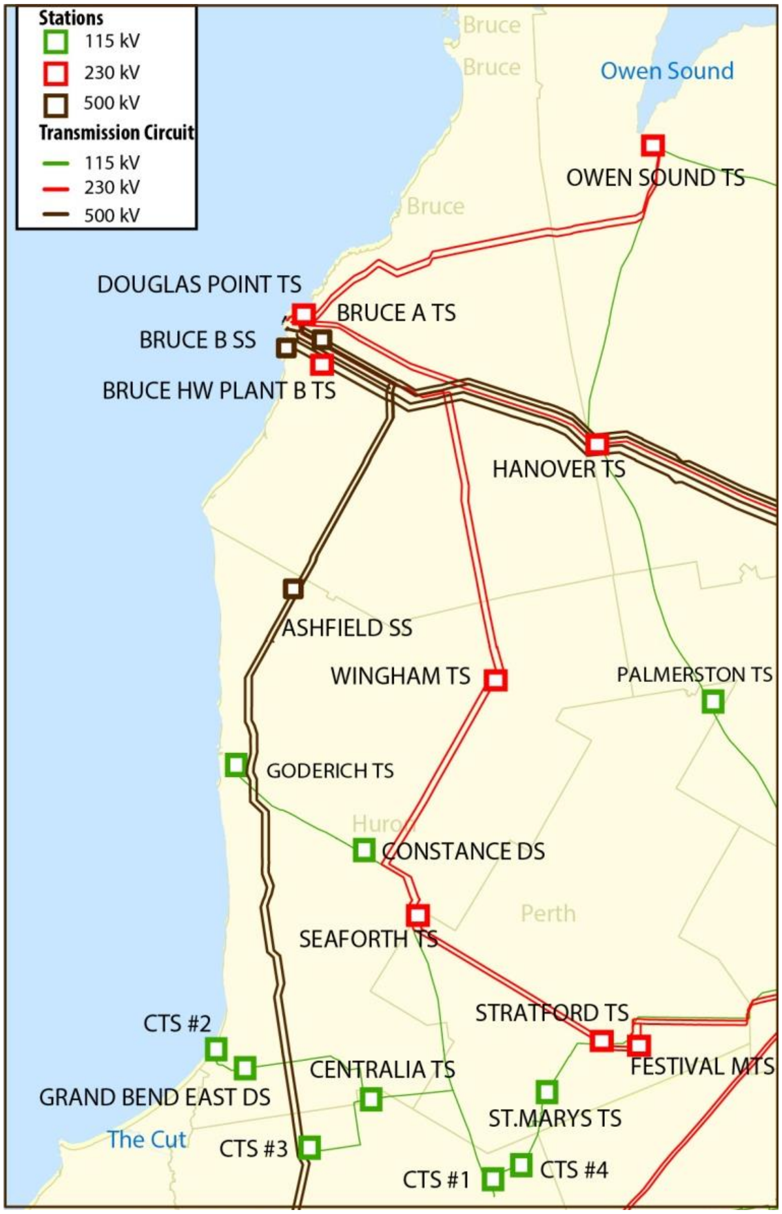
3. Categories of Needs, Analysis and Results

I. Overview of the Region

The Greater Bruce/Huron region is located in southwestern Ontario, and comprises the counties of Bruce, Huron and Perth, as well as portions of Grey, Lambton, Wellington, Waterloo, Oxford, Lambton, and Middlesex counties. Several Indigenous communities reside in the region, including Saugeen First Nation, Nawash First Nation, Chippewas of the Thames First Nation, Aamjiwnaang First Nation, Bkejwanong (Walpole Island First Nation), Chippewas of Kettle and Stony Point, Historic Saugeen Métis and Métis Nation of Ontario.

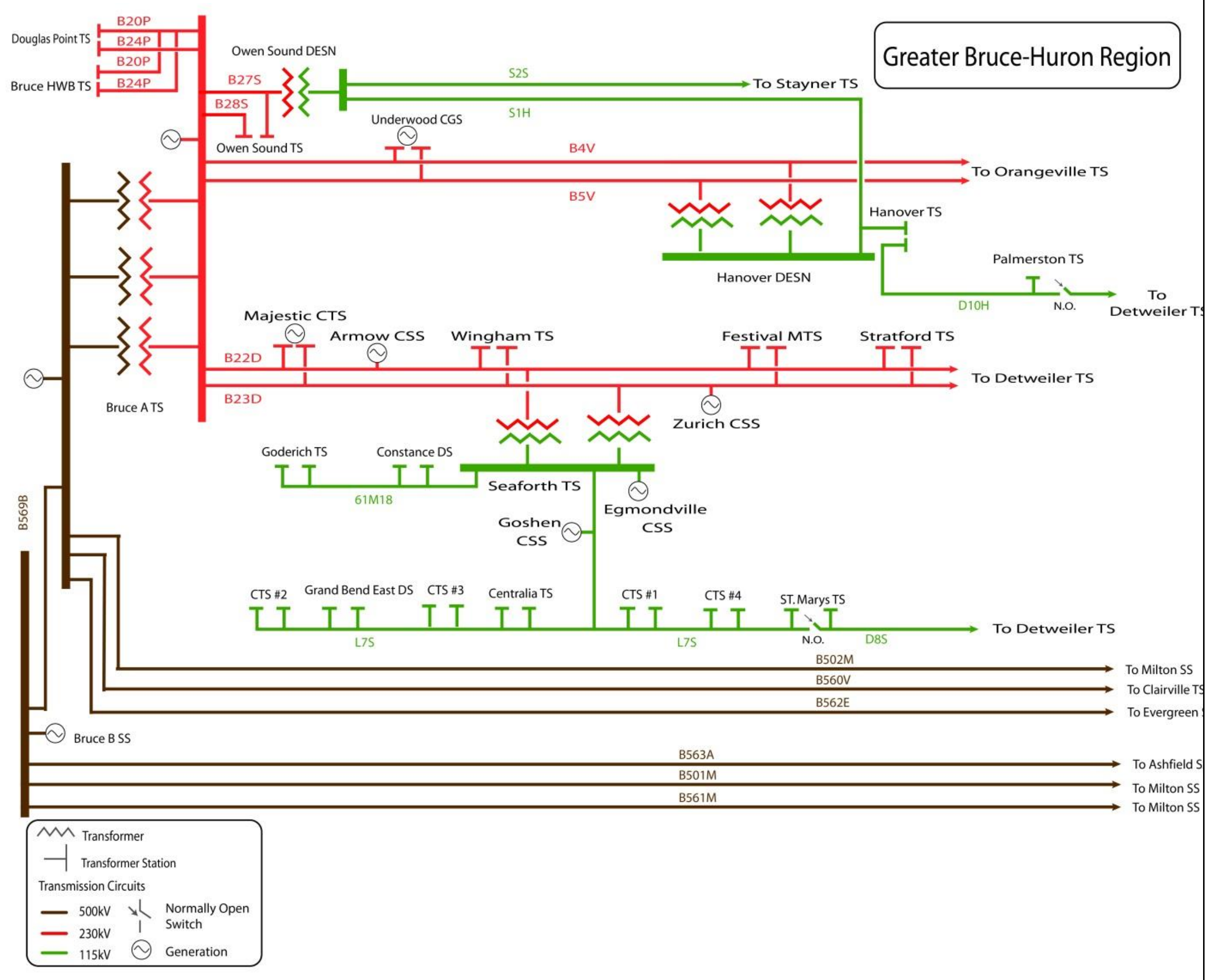
The electricity infrastructure supplying the Greater Bruce/Huron region is shown in Figure 1. Local distribution companies (LDCs) that serve this region include Hydro One Distribution, Festival Hydro Inc., Entegrus Powerlines Inc., ERTH Power, Wellington North Power Inc., and Westario Power Inc.

Figure 1 Electricity Infrastructure in the Greater Bruce/Huron Region[2]



The region is supplied by the 230 kilovolt (kV) and 115 kV transmission lines and stations shown in Figure 2. Main sources of supply come from the Bruce Nuclear Generating Station and local renewable generation facilities. The Bruce A transformer station (TS) and stations in adjacent regions, such as South Georgian Bay/Muskoka and Kitchener-Waterloo-Cambridge-Guelph (KWCG), are connected through 230 kV circuits B4V/B5V, B22D/B23D, B27S/B28S. The recent identified capacity needs in NA are on the 115 kV circuit L7S, located in the southern portion of the region. The L7S circuit provides supply from Seaforth TS and a local wind farm to seven local load stations, including Centralia TS, Grand Bend East DS, St. Marys TS, and four customer transformer stations (CTS). The D8S circuit further connects St. Marys TS to Detweiler TS in the KWCG region.

Figure 2: Single Line Diagram of Greater Bruce/Huron Region[3]



II. Background: the previous planning process

The regional planning process was formalized by the OEB in August 2013. To manage this process, Ontario was organized into 21 regions, each of which was assigned to one of three groups by order of priority, with Group 1 regions scheduled to be reviewed first. Greater Bruce/Huron was assigned to Group 3.

The first cycle of regional planning for Greater Bruce/Huron was triggered in February 2016. Completed in May 2016, the NA – the initial stage in the regional planning process identified a number of near- and medium-term needs. Following the NA, the study team agreed that there was no

[2] The region is defined by electricity infrastructure; geographical boundaries are approximate.

[3] The 500kV side of Bruce A TS, Bruce B SS, and 500 kV lines are not included in the Greater Bruce/Huron study area.

need for further integrated regional planning for the region and localized wires-only plans would be developed to address identified needs. In August 2016, a Regional Infrastructure Plan (RIP) was published that summarized findings from local planning, and reviewed new needs from updated load forecasts in the Kincardine area. The Local Planning Report and RIP recommended: monitoring loading on L7S and increasing the emergency rating once loading approaches capacity; a two-stage plan to reduce frequency and duration of interruptions due to adverse weather; and monitoring load growth in the Kincardine area to identify any potential step-down transformation capacity needs at Douglas Point TS. These recommendations and current status are summarized in Section III.

The second cycle of regional planning was triggered due to potential incremental load from customer connection requests received in 2018 that would exceed the capacity of L7S. The second cycle started in early 2019 with the NA report published by Hydro One on May 31. The needs identified in this report form the basis of the analysis for this scoping assessment, and are discussed in further detail in Section III.

III. Needs Identified

Based on the most up-to-date sustainment plans and 10-year demand forecast, Hydro One's NA identified a number of needs in the Greater Bruce/Huron region. This section outlines the needs and projects/plan identified in the previous cycle of regional planning, and the needs to be addressed in the new cycle.

Needs and plans identified in the last cycle of Greater Bruce/Huron regional planning
The needs and plans recommended in the first cycle of regional planning for the Greater Bruce/Huron region are summarized in Table 1, including summaries of their current statuses.

Table 1: Status of needs and plans from the first cycle of regional planning

Type of Need	Plan	Status
Delivery Point Performance	Enhance delivery point performance for L7S to reduce frequency and duration of outages by installing spacers, ground rods, and remote-controlled load interrupting switches.	Projects to install spacers and ground rods to be initiated and completed in 2020. Installation of remote-controlled load interrupting switches at Kirkton JCT, Biddulph JCT, and St Marys TS are currently in execution phase, expected to be in service by end of 2020.
Capacity	Monitor loading on L7S, and execute solutions from Local Plan that increase emergency thermal rating once loading is anticipated to exceed capacity.	L7S capacity has been re-assessed in the recent NA and capacity needs will be addressed in the new cycle of regional planning.
Capacity	Monitor load growth in Kincardine area connected to Douglas Point TS,	Need is deferred because of slower load growth from latest forecast.

	and execute solutions when load is anticipated to exceed capacity.	

Needs to be addressed in the new regional planning cycle
The needs identified in the 2019 NA are summarized in Table 2 below and are grouped by type. Needs that arise in the next five years are marked as near-term while those arise in the five to ten-year time frame are marked as medium-term timeframe.

Table 2: Needs to be addressed in the new planning cycle

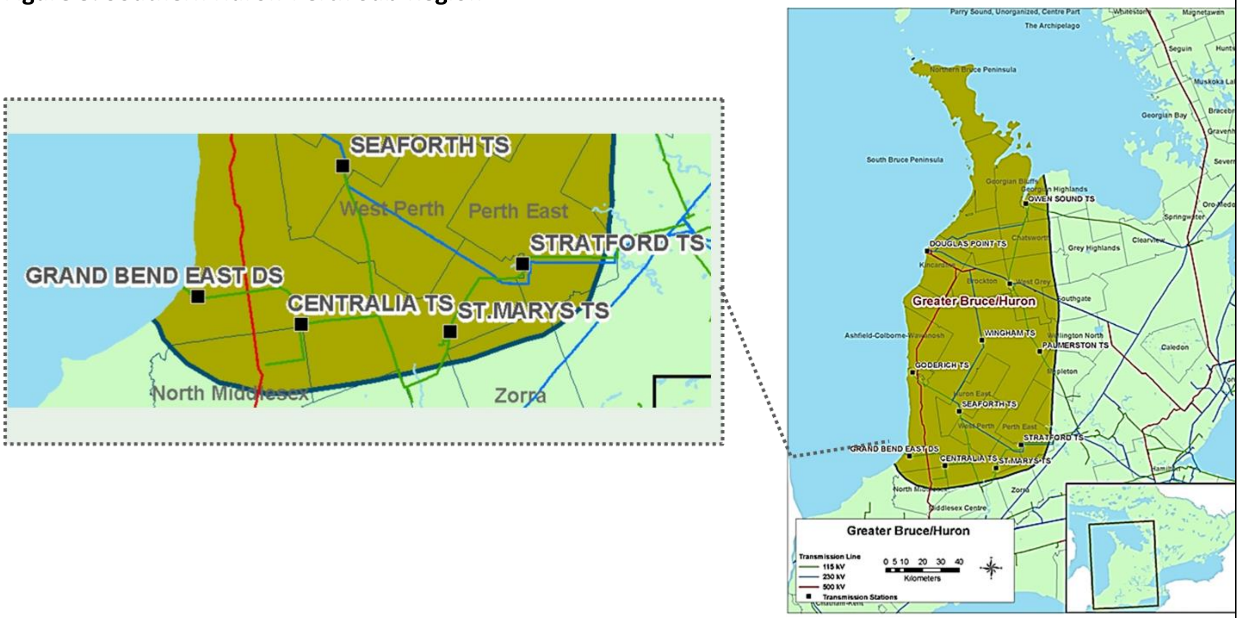
Type of Need	Facilities	Need Date
Equipment End-of-Life	Wingham TS T1/T2 supply transformers and component replacement	2022 (near-term)
	Stratford TS T1 supply transformer and component replacement	2023 (near-term)
	Seaforth TS T1/T2/ supply transformers, T5/T6 autotransformers, and component replacement	2023 (near-term)
	Hanover TS T2 supply transformer and component replacement	2024 (near-term)
Capacity	L7S emergency rating exceeded under contingency (with one element D8S out)	2022 (near-term)
	L7S continuous rating exceeded with all elements in service	2027 (medium-term)

IV. Analysis of Needs and Identification of Sub-Regions

A number of factors were considered in determining recommended planning approaches to address identified needs in NA, and the overall approach for further study in this area. Broadly speaking, where there is a need for regional coordination, and a potential for a wide range of solutions – including conservation, generation, new technologies, wires infrastructure, and non-wires solutions – an integrated approach is optimal.

The Regional Participants have discussed the needs in the Greater Bruce/Huron region and have identified one sub-region for further study through the regional planning process. The sub-region, "Southern Huron Perth" is shown in Figure 3.

Figure 3: Southern Huron-Perth Sub-Region



Southern Huron-Perth Sub-Region

An integrated approach is recommended to address the capacity needs in the Southern Huron Perth sub-region. This sub-region is summer-peaking, and includes the following infrastructure:

- 115 kV Connected Stations – Grand Bend East DS, Centralia TS, St. Marys TS,
- Four customer owned transformer stations
- 115 kV Transmission Lines – L7S, B8S

Customers in this sub-region are supplied by Entegrus Powerlines Inc., Festival Hydro Inc. or Hydro One Distribution. However, the sub-region's transmission connected customers are supplied directly by Hydro One Transmission.

There are potential opportunities to assess wires and non-wires solutions to meet the needs in the area, and coordinate end-of-life needs within the context of updated forecast data.

The section below provides additional details on needs to be assessed in the IRRP planning process.

<u>Integrated capacity planning in the Southern Huron-Perth Sub-region</u>

The NA identified both near- and medium-term capacity needs on L7S resulting from load growth in the area it supplies.

This near-term need is expected to arise in 2022, when the emergency rating will be exceeded once D8S is out of service. This need was first identified in the previous cycle of regional planning, and the Local Planning Report, L7S Thermal Overload, was developed in 2016 to evaluate alternatives and recommended solutions.

In the medium-term, the continuous rating of L7S will be exceeded in 2027, even when all facilities are in service. While the existing infrastructure cannot accommodate the 20-year demand forecast in this area, with the slow load growth, non-wires solutions – such as integration of community energy plans, demand response, distributed generation, and storage – should be explored alongside wires solutions. A capacity margin also needs to be considered to prepare for potential additional load growth.

<u>Opportunities to optimize end-of-life investments</u>

Facilities reaching end-of-life provide an opportunity to re-examine their current use and configuration in the context of the latest load forecast and generation data. This will ensure that any new assets installed in their place will continue to appropriately service both the impacted LDCs and their customers, over their lifetime. To allow enough lead time to conduct planning for facilities that are reaching end-of-life, expected service life (ESL) information will be considered to optimize future end-of-life investment.

The study team recommends that the assessment of needs outlined above will benefit from an integrated view. There are potential opportunities to assess wires and non-wires solutions to meet the needs in the area, and to address multiple needs in an optimal manner. The study team recommends that capacity needs in the area supplied by L7S be studied through an IRRP that focuses on the Southern Huron-Perth sub-region, and opportunities for optimizing future end-of-life investments be investigated.

Local Planning

The remaining needs identified in the 2019 Greater Bruce/Huron NA report are related to end-of-life needs at four transformer stations, as noted in Table 1-3 below. Local planning is recommended to address these needs as they are singular in nature, and there is limited opportunity to reconfigure and resize the facilities to align with other regional needs. In addition, given that all of these end-of-life needs will arise in the near-term, the study team recommends local planning involving the transmitter and the impacted LDCs as the optimal approach for ensuring reliable supply in the region.

Table 3: Needs to be addressed through local planning

Type of Need	Facilities	Need Date	Planning Approach
Equipment End-of-Life	Wingham TS T1/T2 supply transformers and component replacement	2022 (near-term)	Local Planning
	Stratford TS T1 supply transformer and component replacement	2023 (near-term)	Local Planning
	Seaforth TS T1/T2/ supply transformers, T5/T6 autotransformers, and component replacement	2023 (near-term)	Local Planning
	Hanover TS	2024 (near-term)	Local Planning

	T2 supply transformer and component replacement		

In addition, the IESO has identified low voltage issues at Hanover TS upon the loss of 230 kV circuits B4V/B5V. This issue will be further investigated in a bulk study of the Bruce area.

4. Conclusion

The Scoping Assessment concludes that:

- An IRRP be undertaken for the Southern Huron-Perth sub-region to:
    - Plan for near- and medium-term capacity needs in the sub-region supplied by L7S, taking into account of non-wires alternatives
    - Explore opportunities to optimize end-of-life investments
- Additional needs identified in the NA (outlined below) will be addressed through local planning involving the transmitter and relevant LDC:
    - End-of-life replacements
        - T1/T2 transformers and components at Wingham TS
        - T1 transformer and component at Stratford TS
        - T5/T6 autotransformers, and T1/T2 transformers at Seaforth TS
        - T2 transformer and component at Hanover TS
- Hanover TS voltage issue upon loss of 230 kV circuits B4V/B5V will be further investigated in a bulk study of the Bruce area.

The draft Terms of Reference for the Southern Huron-Perth sub-region IRRP is attached in Appendix A.

List of Acronyms

CDM	Conservation and Demand Management
DG	Distributed Generation
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
MW	Megawatt
NA	Needs Assessment
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
TS	Transformer Station

Appendix A: Southern Huron-Perth Sub-region IRRP Terms of Reference

1. Introduction and Background

These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables and timelines for an Integrated Regional Resource Plan (IRRP) for the Southern Huron-Perth sub-region, as part of the Greater Bruce Huron Region.

Based on the needs identified within the sub-region, including opportunities for coordinating demand and supply options with capacity needs in the sub-region supplied by L7S, an integrated regional resource planning approach for the Southern Huron-Perth sub-region is recommended.

The Greater Bruce/Huron Region

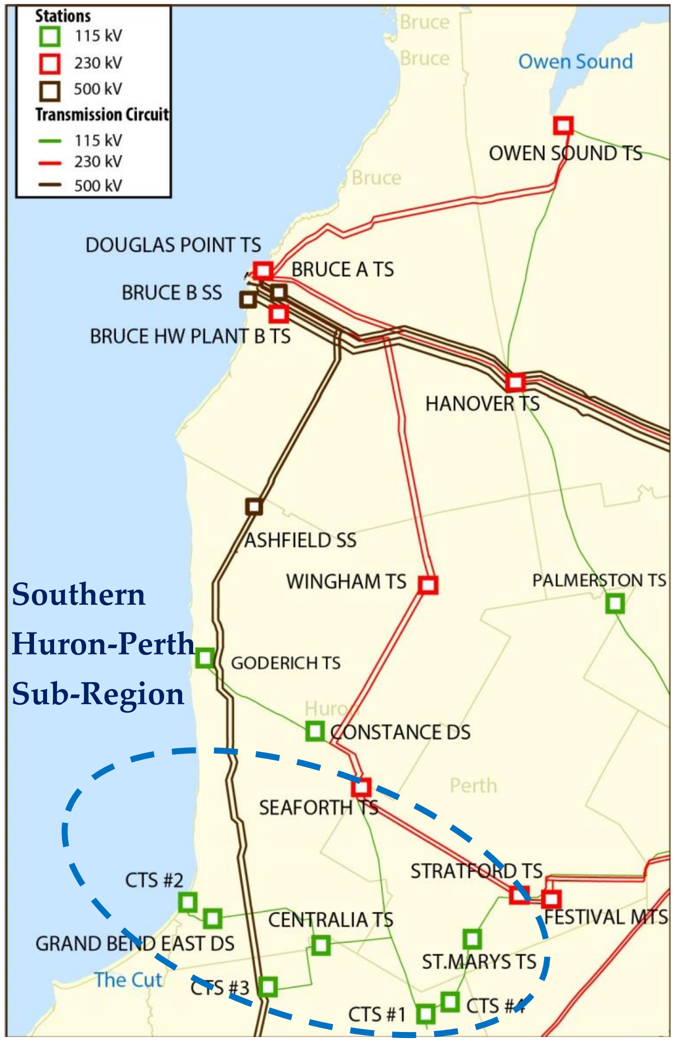
The Greater Bruce/Huron region is located in southwestern Ontario that comprises the counties of Bruce, Huron and Perth, as well as portions of Grey, Wellington, Waterloo, Oxford, Lambton, and Middlesex counties. Several Indigenous communities reside in the region, including Saugeen First Nation, Nawash First Nation, Chippewas of the Thames First Nation, Aamjiwnaang First Nation, Bkejwanong (Walpole Island First Nation), Chippewas of Kettle and Stony Point, Historic Saugeen Métis and Métis Nation of Ontario.

The Southern Huron-Perth Sub-Region

This IRRP is for the Southern Huron-Perth sub-region supplied by L7S, which includes municipalities of Bluewater, South Huron, Lambton Shores, Lucan Biddulph, Middlesex Centre, North Middlesex, Thames Centre, Zorra, Perth South, Town of St. Marys, and West Perth.

The approximate geographical boundaries of the sub-region are shown in Figure A-1.

Figure A-1: Electricity Infrastructure in the Southern Huron-Perth Sub-Region[4]

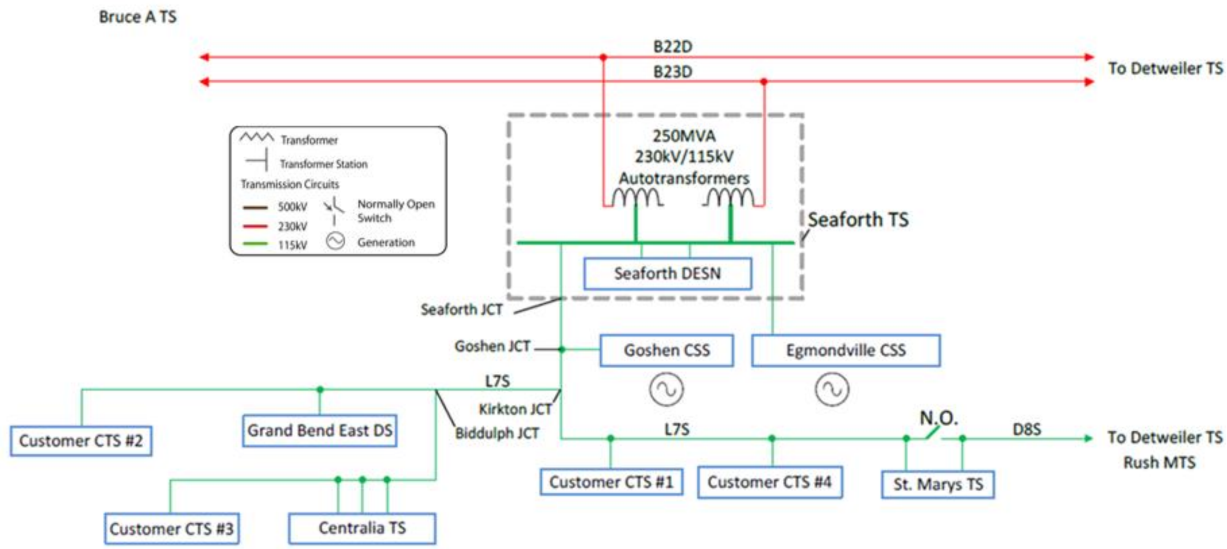


<u>*Greater Bruce/Huron Region Electricity System*</u>

The Greater Bruce/Huron region's electricity demand is comprised of a mix of residential, commercial and industrial loads. It is a winter-peaking region, although the Southern Huron-Perth sub-region, which is the focus of this IRRP, is summer-peaking. The Greater Bruce/Huron region is supplied by 230 kV and 115 kV transmission lines and stations as shown in Figure A-2. In the Southern Huron-Perth sub-region, L7S provides supply from Seaforth TS and a local wind farm to seven local load stations, including Centralia TS, Grand Bend East DS, St. Marys TS, and four customer transformer stations (CTS). The D8S circuit further connects St. Marys TS to Detweiler TS in the KWCG region.

[4] The region is defined by electricity infrastructure; geographical boundaries are approximate.

Figure A-2: Single Line Diagram of Southern Huron-PerthSub-Region



Background

The regional planning process was formalized by the OEB in August 2013. To manage the regional planning process, Ontario was organized into 21 regions, each of which was assigned to one of three groups by order of priority, where Group 1 region were reviewed first. Greater Bruce/Huron was assigned to Group 3.

The first cycle of regional planning of the Greater Bruce/Huron region started in February 2016 with the Needs Assessment (NA) process, and proceeded to local planning. Subsequently, and in accordance with the OEB's process, Hydro One Transmission published a regional infrastructure plan (RIP) in August 2017.

The second cycle of regional planning, triggered primarily by connection requests in the Southern Huron-Perth sub-region, launched in early 2019, starting with the NA process. Hydro One published its NA report on May 31, 2019. Multiple needs identified in the report require an integrated regional consideration. The Scoping Assessment led by the IESO with Hydro One and LDCs in the region has concluded that an IRRP be undertaken to address these needs in the Southern Huron-Perth sub-region.

2. Objectives

The Southern Huron-Perth IRRP will assess the adequacy of electricity supply to customers in the sub-region supplied by L7S, explore opportunities to optimize future end-of-life investments, and make recommendations to maintain reliability of supply to the sub-region over the next 20 years. Specifically, the IRRP will:

- Assess the adequacy of electricity supply to customers in the study area over the next 20 years;
- Determine whether there is a need to initiate development work or to fully commit infrastructure investments in this planning cycle;
- Identify and coordinate major asset renewal needs with customer needs, and develop a flexible, comprehensive, integrated electricity plan for Greater Bruce/Huron; and,
- Develop an implementation plan, while maintaining the flexibility required to accommodate changes in key assumptions over time.

3. Scope

This IRRP will develop and recommend an integrated plan to meet the needs in the Southern Huron-Perth sub-region within the Greater Bruce/Huron region. The plan is a joint initiative involving the IESO, Hydro One Transmission, and LDCs in this sub-region including Hydro One Distribution, Festival Hydro Inc., and Entegrus Powerlines Inc., which are the five members of the Working Group for the SHPIRRP.

The IRRP will focus on these specific items in order of priority:

- Integrated planning for capacity needs for the Southern Huron-Perth sub-region supplied by L7S, including documentation of outcomes and rationale of capacity needs related to L7S emergency rating, and the development of plans for longer term needs related to the L7S continuous rating; and,
- Opportunities to optimize future end-of-life investments

Like all IRRPs, in its identification or confirmation of any capacity or restoration needs, an analysis of options for addressing end-of-life needs, the plan will integrate:

- Forecast electricity demand growth, conservation and demand management (CDM) with transmission;
- Distribution system capability
- Relevant community plans
- Other bulk system developments; and,

- Distributed energy resources (DER) uptake

Based on the identified needs, the Southern Huron-Perth IRRP process will:

1) Create an updated 20-year demand forecast for the study area
2) Confirm the adequacy of transformer station ratings and the area's load meeting capability and reliability through:
    a. Identification or confirmation of transformer station capacity needs and sufficiency of the area's load meeting capability for the study period using the updated load forecast
    b. Confirmation of identified restoration needs using the updated load forecast
    c. Collection of information on any known reliability issues and load transfer capabilities from the local distribution companies (LDCs)
3) For confirmed needs, carry out an assessment of options using decision-making criteria included, but not limited to, technical feasibility, economics, reliability performance, and environmental and social factors
   The options analysis has been divided into groupings based on the priority/timing of the needs, any known lead time information, and the depth of analysis required
4) Develop long-term recommendations and the implementation plan
5) Complete the IRRP report, and document near-, mid-, and long-term needs and recommendations

In order to carry out this scope of work, the working group will consider the data and assumptions outlined in section 4 below.

4. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data
    - Historical coincident and non-coincident peak demand information for the region
    - Historical weather correction, for median and extreme conditions
    - Gross peak demand forecast scenarios by region, TS, etc.
    - Coincident peak demand data including transmission-connected customers
    - Identified potential future load customers

- Conservation and Demand Management
    - LDC CDM plans
    - Incorporation of verified results and CDM programs/opportunities in the area

  - Long-term conservation forecast for LDC customers based on planned provincial CDM activities
  - Conservation potential studies, if available
  - Potential for CDM at transmission-connected customers' facilities
  - Load segmentation data for each TS based on customer type (e.g., residential, commercial, industrial, agricultural) and the proportion of LDC service territory within the study area

- Local resources
  - Existing local generation, including distributed generation (DG), district energy, customer-based generation, non-utility generators and hydroelectric facilities as applicable
  - Existing or committed renewable generation from Feed-in-Tariff (FIT) and non-FIT procurements
  - Future resource proposals as relevant

- Relevant local plans, as applicable
  - LDC Distribution System Plans
  - Community Energy Plans, Indigenous Community Energy Plans, and Municipal Energy Plans
  - Municipal Growth Plans
  - Any transit plans impacting electricity use or tied to community developments

- Criteria, codes and other requirements
  - Ontario Resource and Transmission Assessment Criteria (ORTAC)
    - Supply capability
    - Load security
    - Load restoration requirements
  - NERC and NPCC reliability criteria, as applicable
  - OEB Transmission System Code
  - OEB Distribution System Code
  - Reliability considerations, such as the frequency and duration of interruptions to customers
  - Other applicable requirements

- Existing system capability
  - Transmission line ratings as per transmitter records
  - System capability as per current IESO PSS/E base cases
  - Transformer station ratings (10-day LTR) as per asset owner
  - Load transfer capability
  - Technical and operating characteristics of local generation

- End-of-life asset considerations and sustainment plans

    - Transmission assets
    - Distribution assets
    - Impact of ongoing plans and projects on applicable facility ratings

- Other considerations, as applicable

5. Working Group

The core Working Group will consist of planning representatives from the following organizations including embedded LDCs that have identified needs in the Southern Huron-Perth sub-region:

- Independent Electricity System Operator *(Team Lead for IRRP)*
- Hydro One Distribution
- Festival Hydro Inc.
- Entegrus Power Lines Inc.
- Hydro One Transmission

Authority and Funding

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

6. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended by the IESO and adopted by the provincial government to enhance the regional planning and siting processes in 2013. The Working Group is committed to conducting plan-level engagement throughout the development of the Southern Huron-Perth IRRP.

The first step in engagement will consist of meetings with municipalities (lower tier and upper tier) and Indigenous communities within the planning area to discuss regional planning, the development of the Southern Huron-Perth IRRP, and integrated solutions.

Regional and community engagement will continue throughout the development and completion of the plan. The Working Group will develop a comprehensive stakeholder engagement plan, according to the Activities Timeline shown in Section 6.

7. Activities, Timeline and Primary Accountability

Table A-1 Summary of IRRP Timelines and Activities

	Activity	Lead Responsibility	Deliverable(s)	Time frame
1	**Prepare Terms of Reference considering stakeholder input**	*IESO*	- Finalized Terms of Reference	July – Sept. 2019
2	**Develop the planning forecast for the sub-region**			
	Establish historical coincident and non-coincident peak demand information	*IESO*	- Long-term planning forecast scenarios	Sept. – Nov. 2019
	Establish historical weather correction, median and extreme conditions	*IESO*		
	Establish gross peak demand forecast and high/low growth scenarios	*LDCs*		
	Establish existing, committed and potential DG	*LDCs*		
	Establish near- and long-term conservation forecasts based on planned CDM activities	*IESO*		
	Develop planning forecast scenarios - including the impacts of CDM, DG and extreme weather conditions	*IESO*		
3	**Provide information on load transfer capabilities under normal and emergency conditions**	*LDCs*	- Load transfer capabilities under normal and emergency conditions	Sept. – Nov. 2019
4	**Provide and review relevant community plans, if applicable**	*LDCs and IESO*	- Relevant community plans	Sept. – Nov. 2019
5	**Review expected service life (ESL) information to optimize future end-of-life (EOL) investment**	*IESO and Hydro One Transmission*	- Summary of ESL/EOL review findings regarding optimization opportunities	Sept. – Nov. 2019
6	**Capacity planning of the Southern Huron-Perth sub-region**			
	Complete system studies to identify needs over a 20-year period for the Southern Huron-Perth sub-region - Obtain PSS/E base case, include bulk system assumptions as identified in the key assumptions	*IESO*	- Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q4 2019 – Q2 2020

	Activity	Lead Responsibility	Deliverable(s)	Time frame
	- Apply reliability criteria as defined in ORTAC to demand forecast scenarios - Confirm and refine the need(s) and timing/load levels			
7	**Develop options and alternatives**			
	Develop conservation options	*IESO and LDCs*	- Develop flexible planning options for forecast scenarios	Q2-Q4 2020
	Develop local generation options	*IESO and LDCs*		
	Develop transmission (see Action 7 below) and distribution options	*Hydro One, and LDCs*		
	Develop options involving other electricity initiatives (e.g., smart grid, storage)	*IESO/ LDCs with support as needed*		
	Integrate with bulk needs	*IESO*		
	Develop portfolios of integrated alternatives	*All*		
	Complete technical comparison and evaluation	*All*		
8	**Plan and undertake community and stakeholder engagement**			
	Early engagement with local municipalities and Indigenous communities within study area, First Nation communities who may have an interest in the study area, and the Métis Nation of Ontario	*All*	- Community and stakeholder engagement plan - Input from local communities	Q4 2019
	Develop communications materials	*All*		Q3-Q4 2020
	Undertake community and stakeholder engagement	*All*		
	Summarize input and incorporate feedback	*All*		
9	**Develop long-term recommendations and implementation plan based on community and stakeholder input**	*IESO*	- Implementation plan - Monitoring activities and identification of decision triggers - Hand-off letters - Procedures for annual review	Q4 2020 – Q1 2021
10	**Prepare the IRRP report detailing the recommended near-, medium- and long-term plan for approval by all parties**	*IESO*	- IRRP report	Q1-Q2 2021

ATTACHMENT G

Chatham-Kent/Lambton/Sarnia Regional Infrastructure Plan, August 2017

Chatham-Kent/Lambton/Sarnia

Regional Infrastructure Plan

August 21, 2017

Prepared by Hydro One Networks Inc. (Lead Transmitter)

With support from:

Companies
Independent Electricity System Operator (IESO)
Bluewater Power Distribution Corporation
Entegrus Inc.
Hydro One Networks Inc. (Distribution)

Disclaimer

This Regional Infrastructure Plan ("RIP") was prepared for the purpose of developing an electricity infrastructure plan to address needs identified in the Chatham-Kent/Lambton-Sarnia Region. The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the members in the region.

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EXECUTIVE SUMMARY

This Regional Infrastructure Plan ("RIP") was prepared by Hydro One, with input from the Region's Local Distribution Companies ("LDCs") and the IESO in accordance with the Ontario Transmission System Code ("TSC") and Distribution System Code ("DSC") requirements. It summarizes investments in transmission facilities, distribution facilities, or both, recommended to meet the electricity infrastructure needs within the Chatham-Kent/Lambton/Sarnia Region.

The regional planning process for the Chatham-Kent/Lambton/Sarnia Region was initiated with a Needs Assessment in April 2016, which identified loading at Kent TS would exceed their transformer 10-day Limited Time Rating ("LTR") in 2016 based on the net load forecast. The Needs Assessment Study Team recommended Hydro One and relevant LDCs to develop a Local Plan to address this issue ("Kent TS T3 Capacity Limitation"). This Local Plan was completed in June 2017, and concluded that there is existing distribution transfer capability to ensure that the transformer T3 would not exceed its LTR.

The major sustainment projects planned for the region over the near and medium-term are given as below:

- Refurbishment of existing Wanstead TS is currently underway and is scheduled to be completed in 2018;
- Chatham SS component replacement, including a capacitor and the associated breaker, is planned to be completed by 2023;
- St. Andrews TS T3, T4 & switchyard refurbishment, planned to be completed by 2023;
- Sarnia Scott TS T5 & Component Replacement, which includes autotransformer T5, breaker, and other components, planned to be completed by 2024.

In accordance with the regional planning process as mandated by the TSC and DSC, the next planning cycle will be started no later than 2020. However, should there be a need that emerges due to a change in load forecast or any other reason, the regional planning cycle may commence earlier to address the need.

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1. INTRODUCTION

This Regional Infrastructure Plan ("RIP") summarizes all the regional planning activities undertaken in the Chatham-Kent/Lambton/Sarnia Region. It was prepared by Hydro One Networks Inc. ("Hydro One") as the lead transmitter in the region, and is supported by the representatives from Bluewater Power Distribution Corporation, Entegrus Inc., Hydro One Networks Inc. (Distribution), and the Independent Electricity System Operator ("IESO"). This RIP is the final phase of the regional planning process for the region in accordance with the Ontario Transmission System Code ("TSC") and Distribution System Code ("DSC") requirements.

1.1 Background and Scope

In accordance with the TSC and DSC amendments in August 2013, the regional planning process for the Chatham-Kent/Lambton/Sarnia Region began with Needs Assessment in April 2016 and was completed in June 2016.

Based on the findings, the Needs Assessment Study Team agreed that Scoping Assessment was not required for this region at the time. The only need identified, thermal overloading of transformer T3 at Kent TS, was to be addressed between Hydro One (transmitter) and relevant LDCs through Local Planning process which was completed in June 2017.

Being the final phase of the regional planning process, the scope of this RIP includes a comprehensive summary of the needs and relevant wire plans to address near and medium-term needs (2015-2025) identified in previous planning phases.

2. REGIONAL DESCRIPTION

The Chatham-Kent/Lambton/Sarnia Region, as shown in Figure 2-1, includes the municipalities of Lambton Shores and Chatham-Kent, as well as the townships of Petrolia, Plympton-Wyoming, Brooke-Alvinston, Dawn-Euphemia, Enniskillen, St. Clair, Warwick, and Villages of Oil Springs and Point Edward. The area is bordered by the London area to the east and Windsor-Essex to the southwest. The region's summer coincident peak load was about 710 MW in 2016.

Figure 2-1 Map of Chatham-Kent/Lambton/Sarnia Region

Electricity supply for the region is provided through a network of 230 kV and 115 kV transmission lines. The bulk of the electrical supply is transmitted through 230 kV circuits (N21W/N22W, L24L/L26L, and W44LC/W45LS) towards Buchanan TS. This region also contains a number of interconnections with neighboring Michigan State (B3N, L4D, and L51D). Figure 2-2 shows Hydro One transmission and transmission-connected customers' assets in the Chatham-Kent/Lambton/Sarnia Region.

Large gas-fired generators in the region include: Greenfield Energy Centre CGS, TransAlta Sarnia CGS, St. Clair Power CGS, and Greenfield South Power Corporation (GSPC). Lists of transmission lines, stations, and distributors (LDCs) in the region are provided in Appendix A, B, and C, respectively.

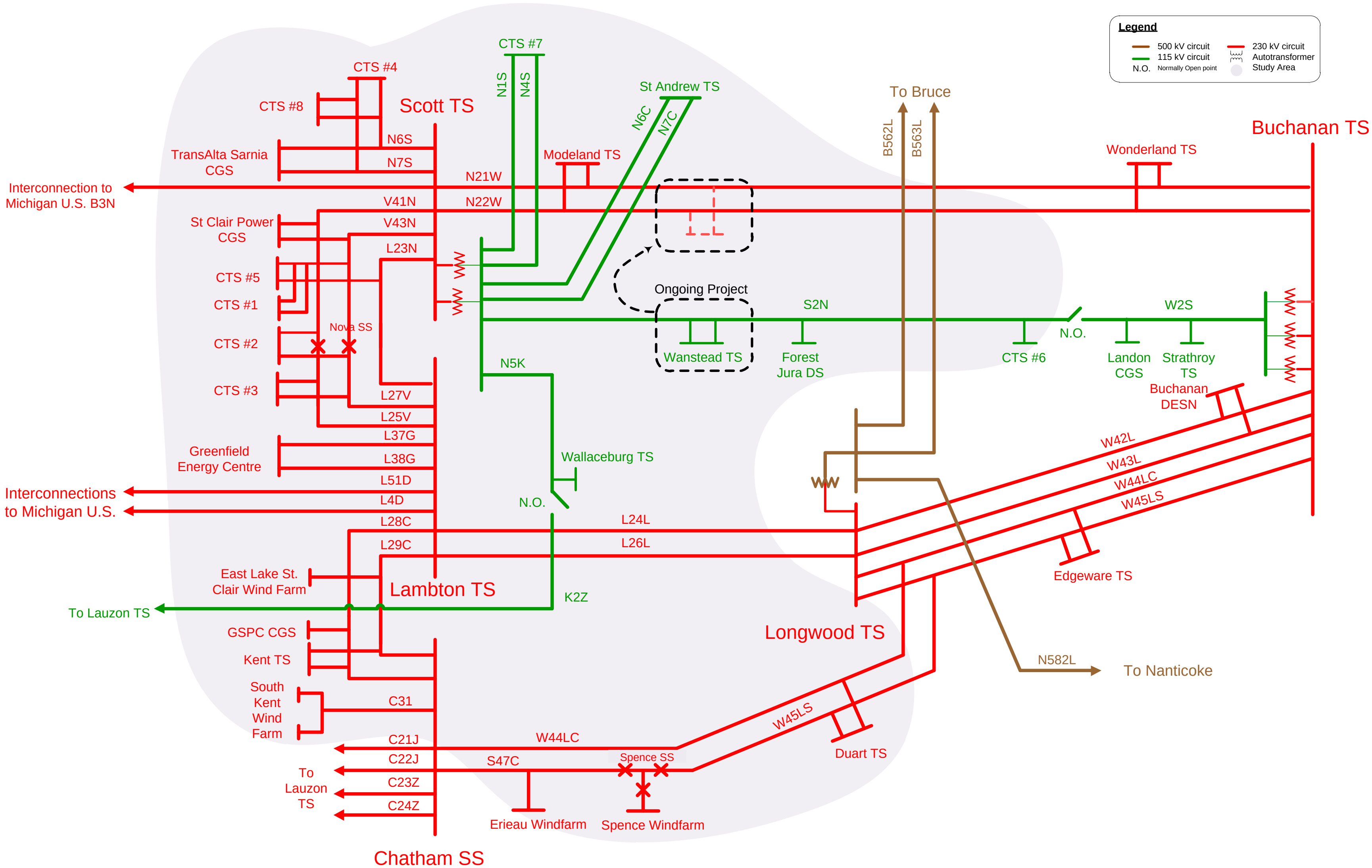

Figure 2-2 Single Line Diagram of Chatham-Kent/Lambton/Sarnia Region

3. NEEDS ASSESSMENT RESULTS

3.1 Load Forecast

During the Needs Assessment phase, LDCs in the region provided gross load forecasts for Hydro One's step-down transformer stations and assumed 2015 historical extreme weather-corrected summer peak loads as reference points. As for transmission connected industrial customers, 2014 historical load levels were assumed throughout the study period.

Based on data provided by the Study Team, the summer gross coincident load in the region is expected to grow at an average rate of approximately 1.3% annually over the next 10 year period. Factoring in the contributions of conservation and demand management and distributed generation, the summer net coincident load in the region is expected to grow at an average rate of approximately 0.2% annually.

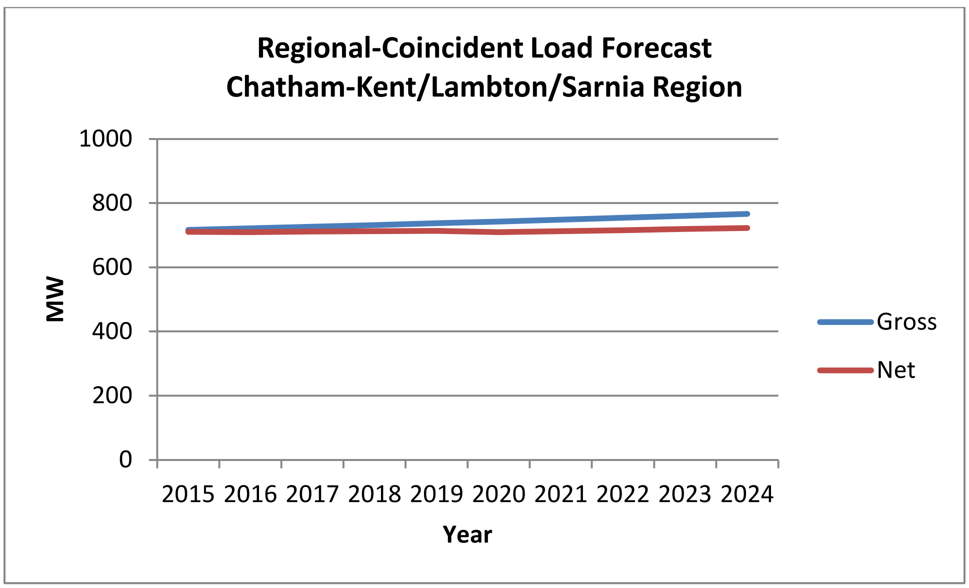

Figure 3-1 Regional load forecast during Needs Assessment

Further load forecast details are provided in Appendix D.

3.2 Major Transmission Projects Completed or Underway

Over the last 10 years, a number of major transmission projects, shown below, have been completed by Hydro One aimed to maintain or improve the reliability and adequacy of supply in the Chatham-Kent/Lambton/Sarnia Region:

- Lambton to Longwood 230kV L24L/L26L Circuit Reconductoring
- New Transformer Station Duart TS

In addition, as part of Hydro One's transmission rates application (EB-2016-0160), existing Wanstead TS has been identified as reaching end-of-life. Effort is underway to convert Wanstead TS from 115 kV to 230 kV and connecting to 230 kV circuits N21W/N22W. The target in-service date is Q4 2018.

3.3 Regional Needs

The results from the Needs Assessment for the region are summarized below:

Table 3-1 Regional Needs

No.	Needs	Description
1	Kent TS Capacity	Loading at Kent TS is expected to exceed the transformer 10-day limited time rating (LTR) in 2016 based on the net load forecast.
2	End-of-Life equipment at St. Andrews TS, Scott TS, and Chatham SS	During the study period, plans to replace end of life equipment at St. Andrews TS, Scott TS, and Chatham SS[1] are identified.

4. RECOMMENDED PLANS

This section provides a consolidated summary of the regional infrastructure plans for addressing needs in the Chatham-Kent/Lambton/Sarnia Region.

4.1 Kent TS Transformation Capacity

Based on the information available at the time of Chatham-Kent/Lambton/Sarnia Region Needs Assessment, it was identified that transformer T3 at Kent TS will be overloaded for the loss of its companion transformer T4. Subsequently, local planning team consists of Hydro One and impacted LDCs had undertaken further investigations and determined there is a sufficient transfer capability on the distribution system to offload Kent TS T3. Therefore, the local planning team agreed no further action is required at this time.

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[1] The need to replace end-of-life equipment at Chatham SS was identified post completion of the 2016 Needs Assessment report.

4.2 Sustainment Plans

As part of Hydro One's transmitter license requirements, Hydro One continues to ensure a reliable transmission system by carrying out maintenance programs as well as periodic replacement of equipment based on their condition. Since the conclusion of Needs Assessment, additional sustainment projects have been planned for the region in the medium-term. Below is a list of Hydro One's major transmission sustainment projects in the Chatham-Kent/Lambton/Sarnia Region that are currently planned. Note that the project scopes and timelines are currently under development and may change accordingly.

- Chatham SS Component Replacement, mainly to replace capacitor SC21 and the associated breaker and is planned to be completed by 2023.
- St. Andrews TS T3, T4 & Switchyard Refurbishment, planned to be completed by 2023. The current scope includes both transformers and a breaker replacement.
- Sarnia Scott TS T5 & Component Replacement, which includes autotransformer T5, breaker, and other components, planned to be completed by 2024.

5. CONCLUSION AND NEXT STEPS

This Regional Infrastructure Plan (RIP) report summarizes the regional planning activities for the Chatham-Kent/Lambton/Sarnia Region and concludes the first regional planning cycle for the region.

As mandated by the OEB, next planning cycle will begin no later than 2020. Should there be a need that emerges due to change in load forecast or any other reason, the regional planning cycle will be started earlier to address the need.

6. REFERENCES

[1] Needs Assessment Report, Chatham-Kent/Lambton/Sarnia Region. June 12, 2016. http://www.hydroone.com/RegionalPlanning/Chatham/Documents/Needs%20Assessment%20Report%20-%20Chatham-Kent-Lambton-Sarnia.pdf

[2] Local Planning Report – Kent TS Transformation Capacity, Chatham-Kent/Lambton/Sarnia Region. June, 2017. http://www.hydroone.com/RegionalPlanning/Chatham/Documents/Kent%20TS%20Transformation%20Capacity%20Local%20Planning%20Report%20(Final).pdf

APPENDIX A: TRANSMISSION LINES IN THE CHATHAM-KENT/LAMBTON/SARNIA REGION

No	Circuit Designation	Location	Voltage (kV)
1	N6S, N7S	Scott TS to TransAlta Sarnia CGS	230
2	V41N, V43N	Scott TS to Nova SS	230
3	L23N	Scott TS to Lambton TS	230
4	L25V, L27V	Lambton TS to Nova SS	230
5	L37G, L38G	Lambton TS to Greenfield Energy Centre CGS	230
6	L28C, L29C	Lambton TS to Chatham SS	230
7	C31	Chatham SS to South Kent Wind Farm CGS	230
8	W44LC	Buchanan TS to Longwood TS to Chatham SS	230
9	W45LS	Buchanan TS to Longwood TS to Spence SS	230
10	S47C	Spence SS to Chatham SS	230
11	L24L, L26L	Lambton TS to Longwood TS	230
12	N21W, N22W	Scott TS to Buchanan TS	230
13	N1S, N4S	Scott TS to CTS	115
14	N6C, N7C	Scott TS to St. Andrews TS	115
15	S2N	Scott TS to CTS	115
16	N5K	Scott TS to Wallaceburg TS	115
17	K2Z	Kent TS (115kV) to Lauzon TS	115

APPENDIX B: STATIONS IN THE CHATHAM-KENT/LAMBTON/SARNIA REGION

No.	Station	Voltage (kV)	Supply Circuits
1	Scott TS	230/115	N/A
2	Lambton TS	230	N/A
3	Kent TS	115	L28C/L29C
4	Duart TS	230	W44LC, W45LS
5	Modeland TS	230	N21W, N22W
6	Wanstead TS	115 (existing) 230 (future)	S2N (existing) N21W/N22W (future)
7	St. Andrews TS	115	N6C, N7C
8	Wallaceburg TS	115	N5K
9	Forest Jura HVDS	115	S2N

Note: Customer-owned transformer stations are excluded

APPENDIX C: DISTRIBUTORS IN THE CHATHAM-KENT/LAMBTON/SARNIA REGION

Distributor Name	Station Name	Connection Type
Bluewater Power Distribution Corporation	Modeland TS	Tx
	St. Andrews TS	Tx
	Wanstead TS	Dx
Entegrus Inc.	Kent TS	Tx, Dx
	Wallaceburg TS	Dx
Hydro One Networks Inc. (Distribution)	Duart TS	Tx
	Forest Jura HVDS	Tx
	Kent TS	Tx
	Lambton TS	Tx
	Wallaceburg TS	Tx
	Wanstead TS	Tx

APPENDIX D: REGIONAL-COINCIDENT LOAD FORECAST (MW)

Coincidental Net Load (MW)

	Forecast (MW)									
Station	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Duart TS	14.5	14.5	14.4	14.5	14.5	14.6	14.7	14.8	15.0	15.1
Forest Jura DS	19.5	19.6	19.8	19.9	20.0	20.2	20.4	20.6	20.9	21.1
Kent TS T1/T2	69.8	70.0	71.1	72.0	72.9	74.0	75.3	76.6	78.1	79.5
Kent TS T3/T4	40.3	40.7	41.3	41.8	42.2	42.8	43.5	44.2	45.0	45.8
Lambton TS	61.7	61.6	61.8	61.7	61.6	61.7	61.9	62.2	62.5	62.8
Modeland TS	82.1	81.4	81.2	80.6	80.1	79.7	79.5	79.4	79.4	79.2
St. Andrews TS	63.0	62.3	61.8	61.1	60.5	60.0	59.6	59.3	59.0	58.7
Wallaceburg TS	27.0	26.8	27.2	27.6	27.9	23.2	23.7	24.2	24.8	25.3
Wanstead TS	28.1	28.2	28.5	28.6	28.8	29.0	29.3	29.6	30.0	30.3
CTS #1	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9
CTS #2	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8
CTS #3	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0
CTS #4	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0
CTS #5	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9
CTS #6	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
CTS #7	53.9	53.9	53.9	53.9	53.9	53.9	53.9	53.9	53.9	53.9
CTS #8	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7

Coincidental Gross Load (MW)

	Forecast (MW)									
Station	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Duart TS	14.7	14.9	15.1	15.3	15.5	15.7	16.0	16.2	16.4	16.7
Forest Jura DS	19.7	20.0	20.4	20.7	21.1	21.4	21.8	22.2	22.6	22.9
Kent TS T1/T2	71.1	72.7	74.4	76.1	77.9	79.7	81.6	83.5	85.4	87.4
Kent TS T3/T4	40.8	41.7	42.6	43.6	44.6	45.5	46.6	47.6	48.7	49.8
Lambton TS	62.3	62.9	63.5	64.1	64.8	65.4	66.1	66.7	67.4	68.0
Modeland TS	82.9	83.3	83.6	84.0	84.3	84.7	85.0	85.3	85.7	86.0
St. Andrews TS	63.6	63.6	63.6	63.6	63.6	63.6	63.6	63.6	63.6	63.6
Wallaceburg TS	27.7	28.3	29.0	29.7	30.3	31.0	31.8	32.5	33.3	34.0
Wanstead TS	28.7	29.2	29.7	30.1	30.6	31.1	31.6	32.2	32.7	33.2
CTS #1	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9
CTS #2	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8
CTS #3	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0
CTS #4	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0
CTS #5	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9
CTS #6	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
CTS #7	53.9	53.9	53.9	53.9	53.9	53.9	53.9	53.9	53.9	53.9
CTS #8	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7

APPENDIX E: LIST OF ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council Inc.
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code

ATTACHMENT H

Windsor-Essex Region Integrated Regional Resource Plan, April 2015

WINDSOR-ESSEX REGION
INTEGRATED REGIONAL RESOURCE PLAN

April 28, 2015

ieso
Independent Electricity System Operator

Integrated Regional Resource Plan

Windsor-Essex Region

This Integrated Regional Resource Plan ("IRRP") was prepared by the IESO pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066.

This IRRP was prepared on behalf of the Windsor-Essex Region Working Group, which included the following members:

- Independent Electricity System Operator
- Essex Powerlines Corporation
- E.L.K Energy Inc.
- Entegrus Inc.
- Hydro One Networks Inc. (Distribution) and
- Hydro One Networks Inc. (Transmission)

The Windsor-Essex Region Working Group assessed the adequacy of electricity supply to customers in the Windsor-Essex Region over a 20-year period; developed a flexible, comprehensive, integrated plan that considers opportunities for coordination in anticipation of potential demand growth scenarios and varying supply conditions in the Windsor-Essex Region; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key assumptions over time.

Windsor-Essex Region Working Group members agree with the IRRP's recommendations and support implementation of the plan through the recommended actions. Windsor-Essex Region Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

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List of Abbreviations

Abbreviation	Description
C&S	Codes and standards ("C&S")
CDM	Conservation Demand Management
CEP	Community Energy Plan
CHP	Combined Heat and Power
CHPSOP	Combined Heat and Power Standard Offer Program
DE	District Energy
DG	Distributed Generation
DR	Demand Response
EA	Environmental Assessment
EM&V	Evaluation, Measurement and Verification
EMS	Energy Management Systems
DESN	Dual Element Spot Network
FIT	Feed-in Tariff
GEA	Green Energy Act, 2009
GHG	Greenhouse Gas
IAP	Industrial Accelerator Program
IESO	Independent Electricity System Operator
IPSP	(2007) Integrated Power System Plan
IRRP	Integrated Regional Resource Planning
L/R	Load Rejection
LAC	Local Advisory Committee
LDC	Local Distribution Company
LTEP	(2013) Long-Term Energy Plan
LTR	Limited Time Rating
MEP	Municipal Energy Plan
MEP/CEP	Municipal or Community Energy Planning
MTS	Municipal Transformer Station
OEB or Board	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPS	(Ontario's) Provincial Policy Statement
PPWG	Planning Process Working Group
PV	Photovoltaic
Region	Windsor-Essex Region
RIP	Regional Infrastructure Plan
SCADA	Supervisory Control And Data Acquisition
SCGT	Simple-Cycle Gas Turbine
SECTR	Supply to Essex County Transmission Reinforcement
SPS	Special Protection System
TOU	Time-of-Use
TS	Transformer Station
Working Group	Technical Working Group for the Windsor-Essex Region

1. Introduction

This Integrated Regional Resource Plan ("IRRP") addresses the electricity needs of the Windsor-Essex Region ("Region") over the next 20 years. This report was prepared by the Independent Electricity System Operator ("IESO") on behalf of a Technical Working Group[1] composed of the IESO, EnWin Utilities Ltd. ("EnWin"), Essex Powerlines Corporation, E.L.K. Energy Inc., Entegrus Inc., and Hydro One Distribution and Hydro One Transmission ("Working Group").[2]

The Region encompasses the City of Windsor, Town of Amherstburg, Town of Essex, Town of Kingsville, Town of Lakeshore, Town of LaSalle, Municipality of Leamington, Town of Tecumseh, the western portion of the Municipality of Chatham-Kent and the Township of Pelee Island. With roughly 400,000 people presently living in the Region, population has remained flat over recent years[3] despite the impacts of the 2008 and 2009 global recession and the decline of automotive manufacturing facilities in the City of Windsor. While the manufacturing sector continues to face recovery challenges in the Region, economic diversification is changing the Region's growth and electricity use. The 2011 Windsor-Essex Regional Economic Roadmap identifies nine industry groups that hold potential for the Region, including advanced manufacturing, tourism, and agri-business.[4] The Region presently has a peak electricity demand of about 800 MW, and this demand is expected to increase at an average of nearly 1% per year.

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is done through regional electricity planning, a process that was formalized by the Ontario Energy Board ("OEB" or "Board") in 2013. In accordance with the OEB regional planning process, transmitters, distributers and the IESO are required to carry out regional planning activities for the 21 electricity planning regions at least once every five years.

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[1] Information on the working group is available at: www.ieso.ca/Windsor-Essex

[2] See Appendix B for a description of some of the LDCs serving the Region.

[3] *Population counts, for Canada, provinces and territories, census divisions, population centre size groups and rural areas, 2011 Census*, Statistics Canada. At https://www12.statcan.gc.ca/census-recensement/2011/dp-pd/hlt-fst/pd-pl/Table-Tableau.cfm?LANG=Eng&T=703&SR=1&S=80&O=A&RPP=99&CMA=0&PR=35

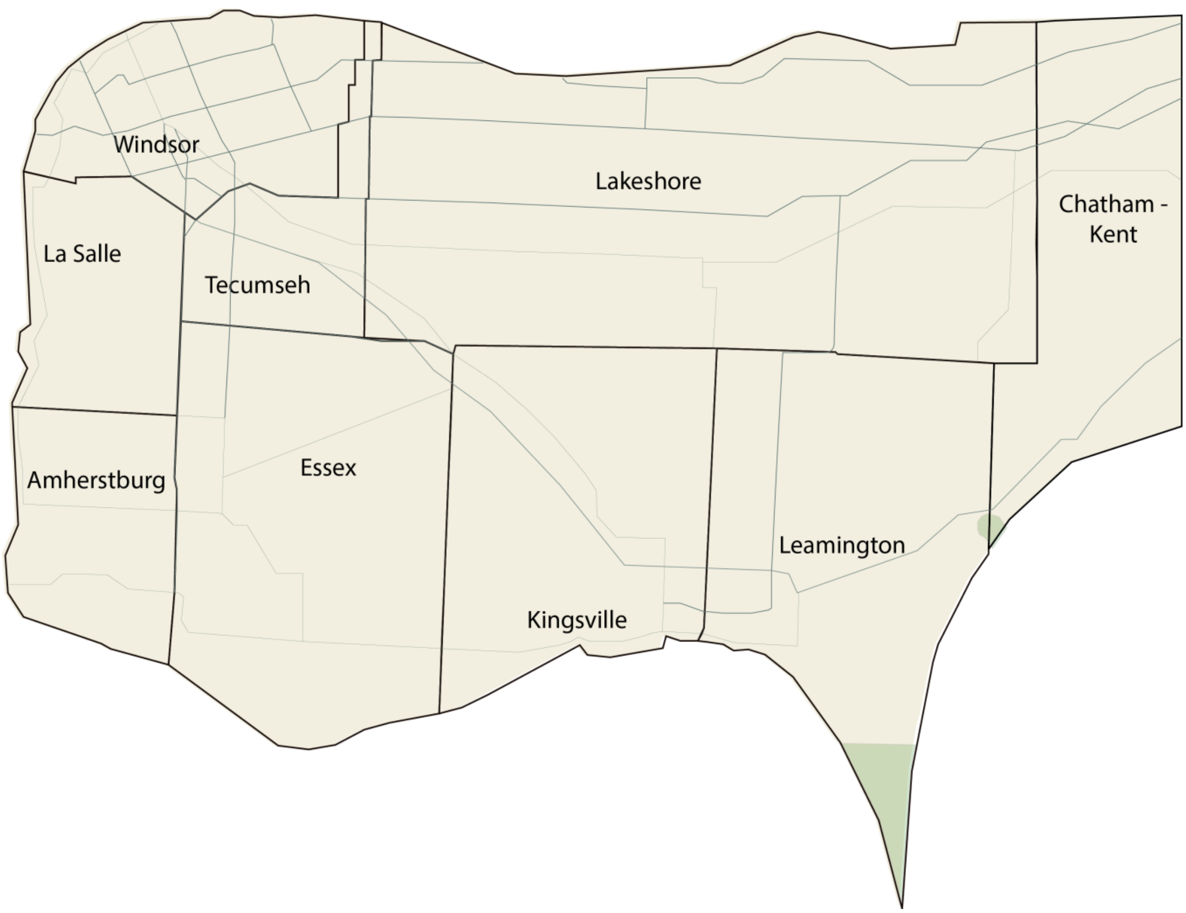
[4] Windsor--Essex Regional Economic Roadmap, Windsor-Essex Economic Development Corporation, February 2011.

Figure 1-1: Ontario's 21 Regional Planning Zones

The area covered by the Windsor-Essex IRRP constitutes one of the 21 electricity planning regions established through the OEB's regional planning process which is shown in Figure 1-1. This IRRP fulfills the requirements for the region as mandated by the OEB.

This IRRP for Windsor-Essex identifies investments for immediate implementation to meet near- and medium-term needs in the Region, and considers whether there are any long-term needs that necessitate options to be developed. No needs were identified for the Township of Pelee Island. Since economic, demographic, and technological conditions will inevitably change, IRRPs will be reviewed on a 5-year cycle so that plans can be updated to reflect the changing electricity outlook. The Windsor-Essex IRRP will be revisited in 2020 or sooner, if significant changes occur relative to the current forecast. The Region, shown in Figure 1-2 below, is defined electrically based on the connectivity of supply stations to Ontario's electricity grid. It is comprised of the City of Windsor, Town of Amherstburg, Town of Essex, Town of Kingsville, Town of Lakeshore, Town of LaSalle, Municipality of Leamington, Town of Tecumseh, and the western portion of the Municipality of Chatham-Kent. The Region has a peak electricity demand of about 800 MW and is served by five local distribution companies ("LDCs"): EnWin Utilities Ltd. ("EnWin"), Essex Powerlines Corporation, E.L.K. Energy Inc., Entegrus Inc., and Hydro One. EnWin and Hydro One are directly connected to the transmission system, while the three other LDCs have low voltage connections to Hydro One distribution feeders.

Figure 1-2: The Windsor-Essex Region



This report is organized as follows:

- A summary of the recommended plan for the Region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the Region and the study scope are discussed in Section 4;
- Demand forecast scenarios, conservation and distributed generation assumptions, are described in Section 5;
- The near- and medium-term plan is presented in Section 6;
- The long-term plan is presented in Section 7;
- A summary of community, aboriginal and stakeholder engagement to date in developing this IRRP and moving forward is provided in Section 8;
- A conclusion is provided in Section 9.

2. The Integrated Regional Resource Plan

The Windsor-Essex IRRP addresses the Region's electricity needs over the next 20 years, from 2014 to 2033, based on application of the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC"). The IRRP identifies needs that are forecast to arise in the near term (0-5 years), medium term (5-10 years) and long term (10-20 years). These planning horizons are distinguished in the IRRP to reflect the different level of commitment required over these time horizons. The plans to address these timeframes are coordinated to ensure consistency. The IRRP was developed based on consideration of planning criteria, including reliability, cost and feasibility; and, in the near term, it seeks to maximize the use of the existing electricity system, where it is economic to do so.

For the near and medium term, the IRRP identifies specific investments that are already being implemented. This is necessary to ensure that they are in service in time to address the Region's more urgent needs, which have been forecast with relative certainty based on current demand trends, conservation targets and other local developments.

For the long term, the IRRP identifies a number of alternatives to meet needs. However, as these needs are forecast to arise further in the future, it is not necessary (nor would it be prudent given forecast uncertainty and the potential for technological change) to commit to specific projects at this time. Instead the IRRP for the long term focuses on developing and maintaining the viability of long-term electricity supply options, engaging with the community, and gathering information to lay the groundwork for future options. A particular emphasis of the long term is identifying the potential for integrating conservation, distributed generation ("DG"), or other localized solutions into the Region and gathering input on community preferences for long-term options.

The needs and recommended actions are summarized below.

2.1 Plan to Address the Near- and Medium-Term Needs

Near- and Medium-Term Needs

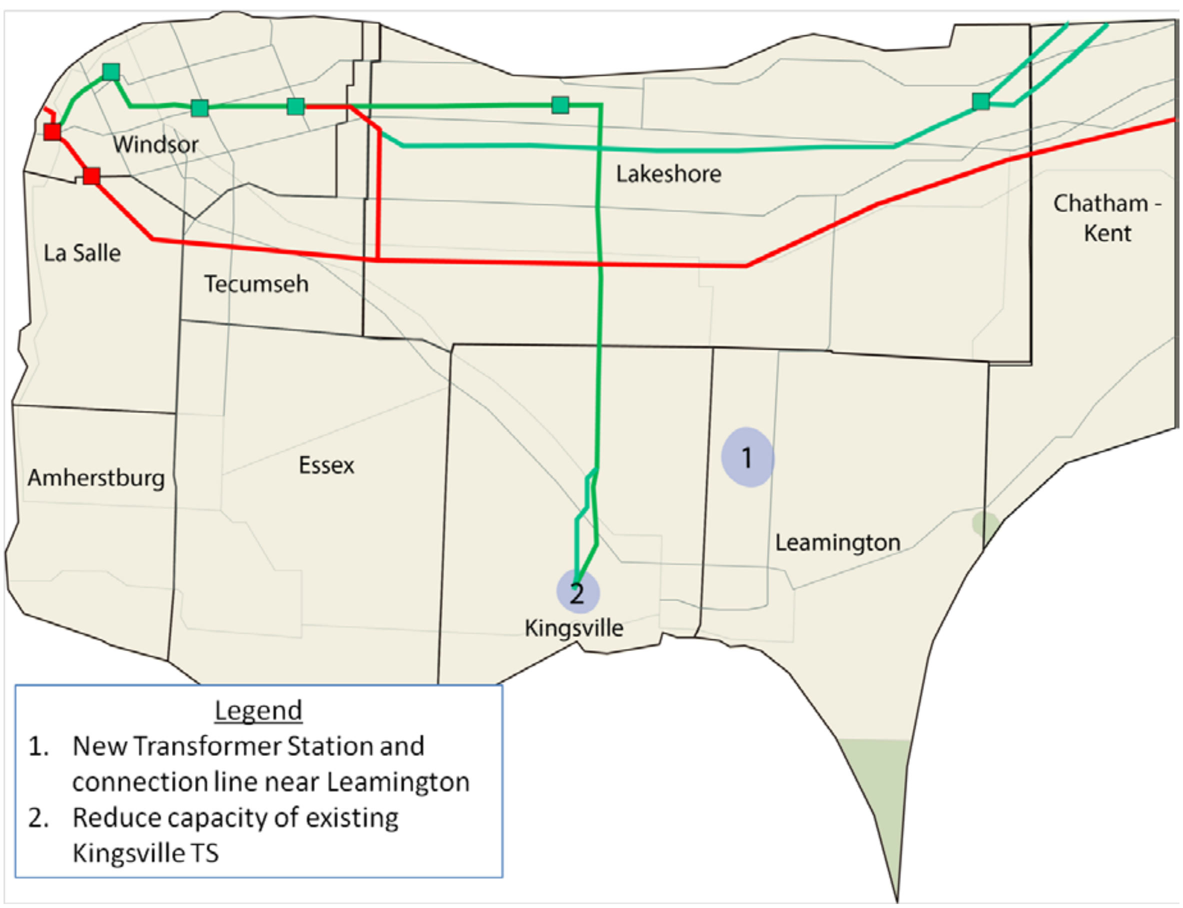
- Additional supply capacity in the Kingsville-Leamington area
- Additional restoration capability in the broader Region

The first component of the near- and medium-term plan is the implementation of targeted conservation. While this planned CDM is expected to make a significant contribution to addressing growth in the

Region, residual demand growth, as well as other reliability needs which are not growth related give rise to near-term supply capacity and restoration needs in the Region (see sidebar). Demand in the Kingsville-Leamington portion of the Region has exceeded the supply capacity in recent years and this is expected to continue over the 20-year forecast period. In addition, supply to a large portion of the Region does not comply with the prescribed ORTAC restoration criteria.

An integrated solution composed of conservation, DG resources, and transmission reinforcements in the Region is recommended to address these supply capacity and restoration needs. These components are described in further detail below and the location of transmission investments are indicated in Figure 2-1.

Figure 2-1: Transmission Projects Included in the Windsor-Essex Near-Term Plan



Recommended Actions:

1. Implement conservation and distributed generation

The implementation of provincial conservation targets established in the 2013 Long-Term Energy Plan ("LTEP") is a key component of the near- and medium-term plan for the Region. In developing the demand forecast, peak-demand impacts associated with the provincial targets established in the LTEP were assumed before identifying any residual need; this is consistent with the Conservation First policy. The achievement of these demand reductions will partially depend on the extent to which LDC conservation programs provide peak-demand reductions. Monitoring of conservation success, including measurement of peak demand savings, will be an important element of the near- and medium-term plan, and will also provide input for long-term planning by gauging the actual performance of specific conservation measures, and assessing the potential for future conservation initiatives in the Region.

Provincial programs that encourage the development of DG, such as the Feed-in Tariff ("FIT"), microFIT, and the Combined Heat and Power Standard Offer Program ("CHPSOP"), can also contribute to reducing peak demands on the transmission system in the Region, these will be influenced by local interest and opportunities for development. The LDCs and the IESO will continue supporting these initiatives and will monitor their impacts. Together, conservation and DG resources are expected to offset more than 90% of the growth in the area between 2014 and 2033.

2. Develop new transformer station in Leamington

The balance of the Region's supply capacity and restoration needs can be addressed by the new Supply to Essex County Transmission Reinforcement ("SECTR") project, plus planned sustainment work in the Region.[5] The transmitter that serves the Region, Hydro One, filed the regulatory application for approval of the SECTR project with the OEB in June, 2014. The project consists of the installation of a new 230 kV-supplied transformer station ("TS") near Leamington connected to the existing 230 kV circuits in the Region via a new 13 km double-circuit 230 kV connection line. The estimated completion date for the SECTR project is 2018 and

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[5] Evidence on the SECTR project is available at the Ontario Energy Board's website at EB-2013-0421: http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm_udf10=eb-2013-0421&sortd1=rs_dateregistered&rows=200
Evidence on the needs and alternatives is available in Exhibit B-1-5. Evidence on cost responsibility is available in Exhibit B-4-4.

the total cost is approximately $77 million. On completion, some of the load currently supplied by Kingsville TS will be transferred to the new Leamington TS.

3. Downsize the existing Kingsville transformer station

In conjunction with transferring the majority of the load from the existing Kingsville TS to the new Leamington TS, the Kingsville TS will be downsized through the retirement of aging assets. This will increase the cost-effectiveness of the overall solution.

Together with targeted conservation, these planned transmission facilities will meet the supply capacity and restoration needs of the Kingsville-Leamington area over the forecast period. The addition of a new supply point will also substantially meet the transmission restoration needs for the broader Region. This integrated solution benefits both local customers and broader transmission ratepayers.

2.2 Plan to Address the Long-Term Needs

No long-term needs have been identified in the Region. The Region's demand growth, conservation achievements and generation development will be monitored until the Region's needs are reassessed in the next regional planning cycle. If significant changes occur relative to the current forecast, the next planning cycle may be initiated in advance of the 5-year minimum review timeline.

3. Development of the IRRP

3.1 The Regional Planning Process

In Ontario, planning to meet the electricity needs of customers at a regional level is done through regional planning. Regional planning assesses the interrelated needs of a region - defined by common electricity supply infrastructure over the near, medium and long term, and develops a plan to ensure cost-effective, reliable, electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions.

Regional planning has been conducted on an as needed basis in Ontario for many years. Most recently, the Ontario Power Authority ("OPA") carried out regional planning activities to address regional electricity supply needs. The OPA conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In 2012, the Ontario Energy Board convened the Planning Process Working Group ("PPWG") to develop a more structured, transparent, and systematic regional planning process. This group was composed of industry stakeholders including electricity agencies, utilities, and stakeholders. In May 2013, the PPWG released the Working Group Report to the Board, setting out the new regional planning process. Twenty-one electricity planning regions in the province were identified in the Working Group Report and a phased schedule for completion was outlined. The Board endorsed the Working Group Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013, as well as through changes to the OPA's licence in October 2013. The OPA license changes required it to lead a number of aspects of regional planning, including the completion of comprehensive IRRPs. Following the merger of the IESO and the OPA on January 1, 2015, the regional planning responsibilities identified in the OPA's licence were transferred to the IESO.

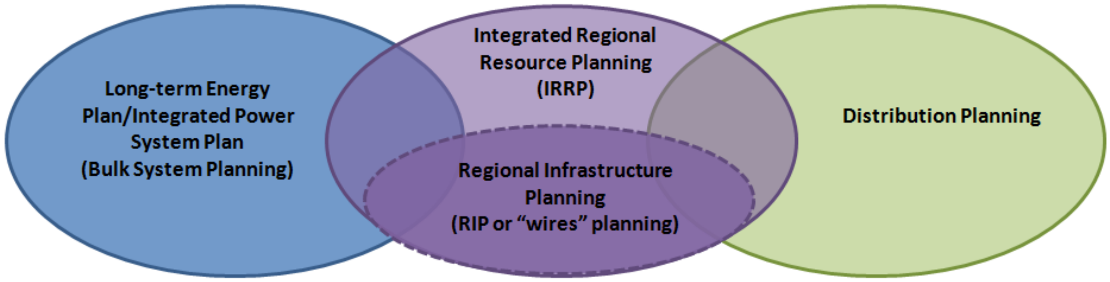
The regional planning process begins with a Needs Screening process performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO then conducts a Scoping Assessment to determine whether a comprehensive IRRP is required, which considers conservation, generation, transmission, and distribution solutions, or whether a straightforward "wires" solution is the only option. If the latter applies, then a transmission and distribution focused Regional Infrastructure Plan ("RIP") is required. The Scoping Assessment process also identifies any sub-regions that require assessment. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter, outside of the regional planning process. At the conclusion of the Scoping Assessment, the IESO produces a report that includes the results of the Needs Screening process – identifying whether an IRRP, RIP or no regional coordination is required - and a preliminary terms of reference. If an IRRP is the identified outcome, then the IESO is required to complete the IRRP within 18 months. If a RIP is required, the transmitter takes the lead and has six months to complete it. Both RIPs and IRRPs are to be updated at least every five years.

The final IRRPs and RIPs are to be posted on the IESO and relevant transmitter websites, and can be used as supporting evidence in a rate hearing or leave to construct application for specific infrastructure investments. These documents may also be used by municipalities and communities for planning purposes and by other parties to better understand local electricity growth and infrastructure requirements.

Regional planning, as shown in Figure 3-1, is just one form of electricity planning that is undertaken in Ontario. There are three types of electricity planning in Ontario:

- Bulk system planning
- Regional system planning
- Distribution system planning

Figure 3-1: Levels of Electricity System Planning



Bulk System Planning

- 500 kV & 230 kV transmission
- Interconnections
- Inter-area network transfer capability
- System reliability (security and adequacy) to meet NERC, NPCC, ORTAC
- Congestion and system efficiency
- System supply and demand forecasts
- Incorporation of large generation
- Typically medium- and long-term focused

Regional Planning

- 230 kV & 115 kV transmission
- 115/230 kV autotransformers and associated switchyard facilities
- Customer connections
- Load supply stations
- Regional reliability (security and adequacy) to meet NERC, NPCC & ORTAC
- ORTAC local area reliability criteria
- Regional/local area generation & CDM resources
- Typically near- & medium-term focused

Distribution Network Planning

- Transformer stations to connect to the transmission system
- Distribution network planning (e.g. new & modified Dx facilities)
- Distribution system reliability (capacity & security)
- Distribution connected generation & CDM resources
- LDC demand forecasts
- Near- & medium-term focused

Planning at the bulk system level typically considers the 230 kV and 500 kV network. Bulk system planning considers the major transmission facilities and assesses the resources needed to adequately supply the province. Bulk system planning is typically carried out by the IESO. Distribution planning, which is carried out by LDCs, looks at specific investments on the low voltage, distribution system.

Regional planning can overlap with bulk system planning. For example, overlap can occur at interface points where regional resource options may also address a bulk system issue. Similarly, regional planning can overlap with the distribution planning of LDCs. An example of this is when a distribution solution addresses the needs of the broader local area or region. Therefore, to ensure efficiency and cost-effectiveness, it is important for regional planning to be coordinated with both bulk and distribution system planning.

By recognizing the linkages with bulk and distribution system planning, and coordinating multiple needs identified within a given region over the long term, the regional planning process provides an integrated assessment of needs. Regional planning aligns near- and long-term solutions and allows specific investments recommended in the plan to be understood as part of a larger context. Furthermore, regional planning optimizes ratepayer interests by avoiding piecemeal planning and asset duplication, and allows Ontario ratepayers' interests to be represented along with the interests of LDC ratepayers. Where IRRPs are undertaken, they allow an evaluation of the multiple options available to meet needs, including conservation, generation, and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process, and by making plans available to the public.

3.2 The IESO's Approach to Regional Planning

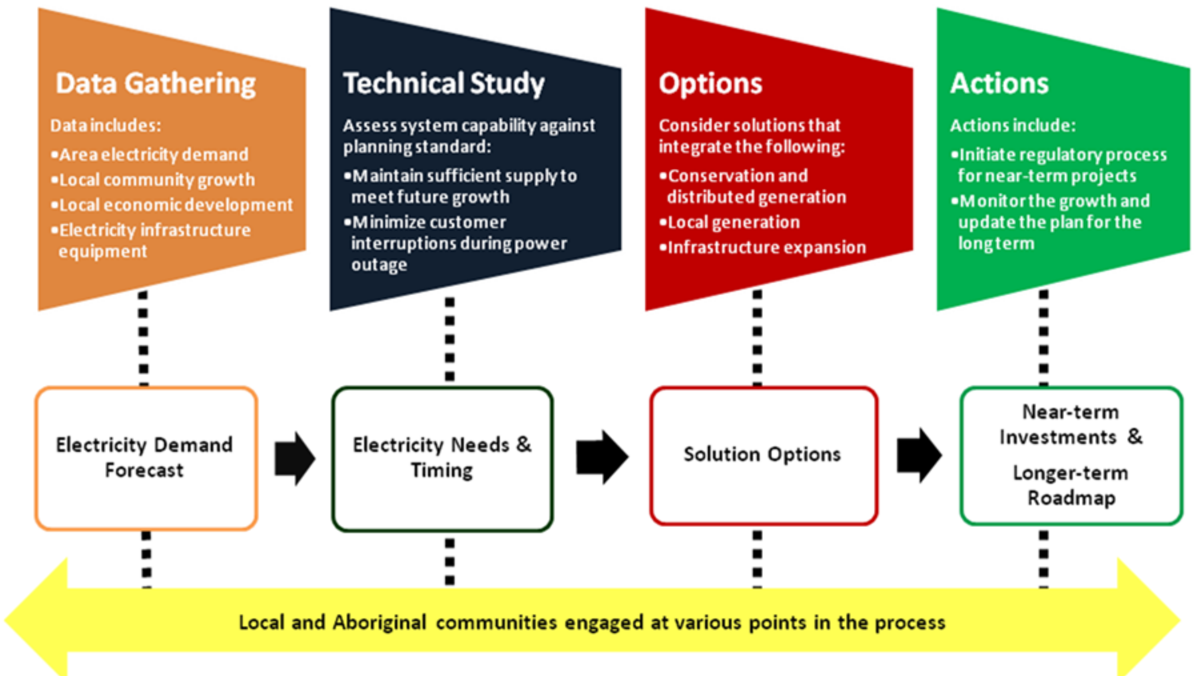
IRRPs assess electricity system needs for a region over a 20-year period. The 20-year outlook anticipates long-term trends so that near-term actions are developed within the context of a longer-term view. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

In developing an IRRP, a different approach is taken to developing the plan for the first 10 years of the plan—the near- and medium-term—than for the longer-term period of 10-20 years. The plan for the first 10 years is developed based on best available information on demand, conservation, and other local developments. Given the long lead time to develop electricity infrastructure, near-term electricity needs require prompt action to enable the specified solutions in a timely manner. By contrast, the long-term plan is characterized by greater forecast uncertainty and longer development lead time; as such solutions do not need to be committed to immediately. Given the potential for changing conditions and technological development, the IRRP for the long term is more directional, focusing on developing and maintaining the viability of options for the future, and continuing to monitor demand forecast scenarios.

In developing an IRRP, the IESO and regional working group (see Figure 3-2 below) carry out a number of steps. These steps include electricity demand forecasts; technical studies to determine electricity needs and the timing of these needs; the development of potential options; and, a recommended plan including actions for the near and long term. Throughout this process, engagement is carried out with First Nation and Métis communities, stakeholders and communities who may have an interest in the regional planning area. The steps of an IRRP are illustrated in Figure 3-2 below.

The IRRP report documents the inputs, findings and recommendations developed through the process described above, and provides recommended actions for the various entities responsible for plan implementation. Where "wires" solutions are included in the plan recommendations, the completion of the IRRP report is the trigger for the transmitter to initiate an RIP process to develop those options. Other actions may involve: development of conservation, local generation, or other solutions; community engagement; or information gathering to support future iterations of the regional planning process in the region.

Figure 3-2: Steps in the IRRP Process



3.3 Windsor-Essex Working Group and IRRP Development

Regional planning was underway in the Windsor-Essex Region prior to the OEB's formalization of the regional planning process. The first phase of regional planning began with the regional plan developed by the former-OPA[6] as part of the 2007 Integrated Power System Plan ("IPSP"), which identified a need for conservation as well as transmission reinforcement in the Region. In 2010, Hydro One received environmental approval for the staged reinforcement identified in the IPSP. The planning work carried out for the IPSP has formed the basis for subsequent regional planning in the Region.

Beginning in 2008, the global economic downturn had a significant impact on electricity demand in the Region, especially the urban portion in and around Windsor. In 2010, a Regional working group consisting of members from the former OPA, the transmitter, the five LDCs, and

[6] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

the IESO, was formed. A study carried out by the former OPA and presented to the working group in 2011 recommended that development activities associated with the proposed Leamington TS temporarily be put on hold as a result of the reduced regional electricity demand.

In 2013 the former-OPA revisited the 2011 study based on an updated load forecast provided by the Region's LDCs. Based on the near-term needs identified, especially in the rural portion in and around Kingsville-Leamington, a transmission solution - the SECTR project - was recommended. In June 2014 Hydro One submitted a Leave to Construct application for this project with the OEB. This was the first of the two stages of transmission expansion described in Hydro One's environmental assessment. The second stage is not contemplated at this time.

As a continuation of this planning work for the Region the former-OPA in 2013 initiated an IRRP for the Region. The Working Group, first established in 2010 and consisting of staff from the former-OPA, the IESO, Hydro One, and the five LDCs serving the Region, was reconvened to support this work.

This Windsor-Essex IRRP is therefore a "transitional" IRRP in that it began prior to development of the OEB's regional planning process and much of the work was completed before the new process and its requirements were known.

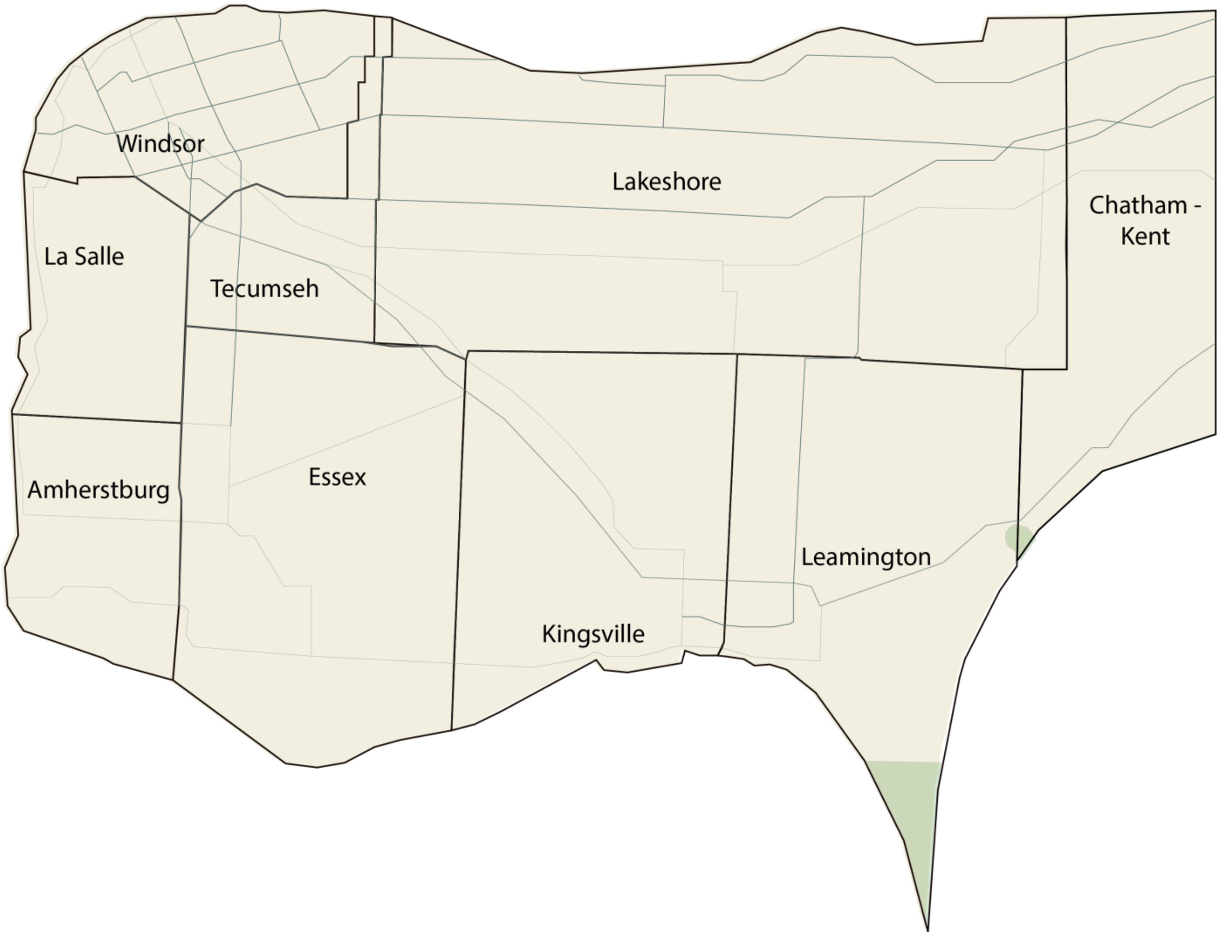
4. Background and Study Scope

This report presents an integrated regional electricity plan for the Windsor-Essex Region for the 20-year period from 2014 to 2033. To set the context for this IRRP, the scope of this IRRP and a description of the Region are described in Section 4.1. Section 4.2 details the transmission-connected generation that plays an important role in providing supply to this Region. Section 4.3 describes the transmission configuration in the Region, and defines the regional planning sub-systems which are used later in this report.

4.1 Study Scope

The Region is comprised of the City of Windsor, Town of Amherstburg, Town of Essex, Town of Kingsville, Town of Lakeshore, Town of LaSalle, Municipality of Leamington, Town of Tecumseh, and the western portion of the Municipality of Chatham-Kent and the Township of Pelee Island. This Region, shown in Figure 4-1 below is comprised of and is served by five LDCs: EnWin Utilities Ltd. ("EnWin"), Essex Powerlines Corporation, E.L.K. Energy Inc., Entegrus Inc., and Hydro One. EnWin and Hydro One are directly connected to the transmission system, while the three other LDCs have low voltage connections to Hydro One distribution feeders.

Figure 4-1: The Windsor-Essex Region



The urban portion of the Region in and around Windsor has a long history of advanced manufacturing, especially in the automotive sector. In light of this the transmitter and distributors over the decades have made investments in electricity infrastructure to enable a very high standard of reliability, which is of strategic importance to the regional and provincial economies. Entertainment tourism is particularly strong in the downtown core, the most significant individual component of which is a provincially owned resort casino.

The rural portion of the Region in Essex County supports a combination of manufacturing and agri-business. Essex County contains the largest concentration of greenhouse vegetable production in North America.[7] This sector is expected to experience major growth in the future, with much of the activity taking place in the Kingsville-Leamington area, increasing electricity

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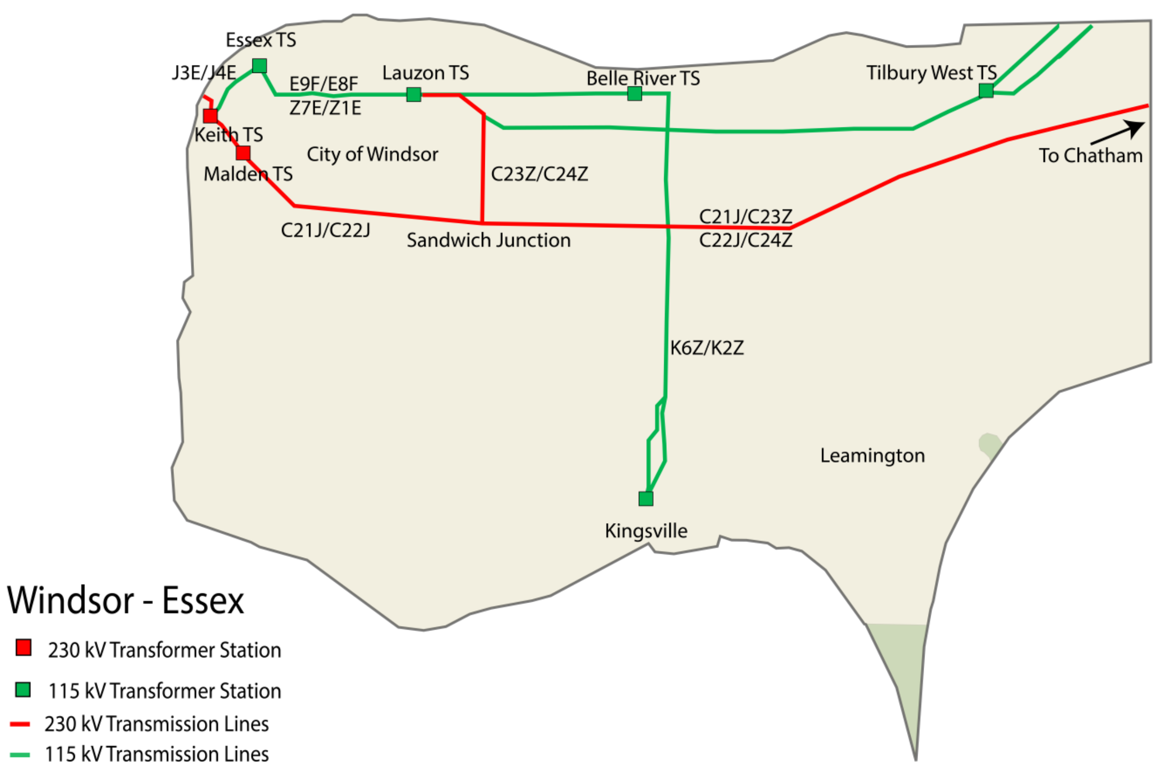
[7] County of Essex website:
http://www.countyofessex.on.ca/wps/wcm/connect/COE/COE/ABOUT+ESSEX+COUNTY/

supply requirements in that part of the Region. The County is also home to several large food processing operations, and a growing winery sector.

The Region is supplied from a combination of local generation and from connection to the Ontario grid via a network of 230 kV and 115 kV transmission lines and stations shown in Figure 4-2 below. Electricity distribution and conservation initiatives are carried out by the five LDCs serving the Region.

Figure 4-2: Transmission System in the Windsor-Essex Region



4.2 Transmission Connected Generation

Transmission connected generation comes from a mix of large natural gas generators, load-offsetting behind-the-meter embedded generators, and renewable generation that is shown in Table 4-1 below.

The impact of DG on the demand forecast for the Region will be discussed in more detail later in this report.

Table 4-1: Transmission Connected Generation Facilities in the Region

Technology	Station Name	Contract Expiry Date	Connection Point	Contract Capacity (MW)	Summer Effective Capacity (MW)
Combined Cycle Generating Facility	Brighton Beach Power Station	December 31, 2024	Keith TS	541	526
Combined Heat and Power ("CHP")	West Windsor Power	May 31, 2016	J2N (Keith TS)	128	107
	TransAlta Windsor	December 1, 2016	Z1E	74	74
	East Windsor Cogeneration Centre	November 5, 2029	E8F/E9F	84	80
Renewables	Gosfield Wind Project	January 12, 2029	K2Z	51	8
	Point Aux Roches Wind Farm	December 5, 2031	K6Z	49	8

Electricity transmission connects the Region to the rest of the province through two 230 kV double circuits and two 115 kV single circuits. The principal connection points are Keith TS and Lauzon TS, both of which are transmission assets owned by Hydro One and are located in Windsor. Hydro One also owns Malden TS, Crawford TS, Essex TS, and Walker 1 TS in Windsor. Hydro One owns Belle River TS and Tilbury TS in the northern part of Essex county and Kingsville TS in the southern part of the county. Hydro One is currently seeking OEB approval to build Leamington TS (as part of the SECTR project), also located in the southern part of the county. EnWin owns five transformer stations. One of these serves a broad base of customers (Walker 2 TS); three others are dedicated to individual large users; and one is in the process of being repurposed to serve a broad base of customers as a result of the closure of the large user it previously served. There is also a customer-owned TS serving that customer's facility in Windsor.

The main transmission corridor in the Region connects with the rest of the province at Chatham SS in the Municipality of Chatham-Kent. Two 230 kV double-circuit lines, C21J/C23Z and C22J/C24Z, run east-west in this corridor, located south of Highway 401, from Chatham SS to Sandwich Junction in the Town of Lakeshore. The circuits are reconfigured at this location and double-circuit line C21J/C22J continues west to Keith TS in Windsor, while double-circuit line C23Z/C24Z runs northwest on another corridor to Lauzon TS in Windsor. Keith TS provides an interconnection with the Michigan system via 230 kV circuit J5D and an in-line phase shifter.

Keith TS and Lauzon TS, connect the Region's 115 kV network to the 230 kV transmission system via two auto-transformers in each station. As can be seen in Figure 4-2, above, the main 115 kV transmission corridor runs through the City of Windsor from Keith TS through Essex TS to Lauzon TS. Double-circuit line J3E/J4E located in this corridor connects Keith TS with Essex TS, and double-circuit line Z1E/Z7E connects Essex TS with Lauzon TS. Other 115 kV transmission corridors provide for circuits K2Z and K6Z. 115 kV circuits E8F and E9F are underground cables and provide supply to four EnWin-owned stations. Approximately 65% of the Region's load is supplied by the 115 kV system, with the remainder supplied by transformer stations connected directly to the 230 kV system. Given the large proportion of load which is supplied by the 115 kV system, the reliability of supply via the two connection points at Keith TS and Lauzon TS is especially important.

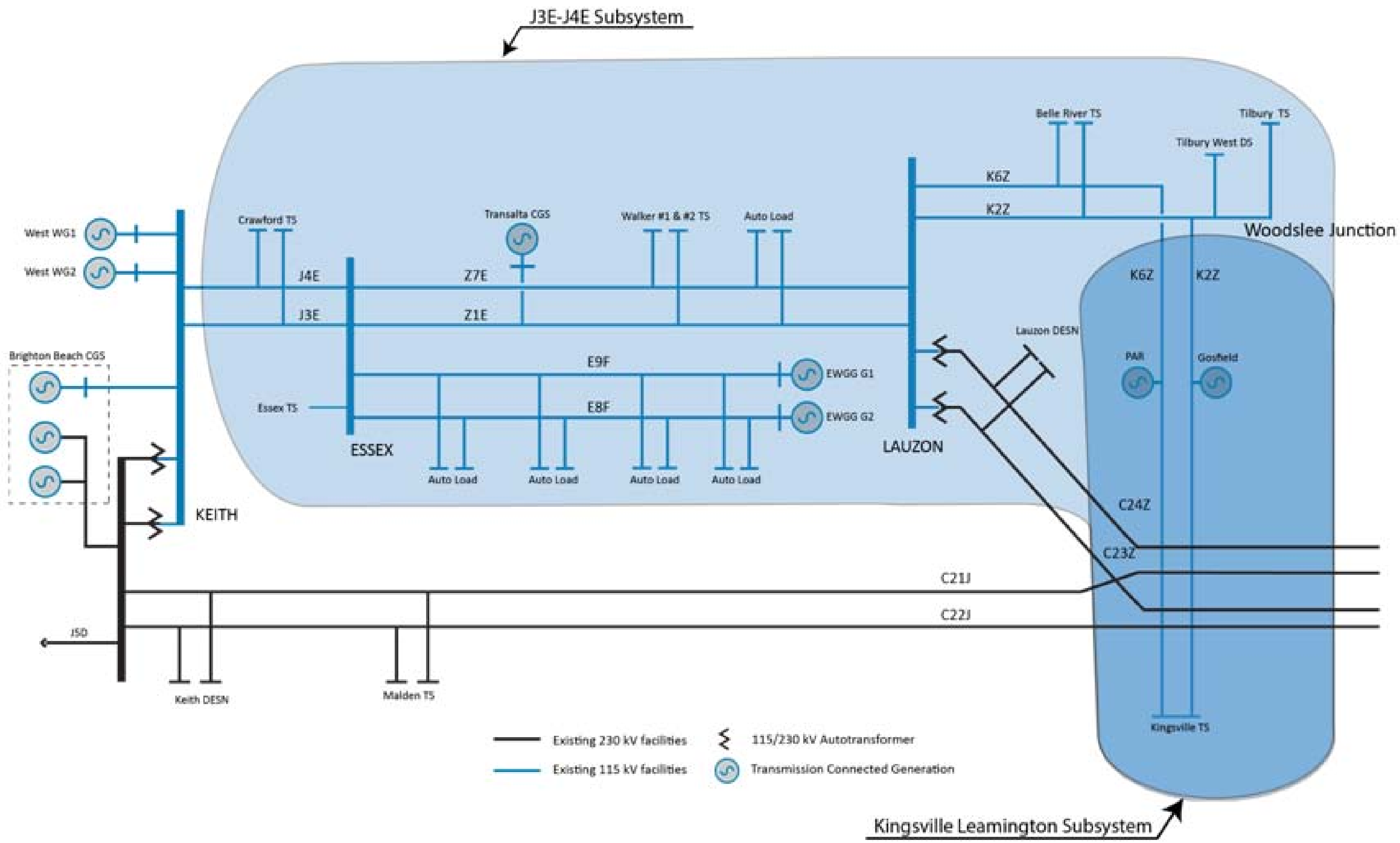
4.2.1 Regional Planning Sub-systems

For the purposes of this IRRP, the transmission system in the Region is divided into the two "nested" sub-systems described below and shown in Figure 4-3:

1. The Kingsville-Leamington sub-system: customers currently supplied from Kingsville TS; and
2. The J3E-J4E sub-system: customers supplied from the 230/115 kV auto-transformers at Keith TS and Lauzon TS via the 115k kV system, as well as customers supplied from the 230 kV Lauzon Dual Element Spot Network ("DESN").

It is important to note that the two sub-systems are overlapping, with the Kingsville-Leamington sub-system nested within the other. Therefore, where the demand for the J3E-J4E sub-system is referred to in this plan it is inclusive of demand in the Kingsville-Leamington sub-system. Similarly, increasing supply to the Kingsville-Leamington sub-system will impact the supply and demand balance in the J3E-J4E sub-system.

Figure 4-3: Windsor-Essex Region Sub-systems



5. Demand Forecast

This section describes the development of the regional demand forecast. Section 5.1 begins by describing electricity demand trends in the Region from 2004 to 2014. Section 5.2 describes the demand forecast used in this study and the methodology used to develop it.

5.1 Historical Demand

The peak demand in the Region has declined from a high of 1,060 MW in the summer of 2006 to approximately 800 MW in both 2013 and 2014. Figure 5-1 shows the historical summer peak demand observed in the Region from 2004 to 2014. A noticeable peak in 2006 is coincident with the all-time peak in Ontario power demand, while a dip in 2008 and 2009 shows the area's response to the global recession. There is a large concentration of automotive manufacturing facilities in the City of Windsor. The sector is a major economic driver and electricity user within the Region. The decline in Ontario's manufacturing sector and the 2008/09 economic downturn have both caused a decline in electricity use in the Region.

While the manufacturing sector continues to face challenges in recovering, economic diversification is changing the Region's growth and electricity use. The 5-year Windsor-Essex Regional Economic Roadmap, released in 2011, identifies nine industry groups that hold growth potential for the Region, including advanced manufacturing, tourism, and agri-business.[8]

It is important to note some other trends that are reflected in this data. First, this measured demand includes the impact of summer weather conditions, which were unusually cool across the province in 2014. Second, demand on the distribution system that was being met by DG resources operating at the time of the annual peak is not reflected in the measured demand that is supplied from the transmission system. Finally, the data also reflects the achievements of provincial conservation and peak-shifting initiatives, including the Industrial Conservation Initiative for large customers.

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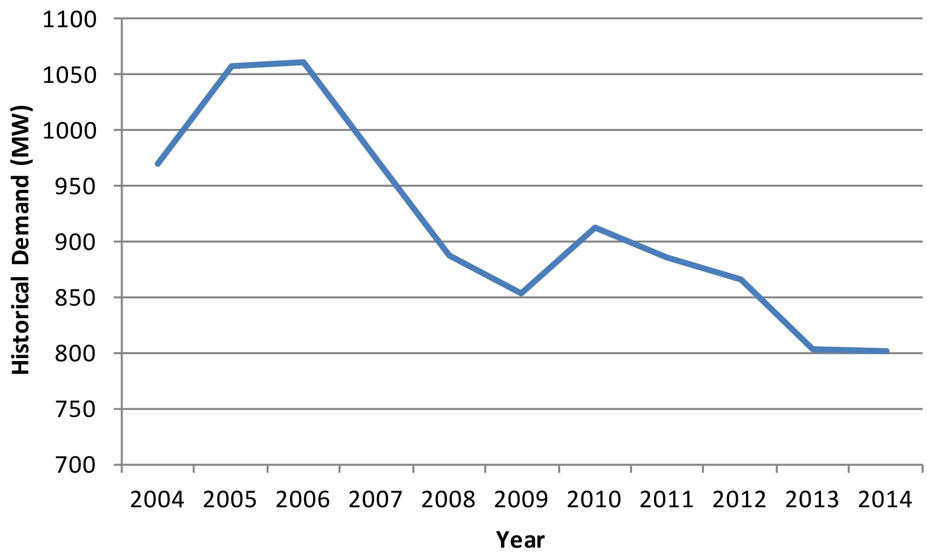
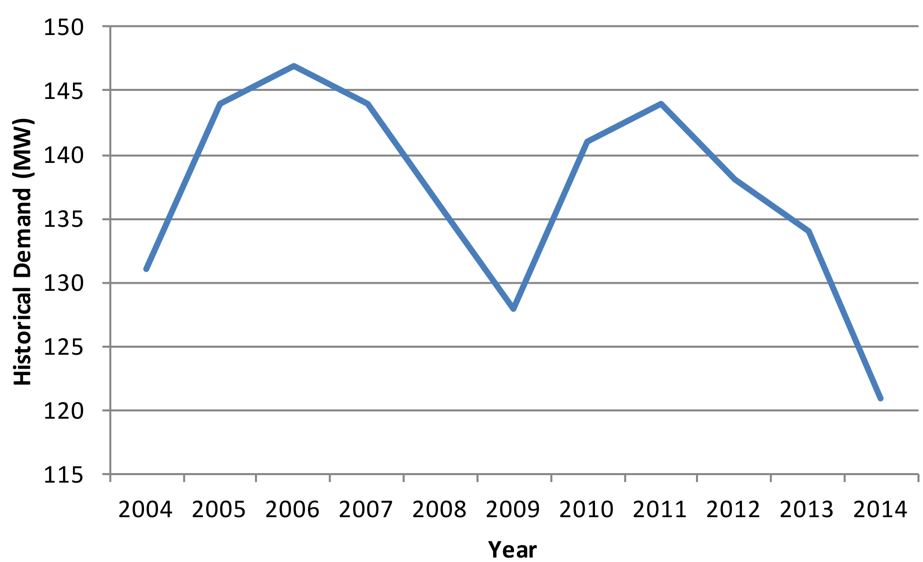
[8] Regional Economic Roadmap, Windsor-Essex Economic Development Corporation, February 2011

Figure 5-1: Historical Electricity Demand in the Region



Peak demand in the Kingsville-Leamington area has experienced fluctuations comparable to the Region since 2004, which is shown in Figure 5-2 below. In addition to the trends described above, this figure shows the impact of approximately 16 MW of effective capacity of DG connected at Kingsville TS by 2015, none of which was connected in 2004.

Figure 5-2: Kingsville-Leamington Historical Electricity Demand[9]



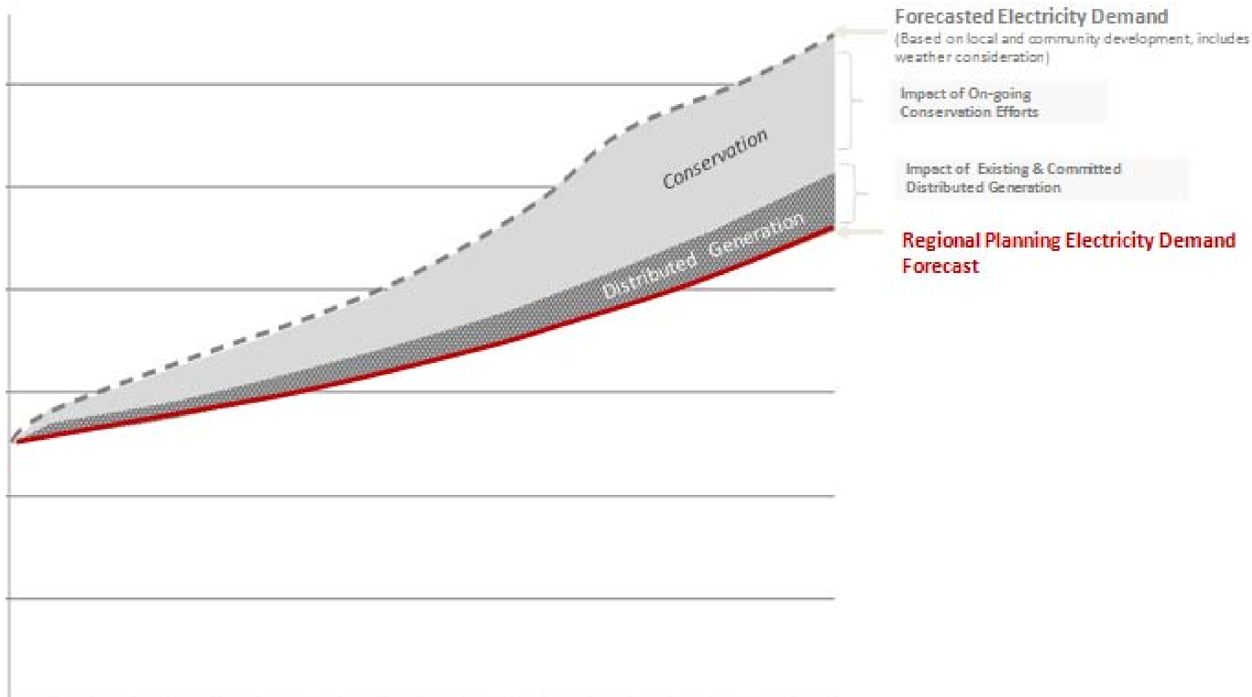
[9] Historical electricity demand reflects the weather experienced at the time of system peak.

5.2 Demand Forecast Methodology

Regional electricity needs are driven by the limits of the infrastructure supplying an area, which is sized to meet peak demand requirements. Therefore, regional planning typically focuses on growth in coincident peak demand, which is the electricity demand of individual stations that coincides in time with the annual peak demand of the region. This represents the electricity demand when the assets in the area are most stressed and resources are most constrained. Energy adequacy is usually not a concern in regional planning, as the Region can generally draw upon energy available from the provincial electricity grid and energy adequacy for the province is planned through a separate process.

A regional peak demand forecast was developed for the forecast period. The steps taken to develop the planning forecast are depicted in Figure 5-3. Gross demand forecasts assuming extreme weather conditions were provided by EnWin and Hydro One, which are directly connected to the transmission system. These forecasts were then modified to reflect the peak demand impacts of provincial conservation targets and DG contracted through provincial programs such as FIT and microFIT to produce a reference planning forecast. The reference planning forecast was then used to assess electricity supply needs in the Region.

Figure 5-3: Development of Demand Forecasts



Using a planning forecast that is net of provincial conservation targets ensures consistency with the province's Conservation First policy by reducing demand requirements before assessing any growth-related needs. However, it should be noted that this inherently assumes that the targets will be met, and that the targets, which are energy-based, will produce the expected local peak demand impacts. An important aspect of plan implementation will be monitoring the actual peak demand impacts of conservation programs delivered by the local LDCs.

For the long-term outlook, from 2024 to 2033, a second demand forecast scenario, consistent with the growth assumptions embodied in the government's 2013 LTEP was added. This low-demand scenario represents a future with lower electricity demand growth, due to higher electricity prices, increased electricity conservation, and lower energy intensity of the economy.

5.3 Reference Forecast

5.3.1 Gross Demand Forecast

Summer peak gross demand forecasts for the 20-year planning horizon were provided by EnWin and Hydro One, the two LDCs which are directly connected to the transmission system, for each of the transformer stations and transmission connected customers in the area. These forecasts reflect the expected demand at each station at the time of the Region's coincident peak under extreme weather conditions, based on factors such as population, household and economic growth, consistent with municipal planning assumptions. It is expected that each station will reach its individual peak demand at a different point in time. From the perspective of ensuring sufficient transmission supply to the Region, it is important to consider the coincident peak, the point in time when the total demand from the stations in the Region peaks. Aggregating the station forecasts identifies the peak electricity demand that must be served by the Region's transmission system.

Based on the LDC's gross demand forecasts, the Region's peak electricity demand is expected to grow by about 175 MW over the next 20 years, with an average annual growth rate of just under 1%, not including the impacts of conservation or DG. The Kingsville-Leamington area is expected to experience over 50 MW of demand growth, or average annual growth of about 1.6%. The reference gross demand forecasts provided by the LDCs are shown in Appendix A.

5.3.2 Conservation Assumed in the Forecast

Conservation plays a key role in maximizing the useful life of existing infrastructure and maintaining reliable supply. Conservation is achieved through a mix of program-related activities including behavioral changes by customers and mandated efficiencies from building codes and equipment standards ("C&S"). These approaches complement each other to maximize conservation results. The conservation savings forecast for the Region are applied to the gross peak demand forecast, along with contracted DG resources, to determine the net peak demand for the Region.

In December 2013 the Ministry of Energy released a revised LTEP, which outlined a provincial conservation target of 30 TWh of energy savings by 2032. In order to represent the effect of these targets within regional planning, the IESO developed an annual forecast for peak demand savings resulting from the provincial energy savings target, which was then expressed as a percentage of demand in each year. These percentages were applied to the LDCs' demand forecasts to develop an estimate of the peak demand impacts from the provincial targets in the Region. The resulting conservation assumed in the reference forecast is shown in Table 5-1. This contribution from conservation is expected to offset most of the growth in electricity demand in the Region to 2033. The above conservation forecast methodology was not applied in developing the low-demand forecast scenario used for the long-term because the scenario already accounts for the anticipated impact of the 2032 conservation targets in its overall growth rate assumptions.

Table 5-1: Peak Demand Savings from 2013 LTEP Conservation Targets in the Windsor-Essex Region

Year	2015	2017	2019	2021	2023	2025	2027	2029	2031	2033
Savings (MW)	12	20	40	58	72	89	105	122	139	149

It is assumed that demand response ("DR") resources already existing in the base year will continue. Savings from potential future DR resources are not included in the forecast and are instead considered as possible solutions to identified needs.

The 2013 LTEP also committed to establishing a new 6-year Conservation First Framework beginning in January 2015 to enable the achievement of all cost-effective conservation. In the near term, Ontario's LDCs have an energy reduction target of 7 TWh to be achieved between 2015 and the end of 2020 through LDC conservation programs enabled by the new Framework. For the program targets, each LDC is required to prepare a conservation plan describing how the target will be achieved. The first conservation plans are due to be completed by LDCs by May, 2015. The LDC conservation plans will link closely with regional plans, providing more detail about how a portion of the conservation targets that have been incorporated into regional planning will be realized.

5.3.3 Distributed Generation Assumed in the Forecast

In addition to conservation resources, DG connected alongside load on the distribution system reduces the amount of demand needed to be supplied via the transmission system. The introduction of the Green Energy and Green Economy Act, and the associated development of Ontario's FIT program, has increased the development of DG in Ontario from renewable fuel sources including wind, solar and biomass. There are also thermal DG resources in the Region, such as combined heat and power generation ("CHP") associated with industrial customers.

With respect to renewable generation, the full installed capacity of these facilities cannot be relied upon to meet the Region's electricity needs due the intermittent nature of the generation. The installed capacity of these facilities is adjusted to reflect the expected, or effective, power output at time of coincident peak. In other words, the effective capacity is the portion of installed renewable generation capacity that contributes to meeting peak demand. Distributed thermal generation is expected to fully contribute to meeting peak demand.

After netting-off the conservation savings, as described above, the forecast is further reduced by the effective capacity of existing and committed DG in the Region. It is estimated that DG in the Region will contribute approximately 65 MW of effective capacity to meeting area peak demand in 2014.

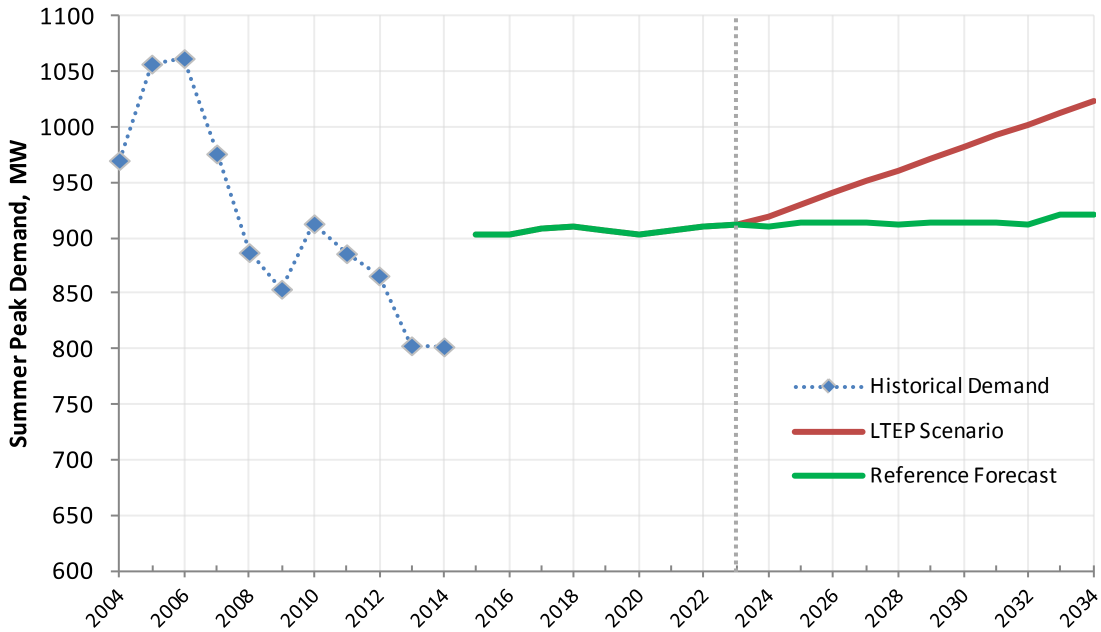
5.4 Windsor-Essex Low Growth Scenario

As noted in Section 5.2, beyond the first 10-years of the planning horizon (ie. beginning in 2024) the IESO developed a second forecast scenario based on the 2013 LTEP. Similar to the reference forecast, this scenario reflects the impact of the conservation targets described in the LTEP. This scenario projects growth over a region, rather than on a station-by-station basis. It was developed by applying the average annual growth rate assumed for southwestern Ontario in the low-demand forecast, about 1.0% per year, to the Region, starting from 2024.

5.5 Planning Forecasts

Figure 5-4 shows the reference forecast and the 2013 low-demand scenario, along with historic demand in the Region.

Figure 5-4: Reference Forecast, 2013 Low-Demand Scenario and Historic Demand in the Region



6. Near- and Medium-Term Plan

Regional planning requires comparing future electricity demand (based on planning forecast) with the capability of the existing system (based on provincial planning criteria). This section includes discussion of the near-term needs and the options to address those needs. No medium-term needs have been identified in the Region. As noted in the previous section, these near-term needs are based on the reference planning forecast provided by the Region's LDCs, reflecting known developments in the area as well as the impact of planned conservation initiatives and DG. These conservation and DG resources are already making a significant contribution toward managing the growth across the Region. For needs related to meeting ORTAC load restoration and load security criteria, which are described in 6.1 Planning Criteria, conservation is not considered a feasible alternative, as these needs are driven by the configuration of the transmission and distribution systems, and are not related to demand growth. Therefore, the Working Group did not consider additional conservation as an alternative to address load restoration times in the Region, and therefore, the near-term plan focuses on improvements to the transmission system.

6.1 Planning Criteria

ORTAC[10] is the provincial standard for assessing the reliability of the transmission system and was applied to assess supply capacity and reliability needs in the Region.

ORTAC includes criteria related to assessment of the bulk transmission system, as well as the assessment of local or regional reliability requirements. The latter criteria are of relevance to regional planning. They can be broadly categorized as addressing two distinct aspects of reliability: (1) providing supply capacity, and (2) limiting the impact of supply interruptions.

With respect to supply capability ORTAC specifies that the transmission system must be able to provide continuous supply to a local area, under specific transmission and generation outage scenarios. The performance of the system in meeting these conditions is used to determine the load meeting capability ("LMC") of an area for the purpose of regional planning. The LMC is the maximum load that can be supplied in the local area with no interruptions in supply or, under certain permissible conditions, with limited controlled interruptions as specified by the ORTAC.

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[10] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

With respect to supply interruptions ORTAC requires that the transmission system be designed to minimize the impact to customers of major outages, such as a contingency on a double-circuit tower line resulting in the loss of both circuits, in two ways: by limiting the amount of customer load affected; and by restoring power to those affected within a reasonable timeframe. Specifically, ORTAC requires that no more than 600 MW of load be interrupted in the event of a major outage involving two elements. Further, load lost during a major outage must be restored within the following timeframes:

- All load lost in excess of 250 MW must be restored within 30 minutes;
- All load lost in excess of 150 MW must be restored within four hours; and
- All load lost must be restored within eight hours.

6.2 Near-Term Needs

Based on an application of ORTAC two near-term transmission system reliability needs, shown in Table 6-1 below, have been identified. These needs affect different groups of customers in the Region (i.e., different sub-systems), however they can be addressed through the same transmission reinforcement project consisting of a new TS located in Leamington.

Table 6-1: Summary of Windsor-Essex Region Reliability Needs

Sub-system	Need Type	Need Description	Need Date
Kingsville-Leamington Sub-system	Capacity to Meet Demand	Forecast loading on K6Z exceeds the thermal load meeting capability	Today
J3E-J4E Sub-system	Minimize the Impact of Interruption	J3E-J4E does not comply with ORTAC service interruption criteria — i.e., restoration of all load within 8 hours	Today

6.2.1 Kingsville-Leamington: Plan to Address the Need for Additional Supply Capacity and End-of-Life Replacement

Within the Region, the strongest growth in electricity demand is expected to occur in the Kingsville-Leamington area. This growth is predominantly attributable to growth in the greenhouse sector as indicated by customer connection requests received by the applicable LDC, the current outlook for expansion of existing greenhouse operations, and anticipated growth from new operations. Such growth expectations are based on approved and proposed development plans provided by the municipalities of Leamington and Kingsville, and a survey completed by the Ontario Greenhouse Vegetable Growers on behalf of local greenhouse growers.

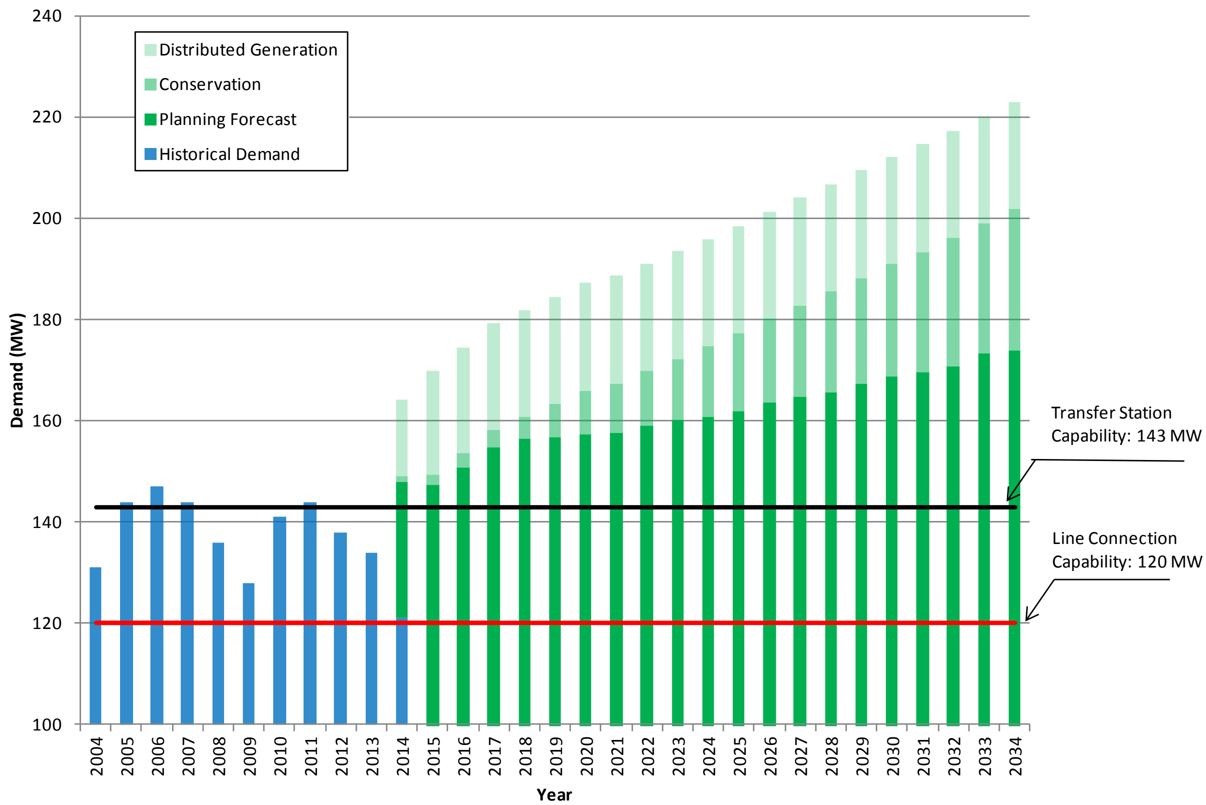
Similarly, the population of Kingsville is expected to increase by 0.5% per year over the next decade, which is higher than the slight population decline expected in the Region overall during the 2014 to 2033 planning horizon.[11]

The planning forecast for the Kingsville-Leamington area is shown in Figure 6-1 below, along with the LMC for the existing Kingsville TS. The approximate planned peak demand reduction between 2014 and 2033 for the Kingsville-Leamington sub-system is 25 MW from conservation, and 6 MW from DG. The peak demand reduction from conservation and DG is expected to offset about 57% of the forecast gross demand growth in the Region between 2014 and 2033. The LMC is based on the 120 MW thermal capability of the 115 kV connection line between Lauzon TS and Kingsville TS, which is the most limiting element of supply to the station. The Kingsville TS capability is higher, at 143 MW.

As shown in Figure 6-1, during the summer months the peak demand has exceeded the 120 MW limit, requiring the use of operating measures. The figure shows that based on the planning forecast, the Kingsville-Leamington area is expected to continue to exceed the capability of the existing Kingsville TS for the forecast period. Additional capacity is therefore required to meet current and future electricity demand in the Kingsville-Leamington sub-system. Until additional capacity is provided, operating measures such as an existing load rejection scheme (which is in violation of ORTAC) will be required. The existing system does not meet ORTAC criteria for supply capacity.

[11] Windsor-Essex Economic Development Corporation website. At www.choosewindsoressex.com.

Figure 6-1: Historical and Forecast Demand and Supply Capabilities in the Kingsville-Leamington Sub-system[12]



After considering "non-wires" and "wires" alternatives, the former-OPA, with the support of working group members, recommended a new station in Leamington to address the need.

In 2014 Hydro One filed a Leave to Construct application with the OEB for transmission expansion in the Leamington area, the SECTR project. The application is currently proceeding through the regulatory process and has a planned in-service date of 2018.

As part of the SECTR planning process, Hydro One identified a near-term need for transformer refurbishment due to end-of-life assets at Kingsville TS. There are currently four transformers at Kingsville TS. One of these units was recently replaced, but the other three units are reaching their end-of-life in the near future. In conjunction with the Leamington area transmission expansion, the option of partially refurbishing Kingsville TS by replacing one of the three transformers that are near end-of-life was recommended. This plan reduces the capacity at

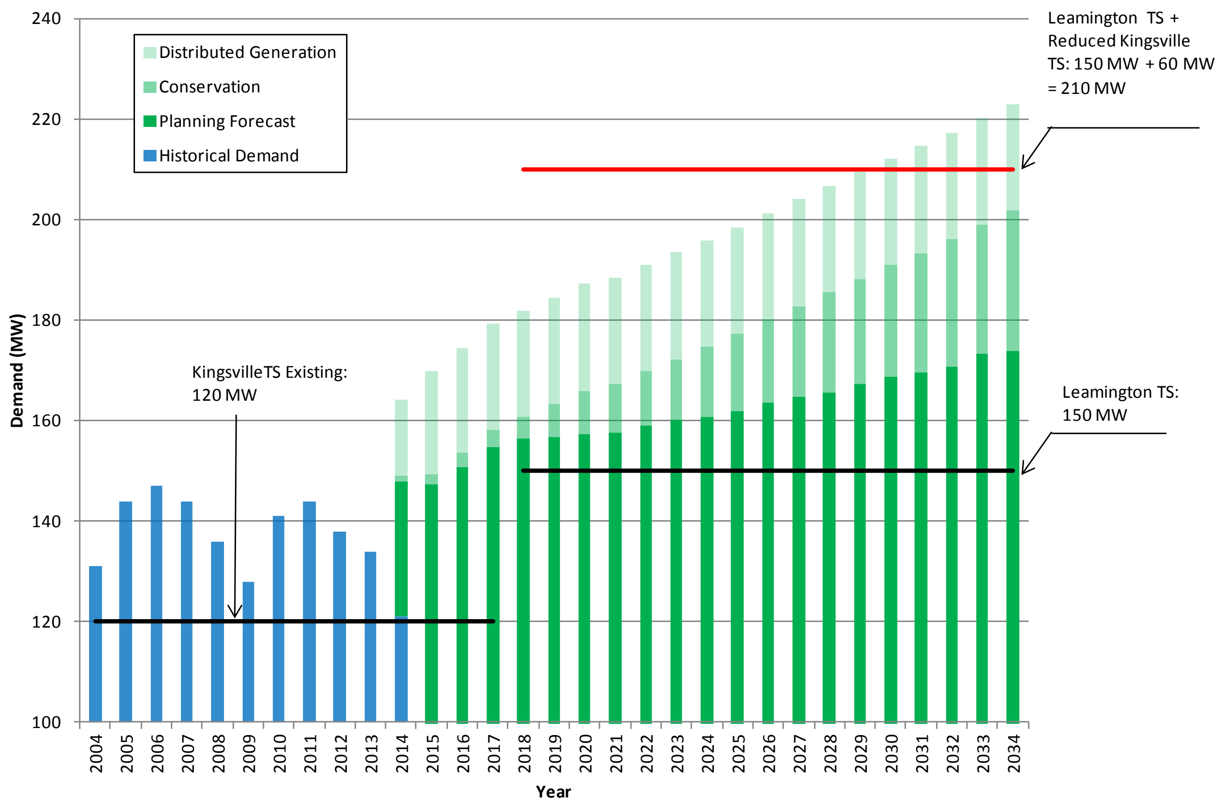
[12] Historic demand values reflect actual electricity demand and weather.

Kingsville TS by reducing the number of the station's transformers from four to two and reduces the LMC of the station from 120 MW to 60 MW, depending on the ability to transfer sufficient existing demand to the new Leamington TS. The result is a net increase in station capacity in the Kingsville-Leamington area, but with a different geographic distribution. This plan results in reduced flexibility for LDCs supplying customers in the Kingsville area. It will, however, be possible to return Kingsville TS to its current capacity in the future, should the forecast indicate the need for additional capacity.

The former-OPA prepared evidence to support Hydro One's regulatory application to the OEB for SECTR. This evidence details the needs in the Region; evaluates "non-wires" and "wires" alternatives; and recommends an integrated solution, comprised of planned conservation and DG resources, the new TS at Leamington, and partial refurbishment at Kingsville TS.

When the SECTR project is completed, and Kingsville TS refurbished with a reduced capacity, the combined supply capability in the Kingsville-Leamington area will be 210 MW. Figure 6-2 shows the supply capability in the Kingsville-Leamington area.

Figure 6-2: Kingsville-Leamington Sub-system Capability after Leamington TS is In-Service



6.2.2 Plan to Minimize the Impact of Supply Interruptions in the Windsor-Essex Region

A large portion of the transmission system in the Region, referred to as the "J3E-J4E sub-system", does not currently comply with ORTAC restoration criteria. In addition to addressing the supply capacity need in the Kingsville-Leamington area, the plan to build a new TS at Leamington will address the restoration need. This need is described in Figure 6-3.

<u>Sub-system Configuration and the Limiting Outage</u>

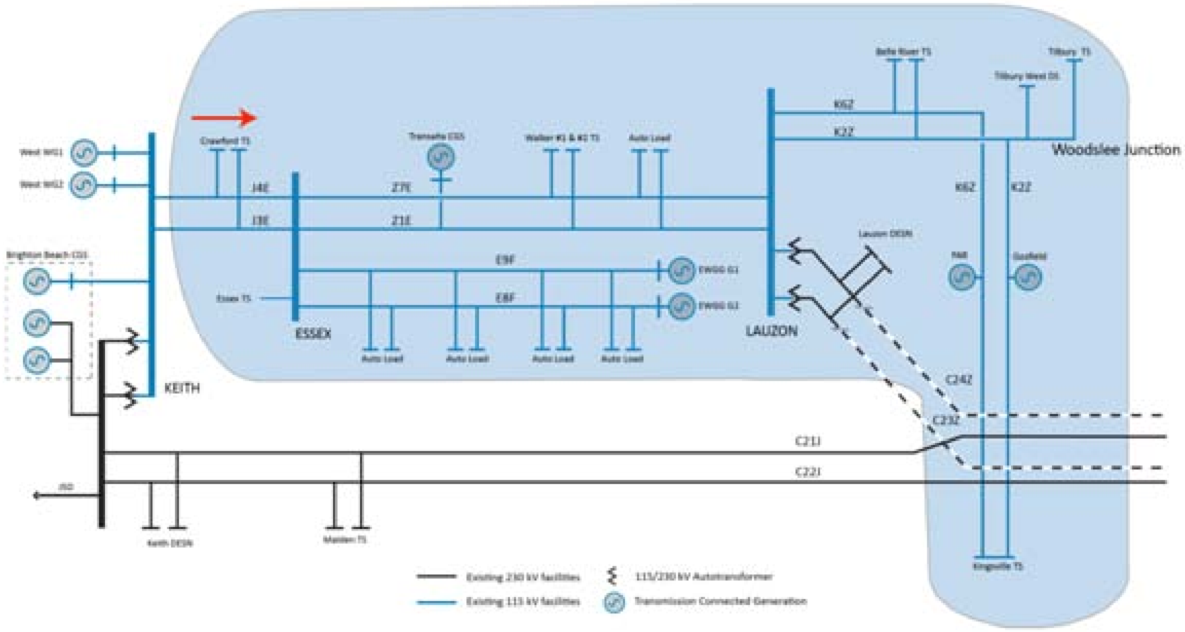
The J3E-J4E sub-system is supplied by two double-circuit 230 kV transmission lines between Chatham SS and Lauzon TS and Keith TS, respectively. The loss of one of these lines (C23Z/C24Z between Chatham and Lauzon) is the most limiting outage for this sub-system. In the event of the loss of the C23Z/C24Z transmission line, the Lauzon DESN station, which is directly connected to this line, is lost immediately. Subsequent to the outage, the 115 kV system supplying most of the City of Windsor, as well as Kingsville, Belle River and Tilbury, must be supplied entirely through the path consisting of the transformers at Keith TS and the 115 kV transmission line between Keith TS and Essex TS (J3E/J4E). The thermal capacity of the two

230/115 kV transformers at Keith TS limits the supply to the 115 kV system to approximately 300 MW. The C23Z/C24Z outage, and the J3E-J4E sub-system which is affected by this outage, are shown in Figure 6-3 below.

One of the Brighton Beach GS gas-fired generators is connected to the 115 kV bus at Keith TS between the Keith transformers and the J3E/J4E transmission line. The capability of the J3E/J4E line, which is higher than the capability of the Keith transformers, can be fully utilized by a combination of supply from the transmission system and generation at Brighton Beach GS. Due to this arrangement, the thermal capacity of the J3E/J4E transmission line limits the supply to the 115 kV system after the C23Z/C24Z double-circuit outage to approximately 440 MW. Because this would not be enough to meet the peak demand on the 115 kV system, the existing load rejection scheme would reject sufficient load immediately following the outage to respect the ratings of J3E/J4E.

The amount of load rejection required will depend on whether or not all local generation is in operation. For example, based on the planning forecast for 2017, following the loss of the C23Z/C24Z double-circuit transmission line, a total of 245 MW of load is interrupted, consisting of about 175 MW at Lauzon DESN and about 70 MW which is interrupted through load rejection, assuming local gas and renewable generation sources are running. This represents approximately 28% of the Windsor-Essex Region electricity demand, and is a substantial amount of demand to be interrupted following an outage. Following the contingency this load must be restored within the period of time prescribed by the ORTAC.

Figure 6-3: Windsor-Essex Region Transmission System Following an Outage to the C23Z/C24Z Transmission Line



Restoration Capability

The existing system lacks the capability to restore power to customers in the J3E-J4E sub-system in accordance with the ORTAC criteria which specifies that load greater than 250 MW must be restored within half an hour, load greater than 150 MW must be restored within 4 hours, and all load interrupted must be restored within 8 hours.

There are three sources of restoration capability which have been identified in the J3E-J4E sub-system: 1) gas-fired generation at Brighton Beach GS and in the J3E-J4E sub-system, 2) transferring load out of the J3E-J4E sub-system, and 3) transmission connected renewable generation within the J3E-J4E sub-system. These three contributors are discussed further below.

As noted previously, one of the gas-fired generating units at Brighton Beach GS is connected to the 115 kV bus at Keith TS. This generation capacity allows the capability of the J3E/J4E transmission line to be fully utilized after the C23Z/C24Z outage.

In addition, there is currently 154 MW of gas-fired generation within the J3E-J4E sub-system, consisting of East Windsor Cogeneration and TransAlta Windsor. The contract for one of these generators, TransAlta Windsor (74 MW), expires in December, 2016. Beyond this date, the amount of gas-fired generation within the sub-system will be reduced to 80 MW. This 80 MW of effective generation will help supply demand in the J3E-J4E sub-system following a major transmission outage until the expiry of the East Windsor Cogeneration contract in November, 2029.

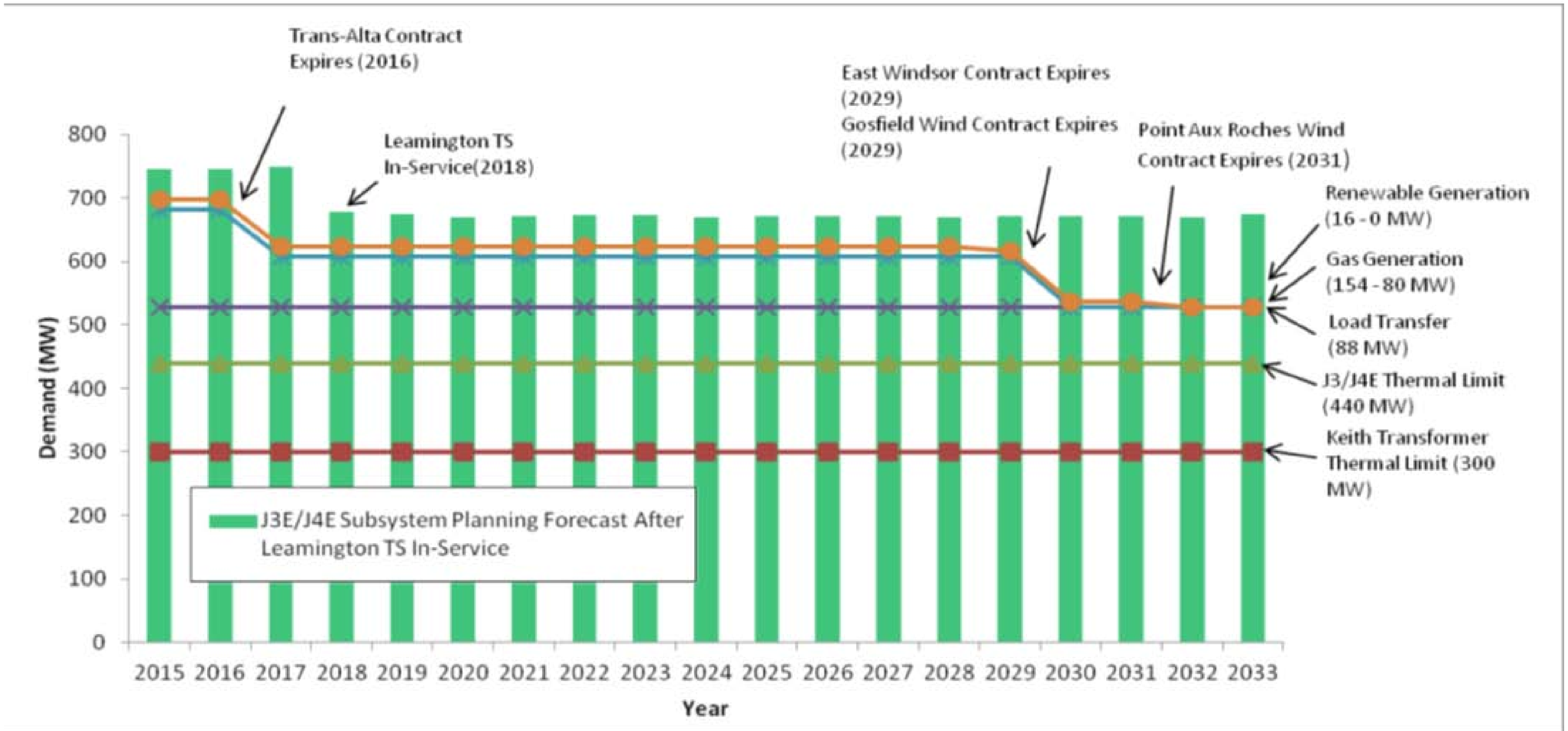
Hydro One has identified that there is a total of 88 MW of capability to transfer load supplied by the 115 kV system to stations supplied by the 230 kV system. This consists of 18 MW of transfer capability to Keith TS, 50 MW to Malden TS, and up to 20 MW of load at Tilbury West DS which can be supplied by the N5K circuit (outside the Region, near Chatham). These transfer capabilities are based on the station capability of Keith TS and Malden TS, and the capability of the N5K circuit.

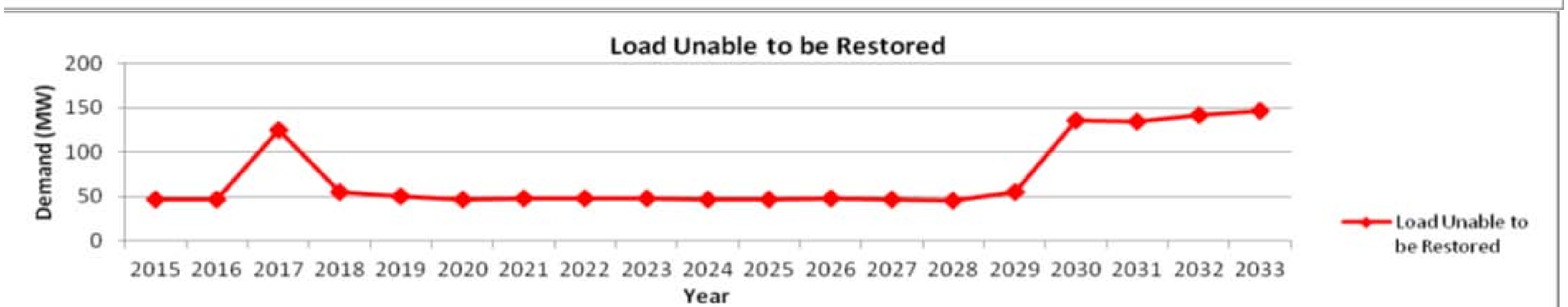
In addition, as noted in Section 4.2 there is 100 MW of transmission connected renewable generation within the Kingsville-Leamington sub-system. It is reasonable to count on the effective capacity of 16 MW from these facilities for the purpose of providing restoration capability until the two contracts expire in 2029 and 2031 respectively.

The new Leamington TS which has a planned in-service date of 2017 would improve the restoration situation by moving some of the load out of the J3E-J4E sub-system to a new 230 kV supply point. Leamington TS will be supplied by C21J and C22J and will therefore not be affected by the C23Z/C24Z contingency.

Figure 6-4 summarizes the above analysis. After 2016 there is a need for approximately 125 MW of additional restoration capability in order to fully restore the J3E-J4E sub-system following the C23Z/C24Z double-circuit contingency. With the planned Leamington TS in-service in 2018 this requirement will decrease to about 50 MW.

Figure 6-4: J3E – J4E Sub-system Restoration





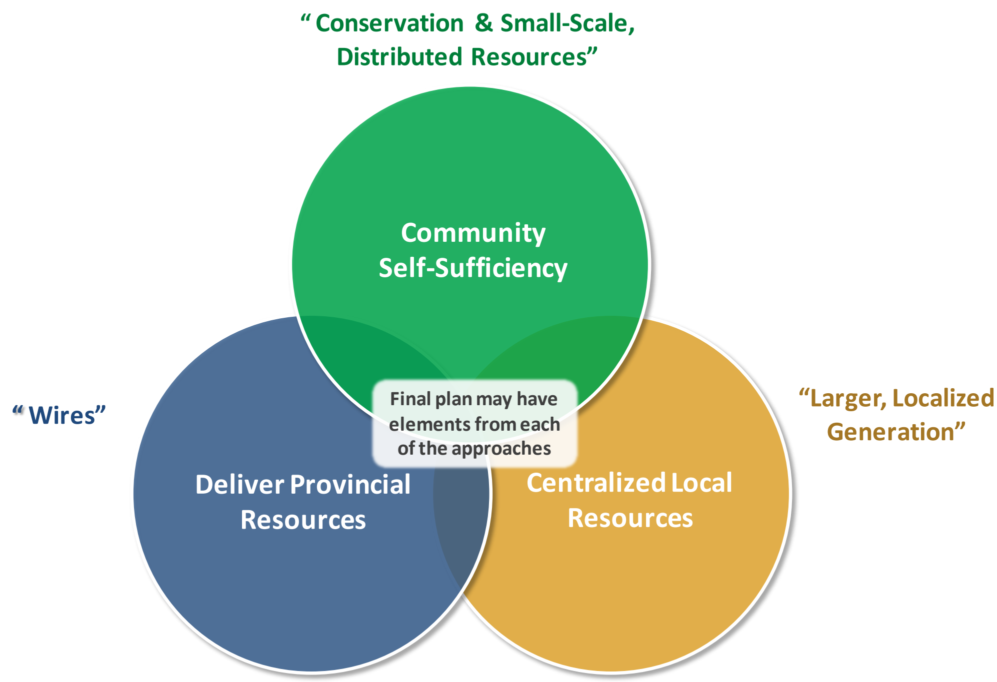
7. Long-Term Plan

No long-term supply capacity needs have been identified in the Region at this time. Therefore, instead of considering specific needs and planning options, long-term planning activities for the Region will include engaging with stakeholders and communities; monitoring demand, conservation, and DG trends in the area; coordinating with municipal or community energy planning activities; and generally laying the foundation for informed planning in the future. The OEB's regional planning process suggests a minimum 5-year cycle, however if significant changes are noted in the region over the coming years the process may be initiated earlier.

In recent years, a number of trends, including technology advances, policy changes supporting DG, greater emphasis on conservation as part of electricity system planning, and increased community interest and desire for involvement in electricity planning and infrastructure siting, are changing the landscape for regional electricity planning. Traditional, "wires" based approaches to electricity planning may not be the best fit for all communities. New approaches that acknowledge and take advantage of these trends, in addition to more traditional "wires-based", should also be considered.

To facilitate discussions about how a community might plan its future electricity supply, three conceptual approaches for meeting a region's long-term electricity needs provide a useful framework (see Figure 7-1). Based on regional planning experience across the province over the last 10 years, it is clear that different approaches are preferred in different regions, depending on local electricity needs and opportunities, and the desired level of involvement by the community in planning and developing its electricity infrastructure.

Figure 7-1: Approaches to Meeting Long-Term Needs



The three approaches are as follows:

- **Delivering provincial resources**, or "wires" planning, is the traditional regional electricity planning approach associated with the development of centralized electric power systems over many decades. This approach involves using transmission and distribution infrastructure to supply a region's electricity needs, taking power from the provincial electricity system. This model takes advantage of generation that is planned at the provincial level, with generation sources typically located remotely from the region. In this approach, utilities (transmitters and distributors) play a lead role in development.
- The **Centralized local resources** approach involves developing one or a few large, local generation resources to supply a community. While this approach shares the goal of providing supply locally with the community self-sufficiency approach below, the emphasis is on large central-plant facilities rather than smaller, distributed resources.
- The **Community self-sufficiency** approach entails an emphasis on meeting community needs largely with local, distributed resources, which can include: aggressive conservation beyond provincial targets; DR; DG and storage; smart grid technologies for managing distributed resources; integrated heat/power/process systems; and electric vehicles. While many of these applications are not currently in widespread use, for regions with long-term needs (i.e., 10-20 years in the future) there is an opportunity to develop and test out these options before commitment of specific projects is required.

> The success of this approach depends on early action to explore potential and develop options, and on the local community taking a lead role. This could be through a municipal energy planning or community energy planning process, or an LDC or other local entity taking initiative to pursue and develop options.

Given that no long-term supply capacity needs have been identified in the Region, it is not necessary to consider the application of these options to Windsor-Essex at this time. These concepts, which are being referenced in other planning regions around the province, are provided as background information for community members and stakeholders who are interested in the long-term considerations for regional electricity supply in Windsor-Essex.

8. Community, Aboriginal and Stakeholder Engagement

Community engagement is an important aspect of the regional planning process. Providing opportunities for input in the regional planning process enables the views and preferences of the community to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken to date for the Windsor-Essex Region IRRP and those that will take place to discuss the Regional planning process and electricity supply needs in the area.

A phased community engagement approach has been developed for the Windsor-Essex IRRP based on the core principles of creating transparency, engaging early and often, and bringing communities to the table. These principles were articulated as a result of the IESO's outreach with Ontarians to determine how to improve the regional planning process, and they are now guiding the IRRP outreach with communities.

Figure 8-1: Summary of Windsor-Essex IRRP Community Engagement Process

Creating Transparency:

Creation of Windsor-Essex IRRP Information Resources

- Dedicated Windsor-Essex IRRP web page created on IESO (former OPA) website providing background information, the IRRP Terms of Reference and listing of the Working Group members
- Dedicated web page added to Hydro One website, and information posted on LDC websites
- Self-subscription service established for Windsor-Essex IRRP for subscribers to receive regional specific updates
- Status: complete

Engaging Early and Often:

Municipal, First Nation & Métis Outreach

- Presentation and discussion at three group meetings with municipal planners from across the planning region
- Information on the plan provided to First Nation communities who may have an interest in the planning area with an invitation to meet
- Information provided to the Métis Nation of Ontario
- Status: initial outreach complete; dialogue to continue

Bringing Communities to the Table:

Broader Community Outreach

- Presentation at Municipal Councils, First Nation communities and Métis Nation of Ontario as requested
- Webinar to discuss regional planning process and electricity needs in the area
- Broader community outreach to be undertaken on education about regional planning in the Windsor-Essex area; feedback from this phase on community values and preferences will inform the decisions to be made in the next planning cycle
- Status: beginning in May 2015; no time limit

Creating Transparency

To start the dialogue on the Windsor-Essex IRRP and build transparency in the planning process, a number of information resources were created for the plan. A dedicated web page was created on the IESO (former-OPA) website to provide a map of the regional planning area, information on why the plan was being developed, the terms of reference for the IRRP and a listing of the organizations involved was posted on the websites of the Working Group members. A dedicated email subscription service was also established for the Windsor-Essex IRRP where communities and stakeholders could subscribe to receive email updates about the IRRP.

Engaging Early and Often

The first step in the engagement of the Windsor-Essex IRRP was providing information to representatives from the municipalities and First Nation communities in the Region. For the municipal meetings, presentations were made to the Windsor-Essex Region municipal planners and Chief Administrative Officers at three group meetings held in Windsor and Chatham during October and November, 2014. Key topics discussed during the meetings included confirmation that the demand forecast reflects municipal planning expectations, system restoration needs, and the strong interest shown by the local greenhouse industry in CHPSOP offered by the former-OPA.

Bringing Communities to the Table

This engagement will begin with a webinar hosted by the Working Group to discuss the plan and approaches for near-term options. Presentations on the Windsor-Essex IRRP will also be made to Municipal Councils, First Nation communities and the Métis Nation of Ontario on request.

To strengthen the discussion, an informational meeting will be held with local representatives from Municipalities including Mayors and economic development groups, Aboriginal communities, local industry and community groups. Following this meeting, a public open house will be held to further expand the discussion and awareness at a community level.

Strengthening processes for early and sustained engagement with communities and the public were introduced following an engagement held in 2013 with 1,250 Ontarians on how to enhance regional electricity planning. This feedback resulted in the development of a series of recommendations that were presented to, and subsequently adopted by the Minister of Energy. Further information can be found in the report entitled "Engaging Local Communities in Ontario's Electricity Planning Continuum"[13] available on the IESO website.

Information on outreach activities for the Windsor-Essex Region IRRP can be found on the IESO website and updates will be sent to all subscribers who have requested updates on the Windsor-Essex IRRP.

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[13] http://www.powerauthority.on.ca/stakeholder-engagement/stakeholder-consultation/ontario-regional-energy-planning-review

9. Conclusion

This report documents the IRRP that has been carried out for the Windsor-Essex Region and it largely fulfils the OEB requirement to conduct regional planning for this Region. The IRRP identifies electricity needs in the Region over the 20-year period from 2014 to 2033, recommends a plan to address near-term needs, and identifies a monitoring and engagement plan for the next few years, to inform the next regional planning cycle.

Implementation of the near-term plan is already underway, with the LDCs developing conservation plans consistent with the Conservation First policy and with infrastructure projects being developed by Hydro One.

The planning process does not end with the publishing of this IRRP. The Windsor-Essex Working Group will continue to meet at least annually to monitor progress and developments in the Region.

ENTEGRUS™

2021-2025 Distribution System Plan Attachments

ATTACHMENT I

IESO Letter of Comment

IESO response to Entegrus Powerlines Inc.'s REG Investment Plan 2021 – 2025

In accordance with the Ontario Energy Board's (OEB) Chapter 5 filing requirements to submit a Distribution System Plan (DSP) with its Cost of Service application, on July 8, 2020, Entegrus Powerlines Inc. (Entegrus) sent its Renewable Energy Generation (REG) Plan as part of its DSP, to the Independent Electricity System Operator (IESO) for comment. The IESO has reviewed Entegrus' REG Plan and notes that it contains no investments specific to connecting REG for the Plan period 2021 - 2025.

The IESO notes that Entegrus' service territory is within four regional planning groups: London Area, Greater Bruce/Huron, Chatham-Kent/Lambton/Sarnia, and Windsor-Essex. For all of these regions the IESO confirms that Entegrus has been a participating member of the Working Groups[1]. The status of regional planning activities for these regions can be found on the IESO's website.

Entegrus' REG Plan, Section 3.1 Planned Investments to Facilitate Renewable Energy Generation Connections states: "Entegrus currently does not have a basis to anticipate significant changes to past REG accommodation trends. Accordingly, Entegrus is not proposing any capital investments to accommodate the needs of new or existing REG proponents over the period of 2021-2026."

The IESO submits that as Entegrus has no REG investments during the 5-year Distribution System Plan period, no comment letter from the IESO is required to address the bullets points in the OEB's Filing Requirements for Electricity Distribution Rate Applications - Chapter 5, Section 5.2.2 Coordinated Planning with Third Parties [2].

The IESO appreciates the opportunity provided to review the REG Plan of Entegrus, and looks forward to working together further throughout the regional planning processes.

[1] Working Group members along with the IESO and Hydro One (Distribution and Lead Transmitter): **Chatham-Kent/Lambton/Sarnia** – Entegrus, and Bluewater Power Distribution Corporation; **Greater Bruce/Huron** – Entegrus, ERTH Power Corp., Festival Hydro Inc., Wellington North Power Inc., and Westario Power Inc.; **London Area** – Entegrus, ERTH Power Corporation, London Hydro Inc., Tillsonburg Hydro Inc.; **Windsor-Essex** – Entegrus, E.L.K Energy Inc., EnWin Utilities Ltd., and Essex Powerlines Corporation.

[2] OEB's Filing Requirements for Electricity Distribution Rate Applications - Chapter 5, Section 5.2.2, page 10: https://www.oeb.ca/sites/default/files/Chapter-5-DSP-Filing-Requirements-20200514.pdf

Connecting Today.
Powering Tomorrow.

ATTACHMENT J

Entegrus Powerlines Inc. 2019

Scorecard

Scorecard - Entegrus Powerlines Inc.

9/29/2020

Performance Outcomes	Performance Categories	Measures		2015	2016	2017	2018	2019	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		99.50%	98.80%	98.48%	97.95%	98.04%	↓	90.00%	
		Scheduled Appointments Met On Time		94.00%	97.80%	99.38%	99.73%	99.53%	↑	90.00%	
		Telephone Calls Answered On Time		81.30%	68.70%	75.60%	71.01%	65.61%	↓	65.00%	
	Customer Satisfaction	First Contact Resolution		78%	79.3%	81%	81%	79%			
		Billing Accuracy		99.78%	99.84%	99.88%	99.90%	99.90%	↑	98.00%	
		Customer Satisfaction Survey Results		91	83.0	94	94	94			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness		82.00%	82.00%	83.00%	83.00%	81.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	NI	C	→		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	2	1	↑		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	1.618	0.805	↑		0.227
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		1.18	0.51	1.72	1.89	1.73	↑		1.16
		Average Number of Times that Power to a Customer is Interrupted [2]		0.87	0.41	1.07	1.21	1.02	↑		0.87
	Asset Management	Distribution System Plan Implementation Progress		100	22	44	60.41	85.6			
	Cost Control	Efficiency Assessment		2	2	2	2	2			
		Total Cost per Customer [3]		$549	$567	$555	$563	$566			
		Total Cost per Km of Line [3]		$23,395	$24,291	$23,124	$26,787	$10,982			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings [4]		67.85%	99.03%	95.92%	98.87%	117.00%			94.35 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%	100.00%	100.00%		100.00%			
		New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%	100.00%	100.00%	100.00%	→	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.69	1.67	1.36	1.34	1.41			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.40	1.44	1.33	1.22	1.20			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.85%	9.19%	9.19%	9.19%	9.19%			
			Achieved	9.92%	7.46%	7.64%	8.20%	10.58%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the now discontinued 2015-2020 Conservation First Framework. 2019 results include savings reported to the IESO up until the end of February 2020.

Legend:
5-year trend: ↑ up ↓ down → flat
Current year: target met / target not met

2019 Scorecard Management Discussion and Analysis ("2019 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2019 Scorecard MD&A:

http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

Entegrus Powerlines Inc. ("Entegrus") owns, operates and manages the assets associated with the distribution of electrical power to approximately 59,800 customers in 17 Southwestern Ontario communities. The roots of Entegrus extend back to the formation of Chatham Hydro in 1914.

The communities serviced by Entegrus in 2019 are: Blenheim, Bothwell, Chatham (including a portion of the Township of Raleigh known as the "Bloomfield Business Park"), Dresden, Dutton, Erieau, Merlin, Mount Brydges, Newbury, Parkhill, Ridgetown, Strathroy, Thamesville, Tilbury, Wallaceburg, Wheatley and St. Thomas. Additional details are provided in the Entegrus Electricity Distribution License (ED-2002-0563).

On April 1, 2018, Entegrus amalgamated with St. Thomas Energy Inc. ("STEI"), a licensed electricity distributor operating within the City of St. Thomas. The merged electricity distributor continues as Entegrus. The scorecard results discussed herein relate to the combined 2019 results.

Entegrus monitors the scorecard measures on an ongoing basis and continuously seeks opportunities to improve its performance. The company is committed to meeting the needs of its customers both today and in the future. Entegrus is confident that its focus on customer outcomes will allow it to continue to meet or exceed performance targets.

Entegrus is committed to continuous year over year performance improvement for 2020 and beyond.

Service Quality

- **New Residential/Small Business Services Connected on Time**
  In 2019, Entegrus connected 98.04% of approximately 1,375 eligible low-voltage residential and small business customers (those utilizing connections under 750 volts) to its system within the five-day timeline prescribed by the OEB. This result was achieved despite a continuing increase in new residential and small business connections requested in 2019. For the five-year period from 2015 to 2019, Entegrus has consistently performed better than the industry target of 90% in this area.

- **Scheduled Appointments Met on Time**
  Entegrus scheduled approximately 2,360 appointments in 2019 to complete work requested by customers (where customer presence is required). Entegrus met 99.53% of these appointments on time. For the five-year period from 2015 to 2019, Entegrus has consistently performed better than the industry target of 90% in this area.

- **Telephone Calls Answered on Time**
  In 2019, Entegrus Customer Service received approximately 74,400 calls from its customers – over 296 calls per working day. In 65.61% of instances, Entegrus answered the call within 30 seconds or less. This result exceeds the OEB-mandated 65% target for timely call response. In 2019, Entegrus harmonized its customer information system across the organization. This resulted in some resource constraints during 2019. Going forward this will allow more flexibility to route calls and improve customer experience.

  Entegrus staffs its Customer Service Call Centre to meet the 65% target, without significantly exceeding it, in order to balance the need to prudently deploy resources in all areas of the business. For the five-year period from 2015 to 2019, Entegrus has consistently performed better than the industry target of 65% in this area.

Customer Satisfaction

- **First Contact Resolution**
  Prior to 2014, specific customer satisfaction measurements were not defined across the industry. In 2014, the OEB instructed all electricity distributors to review and develop measurements in these areas and begin tracking so that the results could be reported on the 2014 Scorecard. Currently, each electricity distributor is permitted to have different measurements of performance until such time as the OEB provides specific direction regarding a commonly defined measure.

  First Contact Resolution ("FCR") traditionally represents a percentage of instances where a customer's need is addressed at the time of their first point of contact on the matter. However, FCR can be measured in a variety of ways and further regulatory guidance will be necessary in order to achieve meaningful, consistent and comparable information across electricity distributors.

Entegrus believes that best practice is to measure FCR based on ongoing third-party surveys of a random sample of those customers who have recently contacted Entegrus. Accordingly, starting in 2014, Entegrus' FCR has been measured based on live agent transactional phone surveys conducted by a third-party service provider. To facilitate these surveys, throughout the year, Entegrus provides the third-party service provider with a report of all customers who had contacted Entegrus Customer Service by telephone within the previous two weeks.

The third-party service provider's telephone agents, in turn, contact and survey Entegrus customers. Customers are asked to rate various facets of their customer experience and are also asked if their issue (i.e. their reason for calling) was resolved on their first contact to Entegrus. In 2019, of the 500 customers surveyed, 395 customers indicated that their issue was resolved on the first call to Entegrus. This equates to the reported FCR figure of 79.0%.

Entegrus continues to maintain its high FCR results by implementing recommendations from the service provider. Accordingly, Entegrus has continued to engage the third-party service provider to assist with ongoing FCR measurement and customer service strategy improvements on specific issue types.

- **Billing Accuracy**

  Prior to 2014, a specific measurement of billing accuracy had not been defined across the industry. In 2014, the OEB instructed all electricity distributors to begin tracking a prescribed billing accuracy measure so that the results could be reported on the 2014 Scorecard.

  In 2019, Entegrus issued 693,989 bills and achieved a billing accuracy of 99.90%. This compares favourably to the prescribed OEB target of 98%.

  Entegrus continues to monitor its billing accuracy results and processes to identify opportunities for improvement.

- **Customer Satisfaction Survey Results**

  Similar to the FCR measure described above, the OEB introduced the Customer Satisfaction Survey Results measure beginning in 2014. At a minimum, electricity distributors are required to measure and report a customer satisfaction result every other year. At this time, the OEB is allowing electricity distributors the discretion as to how this measure is implemented. Starting in 2014, Entegrus engaged a third-party service provider to conduct annual (rather than bi-annual) Customer Satisfaction surveys.

  In 2019, the third-party service provider conducted a random telephone survey for the period September 30, 2019 to October 15, 2019, the service provider agents contacted a random sample of 400 complete Residential surveys and 100 complete Small Commercial surveys. Of the 500 customers surveyed (the denominator), 472 customers (the numerator) rated their Overall Satisfaction in the top 3 boxes. The survey asks customers questions on a wide range of topics, including: overall satisfaction with Entegrus, reliability, customer service, outages, billing and corporate image.

Customer Satisfaction survey results remained steady at 94%. Customer Satisfaction is a key area of focus for Entegrus. Accordingly, Entegrus will continue to measure Customer Satisfaction annually, as opposed to the regulatory requirement to measure it every other year.

Safety

- **Public Safety**

  - **Component A – Public Awareness of Electrical Safety**

In 2015, in consultation with the Electrical Safety Authority ("ESA"), the OEB introduced this new public awareness survey measure. The survey is based upon a representative sample of each electrical distributor's service territory population and gauges awareness levels of key electrical safety concepts related to distribution assets. The survey provides a benchmark of levels of awareness including identifying gaps where additional education and awareness efforts may be required. In accordance with OEB requirements, the survey is conducted every other year. Accordingly, the survey results described below were completed for the 2019 scorecard will also be applicable for 2020 scorecard.

Entegrus conducted a public safety awareness campaign in the spring of 2020 utilizing local media and digital website content. Further, Entegrus continues to conduct: safety awareness through its ongoing work with the Chatham-Kent Children's Safety Village and the MySafeWork program, safety awareness briefings with first responders and visits to grade school classrooms to review electrical safety.

Entegrus engaged a third-party service provider to conduct stratified random telephone surveys of 600 Ontario residents, ages 18 or older, currently residing in the Entegrus service territory during the period from March 2, 2020 and March 16, 2020. The survey asked residents electrical safety questions and then an overall index score was calculated in accordance with a prescribed algorithm. Public Awareness of Electrical Safety results for 2019 were consistent with prior years at 81%.

  - **Component B – Compliance with Ontario Regulation 22/04**

Ontario Regulation 22/04 (Electrical Distribution Safety) establishes objective based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed distributors. The regulation requires the approval of equipment, plans, specifications and inspection of construction before they are put into service. Entegrus is audited annually for compliance and was found to be compliant in 2019.

- **Component C – Serious Electrical Incident Index**

  This is measured as the number of non-occupational (general public) serious electrical incidents occurring on Entegrus' distribution system and reported to the ESA, expressed as a raw number and as the number per 1,000 km of line. Entegrus had no such incidents from 2014 to 2017. Entegrus experienced two incidents in 2018 and one incident in 2019. This incident involved a motor vehicle accident that resulted in broken poles and downed overhead wires.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**

  For this measure, the OEB establishes baseline targets based on the average of the distributor's performance for the period 2011 – 2015 (the baseline period is updated every 5 years). Entegrus' 2019 result of 1.73 is relatively consistent with the prior two year and is above the target of 1.16. This trend is a result of enhancements to Entegrus' outage reporting systems and aging infrastructure.

  Entegrus continues to view reliability of electricity service as a high priority. As further discussed below, Entegrus continued to make substantial progress on its Distribution System Plan ("DSP") implementation in 2019, as well as the design of a new combined and comprehensive DSP for 2021.

- **Average Number of Times that Power to a Customer is Interrupted**

  For this measure, the OEB establishes baseline targets calculated as the average of the distributor's performance for the period 2011 – 2015 (the baseline period is updated every 5 years). Entegrus' 2019 result of 1.02 is relatively consistent with the prior two years and is above the target of 0.87. This trend is a result of enhancements to Entegrus' outage reporting systems and aging infrastructure.

  Entegrus continues to view reliability of electricity service as a high priority. As further discussed below, Entegrus continued to make substantial progress on its DSP implementation in 2019, as well as the design of a new combined and comprehensive DSP for 2021.

Asset Management

- **Distribution System Plan Implementation Progress**

  Entegrus maintains DSP that adopts a proactive, balanced approach to distribution system planning, infrastructure investment and replacement programs to address immediate risks associated with end-of-life assets; manage distribution system risks; ensure the safe and reliable delivery of electricity; and balance ratepayer and utility affordability.

  The Entegrus-Main DSP was completed in 2015 and accepted by the OEB in 2016. The Entegrus-St. Thomas DSP was completed in 2014 and accepted by the OEB in 2015. Entegrus is currently working towards completing a combined and comprehensive DSP for 2021.

  Entegrus reports this metric based on percentage of actual life-to-date capital expenditures divided by the aggregate total DSP (5 year) capital expenditures. The Entegrus 2019 life-to-date actual capital expenditures were $37.7M (the numerator). The total DSP (5 year) capital expenditures were $44.0M (the denominator), inclusive of $38.4M representative of Entegrus-Main rate zone and $5.6M representative of the St. Thomas rate zone. This numerator and denominator equate to the reported DSP Implementation Progress figure of 85.6%.

  In 2019, the implementation focus of the DSP was on continued distribution system renewal, voltage conversions of sections of the system from 4.16 kV to 27.6 KV and deployment of smart grid technologies. System access requests were higher than anticipated, which drove incremental capital expenditures in 2019.

Cost Control

- **Efficiency Assessment**

  The total costs for Ontario local electricity distribution companies are evaluated based on econometric modeling conducted by a consultant (the Pacific Economics Group LLC) on behalf of the OEB to produce a single efficiency ranking. The electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs over the past three years.

  In 2019, Entegrus' actual costs for 2017-2019 were 17.9% lower than the costs predicted by the OEB's consultant. For the eighth year in a row, Entegrus was placed in Group 2, where a Group 2 distributor is defined as having actual costs which are 10% to 25% lower than the costs predicted for the distributor. Group 2 is considered as "more efficient". In 2019, Entegrus ranked 15th out of 59 distributors in terms of cost performance results versus benchmark.

- **Total Cost per Customer**
  Total cost per customer is calculated as the sum of Entegrus' capital and operating costs, divided by the total number of customers that Entegrus serves. Entegrus' cost performance result for 2019 is $566 per customer, which represents a 0.53% increase over 2018.

- **Total Cost per Km of Line**
  This measure uses the same total cost that is used in the Cost per Customer calculation above. The total cost is divided by the kilometers of line that Entegrus operates to serve its customers, which equates to $10,982 per kilometer of line. For 2019 Entegrus had the opportunity to include secondary kilometer of lines in its annual reporting. Accordingly, the decrease in total cost per kilometer of line is due to the inclusion of secondary lines in the cost per kilometer calculation in 2019, whereas, only primary lines were included in 2018.

Conservation & Demand Management

- **Net Cumulative Energy Savings**
  The province launched a new Conservation First Framework ("CFF") on January 1, 2016 for the period 2016-2020. Entegrus' original allocated target was 56.8 GWh, which Entegrus achieved in the first year of the framework (2016). Subsequently, Entegrus entered into a target exchange in December 2017 with another distributor to acquire an additional target of 20 GWh, along with additional conservation funding for its customers. In 2018, Entegrus merged with STEI and acquired an additional 17.5 GWh of target. Accordingly, Entegrus' target for 2016-2020 Net Cumulative Energy Savings (kWh) is 94.35 GWh.

  Life-to-date at December 31, 2019, Entegrus achieved 117.00% of the amended Net Cumulative Energy Savings target. In March 2019, the provincial government announced the winddown of the conservation framework and the uploading of provincial conservation programs from the distributor to the IESO.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**
  Electricity distributors are required to conduct Connection Impact Assessments (CIAs) within 60 days of the receipt of the application for a proposal to connect a mid-sized generation facility or 90 days of the receipt of an application to connect a large embedded generation facility.

  Entegrus successfully completed 4 CIAs in 2019 within the prescribed time. Since 2014, Entegrus has successfully completed all CIA's within the prescribed time limit.

- **New Micro-Embedded Generation Facilities Connected on Time**
  Electricity distributors are required to connect an applicant's micro-embedded generation facility (i.e. MicroFIT projects of less than 10kW or net metering projects) to its distribution system within five business days of the applicant informing the distributor that it has satisfied all applicable service conditions, received all necessary approvals and provided the distributor with a copy of the authorization to connect from the ESA. The minimum acceptable performance level for this measure is 90%.

  In 2019, Entegrus connected 2 new micro-embedded generation facilities within the prescribed time frame of five business days. Entegrus works closely with its customers and their contractors to address any connection issues to ensure the project is connected on time.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**
  Liquidity is calculated by dividing Current Assets by Current Liabilities. This ratio is also known as Working Capital Ratio and measures an entity's ability to pay short-term financial obligations. As an indicator of financial health, a Liquidity Ratio of greater than 1 is considered good, as it indicates that the company can pay its short-term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being "liquid". The higher the number, the more "liquid" and the larger the margin of safety to cover the company's short-term debts and financial obligations.

  The Entegrus current ratio was 1.41 in 2019. Entegrus goal is to maintain a Liquidity Ratio of more than 1.00. As noted above, this means that the organization has resources available in the short term to meet its short-term financial obligations.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**
  The OEB uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5 (60/40). A debt to equity ratio of more than 1.5 indicates that a distributor is more highly levered than the deemed capital structure. A high debt to equity ratio may indicate that an electricity distributor may have difficulty generating sufficient cash flows to make its debt payments. A debt to equity ratio of less than 1.5 indicates that the distributor is less levered than the deemed capital structure. A low debt-to-equity ratio may indicate that an electricity distributor is not taking advantage of the increased profits that financial leverage may bring.

  As demonstrated by its 2019 Leverage Ratio of 1.20, Entegrus continues to maintain a debt to equity structure that closely approximates the deemed 60% to 40% capital mix as set out by the OEB. Entegrus' strong financial position is further supported by its recent Standard & Poor's Rating Services rating of "A/Stable/--".

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**
  Entegrus' 2019 distribution rates were approved by the OEB and includes an expected (deemed) regulatory return on equity of 9.19%. The OEB allows a distributor to earn within +/- 3% of the expected return on equity. When a distributor performs outside of this range, the actual performance may trigger a regulatory review of the distributor's revenues and costs structure by the OEB.

- **Profitability: Regulatory Return on Equity – Achieved**
  Entegrus' achieved a 2019 Regulatory Return on Equity ("ROE") of 10.58%, which is within the +/-3% range of Deemed ROE allowed by the OEB.

Note to Readers of 2019 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgement on the reporting date of the performance scorecard and could be markedly different in the future.

ATTACHMENT K

St. Thomas Energy Inc. 2017

Scorecard

Scorecard - St. Thomas Energy Inc.

9/18/2018

Performance Outcomes	Performance Categories	Measures		2013	2014	2015	2016	2017	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		100.00%	100.00%	100.00%	98.40%	95.72%		90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Telephone Calls Answered On Time		76.50%	68.20%	74.60%	75.80%	77.26%		65.00%	
	Customer Satisfaction	First Contact Resolution		100%	100%	100%	100%	100%			
		Billing Accuracy			99.91%	92.74%	99.95%	99.95%		98.00%	
		Customer Satisfaction Survey Results		A A A+	B+ A A	B+ A A	B+, A, A	B+, A, A			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness				83.00%	83.00%	81.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		NI	NI	C	C	NC			C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0			0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000			0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		0.99	0.57	0.35	1.04	0.47			0.62
		Average Number of Times that Power to a Customer is Interrupted [2]		1.42	1.58	1.04	1.49	0.58			1.12
	Asset Management	Distribution System Plan Implementation Progress		100%	100%	100%	99.58%	121%			
	Cost Control	Efficiency Assessment		3	3	3	3	2			
		Total Cost per Customer [3]		$533	$516	$513	$534	$494			
		Total Cost per Km of Line [3]		$33,412	$33,823	$33,419	$38,032	$34,897			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings [4]				12.26%	37.27%	61.13%			17.51 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%	100.00%		100.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.42	1.17	1.09	1.36	0.84			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		0.83	0.77	0.71	0.65	0.31			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.58%	9.58%	9.30%	9.30%	9.30%			
			Achieved	10.77%	9.36%	11.64%	10.65%	11.60%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework.

Legend:
5-year trend: up, down, flat
Current year: target met, target not met

2017 Scorecard Management Discussion and Analysis ("2017 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2017 Scorecard MD&A:

http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

St. Thomas Energy Inc. ("STEI") is a licensed electricity distributor operating pursuant to license ED-2002-0523 and distributes electricity to approximately 17,500 customers in the City of St. Thomas. STEI's franchise area is primarily contained within the municipal boundaries of the city of St. Thomas and is about 33 square km in area. STEI is largely an urban service territory. STEI's distribution system is supplied by Hydro One Networks Inc. primarily from the Edgeware TS at a voltage level of 27.6 kV.

On April 1, 2018, STEI amalgamated with Entegrus Powerlines Inc. ("EPI"), a licensed electricity distributor operating in 16 communities in Southwestern Ontario. The merged electricity distributor continues as EPI. The scorecard results discussed herein relate to 2017, prior to the merger.

Service Quality

- **New Residential/Small Business Services Connected on Time**
  In 2017, STEI connected 95.72% of approximately 304 eligible low-voltage residential and small business customers (those utilizing connections under 750 volts) to its system within the five-day timeline prescribed by the Ontario Energy Board ("OEB"). This result was achieved amidst a significant increase in new residential and small business connections requested in 2017 (up 60% from 2016). For the five-year period from 2013 to 2017, STEI has consistently performed better than the industry target of 90% in this area.

- **Scheduled Appointments Met on Time**
  STEI scheduled approximately 620 appointments in 2017 to complete work requested by customers, including reading meters, making reconnections, and other requirements. STEI met 100% of these appointments on time, consistent with the 2016 result. For the five-year period from 2013 to 2017, STEI has consistently performed better than the industry target of 90% in this area.

  STEI's staff are aware of the obligations and are committed to exceeding the requirements for making appointments with our customers. Providing excellence in customer service is at the core of STEI's corporate philosophy, and the utility is consistently seeking new ways to foster meaningful two-way communication, expand on the range of service offerings and improve service convenience.

- **Telephone Calls Answered on Time**

  In 2017, STEI Customer Service agents received approximately 23,607 calls from its customers – over 94 calls per working day. In 77.26% of instances, an STEI agent answered the call within 30 seconds or less. This result exceeds the OEB-mandated 65% target for timely call response. For the five-year period from 2013 to 2017, STEI has consistently performed better than the industry target of 65% in this area.

  STEI recognizes the need to balance cost efficiencies with service quality in order to prudently deploy resources throughout the company.

Customer Satisfaction

- **First Contact Resolution**

  Prior to 2014, specific customer satisfaction measurements were not defined across the industry. In 2014, the OEB instructed all electricity distributors to review and develop measurements in these areas and begin tracking so that the results could be reported on the 2014 Scorecard. Currently, each electricity distributor is permitted to have different measurements of performance until such time as the OEB provides specific direction regarding a commonly defined measure.

  First Contact Resolution ("FCR") traditionally represents a percentage of instances where a customer's need is addressed at the time of their first point of contact on the matter. However, FCR can be measured in a variety of ways and further regulatory guidance will be necessary in order to achieve meaningful, consistent and comparable information across electricity distributors.

  STEI has defined FCR as any items that have been escalated to the OEB in which Board staff has confirmed STEI's resolution of the matter. In 2017, 100% of STEI's escalations to the OEB were effectively resolved in-house.

- **Billing Accuracy**

  Prior to 2014, a specific measurement of billing accuracy had not been defined across the industry. In 2014, the OEB instructed all electricity distributors to begin tracking a prescribed billing accuracy measure so that the results could be reported on the 2014 Scorecard.

  In 2017, STEI issued 209,374 bills and achieved a billing accuracy of 99.95%. This compares favourably to the prescribed OEB target of 98%.

  STEI continues to monitor its billing accuracy results and processes to identify opportunities for improvement.

- **Customer Satisfaction Survey Results**
  Similar to the FCR measure described above, the OEB introduced the Customer Satisfaction Survey Results measure beginning in 2014. At a minimum, electricity distributors are required to measure and report a customer satisfaction result every other year. At this time, the OEB is allowing electricity distributors the discretion as to how this measure is implemented. Starting in 2014, STEI engaged a third-party service provider to conduct bi-annual Customer Satisfaction surveys.

  STEI continues to have excellent Customer Satisfaction results. Based on the survey conducted in January and February 2017, STEI received an overall Customer Satisfaction rating of "A" with specific ratings of "B+" in Customer Care, "A" in Company Image and "A" in Management Operations. These ratings exceed the Ontario and Nation averages. The findings are based on telephone interviews with 400 respondents who manage their electricity account. The sample of the phone numbers was drawn randomly to ensure each number on the list had an equal opportunity of being included in the poll. The sample was stratified so that 85% of the interviews were conducted with residential customers and 15% with commercial customers.

  STEI continues to strive to provide superior customer service and commitment to our customers, which is reflected in the strong survey results. As noted in STEI's survey findings, 2017 has been a challenging year as the industry has faced increased scrutiny and media attention over hydro rates. Despite this challenging landscape, 89% of the STEI customers view STEI as trustworthy, as compared to the provincial average of 74%. Further, STEI received 91% in customer satisfaction related to reliability and 92% of respondents indicated that STEI delivers on its service commitments. Customer feedback suggested that STEI can continue to improve by providing enhanced customer interaction programs, technology to assist in account management, notification of power outages, improved billing communications and electricity literacy tools.

Safety

- **Public Safety**

  - **Component A – Public Awareness of Electrical Safety**
    In 2015, in consultation with the Electrical Safety Authority ("ESA"), the OEB introduced this new public awareness survey measure. The survey is based upon a representative sample of each electrical distributor's service territory population and gauges awareness levels of key electrical safety concepts related to distribution assets. The survey provides a benchmark of levels of awareness including identifying gaps where additional education and awareness efforts may be required. In accordance with OEB requirements, the survey is conducted every other year. Accordingly, the survey results described below for 2017 will also be applicable for 2018.

    STEI engaged a third-party service provider to conduct stratified random telephone surveys of 401 Ontario residents, ages 18 or older, currently residing in the STEI service territory during the period from March 6, 2018 and March 19, 2018. The survey asked residents electrical safety questions and then an overall index score was calculated in accordance with a prescribed algorithm. STEI continues to be pleased with its index score result of 81%.

STEI conducted another public safety awareness campaign in the spring of 2018 utilizing local media and digital website content. Further, STEI conducts safety awareness through its ongoing visits to grade school classrooms to review electrical safety.

- **Component B – Compliance with Ontario Regulation 22/04**

  Ontario Regulation 22/04 (Electrical Distribution Safety) establishes objective based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed distributors. The regulation requires the approval of equipment, plans, specifications and inspection of construction before they are put into service. STEI is audited annually for compliance.

  In 2017, STEI was found to not be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). This related to deficiencies in the following areas: update of the major equipment listing, spare transformer testing, and maintenance of inspection documentation. STEI is very committed to safety, and adherence to company procedures & policies. In response to the audit findings, STEI took immediate actions to correct these deficiencies and notified the ESA of this through a declaration of compliance. The ESA confirmed its satisfaction and accepted the declaration of compliance in May 2018.

- **Component C – Serious Electrical Incident Index**

  This is measured as the number of non-occupational (general public) serious electrical incidents occurring on STEI's distribution system expressed as a raw number and as the number per 100 km of line. STEI had no such incidents in 2013-2017 and will continue to make this an area of focus.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**

  For this measure, the OEB establishes baseline targets based on the average of the distributor's performance for the period 2010 – 2014 (the baseline period is updated every 5 years). STEI's 2017 result of 0.47 is below the target of 0.62. This favourable result is due to an ongoing initiative to upgrade of STEI's former delta 2.4 kV system and 13.8 kV system, as well as the lack of significant storm activity in St. Thomas in 2017.

  STEI continues to view reliability of electricity service as a high priority for its customers. In 2014, STEI finalized a Distribution System Plan ("DSP") that adopts a proactive, balanced approach to distribution system planning, infrastructure investment and replacement programs to address immediate risks associated with end-of-life assets; manage distribution system risks; ensure the safe and reliable delivery of electricity; and balance ratepayer and utility affordability.

- **Average Number of Times that Power to a Customer is Interrupted**

  For this measure, the OEB establishes baseline targets calculated as the average of the distributor's performance for the period 2010 – 2014 (the baseline period is updated every 5 years). STEI's 2017 result of 0.58 is below the target of 1.12. This favourable result is primarily due to the lack of significant storm activity in 2017.

  STEI continues to view reliability of electricity service as a high priority for its customers. In 2014, STEI finalized a DSP that adopts a proactive, balanced approach to distribution system planning, infrastructure investment and replacement programs to address immediate risks associated with end-of-life assets; manage distribution system risks; ensure the safe and reliable delivery of electricity; and balance ratepayer and utility affordability.

Asset Management

- **Distribution System Plan Implementation Progress**

  STEI's Distribution System Plan ("DSP") design document was completed in 2014 and submitted to the OEB in 2015 in conjunction with STEI's distribution rate rebasing application (EB-2014-0113). STEI reached a full settlement with the intervenors of record in November 2014, resulting in minimal changes to the DSP.

  Consistent with 2016, STEI continues to report this metric based on percentage of actual annual capital expenditures in the fiscal year divided by the DSP annual capital expenditures. The STEI 2017 actual capital expenditures were $2.646M (the numerator). The annual DSP capital expenditures were $2.178M (the denominator). This numerator and denominator equate to the reported DSP Implementation Progress figure of 121%. This increase is consistent with significant residential customer growth within STEI's service area, resulting in an increase in customer driven work.

Cost Control

- **Efficiency Assessment**

  The total costs for Ontario local electricity distribution companies are evaluated based on econometric modeling by a consultant (the Pacific Economics Group LLC) on behalf of the OEB to produce a single efficiency ranking. The electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs over the past three years.

  In 2017, STEI's actual costs for 2014-2017 were 10.9% lower than the costs predicted by the OEB's consultant. For 2017, STEI improved from Group 3 to Group 2, where a Group 2 distributor is defined as having actual costs which are 10% to 25% lower than the costs predicted for the distributor. Group 2 is considered as "more efficient". In 2017, STEI ranked 21st out of 65 distributors in terms of cost performance results versus benchmark.

- **Total Cost per Customer**
  Total cost per customer is calculated as the sum of STEI's capital and operating costs, divided by the total number of customers that STEI serves. STEI's cost performance result for 2017 is $494 per customer, which represents a 7.5% decrease over 2016.

- **Total Cost per Km of Line**
  This measure uses the same total cost that is used in the Cost per Customer calculation above. The total cost is divided by the kilometers of line that STEI operates to serve its customers. STEI's 2017 rate is $34,897 per KM of line, an 8.2% decrease over 2016.

Conservation & Demand Management

- **Net Cumulative Energy Savings**
  The province launched a new Conservation First Framework ("CFF") on January 1, 2016 for the period 2016-2020. Under the new CFF, STEI's target for 2016-2020 Net Cumulative Energy Savings (kWh) is 17.51 GWh.

  In 2017, STEI combined its conservation plan with EPI and another distributor in the region to create an overall plan for the three distributors.

  Life-to-date at December 31, 2017, STEI has achieved 61.13% of the Net Cumulative Energy Savings target. STEI continues to focus on the conservation needs of all its customers. STEI assists medium to large commercial/industrial customers by engaging them on energy efficient opportunities and offering thorough support throughout the application process. STEI is in the process of adding Small General Service programs such as Small Business Lighting and the Business Refrigeration Incentive, to ensure all customer classes are afforded energy efficient program opportunities.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**
  Electricity distributors are required to conduct Connection Impact Assessments (CIAs) within 60 days of the receipt of the application for a proposal to connect a mid-sized generation facility or 90 days of the receipt of an application to connect a large embedded generation facility.

  In 2017, STEI received a single request for a CIA and it was completed within the prescribed time limit. The completion of CIAs requires a significant amount of coordination with the developer and other third parties involved in the process. In 2015, STEI received no offers to connect. Since 2013, STEI has successfully completed all CIA's within the prescribed time limit.

- **New Micro-Embedded Generation Facilities Connected on Time**
  Electricity distributors are required to connect an applicant's micro-embedded generation facility (i.e. MicroFIT projects of less than 10kW) to its distribution system within five business days of the applicant informing the distributor that it has satisfied all applicable service conditions, received all necessary approvals and provided the distributor with a copy of the authorization to connect from the ESA. The minimum acceptable performance level for this measure is 90%.

  In 2017, STEI connected all 13 new micro-embedded generation facilities within the prescribed time frame of five business days. STEI works closely with its customers and their contractors to address any connection issues to ensure the project is connected on time.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**
  Liquidity is calculated by dividing Current Assets by Current Liabilities. This ratio is also known as Working Capital Ratio and measures an entity's ability to pay short-term financial obligations.

  STEI's current ratio decreased from 1.36 in 2016 to 0.84 in 2017. This decrease is offset in terms of financial position by the reduction in leverage and corresponding additional funding capacity noted below.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**
  The OEB uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5 (60/40). A debt to equity ratio of more than 1.5 indicates that a distributor is more highly levered than the deemed capital structure. A high debt to equity ratio may indicate that an electricity distributor may have difficulty generating sufficient cash flows to make its debt payments.

  STEI's leverage ratio decreased from of 0.65 in 2016 to 0.31 in 2017. The lower leverage ratio means that STEI has reduced financial leverage and higher year over year funding capacity.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**
  STEI's 2017 distribution rates were approved by the OEB and include an expected (deemed) regulatory return on equity of 9.30%. The OEB allows a distributor to earn within +/- 3% of the expected return on equity. When a distributor performs outside of this range, the actual performance may trigger a regulatory review of the distributor's revenues and costs structure by the OEB.

- **Profitability: Regulatory Return on Equity – Achieved**
  STEI's achieved a 2017 Regulatory Return on Equity ("ROE") of 11.60%, which is within the +/-3% range of Deemed ROE allowed by the OEB. This result represents an increase from the 2016 Regulatory ROE of 10.65%.

Note to Readers of 2017 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgement on the reporting date of the performance scorecard and could be markedly different in the future.

ATTACHMENT L

Entegrus Major Event Report, April 2018

Major Event Reporting
April 14, 2018

Date Filed: June 15, 2018

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PRIOR TO THE MAJOR EVENT

1. **Did the distributor have any prior warning that the Major Event would occur?**

   The initial weather forecast from media outlets in the days leading up to the Major Event were somewhat conflicting, but generally indicated that a heavy rain storm was possible for the weekend of April 14-15, 2018. On Friday, April 13, at 6:50 am, Environment Canada issued a weather statement for Southwestern Ontario, indicating that several rounds of rain and occasional thunderstorms were likely for April 14-15. It was further indicated that temperatures might dip below the freezing mark late on April 14, with the threat of freezing rain. Subsequently, at 7:01 am on April 14, 2018, Environment Canada issued a rainfall warning for Chatham-Kent, indicating that the rain would change to freezing rain late in the afternoon.

2. **If the distributor did have prior warning, did the distributor arrange to have extra employees on duty or on standby prior to the Major Event beginning? If so, please give a brief description of arrangements.**

   Entegrus serves 17 communities in Southwestern Ontario. The boundaries of the EPI service territory stretch from Wheatley in the southwest to Parkhill and St. Thomas in the northeast. The boundaries are non-contiguous, and the distance across the Entegrus service territory is approximately two hours travel time by vehicle. Accordingly, Entegrus operates three service centres, located in Chatham, Strathroy and St. Thomas. This structure enhances (through the availability of back up resources) response times to system needs during storms. Staff from all three operational centres were put on alert on the morning of Saturday, April 14 after the Environment Canada rainfall warning. Ultimately, staff from all three centres assisted with the restoration efforts later that day. In addition, Entegrus engaged in discussion on the morning of April 14 with neighbouring utilities regarding mutual assistance, although ultimately this was not required by Entegrus.

3. **If the distributor did have prior warning, did the distributor issue any media announcements to the public warning of possible outages resulting from the pending Major Event? If so, through what channels?**

The weather forecasts from media outlets in the days leading up to the storm were somewhat conflicting. Subsequently, the storm escalated very quickly on the morning of April 14, with freezing rain arriving much earlier than indicated in the rainfall warning issued at 7:01 am that morning. Accordingly, Entegrus did not issue any public warnings prior to the event.

4. **Did the distributor train its staff on the response plans for a Major Event? If so, please give a brief description of the training process.**

Entegrus provides continuous training to staff on the various levels of response required for a Major Event. Entegrus has an established Emergency Preparedness Plan ("EPP") providing details on how employees are called in and how staffing levels are balanced to cover rest time. The EPP is reviewed annually with employees.

Entegrus has significant experience in providing mutual aid support to other areas experiencing severe storm damage. In recent years, Entegrus staff have assisted with restoration efforts in other parts of Ontario, as well as New York, New Jersey and Florida. This experience is invaluable when responding to Major Events.

5. Did the distributor have third party mutual assistance agreements in place prior to the Major Event? If so, who were the third parties (i.e., other distributors, private contractors)?

Yes, Entegrus has third party mutual assistance agreements in place through the Electricity Distributor Association ("EDA") Western Group which includes the following utilities:

- Bluewater Power Dist. Corp.
- E.L.K. Energy Inc.
- ENWIN Utilities Ltd.
- Erie Thames Powerlines Corp.
- Essex Powerlines Corp.
- Festival Hydro Inc.
- London Hydro Inc.
- Tillsonburg Hydro Inc.

Entegrus is also part of the Great Lakes Regional Mutual Assistance Group and the Canadian Electrical Association Mutual Assistance Group. Both of these groups have agreements in place to provide additional assistance during Major Events where needed and available.

As described in #18 below, in conjunction with the restoration of the Entegrus service territory, Entegrus staff provided mutual aid assistance to Hydro One Networks Inc. on April 16, 2018 to restore supply to the area surrounding Parkhill.

During the Event

1. **Please explain why this event was considered by the distributor to be a Major Event.**

   The April 14, 2018 ice storm was considered a Major Event due to the number of customers experiencing a concurrent outage of greater than 15 minutes. Entegrus serves approximately 58,000 customers. At the peak of the Major Event in the afternoon of April 14, 2018, there were 12,597 customers without electricity, representing approximately 22% of Entegrus customers.

2. **Was the IEEE Standard 1366 used to identify the scope of the Major Event? If not, why not?**

   The Entegrus Major Event scope determination policy is based on the prescribed Ontario Energy Board guidance, in particular, option (c), the Fixed Percentage Approach[1]. This alternative defines a Major Event as a fixed percentage of customers affected (Entegrus has selected 10% as the threshold). Entegrus believes this option best aligns with the customer experience and is the easiest to apply and communicate. It also provides for ease of calculation in quickly determining an event's impact and thereby assists in streamlining internal reporting.

3. **Please identify the Cause of Interruption for the Major Event as per the table in section 2.1.4.2.5.**

   This event consisted of the following Cause Codes:

   - Adverse Weather (Cause Code 6)
   - Tree Contacts (Cause Code 3)
   - Defective Equipment (Cause Code 5)

[1] See Report of the Board, EB-2015-0182, Electricity Distribution System Reliability: Major Events, Reporting on Major Events and Customer Specific Measures, page 11

4. Were there any declarations by government authorities, regulators or the grid operator of an emergency state of operation in relation to the Major Event?

No.

5. When did the Major Event begin (date and time)?

The storm came from the southwest on the morning of April 14, 2018 and moved northeasterly through the Entegrus service territory. The first Entegrus community impacted was Chatham, with customers first experiencing outages at approximately 10:45am. As the storm continued to move northeast, the community of Strathroy was impacted, with the first Strathroy outages occurring at 11:52am. The 10% threshold of customers without power threshold was reached at approximately 11:54am on Saturday April 14. Thereafter, outages first commenced in the community of St. Thomas at 3:21pm.

6. What percentage of on-call distributor staff was available at the start of the Major Event and utilized during the Major Event?

Entegrus had 100% of its on-call staff available during the outages. All of this staff was utilized.

7. Did the distributor issue any estimated times of restoration (ETR) to the public during the Major Event? If so, through what channels?

Entegrus provided continual updates on outage and restoration efforts at each specific community level, as there were multiple concurrent outages throughout the Entegrus service territory. The updates were shown on the Entegrus website, including the outage map. Updates were also posted on Twitter and Facebook. All posts included information on investigation efforts, causes and ETRs (where possible). The updates also included safety information, as well as reminders to report downed power lines.

The Entegrus website also contains an embedded Twitter feed to allow for customers who do not follow social media to receive updates.

8. If the distributor did issue ETRs, at what date and time did the distributor issue its first ETR to the public?

Entegrus issued its first ETR on April 14, 2018 at 2:36pm.

9. Did the distributor issue any updated ETRs to the public? If so, how many and at what dates and times were they issued?

Entegrus issued the following ETR updates for the various outages. Note that some of the ETRs on April 15 and April 16 relate to Loss of Supply, as more fully described in #18 below:

April 14th at 4:55pm	April 15th at 4:03pm	April 16th at 1:33am
April 14th at 5:49pm	April 15th at 5:12pm	April 16th at 1:50am
April 15th at 12:39am	April 15th at 5:31pm	April 16th at 8:25am
April 15th at 2:19am	April 15th at 9:14pm	
April 15th at 4:39am	April 15th at 9:33pm	

10. Did the distributor inform customers about the options for contacting the distributor to receive more details about outage/restoration efforts? If so, please describe how this was achieved.

As noted in #7 above, Entegrus continually provided updates on outage and restoration efforts. These updates also included contact numbers, social media links and website addresses to receive more details about the outage/restoration efforts.

11. **Did the distributor issue press releases, hold press conferences or send information to customers through social media notifications? If so, how many times did the distributor issue press releases, hold press conferences or send information to customers through social media notifications? What was the general content of this information?**

    Entegrus did not issue press releases or hold press conferences. As noted in #7 and #10 above, Entegrus sent information to customers through social media notifications. Entegrus released approximately 37 social media updates over the course of 3 days.

12. **What percentage of customer calls were dealt with by the distributor's IVR system (if available) versus a live representative?**

    All inbound customer calls to Entegrus initially route to the IVR system. The customer then has an option to choose to speak to a live representative. Accordingly, 100% of all customer calls were initially dealt with by the IVR system.

13. **Did the distributor provide information about the Major Event on its website? If so, how many times during the Major Event was the website updated?**

    Yes, Entegrus included updates on its website. The website was updated 23 times during the Major Event.

14. **Was there any point in time when the website was inaccessible? If so, what percentage of the total outage time was the website inaccessible?**

    No.

15. **How many customers were interrupted during the Major Event? What percentage of the distributor's total customer base did the interrupted customers represent?**

    Entegrus had 16,190 customers interrupted during the Major Event. This represents approximately 28% of Entegrus customers.

16. How many hours did it take to restore 90% of the customers who were interrupted?

It took 6.8 hours to restore power to 90% of the customers who were interrupted.

17. Was any distributed generation used to supply load during the Major Event?

No.

18. Were there any outages associated with Loss of Supply during the Major Event? If so, please report on the duration and frequency of Loss of Supply outages.

There are no Loss of Supply outages included in the above-noted outage numbers, as Loss of Supply is to be normalized from Major Event calculations[2]. However, as restoration was nearing completion, the Entegrus communities of Parkhill and Ridgetown began experiencing outages related to Loss of Supply. Subsequently, Hydro One Networks Inc., which was experiencing multiple outages throughout its service territory, requested assistance from Entegrus crews on Monday, April 16, 2018 outside of Parkhill. Entegrus assisted with the restoration of power supply to Parkhill and the surrounding area later in the day.

19. In responding to the Major Event, did the distributor utilize assistance through a third party mutual assistance agreement?

No.

20. Did the distributor run out of any needed equipment or materials during the Major Event? If so, please describe the shortages.

No.

[2] See Report of the Board, EB-2015-0182, Electricity Distribution System Reliability: Major Events, Reporting on Major Events and Customer Specific Measures, page 12

After the Major Event

1. **What steps, if any, are being taken to be prepared for or mitigate such Major Events in the future (i.e., staff training, process improvements, system upgrades)?**

   Entegrus conducted a debriefing after the conclusion of the Major Event to review the successes and the areas of improvement. This will result in enhancements to continued staff training, including updates to the EPP to more fully describe requirements for St. Thomas. Further, Entegrus continues to upgrade its distribution system, which will also help with future resiliency.

2. **What lessons did the distributor learn in responding to the Major Event that will be useful in responding to the next Major Event?**

   Entegrus finalized its merger with St. Thomas Energy on April 1, 2018. Accordingly, valuable insight was gained from the Major Event with respect to organizing and coordinating the response of three operational centres with multiple crews. Entegrus has also identified an opportunity to utilize emergency radio channels to allow for improved communication between trucks across all operational centres.

3. **Did the distributor survey its customers after the Major Event to determine the customers' opinions of how effective the distributor was in responding to the Major Event? If so, please describe the results.**

   Entegrus did not complete a customer survey related to this Major Event. However, Entegrus did receive many messages from customers via social media containing feedback. Screenshots of these messages (with names redacted) have been included in Attachment A of this report.

Attachment A

Entegrus
Published by Hootsuite [?] · April 14 at 5:49pm ·

Update for #Strathroy outage: isolation of the damaged area is complete and switching has started. Power should be restored in 20 minutes for the vast majority. Thank you to everyone in #Strathroy for your patience.

1,216 people reached · Boost Post

Like · Comment · Share

[redacted] and 32 others · Top Comments

3 Shares · 8 Comments

Write a comment...

[redacted] Thank you for your hard work in not so pleasant conditions.
Like · Reply · Message · 1d · 1

[redacted] Many thanks to your hardworking crew!
Like · Reply · Message · 1d · 2

[redacted] Thank you to the Entegrus crew for fixing it in this horrid weather
Like · Reply · Message · 1d

[redacted] Thank you for your time and hard work.
Like · Reply · Message · 1d

[redacted] Power came back in North end about 5:20💕 thanks Entegrus!!
Like · Reply · Message · 1d

Entegrus
Published by Hootsuite [?] · April 14 at 6:05pm ·

Majority of power in #Strathroy should now be restored. Thanks again to everyone for your patience and the guys truly appreciate the thank you notes!

2,421 people reached · Boost Post

Like · Comment · Share

[redacted] and 30 others · Top Comments

4 Shares · 14 Comments

Write a comment...

[redacted] Thanks a million, guys! Shitty day to be outside working. Much appreciated!
Like · Reply · Message · 1d · Edited · 2

[redacted] Great work guys thanks so much !!
Like · Reply · Message · 1d · 1

[redacted] hank you guys for getting us back up and running at dinner, appreciate your help
Like · Reply · Message · 1d

[redacted] Thanks for working in horrible weather to restore our power👏👌
Like · Reply · Message · 1d

[redacted] THANK YOU!! A crappy day to be outside working. thanks

[redacted] Thank you!!!
Like · Reply · Message · 1d

[redacted] Is Kittridge restored?
Like · Reply · Message · 1d

[redacted] Great job & thanks
Like · Reply · Message · 1d

[redacted] Great job.
Like · Reply · Message · 1d

[redacted] THANK YOU!!!!!
Like · Reply · Message · 1d

[redacted] Thank you
Like · Reply · Message · 1d

[redacted] THANK YOU!!!!
Like · Reply · Message · 1d

Crews are still working on restoring power outside the Entegrus service area They estimate 11:00am as a restore time for Parkhill

1,691 people reached · Boost Post

Like · Comment · Share

[redacted] · Top Comments

13 Shares

Write a comment...

Jaclyn Landes It was 11pm. Then 9am. Now 11am. May aswell say [redacted] it'll turned back on. Instead of posting more few hours later again.
Like · Reply · Message · 12h · 1

[redacted] Did you actually read what they wrote? It's outside their service area,so it's not their crew working on it.
Like · Reply · Message · 5h · 1

Write a reply...

[redacted] Thanks for the update. I know your crew are doing the best they can!
Like · Reply · Message · 10h · 4

Update on the Parkhill outage: there are a multitude of issues within Hydro One's service area affecting the town of Parkhill. Hydro One estimates power will be restored to the town by 9am Monday morning. Thank you.

2,552 people reached Boost Post

Like Comment Share

[redacted] Top Comments

14 Shares

Write a comment...

[redacted] Thanks , and thanks Hydro One for doing their best to get us lit up again. I'm sure the workers would like to be home and dry !

Like · Reply · Message · 8h

[redacted] Changed again. Now it's 11am. Waiting for another post changing the time again

Like · Reply · Message · 12h

[redacted]

Like · Reply · Message · 17h

[redacted]

Like · Reply · Message · 16h