# Exhibit 1:

# Administration

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## LIST OF ATTACHMENTS

## 1.1 Application

**IN THE MATTER OF** the Ontario Energy Board Act, 1998, S.O. 1998, c.15, 3 Schedule B, as amended (the "OEB Act");

**AND IN THE MATTER OF** an Application by Entegrus Powerlines Inc. under Section 78 of the OEB Act to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2016.

(this "Application")

**Applicant's Name:** Entegrus Powerlines Inc.
(the "Applicant" or "EPI").

### 1.1.1 Certification of Evidence

For the EPI Certification of Evidence, please refer to Attachment 1-A.

### 1.1.2 Filing Requirements Checklist

EPI has completed the Board's 2016 Cost of Service Filing Checklist. Please refer to Attachment 1-B.

## 1.2 Evolution of Entegrus

### 1.2.1 Overview

Chatham Hydro was the largest predecessor to what is now EPI, and was founded in 1914. Subsequently, Chatham-Kent Hydro ("CKH") was formed in 1998 as an amalgamation of eleven former Municipal Electric Utilities (MEUs) in 1998. The amalgamation of the MEUs was part of the municipal amalgamation of approximately twenty-two municipalities and townships into what is now the Municipality of Chatham-Kent.

The former CKH was a local electricity distribution company (OEB Distributor Licence ED-2002-0563) serving the Ontario communities of Blenheim, Bothwell, Chatham, Dresden, Erieau, Merlin, Ridgetown, Thamesville, Tilbury, Wallaceburg, Wheatley, and certain designated land parcels in the Township of Raleigh, known as the Bloomfield Business Park.

On March 24, 2005, CKH's parent company, the former Chatham-Kent Energy Inc. ("CK Energy"), submitted MAAD application EB-2005-0255 requesting Board approval to acquire all shares of Middlesex Power Distribution Corporation ("MPDC"). At that time, MPDC was a local distribution company (former OEB Distributor Licence ED-2003-0059) servicing the Ontario communities of Strathroy, Mount Brydges and Parkhill.

The Board approved this acquisition in its Decision and Order issued on June 24, 2005. CK Energy's acquisition of MPDC subsequently closed June 30, 2005.

On October 15, 2008, MPDC submitted MAAD applications EB-2008-0332 and EB-2008-0350 requesting Board approval to acquire all shares of the former Dutton Hydro Limited and the former Newbury Power Inc. and to amalgamate all entities into MPDC. The Board approved these acquisitions and the amalgamation in its Decision and Order issued February 9, 2009. MPDC closed this transaction on April 30, 2009. Subsequently, MPDC served the distribution areas formerly licensed to each of MPDC, Dutton Hydro Limited & Newbury Power Inc. and maintained separate sets of rates for each of these three areas.

On August 31, 2011, CKH applied to the Board for leave to amalgamate MPDC with CK Hydro (MAAD applications EB-2011-0328 and EB-2011-0329). On December 16, 2011, the Board approved the amalgamation, and on January 11, 2012, CKH notified the Board that this transaction was complete. On January 20, 2012, CKH received its amended Licence ED-2002-0563 and notification that the MPDC Licence ED-2003-0059 was cancelled.

Subsequently, on January 31, 2012, CKH applied to the Board to amend the company name on its Electricity Distribution Licence (ED-2002-0563) to Entegrus Powerlines Inc. ("EPI"). The Board approved this change and issued an updated Licence on February 24, 2012.

On December 31, 2014, the utility-related assets of EPI's unregulated affiliate, Entegrus Services Inc. ("ESI"), were transferred to EPI. Subsequently, on January 1, 2015, the employees of ESI were transferred to EPI. ESI previously provided Customer Service and Administrative support to EPI. This reorganization was driven by the following reasons:

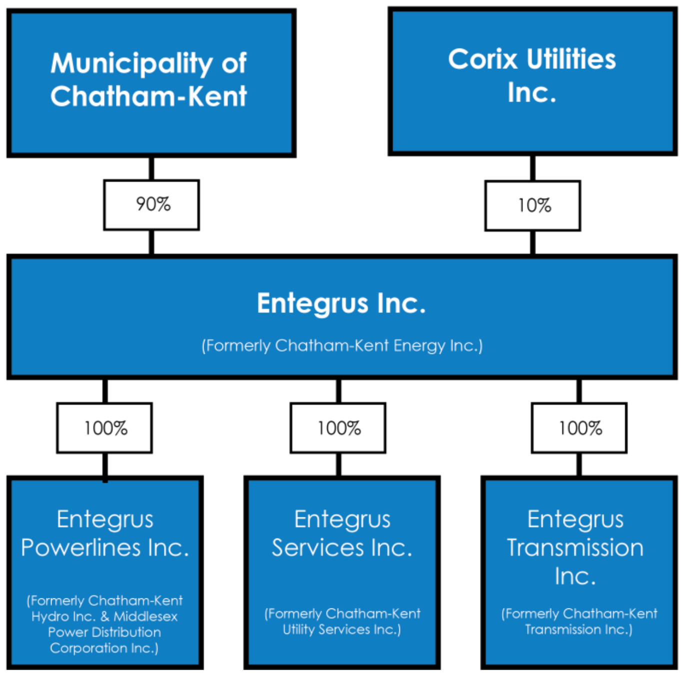
- The opportunity to unify employees under one banner;
- Limited remaining opportunities, circa 2015, to sell administrative services to other distributors (as compared to the period after Market Opening); and,
- The opportunity to simplify the business

As of 2015, EPI has approximately 40,000 customers and is ranked approximately 21st in the Province of Ontario in terms of electrical utility size by number of metered customers.

### 1.2.2 Corporate Entities

The following chart illustrates the corporate structure of the Entegrus Group, and the organizational relationship between EPI and its shareholder and its affiliates:

**CHART 1-1: THE ENTEGRUS GROUP CORPORATE STRUCTURE**




## ORGANIZATION OF ENTITIES

### ENTEGRUS INC.

Entegrus Inc. is 90% owned by the Municipality of Chatham-Kent and 10% by Corix Utilities Inc. ("Corix"). Corix is a privately held Canadian corporation (headquartered in Vancouver, British Columbia) specializing in providing products and utility solutions for sustainable infrastructure in the water, wastewater and energy sectors for clients across North America. For additional details on Corix, see Section 1.10.1.

### ENTEGRUS POWERLINES INC.

EPI is a wholly-owned subsidiary of Entegrus Inc. EPI owns, operates and manages the assets associated with the distribution of electrical power within the service territory described above and as set out in Electricity Distribution Licence ED-2002-0563.

As of January 1, 2015, EPI also provides billing and collection services to the Chatham-Kent Public Utilities Commission, the Municipality of Strathroy-Caradoc and the Village of Newbury. These services were previously provided by ESI (see below).

## ENTEGRUS SERVICES INC.

ESI owns and operates an unregulated data centre located in Chatham, Ontario.

Until December 31, 2014, ESI also provided billing, collection, administration, financial and regulatory services to EPI, the Chatham-Kent Public Utilities Commission, the Municipality of Strathroy-Caradoc and the Municipality of Dutton-Dunwich. On December 31, 2014, the utility-related assets of EPI's unregulated affiliate, Entegrus Services Inc. ("ESI"), were transferred to EPI. Subsequently, on January 1, 2015, the employees of ESI were transferred to EPI. ESI previously provided Customer Service and Administrative support to EPI.

The aforementioned data centre assets continue to be owned and operated by ESI.

## ENTEGRUS TRANSMISSION INC.

ETI is a licensed electricity transmitter (OEB Transmitter Licence ET-2010-0351). ETI owns and maintains a land corridor running from Tilbury, Ontario to St. Thomas, Ontario. ETI also provides transmission maintenance for certain transmission facilities operating on its corridor.

Currently, ETI does not own or operate a transmission system. The goal of ETI is to own and operate transmission systems to enable the development and connection of renewable energy generation in Ontario and to improve the overall reliability, safety and cost-effectiveness of electrical transmission in the province of Ontario.

### 1.2.3 The EPI Rate Zones

As the result of the above-described service territory evolution, EPI currently has 4 separate rate zones as follows:

### Chatham-Kent ("CK") Rate Zone

- The former CKH service territory, now serving approximately 32,500 customers;
- Base rates were last set effective May 1, 2010 in the CKH Cost of Service application EB-2009-0261, based on the Third Generation Cost of Service process ("IRM3").

### Strathroy, Mt. Brydges & Parkhill ("SMP") Rate Zone

- The original MPDC service territory, now serving approximately 7,400 customers;
- Base rates were last set effective May 1, 2006 in the MPDC rate application EB-2005-0351, based on the 2006 Electricity Distribution Rate ("EDR") process.

### Dutton Rate Zone

- The original Dutton Hydro service territory, now serving approximately 600 customers
- Base rates were last set effective May 1, 2010 in MPDC rate application EB-2009-0177, based on the 2006 EDR process and with escalation in accordance with 2007, 2008 and 2009 IRM adjustments.

### Newbury Rate Zone

- The original Newbury Power service territory, now serving approximately 200 customers
- Base rates were last set effective May 1, 2007 in MPDC rate application EB-2005-0392, based on the 2006 EDR process.

As shown above, it is apparent that three rate zones other than CKH described above, which formerly comprised MPDC, have three different re-basing effective dates. Also as noted in Section 1.2.1 above, Dutton and Newbury were acquired by MPDC in 2009. Accordingly, the Newbury EB-2005-0392 application was filed independently in 2005 by its previous ownership. Conversely, the previous ownership of Dutton did not file a 2006 EDR application; this resulted in MPDC filing the EB-2009-0177 application in 2009.

In the above-described MAAD application for leave to amalgamate MPDC with CKH (EB-2011-0328/0329), the Board accepted EPI's proposal to defer rebasing and rate harmonization until May 1, 2016.

In this Application, EPI seeks leave to harmonize the current 4 rate zones into 1 single rate zone.

### 1.2.4 Chatham-Kent Territory & Operations Centre

The EPI head office and primary operations centre continues to be located in Chatham, which is the largest community, and most centrally located community geographically, in Chatham-Kent.

The Municipality of Chatham-Kent (population 104,000) is located in the heart of Southwestern Ontario, midway between Windsor and London, with Lake Erie to the south and Lake St. Clair to the west. Chatham-Kent was created in 1998 by the merger of Kent County and 22 municipalities, at which time the former CKH was created.

At 2,458 square kilometres, Chatham-Kent is the 12th largest municipality by geographic area in Canada – and the largest in southwestern Ontario. As described herein, EPI serves 11 communities of Chatham-Kent, plus the Bloomfield Business Park (an industrial park on the outskirts of Chatham located along Highway 401). The Chatham-Kent portion of EPI's service territory covers approximately 76.5 square kilometres (of EPI's total service territory area of 99.5 square kilometres). As described in Section 1.2.3, it includes approximately 32,500 residential and commercial customers (of approximately 40,700 total EPI customers).

Two service areas, Chatham and Bloomfield Business Park, are directly connected to the Hydro One Networks Inc. ("HONI") transmission system. These areas represent approximately 50% of the EPI Chatham-Kent load. The remaining Chatham-Kent service areas are embedded in HONI's distribution system. The areas of Chatham-Kent that are not served by EPI are served by HONI.

Chatham-Kent has a moderate humid continental climate, with a climate classification of Köppen Dfa. The region has warm, humid summers and cold, usually moist winters. A typical summer features heat waves with temperatures often exceeding 30 °C. Winters are typically cold, but feature mild stretches of weather. Occasional winter cold snaps can bring temperatures below −15 °C. In 2014 and 2015, these cold snaps were sustained throughout much of January and February, as a consequence of the "polar vortex" phenomena, resulting in numerous record-breaking cold days. The area is susceptible to frequent thunderstorms during the spring and summer time period, and is located in Southwestern Ontario's "Little Tornado Alley". Chatham-Kent typically experiences an average of approximately 1 metre of snowfall per year.

The economy of Chatham-Kent has always been largely dependent upon agricultural and manufacturing industries. Starting in 2008, the local manufacturing sector (especially its automotive segment), was hit particularly hard by the global economic recession. During this recessionary period, there were a significant number of plant closures, culminating with the closure of Navistar International's Chatham plant in 2010. As a result, over 6,000 jobs were lost and the Municipality experienced a 4% population decline between the 2006 census and the 2011 census.

The Chatham-Kent unemployment rate peaked at over 14% in 2009 and 2010 and has now stabilized at a rate between 8% and 10%, dependent upon the seasonal impact of agricultural employment. EPI notes that Chatham-Kent unemployment data is an amalgam of other Southwestern Ontario regional data, including Sarnia-Lambton. Accordingly, these unemployment data represent an approximation.

### 1.2.5 Strathroy-Caradoc Territory and Operations Centre

As described above, the former MPDC (serving the communities of Strathroy, Parkhill and Mount Brydges), was acquired by EPI's parent company in 2005. Subsequently in 2009, MPDC acquired the former Dutton Hydro and the former Newbury Power. The five communities of Strathroy, Parkhill, Mount Brydges, Dutton and Newbury became part of the EPI service territory upon the amalgamation of CKH and MPDC in 2012.

The communities are served out of EPI's secondary operations centre in Strathroy, which is geographically central to EPI's eastern service territory. The distance between Chatham and Strathroy is approximately 1.5 hours, based on driving time.

The Municipality of Strathroy-Caradoc (population 21,000) is located 40 kilometres west of London. Strathroy-Caradoc was formed in 2001, after the amalgamation of the Town of Strathroy and the Township of Caradoc, and covers an area of 274 square kilometres. The Strathroy-

Caradoc/Dutton/Newbury portion of EPI's service territory covers approximately 23.3 square kilometres (of EPI's total service territory area of 99.5 square kilometres). Further, it includes approximately 8,200 residential and commercial customers, of whom approximately 7,400 reside in Strathroy-Caradoc, approximately 600 reside in Dutton and approximately 200 reside in Newbury.

EPI's Strathroy-Caradoc/Dutton/Newbury distribution system is 100% embedded in HONI's distribution system.

The climate of Strathroy-Caradoc is similar to that of Chatham-Kent, albeit at the edge of the Köppen Dfa moderate humid continental climate zone boundary. In particular, Strathroy-Caradoc experiences heavier snowfall than Chatham-Kent, averaging over 2 metres per year. In 2014 and 2015, Strathroy-Caradoc experienced the impact of the "polar vortex" phenomena, particularly in January and February, resulting in numerous record-breaking cold days. Similar to Chatham-Kent, Strathroy-Caradoc is located in Southwestern Ontario's "Little Tornado Alley".

Strathroy-Caradoc is the major centre of services for the communities in western Middlesex and eastern Lambton Counties. Strathroy, in particular, has a solid industrial base and, starting in the 1990's, became increasingly recognized as a "bedroom community" of London. Accordingly, the area did not experience the magnitude of impact of the 2008 recession witnessed by Chatham-Kent, and instead experienced a 5% population increase between the 2006 census and 2011 census.

# 1.3 Applicant Overview

## 1.3.1 Overview of Service Area

The EPI service territory covers 96 square kilometers of urban areas, encompassed within a 5,000 square kilometer geographic area located in southwestern Ontario between Windsor (to the west), London (to the east) and Sarnia (to the north).

The EPI service territory is more specifically described in EPI's distribution Licence (ED-2002-0563), as encompassing the following:

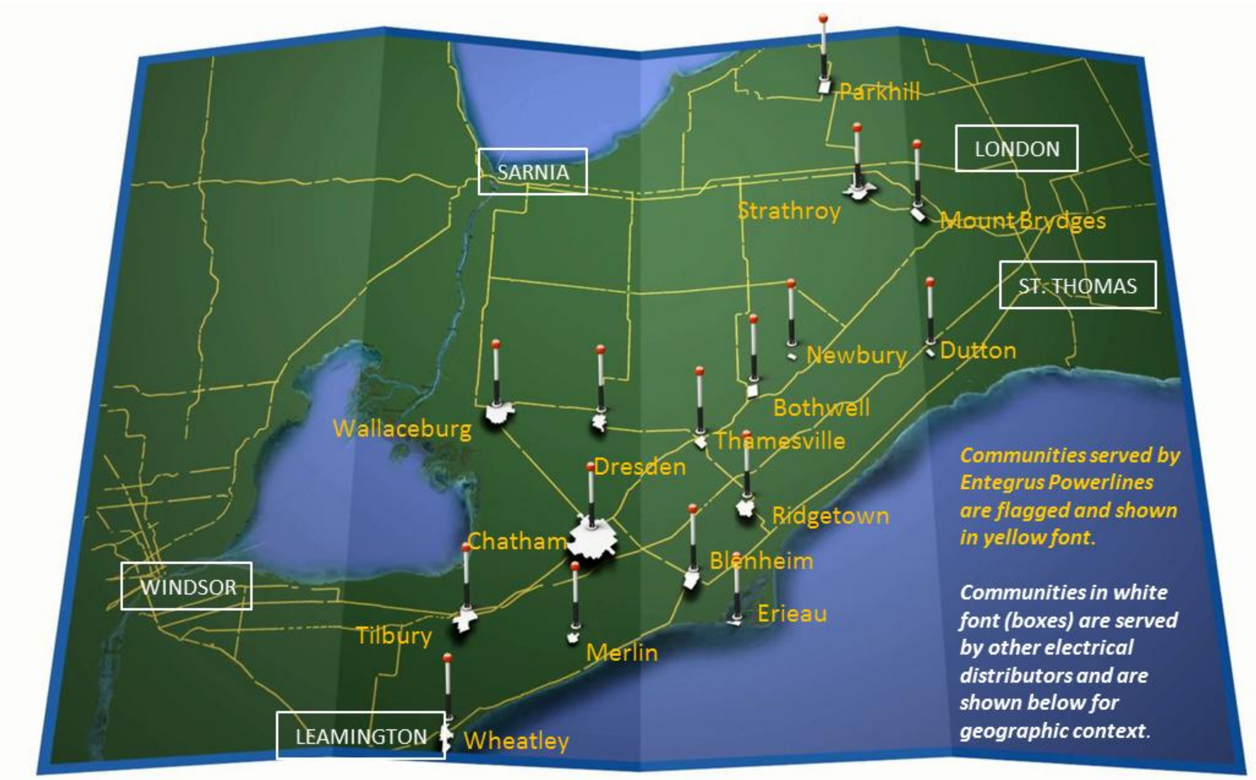
- *Those parts of the following former municipalities (including the former Police Village of Merlin) that the former dissolved public utilities served on December 31, 1997:*
    - *Town of Blenheim,*
    - *Town of Bothwell,*
    - *City of Chatham,*
    - *Town of Dresden,*
    - *Village of Erieau,*
    - *Police Village of Merlin,*
    - *Town of Ridgetown,*
    - *Village of Thamesville,*
    - *Town of Tilbury,*
    - *Town of Wallaceburg,*
    - *Village of Wheatley, and*
- *Part Lots 16 & 17, Concession A, Geographic Township of Raleigh, designated as Part 1, Reference Plan 24R 7195, Municipality of Chatham-Kent, and Part Lot 17, Concession A, Geographic Township of Raleigh, designated as Part 2, Reference Plan 7195, Municipality of Chatham-Kent as per Board Order RP-2003-0044, dated September 16, 2003.*

- *The former Town of Strathroy as of December 31, 2000.*
- *The former Police Village of Mount Brydges as of December 31, 2000.*
- *The former Town of Parkhill as of December 31, 2000.*

- *The Village of Dutton as of December 31, 1997, now within the Municipality of Dutton/Dunwich.*
- *The Village of Newbury as of November 7, 1998.*

Please refer to Table 1-1 below for a map of the EPI service territory. Refer to Attachment 1-C for maps of each of the communities served by EPI.

**TABLE 1-1: MAP OF THE EPI SERVICE TERRITORY**




## THE EPI DISTRIBUTION SYSTEM

EPI has a total of approximately 948 circuit kilometers of primary wire and underground cable installed, of which approximately 680 km (72%) is overhead and 268 km (28%) is underground. Please refer to Table 1-2 below for more details on EPI distribution system characteristics.

**TABLE 1-2: EPI DISTRIBUTION SYSTEM CHARACTERISTICS**

| No. of Phases | Overhead Line (km) | | | Underground Line (km) | | |
|---|---|---|---|---|---|---|
| | 4.16kV | 8.0kV | 27.6kV | 4.16kV | 8.0kV | 27.6kV |
| 1-Ø | 47 | 31 | 64 | 35 | 6 | 173 |
| 2-Ø | 0.4 | 0 | 0.4 | 0 | 0 | 0.2 |
| 3-Ø | 74 | 36 | 427 | 18 | 1 | 35 |
| Totals | 121.4 | 67 | 491.4 | 53 | 7 | 208.2 |

The EPI distribution system has 15 distribution substations remaining used to step down voltage from 27.6 kV for the remaining old 4.16 kV distribution system. A program to convert the remaining 4.16 kV distribution system to 27.6 kV is further discussed in Section 2 of the application.

For the original utilities that now comprise EPI, much of the economic growth occurred between 1950 and 1970. For example, the average age of EPI's 19 substation transformers is more than 40 years. Section 2 provides additional details on the composition of EPI's distribution system equipment and its ageing infrastructure.

### 1.3.2 IDENTIFICATION OF EMBEDDED OR HOST UTILITIES

Given the large geographic area served, the EPI distribution system electrical supply is sourced from a variety of HONI transmission and distribution stations, mainly at a primary voltage level of 27.6 kV (8 kV for the communities of: Erieau, Merlin, Bothwell, Mt. Brydges, Dutton and Newbury).

With of the exception of the Chatham population centre and the Bloomfield Business Park, the EPI distribution system is embedded within the HONI system. However, it should be noted that HONI is virtually embedded to EPI within the community of Dresden.

Five HONI stations serve Chatham-Kent: Kent TS, Kingsville TS, Wallaceburg TS and Tilbury West DS.

Four HONI stations serve Strathroy-Caradoc/Dutton/Newbury: Strathroy TS, Longwood TS, Centralia TS and Dutton DS. Primary voltages are stepped down to utilization voltages through approximately 4,170 EPI-owned distribution transformers.

**LIST OF NEIGHBOURING UTILITIES:**

EPI is bounded by HONI on all service territory boundaries.

### 1.3.3 TRANSMISSION ASSETS

EPI does not have any transmission or high voltage asset (>50kV) deemed previously by the Board as distribution assets and does not have any such assets for which EPI is seeking Board approval to be deemed as distribution assets in this Application.

# 1.4 Management Discussion & Analysis

## 1.4.1 The Renewed Regulatory Framework for Electricity ("RRFE")

On October 18, 2012, the Board issued its "*Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*" (the "RRFE"). The RRFE is a comprehensive performance-based approach to regulation based on the achievement of four outcomes that ensure that Ontario's electricity system provides value for money for customers. The RRFE emphasizes outcomes (rather than activities) and response to customer preferences in order to enhance distributor productivity and promote innovation. The four RRFE outcomes are as follows:

- **Customer Focus:** services are provided in a manner that responds to identified customer preferences;
- **Operational Effectiveness**: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;
- **Public Policy Responsiveness**: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and,
- **Financial Performance**: financial viability is maintained.

The actions and culture of EPI have been and continue to be consistent with the RRFE. EPI is very supportive of the Board policies and direction. This is evidenced by EPI's participation in the following recent and upcoming Board committees and initiatives:

- Ontario Energy Board Chair's Roundtable;
- Industry Advisory Steering Committee;
- Regulatory Affairs Standing Committee;
- Scorecard Implementation Working Group;
- Smart Grid Advisory Committee;
- Distribution Network Investment Planning Working Group;
- Regional Planning Process Advisory Group;

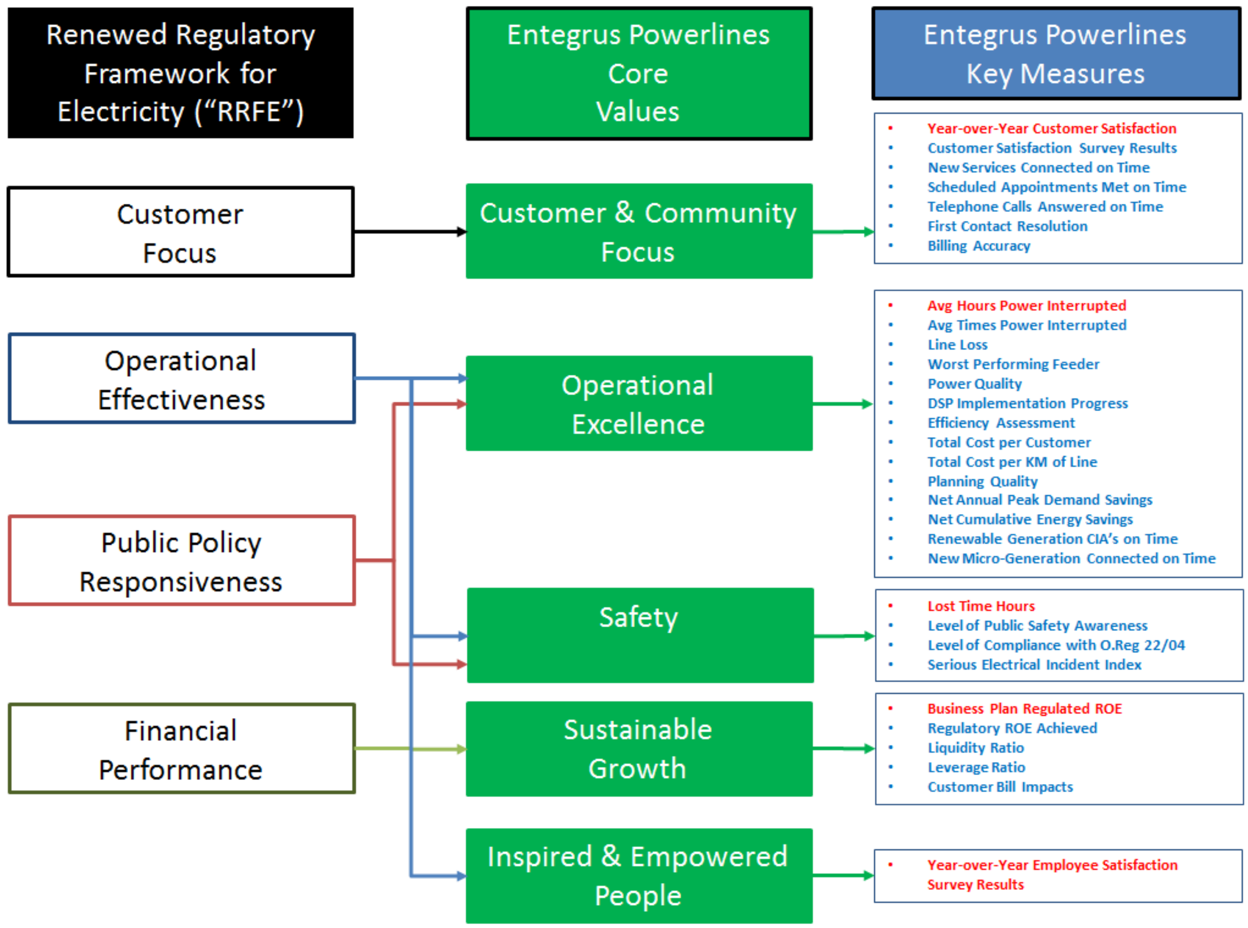
- Load Displacement Working Group;
- Distribution system Planning Working Group; and,
- Reliability Data Working Group

The launch of the RRFE, however, highlighted the need for EPI to update the organization's Vision, Mission and Core Values. The purpose of the update is to ensure that there is continued alignment with Board policies and stakeholder needs and to solidify the culture of the organization to consider outcomes in all decisions throughout the company.

The process to update the Vision, Mission and Core Values was initiated in 2013, starting with a series of Employee Town Halls and meetings. The process involved participation from employees, directors and shareholders. Stakeholders were provided with a summary of the RRFE which was described as the overarching measure by which the final Vision, Mission and Core values would be evaluated. Senior management felt it was important to provide the RRFE as an overall guide to the development of the Vision, Mission and Core Values. Further, there was focus on developing these in a manner uniquely interconnected to the EPI organization and in such a way as to resonate with employees.

It is evident that there is strong alignment between the EPI strategy described above and the four areas of focus identified by the Board in the RRFE. This alignment – including the associated key measures that EPI tracks against – is depicted by Table 1-3 below:

**TABLE 1-3: ALIGNMENT BETWEEN THE ENTEGRUS CORE VALUES & THE RRFE**




## 1.4.2 EPI'S BUSINESS PLAN AND OBJECTIVES

In conjunction with the development of the Vision, Mission and Core Values, management undertook a comprehensive review of its business strategy and key metrics and received final approval of the resulting initiatives from its Board of Directors.

Subsequently, the approved Mission, Vision, Core values and Strategic Success Factors were rolled out to employees in a Town Hall, using the EPI Strategic Compass diagram shown in Attachment 1-D. As noted in Section 1.2.1 above, in January 2015 the employees of ESI were transferred to EPI. The unification of employees under one banner represented the culmination of the evolution of the organization and is consistent with EPI's strategy.

The Mission, Vision, Core Values and Strategic Success Factors are further described below.

## VISION

***"To be an industry leader in all we do"***

## MISSION

***"To provide safe, reliable delivery of electricity and related services, in an environmentally and fiscally responsible manner. To provide exceptional service to our customers, support to the communities we serve and rewarding growth opportunities for our employees."***

## CORE VALUES

The core values are shown in Attachment 1-D in the black circumference of the EPI Strategic Compass. The core values are as follows:

**Safety:** ***"Safety first in everything we do"***

- Safety is the top priority in all work at all levels
- Be a recognized leader in Health & Safety (H&S)
- Build and maintain a best-in-class H&S culture

**Sustainable Growth:** ***"Delivering sustainable growth for our stakeholders through wise investments"***

- Investing wisely
- Maximizing shareholder return
- Serving community/communities

**Customer & Community Focus:** ***"Exceeding the needs of our customers and the communities we serve, by having a customer and community focus"***

- Understanding & exceeding the needs of customers
- Leading customer service
- Community engagement

**Inspired & Empowered People:** ***"Having a workforce of inspired and empowered people who are passionate about their jobs"***

- Powered by integrity
- Education and growth opportunities
- Right people in the right places

**Operational Excellence:** ***"Achieving operational excellence by always striving for continuous improvement."***

- Efficient
- Effective
- Continuous improvement
- Intelligent investment

## THE EPI STRATEGIC COMPASS AND STRATEGIC SUCCESS FACTORS

In order for EPI and its employees to "live" the mission, vision and core values, measureable Strategic Success Factors were developed. These success factors were incorporated, along with the other strategic elements, into the EPI Strategic Compass diagram, which is posted throughout the EPI operational centres (refer to Attachment 1-D). The Strategic Success Factors are shown as the "How" in the blue centre portion of the Compass.

The Strategic Success Factors are key measureables, and described in further detail below. Moving forward, each department will create its own compass, tying in and supporting the overall direction of the organization.

## THE EPI SCORECARD

EPI has historically measured its performance against Service Quality Index ("SQI") results.

On March 5, 2014, the Board issued its report on *Performance Measurement for Electricity Distributors: A Scorecard Approach*. The report set out the Board's policies on the measures to be used to assess a distributor's effectiveness and improvement in the four performance outcome areas of the RRFE (as shown above).

EPI embraced the Scorecard initiative, and commencing with the 2013 EPI Scorecard (as published in 2014), EPI began utilizing the Scorecard as a primary source of performance measurement. The Scorecard provides continuity on many of the SQI's that EPI has tracked in the past, as well as additional new measures. Please refer to Attachment 1-E for the EPI 2013 Scorecard and Attachment 1-F for the EPI 2014 Scorecard. Note that the 2014 scorecard is currently shown in draft. The final version, including Management Discussion & Analysis, is scheduled to be published on the EPI and Ontario Energy Board websites on September 30, 2015. For the final version, please see www.entegrus.ca/regulatory or www.ontarioenergyboard.ca on, or after, September 30, 2015. EPI will also file a copy with the Board in this proceeding that time.

As shown in Attachment 1-E, in 2013 EPI met all Scorecard targets. Results are discussed in further detail under each of the EPI Core Values areas below in this section. As shown in Attachment 1-F, EPI met all 2014 Scorecard targets, with the exception of the Conservation & Demand Management "Net Annual Peak Demand Savings" target. This result is further discussed below under Section 1.4.3 (under Operational Excellence / Key Measures & Performance Discussion / Net Annual Peak Demand Savings).

Starting in 2015, senior management supplemented the EPI Scorecard with additional key measures from the following sources:

- The Strategic Success Factors described above which relate to overarching continuous improvement; and,
- Specific goals from the EPI Distribution System Plan ("DSP"), as described in Exhibit 2, Attachment 2-D.

The Key measures and their sources (i.e. Scorecard, Strategic Success Factor or DSP Goal) are further discussed below under their associated Core Value.

### 1.4.3 The EPI Business Plan Strategy, Core Values and the RRFE

EPI will demonstrate below how the EPI business plan ties to its core values and the RRFE.

#### Safety

EPI's Core Value of Safety encompasses the Board's RRFE outcomes of Operational Effectiveness and Public Policy Responsiveness. The Safety Core Value is defined as:

***"Safety first in everything we do"***

- Safety is the top priority in all work at all levels
- Be a recognized leader in Health & Safety (H&S)
- Build and maintain a best-in-class H&S culture

The electrical distribution industry has an inherently high safety risk profile, and accordingly there is a significant degree of public policy to be adhered to in this area. EPI believes that Employee Health & Safety ("EH&S") and Electrical Public Safety are of paramount importance. EPI seeks to instill this mindset in its employees, such that safety is an area of continuous focus.

#### APPROACH & ACTIONS

EPI has a strong safety record, reflected by the results of the measures discussed below. However, EPI does not take safety for granted and makes EH&S training and reinforcement of the safety practices a continuous area of focus.

EPI seeks to be a recognized leader in the area of safety, by maintaining a best in class safety culture. This mindset is reinforced by the approach and actions described below, which are shown in the following categories: Employee Safety Actions, Contractor Safety Actions and Public Safety Actions.

##### EMPLOYEE SAFETY ACTIONS

- Oversight by the Environmental Health & Safety Committee of the EPI Board of Directors, which continuously reviews: health and safety practices and annual safety objectives and training plans, health and safety risk mitigation activities, and the handling and storing of environmentally sensitive material

- An active employee Joint Health and Safety Committee ("JHSC"), which includes two members of management and 7 unionized personnel (the JHSC meets at least 6 times annually)
- EPI representation on the Ontario board of the Association of Electrical Utility Safety Professionals ("AEUSP")
- Operational safety meetings every Monday morning, led by the H&S Manager
- Quarterly safety meetings with all operational and administrative staff, led by the H&S Manager and JHSC members
- A minimum of 6 worksite crew visits per month conducted by the H&S Manager, plus additional ad hoc site visits conducted each month by senior management and members of the JHSC
- Annual First Aid, CPR and defibrillator training for all staff members
- Operational safety training on specialized topics throughout the year

In addition, in 2014 EPI partnered with the Infrastructure Health & Safety Association ("IHSA") to build a training centre on the EPI Chatham Operational Centre yard. This facility enables on-site IHSA training for both new and existing EPI employees, as well as other utility employees in the region.

## CONTRACTOR SAFETY ACTIONS

EPI works with local contractors in the course of conducting operations and offering conservation programs:

- Multiple times per year, EPI conducts topic specific seminars for its community contractors, focusing on topics such as: working near high voltage power lines, hydro vacuum excavating;
- EPI also offers conservation outreach training to its contractors;

- EPI periodically provides specific safety training to local industry when the need arises. Most recently, this included power line safety awareness training to a local waste recycling company who had purchased a new fleet of garbage trucks that reach 25 feet in the air when dumping a load; and,

- In September 2014, EPI hosted "Electrical Safety for First Responders" training. Representatives from Chatham-Kent Fire, Police & Emergency services took part in the training, which covered best practices for coping with electrical hazards in rescue and fire situations.

## PUBLIC SAFETY ACTIONS

In terms of public electrical safety, EPI conducts and participates in various in-classroom programs, including the following:

- EPI teams annually with Rob Ellis and the International Brotherhood of Electrical Workers (an EPI union) to present the MySafeWork program in high schools. The program stresses the importance of health & safety for young workers in part-time and first-time jobs.

- EPI employees periodically visit grade school classrooms and career events to teach students about conservation and electrical awareness. Mostly recently, EPI's Systems Planning Engineer conducted such a visit with a local Girl Guide Troop in 2015.

- EPI sponsors the local Children's Safety Village, and annually our operations staff teaches electrical awareness training during a 6 week period to school children.

## ACHIEVEMENTS

Based on EPI's safety achievements, the company has been recognized with various H&S awards:

- EUSA Bronze Safety Award Medal (August 2005)

- EUSA Effort Safety Award Medal (April 2007)

- EUSA Commitment Safety Award (October 2007)

- EUSA Outcomes Safety Award (April 2009)

- IHSA Zero Quest Safety Award (October 2013)
- IHSA Certificate of Recognition ("COR") (July 2015)

EPI is particularly proud of its July 2015 achievement of the IHSA's COR (see COR certificate, Exhibit 2, Attachment 2-D, Appendix XVI). EPI is only the second Ontario LDC to receive this recognition. However, EPI is mindful that a safety mindset and continued safety actions are critical and must be ongoing.

## KEY MEASURES & PERFORMANCE DISCUSSION

In order to measure Safety and ensure that EPI is on course, EPI focuses on its Strategic Success Factor related to EH&S, entitled: "Lost Time Hours". EPI also tracks three additional measures related to public safety.

These measures and the associated performance discussion are detailed below.

### LOST TIME HOURS (STRATEGIC SUCCESS FACTOR)

| Measure | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 June YTD |
|---|---|---|---|---|---|---|
| Lost Time Hours | 106.9 | 0 | 0 | 0 | 0 | 0 |

It is critical that EPI measure EH&S. In order to do so, EPI tracks Lost Time Hours. Lost Time Hours occur when an employee gets injured while carrying out a work task for the employer and is unable for perform the regular duties for a complete shift. EPI measures Lost Time Hours through review of statement of claim summaries provided by the Workplace Safety and Insurance Board ("WSIB").

It should be noted that the Lost Time statistics above for all years also include the former ESI employee base (who became EPI employees on January 1, 2015). EPI has not experienced any Lost Time Hours since 2011, which as of July 2015 translates into 824,854 hours without a Lost Time Injury.

EPI's goal is to have zero Lost Time Hours each year.

### LEVEL OF PUBLIC SAFETY AWARENESS (SCORECARD MEASURE)

| Measure | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Level of Public Awareness (measure to be determined) | not measured - new in 2015 | | | | |

In 2015, the Board (in consultation with the Electrical Safety Authority ("ESA")) released three new industry measures related to distributor electrical safety. The measurement methodology for the first of these three measures, the Level of Public Awareness, has yet to be fully determined. However, it is known that the new metric will measure levels of awareness of key electrical safety precautions amongst the public residing within an electrical distributor's service territory. This will be done via a biennial survey using standardized questions. EPI will commence tracking this measure in 2015 at such time as the measurement methodology is released.

## LEVEL OF COMPLIANCE WITH ONTARIO REGULATION 22/04 (SCORECARD MEASURE)

| Measure | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Level of Compliance with Ontario Regulation 22/04 | NI | NI | C | C | C |

The second public safety measured released by the Board (in consultation with the ESA) in 2015 relates to compliance with The Electrical Distribution Safety Regulation (Ontario Regulation 22/04, or the "Regulation"). The Regulation establishes a standard for safety performance and offers distribution companies options for achieving compliance. Specifically, the Regulation requires the approval of equipment, plans, specifications and inspection of construction before they are put into service. A consultant engaged by the ESA conducts annual audits of each distributor's compliance with the Regulation. Audit results are assessed according to the following outcomes:

- **Non-Compliance ("NC"):** A failure to comply with a substantial part of the Regulation; or continuing failure to comply with a previously identified "Needs Improvement" item.
- **Needs Improvement ("NI")**: A failure to fully comply with part of the Regulation; or non-pervasive failure to comply with adequate, established procedures for complying with the Regulation.
- **Compliant ("C")**: Substantially meeting the requirements of the Regulation.

Historical data related to this measure has been tracked by EPI and the ESA. For 2012, 2013 and 2014, EPI was assessed as Compliant. Previously, in 2010 and 2011, EPI had been assessed as "Needs Improvement", primarily due to inconsistent record-keeping practices. Subsequently, EPI made improvement a significant area of focus, and the 2012, 2013 and 2014 results are consistent with the efforts EPI is making toward public safety.

### SERIOUS ELECTRICAL INCIDENT INDEX (SCORECARD MEASURE)

| Measure | | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|
| Serious Electrical Incident Index | Number of General Public Incidents | 0 | 0 | 0 | 0 | 0 |
| | Rate per 100 km of line | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |

The third public safety measure released by the Board (in consultation with the ESA) in 2015 relates to the Serious Electrical Incident Index. For EPI, this is measured as the number and percentage of non-occupational (general public) serious electrical incidents occurring on EPI's distribution system per 100 km of line.

Historical data related to this measure has been tracked by EPI and the ESA. EPI is proud to have had no such incidents in 2010-2015, and will continue to make this an area of focus.

## SAFETY – BUSINESS PLAN GOALS MOVING FORWARD

EPI is committed to continuously improving its safety processes in order to maintain a safe and healthy environment for employees and the public.

As noted above, EPI will commence tracking the new Level of Public Safety Awareness Measure in 2015. Once full details of this measure are understood, EPI plans to launch a public safety marketing campaign in 2016. This will include a public safety video, along with associated community marketing materials and promotions.

In terms of EH&S, EPI's achievement of the IHSA's COR in July 2015 has resulted in the identification of additional actions that EPI can take to continue to improve employee safety. These actions include additional processes, procedures, inspections and training that will be implemented throughout late 2015 and 2016.

## CUSTOMER AND COMMUNITY FOCUS

EPI's Core Value of Customer and Community Focus encompasses the Board's RRFE outcomes of Customer Focus and Public Policy Responsiveness. The Customer and Community Focus Core Value is defined as:

***"Exceeding the needs of our customers and the communities we serve, by having a customer and community focus"***

- Understanding & exceeding the needs of customers
- Leading customer service
- Community engagement

EPI recognizes that customer engagement is vital in order to remain relevant and understand the needs and preferences of its customers.

## APPROACH & ACTIONS

EPI engages with customers through various everyday touch points to understand their preferences. Examples of everyday touch points include:

- In 2014, 65,782 inbound phone calls were answered by Customer Service staff on various topics of customer concern, including: account information and activating new accounts, questions on bills and components and outages;
- In 2014, over 12,000 outbound calls were made on various issues, including calls to customers and calls to co-ordinate service arrangements with operations personnel;
- As of December 31, 2014, 5,000 customers have signed up to access "My Account" (EPI's web portal that allows customers to access and analyze their electricity consumption data) and 5,600 customers had signed up for eBilling;
- Many customers are contacted each year to discuss operational activities occurring in their area, including EPI maintenance and vegetation management projects occurring;
- Monthly bill inserts and on-bill message on topics of interest and relevance to customers. For example, the July 2015 bill insert provided information on saveONenergy coupons, as well as details about Ontario One Call. The August 2015 bill insert provided information on the saveONenergy Fridge & Freezer Pickup program; and,

- EPI provides semi-annual rate update brochures to customers in May and November of each year

EPI also engages with larger commercial and industrial customers on areas of importance. Typical discussions and engagement include electricity supply considerations, energy conservation program offerings and Global Adjustment options (i.e. Class A versus Class B opt in). In particular, EPI has recently worked closely with a large industrial customer on the development of a new load displacement generation project, which is anticipated to launch in late 2015. EPI engaged with government agencies to assist in funding approvals for this project and also provided technical assistance on electrical distribution matters throughout the project completion period.

In addition, EPI has recently undertaken the following initiatives to engage with customers to understand their needs and preferences:

## COMMERCIAL & INDUSTRIAL CONSERVATION CONFERENCES

In May 2015, EPI held a customer outreach conference at the John D. Bradley Centre in Chatham, entitled *"Power Play: Profiting from Sustainability & Electricity Conservation Strategies"*.

The purpose of the conference was to engage and educate Commercial, Industrial and Institutional customers on their conservation options and the benefits of participating in the saveONenergy programs. Over 30 companies attended the event, representing the Manufacturing, Automotive, Fabrication, Hospitality, Grocery/Food distributor, Greenhouse, Agriculture, Electrical Supply/Distribution, Building/Construction, Municipal, Skilled Trades, and HVAC industries.

The event agenda included guest speakers on the topic of conservation, as well as a Q & A panel discussion with the guest event speakers. The event also provided the opportunity for face-to-face conversations with EPI and provincial energy agencies.

The event was televised by TV Cogeco and will be airing over the summer in an effort to increase awareness of conservation programs available to the community. 77% of companies in attendance requested contact from the Conservation Department to discuss potential opportunities, or were already working with EPI prior to attending the event.

Previously, in April 2014, EPI received the EDA Public Relations Excellence Award for its inaugural customer conservation conference, entitled "Taking Charge of Your Energy Costs". This event was held in December 2013 amidst a growing number of inquiries from commercial and industrial customers regarding billing, and specifically the global adjustment charge. A number of breakout sessions were held, including a session entitled, "Understanding Your Bill". The conference helped foster a more collaborative approach to energy-cost control and was the impetus for the May 2015 conference.

## COMMUNITY CONSERVATION EVENTS

EPI conducts numerous community conservation outreach events each year. For example:

- EPI hosted the 'Dollars to Sense' Energy Management Workshop offered by Natural Resources Canada from 2012 – 2014

- In June 2013, EPI hosted a media event to promote the Home Assistance Program. Representatives from our service provider, Greensaver, the Mayor of the Municipality of Chatham-Kent, and EPI senior management were present to address the needs & concerns of low income customers

- In October 2013, a media event was held to celebrate the installation of Chatham-Kent's first hybrid and electric vehicle charging station, and to discuss the positive impact of renewable energy in the area. The event coincided with a PR event organized by Sun County Highway, where the Chatham charging station was one of 17 stops on a Tesla Electric Vehicle Tour from Montreal to Windsor. EPI partnered with the Downtown Chatham Centre to provide free electric vehicle charging for two years

- In December 2013, EPI & the Public Utilities Commission (PUC) hosted a media event to celebrate the completion of the PUC's Biogas plant. EPI worked in partnership with the PUC & CEM Manufacturing to complete this project under the Ontario Government's "Feed-In Tariff" (FIT) Program

- EPI employees had set up informational booths and displays at local movie theatres, grocery chains, festivals, and various retailers in the summer and fall of 2014 to discuss conservation with residential customers, and explained the Peaksaver Plus conservation program
- EPI developed a campaign in 2014 to promote 'Peaksaver PLUS®' on screen at the local Cineplex that included both still ads, and video ads that would play prior to the start of a movie
- The EPI conservation team participated with other electrical distributors in the saveONenergy Show and Symposium in 2013 & 2014
- A Customer Appreciation Event was held in late 2014 as a thank you to current program contractors, and to discuss the future of conservation programming; and,
- Throughout the entire 2011 – 2014 conservation framework, EPI hosted booths at large retailers, festivals, movie theatres and other locations and community events to educate and engage with customers on residential programs that are available.

## WEBSITE & SOCIAL MEDIA

In 2014, EPI overhauled its online customer service offerings to improve the experience the digital customer experience. This process included:

- Redesign the EPI website, with the following new features: an innovative responsive design to meet accessibility standards and ensure usability on any device, a clean and customer friendly layout to easily locate information, a home page alert bar to immediately notify customers of major outages, and a comprehensive FAQ database;
- A new online self-service portal platform entitled "My Account", including automated forms; and,
- Launch of social media channels on Facebook, Twitter and YouTube. The importance of electrical distributors having a social media presence was highlighted to EPI after the industry's experiences during the Greater Toronto Area ice storm of 2013. The three digital channels were released consecutively over six weeks, followed by a "Centennial Celebration" promotion

highlighting 100 years in the industry, and in turn drawing customers to the company's new digital offerings.

EPI was subsequently recognized with the EDA's 2015 Customer Service Excellence Award for these initiatives.

### ST. CLAIR COLLEGE – POWERLINE MAINTAINER PROGRAM

EPI supports the St. Clair College Thames (Chatham) Campus in its development of the Powerline Technician program. EPI operational managers donate time to the Advisory Board of this program, and multiple EPI employees and retirees act as instructors.

Starting in 2013, EPI began hiring co-op students from the program, and a diploma from this program is now a prerequisite for candidates for EPI apprentice positions. The two apprentices hired full-time by EPI in 2014 were both graduates of the St. Clair College program with previous co-op experience with EPI.

### HOLIDAY MEAL PREPARATION FOR CITIZENS IN NEED

Every Thanksgiving, EPI Chatham employees make and then serve the Thanksgiving luncheon at the local Spirit and Life Centre for citizens in need. EPI serves over 200 patrons. Similarly, EPI Strathroy employees serve Thanksgiving and Christmas dinners. EPI believes that this experience helps the community while also fostering employee understanding of a less fortunate segment of EPI's customer base.

### CUSTOMER ENGAGEMENT SURVEYS

In addition to the interactions described above, in 2014 and 2015, EPI conducted customer engagement exercises related to the DSP, the 2016 rate application and the EPI Scorecard. These exercises sought to understand the needs and preferences of EPI customers, and are described in detail in Section 1.5 below.

## KEY MEASURES & PERFORMANCE DISCUSSION

In order to measure Customer and Community Focus and ensure that EPI is on course, EPI focuses on its Strategic Success Factor, entitled: "Year-Over-Year Customer Satisfaction". EPI also tracks six additional measures related to Customer Service quality, including First Contact Resolution and billing accuracy.

These measures and the associated performance discussion are detailed below.

### YEAR-OVER-YEAR CUSTOMER SATISFACTION (STRATEGIC SUCCESS FACTOR)

In 2014, EPI received a 92% Customer Satisfaction survey result. Further details on this survey are discussed below in this section. While EPI is proud of this survey result, it seeks to achieve continuous improvement in Customer Satisfaction.

Accordingly, commencing in 2015, EPI has complimented the existing Customer Satisfaction Scorecard Measure by way of a goal to achieve year-over-year improvement on this metric. This will necessitate focus on all the other key measureables further described below.

For 2015, EPI seeks to improve on its 2014 Customer Satisfaction achievement of 92%. This will entail EPI conducting a "Top-Down" Customer Satisfaction survey on an annual basis.

### CUSTOMER SATISFACTION SURVEY RESULTS (SCORECARD MEASURE)

| Measure | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Customer Survey Satisfaction Results | not measured - new in 2014 | | | | 92% |

EPI began measuring Customer Satisfaction in 2014. An industry target for this measure has not yet been determined.

For the period October 21, 2014 to November 7, 2014, agents from a third party consultant, Convergys Corporation ("Convergys"), conducted a random sample of 500 complete Residential surveys and 96 complete Small Commercial surveys. In terms of Overall Customer Satisfaction, the question posed to customers by Convergys was, "Taking everything into consideration, how would you rate your overall Entegrus experience? Please use a 1 to 5 scale where 1 is not at all satisfied and 5 is very satisfied."

Of the 596 Top-Down Survey customers (the denominator) surveyed from October 21, 2014 to November 7, 2014, 548 customers (the numerator) rated their Overall Satisfaction as a 3, 4 or 5. This numerator and denominator equate to the reported Customer Satisfaction figure of 92%. Additional details on the Customer Satisfaction survey process and Convergys are described in Section 1.5.1.

## FIRST CONTACT RESOLUTION (SCORECARD MEASURE)

| Measure | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| First Contact Resolution | not measured - new in 2014 | | | | 76% |

EPI began measuring First Contact Resolution ("FCR") in 2014. FCR measures (as a percentage) the number of instances where a customer's need is addressed the first time the customer calls. An industry target for this measured has not yet been determined.

EPI believes that <u>FCR can only be measured properly by surveying a random sample of those customers who actually recently contacted EPI</u>. Hence, the third party consultant who conducted the survey (Convergys) used a transactional survey approach, and typically contacted EPI customers by telephone within 2 weeks of their initial inbound call to EPI, posing the following question: *"Was the specific question or issue you called about on [*insert date] resolved during that call?" Of the 153 customers surveyed (the denominator) from October 1, 2014 to December 31, 2014, 116 customers (the numerator) indicated that their issue was resolved on the first call to EPI. This numerator and denominator equate to the reported FCR figure of 76%.

EPI seeks to improve its 2014 FCR result of 76%. Accordingly, EPI has continued to engage Convergys to assist with FCR measurement and an associated improvement strategy.

Additional details on FCR, Convergys and the improvement strategy are described in Section 1.5.1.

## NEW RESIDENTIAL/SMALL BUSINESS SERVICES CONNECTED ON TIME (SCORECARD MEASURE)

| Measure | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| New Residential Services Connected on Time | 97.60% | 93.80% | 92.00% | 97.00% | 98.80% |

The Distribution System Code ("DSC") requires electricity distributors to complete a connection for new service under 750 volts within five days from the day on which all applicable service conditions are satisfied. For the five-year period from 2010 to 2014, EPI has consistently performed better than the industry standard of 90% in this area.

## SCHEDULED APPOINTMENTS MET ON TIME (SCORECARD MEASURE)

| Measure | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Scheduled Appointments Met on Time | 100.00% | 98.70% | 99.00% | 99.40% | 98.00% |

The DSC requires that electricity distributors offer to schedule an appointment within a window of time that is no greater than four hours. The electricity distributor must then arrive for the appointment within the scheduled timeframe 90% of the time. For the five-year period from 2010 to 2014, EPI has consistently performed better than the industry standard of 90% in this area.

## TELEPHONE CALLS ANSWERED ON TIME (SCORECARD MEASURE)

| Measure | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Telephone Calls Answered on Time | 67.00% | 68.80% | 95.90% | 77.40% | 72.71% |

The DSC requires that electricity distributors answer calls within 30 seconds 65% of the time. EPI has historically staffed its Customer Service Call Centre to meet this goal, 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 2010 to 2014, EPI has consistently performed better than the industry standard of 65% in this area.

In 2012, EPI engaged contract resourcing to assist with additional calls related to Time-of-Use billing, which resulted in quicker call response times. This contract resourcing was discontinued to 2013. In 2014, EPI overhauled its online customer service offerings to improve the digital customer experience. This process included: redesign of the EPI website, a new online self-service portal and the launch of social media channels. An objective of improving the digital customer experience is to reduce certain call types in favour of self-service, which will assist EPI in enhancing call response time.

### BILLING ACCURACY (SCORECARD MEASURE)

| Measure | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Billing Accuracy | not measured - new in 2014 | | | | 99.73% |

In 2014, the Board introduced the Billing Accuracy measure, effective for October 1, 2014. The measure is defined as the number of accurate bills issued expressed as a percentage of total bills issued. It is calculated as: the number of bills accurately issued for the year, divided by the total number of bills issued for the year.

EPI began tracking Billing Accuracy in October 2014. The DSC requires electricity distributors maintain 98% Bill Accuracy, meaning that the number of instances (as a percentage) where a customer's bill does not contain errors and does not result in re-issuance.

In 2014, EPI outperformed the industry standard of 98% in this area.

## CUSTOMER AND COMMUNITY FOCUS – BUSINESS PLAN GOALS MOVING FORWARD

Customer engagement confirmed and revealed various customer needs and preferences that EPI seeks to act on. These needs, and EPI's planned associated actions include:

### ASSISTING CUSTOMERS WITH ENERGY LITERACY

- Timeline: Early 2016
- Additional explanatory content on the EPI website
- Creation of educational videos (i.e. understanding your bill, electrical safety, conservation, distribution system enhancements) to provide further relevant information to customers
- For examples of previous customer education videos created by EPI for its 2015 customer engagement activities, please see the following links:
    - **EPI's History:** https://www.youtube.com/watch?v=m7d3UmlU8gU
    - **How it Works – Generation, Transmission & Distribution:** https://www.youtube.com/watch?v=daeyoS-PCUA
    - **Infrastructure**: https://www.youtube.com/watch?v=11TQzljemCA
    - **Smart Grid:** https://www.youtube.com/watch?v=LSICp9ZHlPA
    - **Rate Harmonization:** https://www.youtube.com/watch?v=nToaJic1DvM

  - **The Bill:** https://www.youtube.com/watch?v=BytYGuGtMoI

## CONSUMPTION MANAGEMENT TOOLS AND DRIVING AWARENESS

- Timeline: Late 2015 / Early 2016
- Additional marketing to drive more customer awareness of the existing web-based tools that were launched in 2014 and are available to customers
- Enhancements to EPI's "My Account" on-line consumption management tool to provide more information and access for the larger volume rate classes

## PROVIDING MORE COMMUNICATION ON OUTAGES

- Timeline: Late 2015
- Leverage smart meter "last gasp" outage data and existing systems such as SCADA, ODS, GIS, CIS to development graphical mapping displays of outages
- Complement the existing social media outage communications with more detailed information

## IMPROVING FIRST CALL RESOLUTION

- Timeline: September 2015
- Work with third party consultant to provide each Customer Service Representative with access to an on-line portal that compares their ongoing individual survey results against the aggregate departmental results
- Utilize the on-line portal to identify which type of customer contact issues are being handled well and where there are opportunities for additional training

## OPERATIONAL EXCELLENCE

EPI's Core Value of Operational Excellence encompasses the Board's RRFE outcome Operational Effectiveness. The Operational Excellence Core Value is defined as:

***"Achieving operational excellence by always striving for continuous improvement"***

- Efficient

- Effective
- Continuous improvement
- Intelligent investment

Operational Excellence means that EPI employees are encouraged to continually improve upon past successes and avoid the pitfall of satisfaction with the status quo.

A recent major focus in the area of Operational Excellence has been the development of the EPI DSP, which accompanies this Application as Exhibit 2, Attachment 2-D. EPI also continues to be focused on the implementation of public policy initiatives.

## APPROACH & ACTIONS

### THE DSP

Historically, the EPI Engineering Department has managed its distribution system assets using data from various traditional sources:

- Field crews, inspecting distribution lines as a part of a regular patrol procedure
- Infra-red scanning results
- Supervisory Control and Data Acquisition ("SCADA") system measurements at the feeder level (i.e. loading data and outage information – this information was used to identify worst performing feeders, feeder imbalances, and load constraints)

In March of 2013, the Board released new Filing Requirements, which included the direction for electrical distributors to complete a DSP. The Board noted that good distribution planning is an essential pre-requisite to the performance-based rate-setting approaches established under the RRFE, and that a DSP would provide a record of the following key stakeholder information:

- A distributor's asset-related performance objectives and approach to evaluating its performance relative to those objectives ;

- The distributor's approach to lifecycle asset management planning and the management of asset-related operational and financial risk; and,
- The distributor's plan for capital-related expenditures over the five-year forecast period

Subsequently, working together with METSCO Energy Solutions ("METSCO"), EPI began the EPI DSP project. This involved compiling additional asset condition assessment information for the development of an Asset Condition Report ("ACR") and the creation of an Asset Management Plan ("AMP"), based on the PAS 55 (or ISO 55000) Asset Management standard; this resulted in the creation of a framework for risk assessment and lifecycle management for field assets. The process also involved a focus on investment in new technologies (e.g. Smart Grid) and new operational processes. METSCO assisted with the delivery of associated senior management training and user sessions.

The DSP was finalized in the summer of 2015 and provides the "blueprint" for EPI's investment priorities on a go forward basis. The DSP is attached as Exhibit 2, Attachment 2-D.

## IMPLEMENTATION OF PUBLIC POLICY INITIATIVES

EPI is committed to embracing and supporting public policy initiatives. Recent examples of implementation of public policy initiatives include:

- **Smart Meters:** As one of the first electrical distributors in Ontario to pilot and install Smart Meters, EPI takes great pride in its pioneering role in this initiative. EPI was an early adopter of Advanced Metering Infrastructure and Smart Meter technology, and demonstrated leadership in the implementation process both in its own service areas and by sharing its learnings and experience with the industry.
- **Time-of-Use Billing:** EPI piloted Residential TOU billing in 2007 and completed Small General Service TOU billing on deadline by June 2011, without seeking an extension from the Board throughout the process.
- **Conservation and Demand Management ("CDM"):** EPI's has offered the OPA/IESO save-ON-energy CDM programs since their inauguration in 2006, including launching these programs at legacy utilities as they were acquired. EPI puts strong focus on meeting CDM targets.

- **Renewable Generation:** EPI continues to focus on supporting renewable generation, including ensuring that connection requirements are met.

In addition, EPI continues to meet Ontario One Call requirements and has met the requirements regarding the transition to International Financial Reporting Standards ("IFRS") for accounting.

## KEY MEASURES & PERFORMANCE DISCUSSION

In order to measure Operational Excellence and ensure that EPI is on course, management focuses on its Strategic Success Factor related to reliability, entitled: "Average Number of Hours that Power to a Customer is Interrupted". (This measure is also known as System Average Interruption Duration Index, or "SAIDI").

EPI also tracks additional measures related to reliability, system performance, cost containment, planning quality and public policy implementation.

These measures and the associated performance discussion are detailed below.

### AVERAGE NUMBER OF HOURS THAT POWER TO A CUSTOMER IS INTERRUPTED (STRATEGIC SUCCESS & SCORECARD MEASURE)

| Measure | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Average Number of Hours that Power to a Customer is Interrupted | 1.33 | 0.88 | 1.18 | 1.23 | 1.31 |

For this measure, the target for each distributor is to be at least within the range of the low point and high point from the past four years of results. Accordingly, EPI's 2014 target range was to be at least within 0.88 – 1.33. EPI's 2014 result of 1.31 is within this range, and compares well to the 2014 industry average of 1.60, demonstrating that the EPI distribution system is performing reliably.

In order to maintain focus on system reliability, EPI tracks two complimentary measures (Line Loss and Worst Performing Feeder), which are further discussed below.

## AVERAGE NUMBER OF TIMES THAT POWER TO A CUSTOMER IS INTERRUPTED (SCORECARD MEASURE)

| Measure | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Average Number of Times that Power to a Customer is Interrupted | 0.91 | 0.72 | 0.97 | 0.94 | 0.84 |

For this measure, the target for each distributor is to be at least within the range of the low point and high point from the past four years of results. Accordingly, EPI's 2014 target range was to be at least within 0.72 – 0.97. EPI's 2014 result of 0.84 is within this range, and compares well to the 2014 industry average of 1.64, demonstrating that the EPI distribution system is performing reliably.

As noted above, in order to maintain focus on system reliability, EPI tracks two complimentary measures (Line Loss and Worst Performing Feeder), which are further discussed below.

## LINE LOSS (DSP MEASURE)

| Measure | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Line Loss | 1.0426 | 1.0403 | 1.0464 | 1.0459 | 1.0405 |

Line loss is calculated as the percentage of electrical energy lost, due to heat and transformer losses, in the transmission of electrical energy from the supply points with HONI or the IESO grid to EPI's customers. By focusing on reducing line loss, EPI can ensure more efficient distribution of electricity and reduce customer bill costs.

EPI does not have a target for this metric but strives to see a year-over-year decrease. Line loss is further discussed in Exhibit 2, Attachment 2-D.

## WORST PERFORMING FEEDER (DSP MEASURE)

Worst Performing Feeder ("WPF") analysis is intended to identify those portions of the distribution system (feeders) that are experiencing sustained interruptions. This involves plotting the number of customers interrupted (x-axis) versus the number of customer hours of interruption (y-axis), and then identifying the worst performers. The WPFs can then be targeted for replacement or conversion upgrades, which results in the removal of problematic assets from the system and drives enhanced reliability.

WPF analysis is a key input to the DSP, and is discussed in further detail in Exhibit 2, Attachment 2-D.

## POWER QUALITY (DSP MEASURE)

The communities served by EPI continue to depend on a relatively large industrial manufacturing base. Recently, engagement with these customers has indicated that their increasingly complex modern production machinery has very low tolerances for voltage variations. Momentary outages, or minute voltage variations (within traditional specification levels), can result in time consuming stoppages to the manufacturing process.

These types of variations are traditionally not captured by metrics such as Average Number of Hours that Power to a Customer is Interrupted (SAIDI) and Average Number of Times that Power to a Customer is Interrupted (SAIFI). As a result, EPI plans to establish a set of measures and policies based on established industry standards to define the various types of power quality problems. The establishment of such standards is still in its infancy but EPI plans to use measures established by other leading North American electric utilities, which typically lever standards developed by the IEEE Institute of Electrical and Electronics Engineers ("IEEE").

Measurement of power quality is a key area of focus in the EPI DSP, as shown in Exhibit 2, Attachment 2-D.

## DISTRIBUTION SYSTEM PLAN IMPLEMENTATION PROGRESS (SCORECARD MEASURE)

| Measure | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Distribution System Plan Implementation Progress | not measured - new in 2013 | | | 50% | 80% |

EPI began measuring DSP Implementation Progress in 2014. The Board has not defined an Asset Management Measure. Instead, distributors have been asked to focus on a measure that they believe most effectively reflects their performance in implementing their DSP. Since the first EPI DSP is to be filed with this Application, EPI selected percentage of completion as its measure, which represents the degree of project completion in terms of the DSP document itself.

Effective August 2015, the EPI DSP document is 100% complete, and EPI has filed the DSP with this Application (refer to Exhibit 2, Attachment 2-D).

In 2016, EPI anticipates that this metric will be adjusted to report the progress toward physical implementation of the DSP.

## EFFICIENCY ASSESSMENT (SCORECARD MEASURE)

| Measure | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Efficiency Assessment | 1 of 3 | 1 of 3 | 2 of 5 | 2 of 5 | 2 of 5 |

EPI began tracking the Board's efficiency measures since inception. EPI considers these measures to be of particular importance. The Board's most recent efficiency ranking methodology, entitled "Efficiency Measure" (along with the Total Cost per Customer Measure and the Total Cost per KM of Line Measure) is based on a statistical total cost benchmarking study commissioned by the Board, which is designed to make inferences on the cost efficiency of individual distributors.

Under the Board's previous efficiency assessment methodology, EPI and its legacy distributors (CKH and MPDC) were ranked in the topmost of three tranches since 2010. The previous methodology ranked efficiency in terms of expenses only, and did not consider capital. Since the current methodology was released for 2012, EPI has been ranked in the second of five tranches.

EPI's goal in terms of the Efficiency Measure is for its actual total costs to be below the total costs predicted by the Board's econometric model. To-date, EPI has been successful in meeting this Efficiency Measure goal. The 2014 benchmarking performance released by the Board on July 30, 2015 (encompassing the three year period of 2012-2014), showed that EPI actual costs were 13.4% below the total costs predicted by the econometric model.

## TOTAL COST PER CUSTOMER (SCORECARD MEASURE)

| Measure | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Total Cost per Customer | $507 | $517 | $495 | $531 | $537 |

As discussed above under the Efficiency Measure, Total Cost per Customer is based on a statistical total cost benchmarking study commissioned by the Board. For this measure, each distributor's Total Costs are adjusted by a "same sizing" factor, and then the resulting Adjusted Total Costs are divided by the number of customers applicable to each distributor. Accordingly, while useful as a comparative benchmark indicator, this measure may not necessarily represent actual Total Cost per Customer.

In terms of cost containment, EPI's overarching goal (as discussed above under the Efficiency Measure) is for its actual total costs to be below the total costs predicted by the Board's econometric model. Achieving this goal, in turn, will continue to drive a fair Total Cost per Customer result.

As discussed above under the Efficiency Assessment Measure, EPI has had a strong history of achievement in terms of efficiency benchmarking for the period from 2010-2014.

## TOTAL COST PER KM OF LINE (SCORECARD MEASURE)

| Measure | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Total Cost per Km of Line | $20,075 | $21,921 | $20,765 | $22,407 | $22,687 |

As discussed above under the Efficiency Measure, Total Cost per KM of Line is based a statistical total cost benchmarking study commissioned by the Board. For this measure, each distributor's Total Costs are adjusted by a "same sizing" factor, and then the resulting Adjusted Total Costs are divided by the km of line applicable to each distributor. Accordingly, while useful as a comparative benchmark indicator, this measure may not necessarily represent actual Total Cost per KM of Line.

In terms of cost containment, EPI's overarching goal (as discussed above under the Efficiency Measure) is for its actual total costs to be below the total costs predicted by the Board's econometric model. Achieving this goal, in turn, will continue to drive a fair Total Cost per KM of Line result.

As discussed above under the Efficiency Assessment Measure, EPI has had a strong history of achievement in terms of efficiency benchmarking for the period from 2010-2014.

## PLANNING QUALITY (DSP MEASURE)

Planning quality is a new measure being introduced in 2015 as part of the implementation of a new estimating system integrated with EPI's existing financial system. The new system allows for the creation and cataloguing of detailed estimates and the integration with the financial system allows for accurate variance reporting with actual costs.

Planning quality is measured as the variance from estimated cost to actual cost for each project identified in the capital plan. At the completion of each job, actual costs are compared to estimate costs and an analysis is made to determine the quality of the plan and estimate. Information garnered from these exercises is recycled into the estimating and planning process in order to refine and improve the process. EPI's goal is that no project's actual cost should differ by more than ± 10%. Planning Quality is further discussed in the DSP (refer to Exhibit 2, Attachment 2-D).

## NET ANNUAL PEAK DEMAND SAVINGS (SCORECARD MEASURE)

| Measure | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Net Annual Peak Demand Savings (% of target achieved) | not measured | 13.00% | 11.00% | 11.30% | 48.00% |

In November 2010, under the direction of the Minister of Energy and Infrastructure of Ontario, the Board amended EPI's Distribution Licence of EPI to require EPI, as a condition of its licence, to achieve net annual peak demand savings of 12.16 MW by December 2014. Peak demand savings are reductions in overall demand during summer peak periods as defined by the IESO for the 2011-2014 timeframe. The savings shown above (as a percentage of the 12.16 MW target) are tracked by EPI and verified against OPA/IESO reporting.

Despite a concerted marketing push and successful uptake of Demand Savings programs by local businesses, EPI did not achieve its allocated Demand Savings target at December 2014. EPI notes that a major focus of its efforts for Demand Savings was a large anticipated co-generation project at a large customer, involving the installation of a 5.2 MW nameplate load displacement generator. This project would have accounted for an additional 42.7% of the EPI Demand Savings target and was scheduled to launch in 2014. However, this project was delayed due to further review of the Combined Heat and Power ("CHP") program by the Ontario Power Authority ("OPA").

On March 31, 2014, under the direction of the Minister of Energy, the Board amended EPI's licence to reflect the conservation goals of the new Conservation First Framework ("CFF"). Under the CFF, Peak demand savings are no longer a target. However, EPI intends to continue to track and record demand savings achieved through CDM activities. This metric remains of use to EPI due to the nature of its distribution system planning. Capital system planning is typically done based on a peak demand, thus having CDM information available on the energy side at a peak is important in system planning and, accordingly, in capital planning. Energy targets are converted by an industry standard formula to be applied to a peak, which is used to assist in capacity planning, specifically as it relates to forecasting.

## NET CUMULATIVE ENERGY SAVINGS (SCORECARD MEASURE)

| Measure | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Net Cumulative Energy Savings (% of target achieved) | not measured | 22.00% | 60.00% | 81.10% | 107.40% |

In November 2010, under the direction of the Minister of Energy and Infrastructure of Ontario, the Board amended the Distribution Licence of EPI to require EPI, as a condition of its licence, to achieve 46.53 GWh of net persistent cumulative energy savings over the period of January 2011 through to December 2014. Net Cumulative Energy Savings (kWh) represent reductions in total energy consumption in the EPI service territory. The savings shown above (as a percentage of the 46.53 GWh target) are tracked by EPI and verified against OPA/IESO reporting.

As shown above, as of December 21, 2014, EPI exceeded its Net Cumulative Energy Savings target.

On March 31, 2014, under the new CFF, the Board amended EPI's licence to reflect a new 2015-2020 Net Cumulative Energy Savings (kWh) target of 56.83 GWh. It is EPI's goal to exceed this target and achieve savings of 62.08 GWh (109.23%) by the end of 2020.

## RENEWABLE GENERATION CONNECTION IMPACT ASSESSMENTS COMPLETED ON TIME (SCORECARD)

| Measure | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Renewable Generation Connection Impact Assessments Completed On Time | not measured | 60.00% | 60.00% | N/A | 100.00% |

The DSC requires that distributors provide an impact assessment of a renewable energy generation facility's connection application 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.

Due to the nature of its service territory, EPI receives a limited number of offers to connect in a given year (i.e. 7 in 2014). The completion of connection impact assessment ("CIA") requires a significant amount of coordination with the developer and HONI. In 2011 and 2012, EPI was new to this process and did not achieve the desired degree of success on this measure. Consequently, EPI enhanced its internal processes around the CIA process. In 2013, EPI received no offers to connect.

EPI's goal is to ensure that 100% of all renewable generation CIAs are completed on time. This goal was met in 2014.

## NEW MICRO-EMBEDDED GENERATION FACILITIES CONNECTED ON TIME (SCORECARD)

| Measure | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| New Micro-embedded Generation Facilities Connected on Time | not measured | | | 100.00% | 100.00% |

The DSC requires that distributors connect an applicant's micro-embedded generation facility 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.

Due to the nature of its service territory, EPI receives a limited number of such requests to connect in a given year (i.e. 4 in 2014).

EPI's goal is to ensure that 90% of all new micro-embedded generation facilities are connected on time. This goal was exceeded in 2014.

# OPERATIONAL EXCELLENCE – BUSINESS PLAN GOALS MOVING FORWARD

## THE DSP

As noted above, the EPI DSP was finalized in August 2015 and provides the "blueprint" for investment priorities on a go forward basis.

The next key initiative is the transfer of the EPI DSP methodologies and associated algorithms from the current spreadsheet model to an engineering software platform in 2016. The objectives of this software project is to allow the EPI Engineering Department to update the DSP more efficiently and to facilitate the running of quicker iterations, including "what if" scenario planning. This will allow EPI's engineers to spend more of their time on more such value-added scenario planning activities, as opposed to spending more time on updating and flowing through changes on the current spreadsheet model.

## POWER QUALITY

As part of the DSP, EPI has committed to implementing a new power quality program in 2016 to address the concerns of commercial and industrial customers with regard to the impact of momentary outages or minute voltage variations on increasingly complex modern production machinery. The program will involve investment in portable enhanced power quality metering at various sites to be deployed as issues arise, and additional engineering resources, in order to help customers resolve power quality issues and better understand and control their energy usage.

## SUSTAINABLE GROWTH

EPI's Core Value of Sustainable Growth encompasses the Board's RRFE outcome of Financial Performance. The Sustainable Growth Core Value is defined as:

***"Delivering sustainable growth for our stakeholders through wise investments"***

- Investing wisely
- Maximizing shareholder return
- Serving community/communities

## APPROACH & ACTIONS

Sustainable Growth encompasses the concept of making prudent investment decisions that support customer and community needs at a reasonable cost while balancing this against regulatory requirements and other obligations.

In accordance with its governance practices (see Section 1.10 below), the EPI Board of Directors and senior management team must ensure that, as an electrical distributor, EPI's financial viability is maintained, while balancing the need for prudent investment with an appropriate level of return is provided for its shareholder.

## KEY MEASURES & PERFORMANCE DISCUSSION

In order to measure Sustainable Growth and ensure that EPI is on course, EPI focuses on its Strategic Success Factor related to profitability, entitled: "Business Plan Regulated Return on Equity". EPI also tracks three additional measures related to liquidity, leverage and profitability.

These measures and the associated performance discussion are detailed below.

### BUSINESS PLAN REGULATED RETURN ON EQUITY (STRATEGIC SUCCESS FACTOR)

| Measure | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| Return on Regulatory Equity Forecasted | 9.40% | 8.90% | 9.20% | 9.20% | 9.30% | 9.30% |

The EPI Business Plan is typically completed in the third quarter of the year prior to the Plan Year. However, the budgetary portion of the EPI 2016 Business Plan was completed in the summer of 2015 in support of this Application. The Business Plan process comprises the establishment of a five year financial forecast. Each department provides forecast information, with particular focus on the upcoming year (i.e. 2016). The "out years" (i.e. 2017-2020) are primarily roll forward estimates based on the forecast year and incorporating the DSP. The information is submitted to Finance for consolidation and review, and then is subsequently reviewed by senior management. The Business Plan is reviewed and approved by the EPI Board of Directors before being finalized. See Exhibit 4, Section 4.2.1 for more details on the EPI budget process.

EPI seeks to provide an appropriate level of return for its shareholder, commensurate with its level of investment. Accordingly, EPI has a goal to meet or exceed its annual business plan ROE targets. For the 2016 Test Year, the target is based on the cost of capital parameters issued by the Board on November 20, 2014, which reflect an ROE of 9.30%. The actual calendar year goal of 8.90% is less than this, since EPI's May 1 rate year results in new distribution rates impacting only the latter two thirds of any given calendar year, but it reflects the achievement of the full ROE parameter.

## REGULATORY RETURN ON EQUITY ACHIEVED (SCORECARD MEASURE)

| Measure | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Return on Regulatory Equity Achieved | not measured | 11.20% | 7.61% | 7.61% | 10.20% |

The Regulatory Return on Equity Achieved Measure ("Regulated ROE") is calculated by dividing Rate-Regulated Net Income by Regulated Deemed Equity (i.e. 40% of Rate Base).

EPI last re-based rates in the CKH 2010 Cost of Service Application (EB-2009-0261), which resulted in Deemed Return on Regulatory Equity of 9.85% being included in rates. In 2012, consistent with Rate Base growth and other factors, EPI started to experience a decline in Regulated ROE. In 2014, Regulated ROE increased due to the conversion to Canadian Generally Accepted Accounting Principles ("CGAAP") to Modified International Financial Reporting Standards ("MIFRS"); the conversion to MIFRS resulted in lower depreciation and PILS, which increased profitability. In accordance with Board Filing Requirements, EPI has tracked CGAAP to MIFRS conversion differences in Account 1576, which is proposed to be disposed of (to the benefit of customers) in this Application.

## LIQUIDITY RATIO (SCORECARD MEASURE)

| Measure | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Liquidity: Current Ratio (Current Assets/Current Liabilities) | 1.40 | 1.35 | 1.19 | 1.16 | 1.61 |

The Liquidity Ratio 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. The Liquidity Ratio shows that EPI remains liquid, and has the ability to meet short-term financial obligations.

EPI's goal is to maintain a Liquidity Ratio of more than 1.00. As noted above, this means that the entity has resources available in the short term to meet its short-term financial obligations.

## LEVERAGE RATIO (SCORECARD MEASURE)

| Measure | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio | 1.31 | 1.27 | 1.28 | 1.22 | 1.44 |

The Board uses a deemed capital structure of 60% debt and 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.

EPI's goal is to continue to maintain a debt to equity structure that closely approximates the deemed 60% to 40% capital mix as set out by the Board – this is demonstrated by the 2014 debt to equity ratio of 1.44. EPI's Leverage Ratio is consistent with regulated guidelines and provides sufficient capital to fund the proposed DSP investments.

## BILL IMPACTS (DSP MEASURE)

EPI tracks two measures to quantify bill impacts to customers: (a) Percentage Average Total Bill Impact, and (b) Average Dollar Impact.

EPI calculates these Bill Impacts at the outset of the development of the DSP in preparation for a rate application and, at such time as significant modifications to the capital expenditure plan are contemplated. Due to the mechanistic nature of the IRM process, it is understood that bill impacts resulting from contemplated DSP modifications and resulting investments in Rate Base, do not take effect until such time as the next rebasing, or when an ICM/ACM is approved in the interim. The objective of this exercise is to ensure that modifications to the DSP do not trigger corresponding bill impacts greater than 10%. In such case, mitigating actions would be instigated.

As noted below in Section 1.6.9, the proposed bill impacts related to this Application are flat or declining for the majority of customers. EPI believes that this demonstrates recognition of the need to keep distribution rates affordable for its customers

## SUSTAINABLE GROWTH – BUSINESS PLAN GOALS MOVING FORWARD

EPI anticipates that after re-basing rates for May 1, 2016 on an MIFRS basis in this Application, EPI's Regulated ROE will continue to be fairly consistent with the Board's Deemed ROE levels. EPI further anticipates that the Liquidity Ratio will remain above 1.00 and the Leverage Ratio will closely approximate a deemed 60% to 40% capital mix.

### INSPIRED & EMPOWERED PEOPLE

EPI's Core Value of Inspired & Empowered People encompasses the Board's RRFE outcome of Operational Effectiveness. EPI's Core Value of Sustainable Growth is defined as:

***"Having a workforce of inspired and empowered people who are passionate about their jobs"***

- Powered by integrity
- Education and growth opportunities
- Right people in the right places

Beyond its moral and ethical obligation to be a good employer, EPI believes that these initiatives and treating employees with respect helps to ensure that employees regard EPI is a great place to work. EPI is committed to developing, nurturing and stimulating a culture that challenges employees to perform their best. Employees are encouraged to continually seek to improve their performance and increase their own skills towards achieving these goals.

As discussed in Exhibit 4, the EPI workforce is ageing and EPI faces challenges when recruiting skilled resources. Employee satisfaction is critical to retaining employees.

## APPROACH & ACTIONS

EPI offers a number of programs and policies to assist its employees, as well as to engage and recognize them. These programs are described in Table 1-4 below:

**TABLE 1-4: EPI EMPLOYEE PROGRAMS**

| INITIATIVE | DESCRIPTION |
|---|---|
| **The Employee Assistance Program ("EAP")** | • Provides professional, confidential assessment and referral service to help employees, their spouses and dependents resolve problems impacting their personal lives or work performance. The EAP program offers coverage to a maximum of $200 per employee, spouse and dependent for assistance with these services. |
| **Town Halls and Employee Feedback Events** | • These events provide the opportunity for employees to provide feedback on employee matters that are going well, or where they feel that changes are needed. Discussions may involve workplace culture, environment, how the business operates, etc. |
| **Employee Ideas Submission Program** | • The program seeks to encourage employees to share ideas that will improve the workplace or work processes. Employees submit their ideas online. On a quarterly basis, senior management reviews the ideas submitted and assesses each in terms of: approve/decline/or send back need more information. If the employee idea is approved the appropriate manager will work with the employee on an implementation plan.<br>• Each quarter, 1st, 2nd and 3rd place winners are chosen and revealed at a Town Hall meeting. Quarterly winners receive a small cash prize, and at the end of the year, an overall winner is chosen (who receives $1,000).<br>• 2014 Stats:<br>- 63 ideas submitted<br>- 45 ideas approved<br>- 28 implemented |
| **FISH! Committee** | • The employee-driven FISH! Committee supports EPI's workplace culture and is similar to a "social" or "spirit" committee.<br>• The Committee name is based on the Entegrus Group's FISH! Philosophy, which is in turn modeled after an effective employee culture that emerged from Seattle's Pike Place Fish Market. The philosophy centres on organizational culture philosophy which strives to actively engage employees in the workplace by centring on four tenets: choosing one's |

| | |
|---|---|
| | attitude, "playing" at work (i.e. making work fun), making someone's day, and being present at all times, both physically and mentally.<br>• The EPI FISH! Committee works toward this philosophy by identifying and implementing actions to promote employee interaction and team building, communication and appropriate fun in the workplace.<br>• Events organized and run by the FISH Committee include: after hours social events, golf tournaments, curling tournaments, company picnics, company garden planting, and children and staff Christmas parties.<br>• The FISH! Committee conducts annual fundraising (funded by employees personally) to support local charity groups that our employees are directly involved in. Some of the fundraising efforts include charity BBQ's, breakfasts and raffles.<br>• The FISH Committee also supports Wellness initiatives that have included Wellness Challenges (i.e. "Biggest Loser", boot camps and wellness lunch and learns with nutritionists, stress management experts, etc.)<br>• The FISH Committee has implemented an Employee Recognition Program called the StarFISH! Award where employees are able to nominate fellow employees in recognition for having "gone above and beyond" their normal duties. Winners have the opportunity to receive a small gift card from a prize draw of each month's StarFISH! winners. |
| **Take Your Child to Work Day** | • Take Your Child to Work Day is an annual program that is organized in coordination with local high schools for Grade 9 students. EPI participates by allowing the Grade 9 students of employees to come to work with their part for an organized agenda of activities that allow the students to learn about the company and electrical safety while having appropriate fun. |
| **Wellness Program** | • EPI encourages employees to lead healthy lifestyles by supporting healthy exercise and physical fitness. Entegrus provides financial assistance to each participating employee for the cost of approved exercise training, up to a cumulative maximum of $200 annually. |
| **Corporate Charity Events** | • EPI employees support and participate in many major charity events such as Relay for Life, Heart & Stroke Big Bike Ride and Simply Red, Parade of Chefs, Soup Kitchens, Festival of Giving, Habitat for Humanity Rebuild. |
| **Employee Donation Fund** | • EPI supports employee volunteer efforts that improve quality of life, health or the environment in the communities that we serve. The employee donation fund provides annual funding that can be requested by each employee to a maximum of $500, providing that the associated charitable cause meets sponsorship eligibility. The employee must personally be involved in the charitable cause that is being supported. |

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EPI believes that these initiatives – and treating employees with respect – help to ensure that employees regard EPI is a great place to work. As discussed in Exhibit 4, the EPI workforce is aging and EPI faces challenges when recruiting skilled resources. Employee satisfaction is critical to retaining employees and thus ensuring that EPI maintains the skilled resources currently in place. EPI is committed to doing annual surveys to measure employee satisfaction, as further described below.

EPI must also support its employees by equipping them with modern and appropriate tools and technology to allow them to perform their jobs at the best level possible. EPI must also conduct succession planning to ensure that appropriate balance of skill sets continues to be in place to sustain its operations and which allows employees to support and complement one another. Currently, succession planning is focused on the Lines and Engineering departments, as further discussed in Exhibit 4.

## KEY MEASURE

In order to ensure that employees are “Inspired and Empowered”, EPI focuses on its associated Strategic Success Factor, which is Employee Satisfaction.

This measure and the associated performance discussion are detailed below.

### EMPLOYEE SATISFACTION SURVEY RESULTS (SUCCESS FACTOR)

| Measure | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|---|
| Employee Satisfaction | 59.8% | N/A | N/A | 69.2% | N/A | TBD |

In 2010 and 2013, the Entegrus Group engaged Metrics@Work (“MW”) to measure employee satisfaction. MW conducted a survey of Entegrus employees covering 31 areas of employee satisfaction. Average scores were calculated for each area based on a 1 to 7 point rating system, with 1 representing “strongly disagree" and 7 representing "strongly agree". The resultant averages were then converted by MW to a range of 0% to 100%. A value of 0% indicates that everyone in the analysis "strongly disagrees" with each positively worded question and a value of 100% indicates that everyone in the analysis "strongly agrees" with each positively worded question. Values between 0% and 100% are the result of varying degrees of staff's agreement or disagreement with each driver or item area.

A snapshot of overall Entegrus Group employee satisfaction was calculated for both years by MW by taking the Grand Average of all areas of employee satisfaction. In 2010, the Grand Average result was 59.8%, and in 2013 the Grand Average Result was 69.2%, an improvement of almost 1000 basis points.

EPI's goal is to achieve year-over-year improvement in employee satisfaction survey results. For 2015, this means targeting an increase over the last survey results (the 2013 Grand Average Result of 69.2%).

## INSPIRED & EMPOWERED PEOPLE – BUSINESS PLAN GOALS MOVING FORWARD

As discussed above, the Entegrus Group plans on conducting another employee satisfaction survey in late 2015.

Moving forward, EPI plans to continue to offer its existing employee initiatives and will support the employee FISH! Committee in developing new team building events. In terms of succession planning, EPI plans to hire two additional Lines Apprentices in late 2015, and an Engineer-in-Training in early 2016. These hiring plans are further detailed in Exhibit 4.

## BUSINESS PLAN - EXPECTED MEASURE RESULTS

As described above, it is evident that there is strong alignment between the EPI strategy and the four areas of focus identified by the Board in the RRFE.

Subject to Board approval of the 2016 Test Year distribution rates forecasted in this Application, EPI anticipates continuing to achieve the goals and measures described above.

## 1.5 Customer Engagement

The RRFE Report anticipates enhanced engagement between distributors and their customers in order to provide better alignment between distributor operational plans and customer needs and expectations.

EPI conducts various ongoing customer engagement initiatives, including:

- Inbound/outbound customer phone calls;
- EPI's "My Account" customer consumption management web portal;
- Rate brochures and bill inserts;
- Hosting of commercial and industrial conservation conferences;
- Community conservation events;
- Website and social media (Twitter / Facebook / YouTube);
- The St. Clair College Powerline Maintainer Program; and,
- Holiday meal preparation for citizens in need

These ongoing initiatives, and additional ongoing activities, are described in further detail in Section 1.4.1 above (under Customer and Community Focus / Approach & Actions).

Further, in 2014 and 2015, EPI conducted multiple customer engagement processes which informed and supported this Application. These processes engaged the full spectrum of EPI's customer base, from Residential customers to Large Use customers, in order to best understand the different types of customer issues and concerns.

For further detail on how the customer engagement activities conducted by EPI have shaped the Application, please refer to the Appendix 2-AC, Customer Engagement Activities Summary, which is shown as Attachment 1-G.

Overall, customers indicated that they were satisfied with the level of service that EPI provides. Results are more fully described below.

### 1.5.1 Selection of Customer Satisfaction & Customer Engagement Consultants

In the spring of 2014, EPI conducted a joint mini-RFP in conjunction with Brantford Power. The objective of this joint process was to combine efforts to secure the services of a third party survey consultant to conduct live agent telephone surveys on Customer Satisfaction, First Contact Resolution and other measures, consistent with the Board's requirements for the EPI Scorecard. A secondary objective identified by EPI and its mini-RFP partner LDC was to receive value-added Customer Service consultation in order to drive ongoing improvements in the area of Customer Service.

Four potential service providers were issued invitations to participate in the mini-RFP process. Three of the service providers elected to participate in the process.

Subsequent to review and presentation of proposals by the vendors, and follow-up questioning, the selected vendor was Convergys, a customer management firm specializing in live agent customer surveys and associated statistical analysis. Convergys is made up of 125,000 employees working in more than 150 service centres in 31 countries. Convergys is experienced in providing Customer Service enhancement recommendations to call centres.

In addition, EPI individually sought to secure the services of a third party customer engagement consultant to assist in conducting focus groups and surveys specific to the EPI 2016 rate application, consistent with the Board's Filing Requirements relating to customer engagement. Although EPI originally envisioned hiring one service provider to conduct both Scorecard survey consultation and Cost of Service Application customer engagement services, it became clear during the Scorecard mini-RFP that EPI would be best served by engaging two different service providers in order to best meet each of the separate objectives. Accordingly, EPI engaged Innovative Research Group ("INNOVATIVE") to assist in conducting the customer engagement activities for the EPI 2016 rate application. INNOVATIVE is a Canadian strategy firm that offers research, strategic counsel and communications advice, including focus groups and telephone and online surveys. INNOVATIVE is experienced at providing Ontario LDCs with customer engagement assistance with respect to rate applications.

### 1.5.2 Convergys Surveys

In order to capture Customer Satisfaction and the other metrics identified in the Board's Scorecard requirements, while also appropriately measuring First Call Resolution, Convergys conducted employed two different survey methodologies:

1. Top-Down Survey: A random sample of the entire EPI customer base, and;
2. Transactional Survey (or Bottom-Up): A random sample from only the population of customers who had recently contacted EPI Customer Service

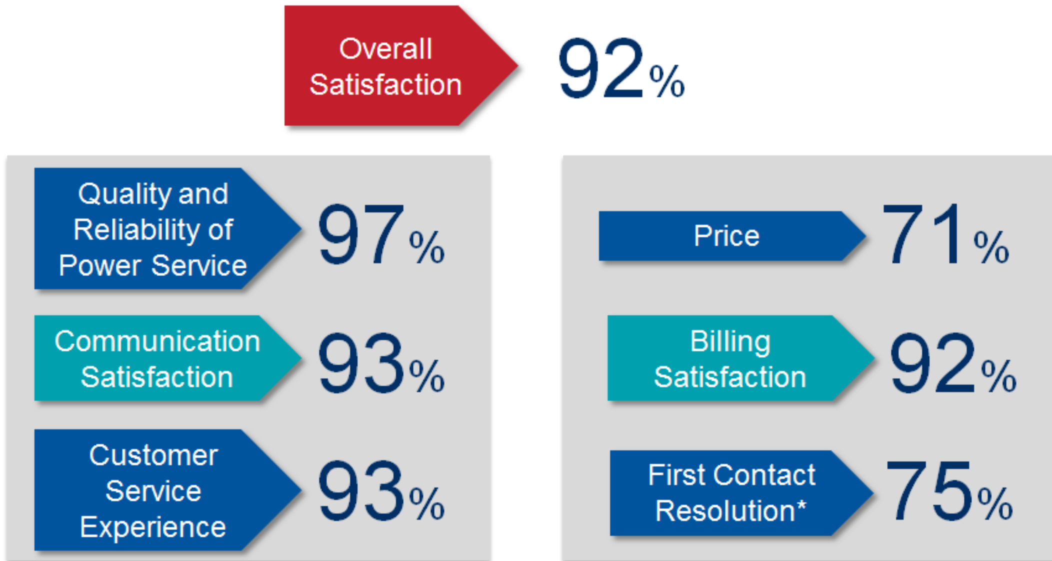
#### Convergys Top Down-Survey: Methodology, Results and Recommendations

For the purposes of the Convergys Top-Down Survey, EPI provided Convergys with contact numbers for all of its customers. During the period October 21, 2014 to November 7, 2014, Convergys agents conducted a random sample of 500 EPI customers to complete Residential surveys and 96 complete Small Commercial surveys. Customers were asked survey questions by Convergys agents on a variety of facets of EPI' business, including: Quality and Reliability of Power Service, Communication Satisfaction, Customer Service Experience, Price, Billing Satisfaction and Overall Satisfaction. In terms of Overall Customer Satisfaction, the exact wording of the survey question posed to customers by Convergys was, "Taking everything into consideration, how would you rate your overall Entegrus experience? Please use a 1 to 5 scale where 1 is not at all satisfied and 5 is very satisfied." Convergys then recorded the customer response into a database.

Of the 596 Top-Down Survey customers (the denominator) surveyed from October 21, 2014 to November 7, 2014, 548 customers (the numerator) rated their Overall Satisfaction in the top 3 boxes. This numerator and denominator equate to the reported Customer Satisfaction figure of 92%.

See Attachment 1-H for a copy of the Convergys Top-Down Customer Survey results. The results are summarized on page 7 of the report, which is excerpted below as Table 1-5.

**TABLE 1-5: CONVERGYS TOP-DOWN SURVEY RESULTS**




*First Contact Resolution (FCR) is measured by Transactional surveys that occur after a customer interaction (data from Oct-Dec 2014). All other measures are from the "Top-Down" survey which measures the entire customer experience.

The Convergys process also studied the statistical key drivers of customer satisfaction, and used these results to develop recommendations. The recommendations arising from the survey are shown on pages 25-27 of the report, and are summarized as follows:

1. **Enhanced Customer Communication:** drive awareness of consumption management tools
2. **Enhanced Billing Communication:** include billing literacy materials and videos on website
3. **Enhanced Marketing of Self-Service Tools:** make self-service more prominent on website, etc.
4. **Power Quality & Reliability:** focus on decreasing outages and improving service reliability
5. **Business vs. Residential Customer Differentiation:** enhance targeted website messaging
6. **Survey Attributes:** update survey communication attributes

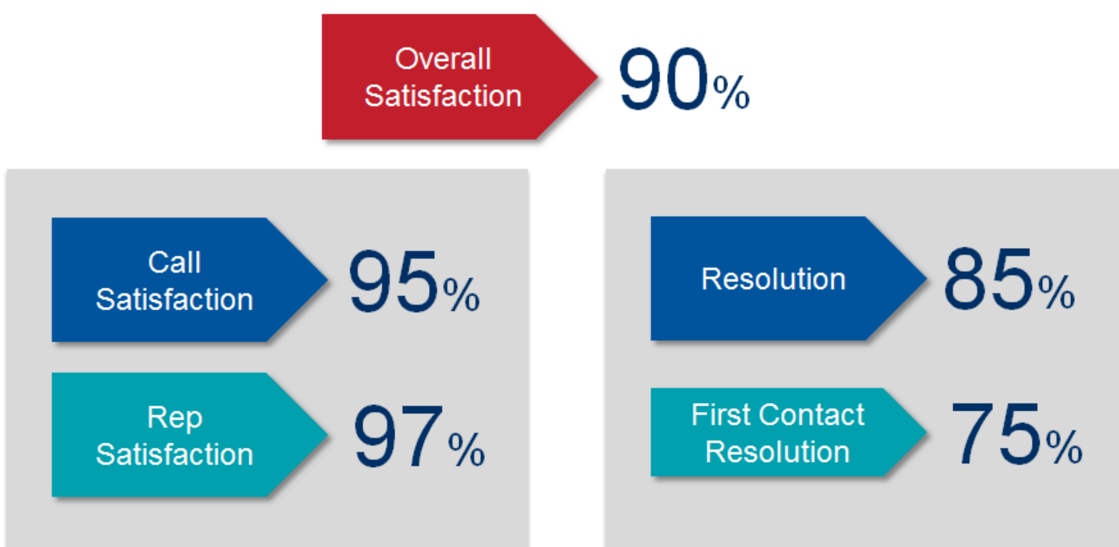
## Convergys Transactional Survey: Methodology, Results and Recommendations

For the purposes of the Convergys Transactional Survey, for the period October 1, 2014 to December 31, 2014, EPI provided Convergys with a bi-weekly report of all inbound customer telephone calls into EPI Customer Service. Convergys telephone agents, in turn, contacted and surveyed EPI customers - typically within two weeks of their initial inbound contact. Customers were asked by Convergys to rate various facets of their customer experience, including: Call Satisfaction, Rep Satisfaction, Resolution, First Contact Resolution and Overall Satisfaction. The exact wording of the First Contact Resolution survey question posed to customers by Convergys was, "Was the specific question or issue you called about on [insert date] resolved during that call?" Convergys then recorded one of the following customer answers into a database: (1) Yes, (2) No, or (3) Still Waiting.

Of the 153 Transaction Survey customers surveyed (the denominator) from October 1, 2014 to December 31, 2014, 116 customers (the numerator) indicated that their issue was resolved on the first call to EPI. This numerator and denominator equate to the reported First Contact Resolution figure of 76%.

See Attachment 1-I for a complete copy of the Convergys Transactional Survey results. The results are summarized on page 10 of the report, which is excerpted below as Table 1-6:

**Table 1-6: Convergys Transactional survey results**



The Convergys process also studied the statistical key drivers of customer satisfaction, and used these results to develop recommendations. The recommendations arising from the Transactional survey are shown on page 25 of the report, and are focused on elements of Customer Service intended to drive enhanced customer satisfaction. These elements are summarized as follows:

1. **Focus on Key Drivers of Satisfaction:** coach CSRs on hard skills and use of positive language
2. **Improve First Call Resolution:** identify common multiple call issues and improve processes
3. **Educate Customers on Self-Service Opportunities:** more self-service marketing
4. **Survey Modification:** enhance survey questions

### 1.5.3 Innovative Research Customer Engagement: The Process

In response to the Board's Filing Requirements to engage customers on the specific proposals contained in this Application, EPI retained Innovative to design, collect feedback and document its customer engagement and consultation process as part of the development of this Application.

Working together with INNOVATIVE, EPI sought to engage customers on the following matters specific to the Application:

1. The DSP, including aging asset replacement and grid modernization
2. The Operating Budget
3. The Rate Harmonization Plan
4. Overall Rate Impacts

A complete copy of the INNOVATIVE Customer Engagement Report is included as Attachment 1-J.

The consultation encompassed five core elements of customer engagement.

A. **General Service and Residential Consultation Groups (33 customers):** This qualitative phase of the consultation was designed to educate customers, assess their preferences and priorities, gauge reaction to proposed rate changes, and ultimately inform the quantitative phases of the consultation. The groups were randomly recruited and consultations were held in Strathroy and Chatham. A workbook was used to provide the participants with core information about the provincial and local electricity system, EPI's proposed capital investment and operating spend to maintain system reliability, as well as the rate impact for each respective rate class. Participants were provided incentives in recognition of their time commitment.

B. **Mid-Market Workshops (12 customers)**: General Service customers (GS > 50 kW and Intermediate customers) were engaged through a randomly recruited workshop. This workshop included a presentation delivered by EPI Regulatory and Engineering staff on the utility's DSP and rate implication for this rate class, a Q&A session with EPI staff, and "breakout style" discussion groups lead by INNOVATIVE staff.

C. **Key Account Validation Interviews (2 customers)**: Large Use Accounts were consulted on the proposed 5-Year plan by EPI staff. INNOVATIVE followed-up by telephone with large users after their consultation session to validate the process and to verify that EPI provided these customers with the information they needed to provide informed feedback on the proposed plan.

D. **Online Workbook (631 customers)**: The online workbook was promoted through print and online advertising with local media outlets, social media, inserts in customer bills and e-bills, as well as EPI's website. This phase of the consultation was available to any EPI customer who wanted to participate.

E. **Random Telephone Surveys (620 customers)**: INNOVATIVE conducted telephone surveys with residential and general service (GS < 50kW) customers to provide a quantitative assessment of key aspects of the system plan. Customer lists for both respondent groups were provided by EPI and the sample was randomly selected by INNOVATIVE.

## PROMOTIONAL CAMPAIGN TO INFORM CUSTOMERS OF THE CONSULTATION

As noted in the INNOVATIVE report (shown in Attachment 1-J), EPI worked with Innovative to develop a consultation workbook to cover key issues included in the Application and to frame meaningful questions about customer needs and preferences.

Subsequently, EPI conducted a promotional campaign to create customer awareness of the opportunity to participate in the consultation. This included use of the EPI website and social media, and well as other external media sources. This promotional campaign is detailed in Attachment 1-K. Recruitment of Residential and General Service focus group consultation participants was conducted by INNOVATIVE, and is described in Attachment 1-J.

## INNOVATIVE RESEARCH CUSTOMER ENGAGEMENT: FINDINGS

The INNOVATIVE report shows that almost all EPI customers are satisfied with the job the utility is doing at running the electricity distribution system. This pattern was consistent across all rate classes in all phases of the customer consultation.

TABLE 1-7: CUSTOMER CONSULTATION - OVERALL SATISFACTION ACROSS CONSULTATION ACTIVITIES

*Question: "Generally speaking, how satisfied are you with the job Entegrus is doing running your electricity distribution system?"*

| Response | Directional (Focus Groups) | | Directional (Workshop) | Directional (Online) | | Generalizable (Telephone Surveys) | |
|---|---|---|---|---|---|---|---|
| | Small GS | Residential | Mid-market & Large GS | Small GS | Residential | Small GS | Residential |
| Very satisfied | n=7 | n=2 | n=7 | n=16 | 46% | 30% | 36% |
| Somewhat satisfied | n=8 | n=13 | n=4 | n=7 | 44% | 55% | 52% |
| Somewhat dissatisfied | n=1 | n=0 | n=0 | n=2 | 6% | 6% | 5% |
| Very dissatisfied | n=0 | n=0 | n=0 | n=2 | 3% | 4% | 3% |
| Don't know / Refused | n=1 | n=1 | n=1 | n=0 | 1% | 5% | 4% |
| TOTAL | n=17 | n=16 | n=12 | n=27 | n=604 | n=111 | n=509 |

When asked what EPI could do better to improve services, most customers were either satisfied, and had nothing to suggest, or simply didn't know how the utility could improve services. However, among those who did have suggestions, comments focused on two areas:

- Lowering rates; and
- Improvements to reliability or reduced outages.

This paradox of lower rates while seeking improvements in reliability is the key dilemma the consultation sought to explore and better understand.

A summary of the needs and preferences across EPI's customer base, as identified in the INNOVATIVE report, is as follows:

- Assist customers with energy literacy
- Provide more communication on outages
- Focus on affordable rates
- Focus on improved reliability
    - Replace ageing assets
    - Modernize the distribution system
    - Enhance commercial and industrial power quality

## INNOVATIVE RESEARCH FINDINGS: RELIABILITY OF SERVICE

One of the focuses of the consultation was on the question of power service interruptions. In both the qualitative and quantitative phases of the consultation, information about the system's current average level of reliability was provided to customers. The consultation collected feedback on satisfaction with the current level of reliability, EPI' efforts to address reliability, and impact of power outages.

The qualitative consultation phases explored the impacts of outages on customers, acceptable frequencies, and durations of outages. Subsequently, the telephone surveys built on the qualitative feedback and asked questions about customer preferences on the trade-off between cost and reliability.

Most residential (83%) and general service (86%) customers had experienced at least one outage in the 12 months leading up to the survey, with most outages lasting less than an hour. Asking respondents to think back to their most recent power outage:

- Half (52%) of residential respondents said the outage caused a *minor inconvenience*, while 28% said it caused *no inconvenience at all*. The most recent power outage was a *major inconvenience* for 11% of residential customers.

- This question was posed differently to general service customers. Almost one quarter (23%) reported the most recent outage to have had a *minor cost* to their business, while 38% said it had *barely any cost, just a bit of inconvenience.* The outage had a *major cost* to 22% of businesses.

When it comes to addressing power outages, a majority of residential and general service customers want to see spending focused on maintaining the current number and duration of outages that are experienced. This is further evidenced by the results below.

Regarding the number of power outages:

- One-in-five (22%) residential customers think EPI should spend what is needed to reduce the number of power outages, while almost half (45%) think they should spend what is needed to maintain the current level. Only 13% state that EPI should accept more power outages in order to keep customer costs from rising.

- General Service customers respond similarly on how to address the number of outages: 21% think that EPI should spend what is needed to reduce the number of power outages and 37% say they should spend what is needed to maintain the current level. Again, only a small minority (13%) believe that EPI should accept more power outages in order to keep customer costs from rising. Three-in-ten (29%) don't know how they feel.

Regarding the length of power outages:

- Almost seven-in-ten (68%) of residential customers think EPI should spend what is needed to either reduce (23%) or maintain (45%) the length of power outages. Only 16% think that EPI should accept longer power outages to help minimize customer costs from rising.
- Slightly different proportions of general service customers think that EPI should spend what is needed to reduce (27%) or maintain (36%) the length of power outages. 17% think that EPI should accept longer power outages to help minimize customer costs from rising.

Survey respondents were informed of EPI's proposed capital investment required to maintain system reliability and then asked to think about reliability in terms of bill impact.

- Two-thirds (66%) of residential customers and 58% general service customers believe that EPI should invest in aging infrastructure to maintain system reliability, even if it means their bills may increase.
- In regard to replacing the aging infrastructure both residential (70%) and general service (74%) or more in favour of replacing non-critical equipment before it breaks down, as opposed to waiting until it breaks down in order to get the full value from each piece.
- 62% of residential customers and 55% of general service customers feel that, while EPI should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably.
- Approximately four-in-five customers in both groups (82% residential; 82% general service) think the benefits of new technology are important enough to be a priority for EPI.

Power quality also came up as a key issue among EPI's larger business customers in the qualitative workshop consultations. While there was some concession among customer that no system is perfect and that there will always be the occasional outages, it was power quality that appeared to be the bigger concern among this group of customers. Particularly for organizations that rely heavily on automated machinery, these blips can be just as costly as long outages.

The need for stable and uniform power quality is becoming increasingly important as the technology used to run automated systems becomes more refined. Newer systems are much more precise and therefore have a much smaller window for variation. Even with the protection of a UPS, variation that would have previously gone unnoticed can cause a system to trip resulting in severe losses in product and productivity. The slightest variation in power quality can have an incredible cost in a matter of seconds.

Larger business customers very much expressed a need for EPI to invest in grid modernization technologies to help alleviate issues with power quality.

## INNOVATIVE RESEARCH FINDINGS: AFFORDABLE ELECTRICITY COSTS

It is true that many customers are feeling a "financial pinch" when it comes to their electricity bills. However, more customers feel they are obligated to invest in the system to maintain reliability for future generations.

When it comes to the impact on household finances and the bottom line, a number of customers indicate that their electricity bill has a significant impact:

- 69% of residential customers agree that *"The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities"*;
- While 78% of GS customers agree that *"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."*

Both residential and general service customers feel that it is important to contribute to the system in order to maintain reliability for years to come.

- 87% of residential and 80% of GS customers agree that "*Nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local electrical system for future generations*."

## INNOVATIVE RESEARCH FINDINGS: CUSTOMER REACTION TO PROPOSED RATE INCREASE

INNOVATIVE notes in its report that, "asking customer whether they support or oppose a rate increase puts many participants in a difficult spot. It is clear that many customers have an issue with the idea of 'supporting' a rate increase. While they do not want or like a rate increase, they are often not opposed to a rate increase. In fact, many feel a rate increase is needed. As such, we created a response for these customers: 'I don't like it, but I think the rate increase is necessary'."

INNOVATIVE further notes, "Other participants had no problem in expressing outright support for a rate increase. The statement we provided for them is 'The rate increase is reasonable and I support it. When we refer to the combination of these two groups – I don't like it but it's necessary and I support the rate increase – we refer to the level of **'social acceptance'**."

Referring to the generalizable results from the telephone surveys, 74% of residential customers accept EPI's proposed rate increase, while 75% of general service customers accept the proposed rate increase. These results are shown in further detail in Table 1-8 below.

TABLE 1-8: CUSTOMER CONSULTATION - THE PROPOSED RATE INCREASE

***Question: "Considering the cost of Entegrus' proposed plan, would you say…"***

| Response | Directional (Focus Groups) | | Directional (Workshop) | Directional (Online) | | Generalizable (Telephone Surveys) | |
|---|---|---|---|---|---|---|---|
| | Small GS | Residential | Mid-market & Large GS | Small GS | Residential | Small GS | Residential |
| The rate increase is reasonable and I support it | n=2 | n=2 | n=4 | n=3 | 16% | 39% | 32% |
| I don't like it, but I think the rate increase is necessary | n=8 | n=10 | n=7 | n=15 | 50% | 36% | 42% |
| The rate increase is unreasonable and I oppose it | n=4 | n=4 | n=1 | n=9 | 28% | 22% | 24% |
| Don't know / Refused | n=3 | n=0 | n=0 | n=0 | 6% | 3% | 2% |
| **TOTAL** | **n=17** | **n=16** | **n=12** | **n=27** | **n=604** | **n=111** | **n=509** |

INNOVATIVE notes, "As seen throughout the EPI customer consultation, there is no simple answer to electricity utility spending and investing from the customer's perspective. Rate increases are undesirable, but lower reliability is clearly unacceptable and a proactive and consistent approach to system maintenance is understood and accepted."

INNOVATIVE concludes, "As a result, EPI's customers accept the proposed spending and investment plan and its accompanying rate increase as an unfortunate necessity."

## INNOVATIVE RESEARCH FINDINGS: CUSTOMER REACTION TO RATE HARMONIZATION

INNOVATIVE engaged EPI customers on the proposed rate harmonization plan. This involves the proposed harmonization of the current CKH, SMP, Dutton and Newbury rate zones effective May 1, 2016.

The survey results show a strong majority of both residential (72%) and general service customers (69%) agree with the concept of rate harmonization. That is, EPI customers should pay the same rates for the same level of service, regardless of where they reside or businesses are located.

TABLE 1-9: CUSTOMER CONSULTATION – THE PROPOSED RATE HARMONIZATION (DIRECTIONAL)

***Question: "How strongly do you agree or disagree with the following statement: Entegrus customers should pay the same rates for the same level of service, regardless of where they live or operate a business?"***

| Response | Generalizable (Telephone Surveys) | |
|---|---|---|
| | General Service | Residential |
| Strongly agree | 42% | 46% |
| Somewhat agree | 27% | 27% |
| Neither agree nor disagree | 3% | 1% |
| Somewhat disagree | 8% | 9% |
| Strongly disagree | 9% | 8% |
| Don't know/Refused | 10% | 9% |
| TOTAL | n=111 | n=509 |

Although only directional, larger GS customers also indicated that they generally support the idea of the proposed rate harmonization. When asked in the mid-market workshop, 'Which of the following best describes how you feel about rate harmonization?' a majority indicated that they though rate harmonization made sense and that they support it.

### 1.5.4 Summary of Customer Needs & Preferences

EPI noted strong consistency between the results of the INNOVATIVE customer engagement results and the Convergys survey reports.

EPI reviewed both reports in detail and identified the following customer needs and preferences:

i. Focus on Affordable Distribution Rates
   a. Customers accept the proposed rate plan
   b. Customers accept the proposed rate harmonization plan
ii. Focus on Improving or Maintaining Reliability
   a. Customers support investment in ageing infrastructure
   b. Customers support investment in new technology to modernize the distribution system (i.e. smart grid)
   c. Commercial and industrial are particularly focused on the need for more stable and uniform power quality
iii. Enhance Customer Communication
   a. Assist customers with energy and billing literacy
   b. Drive awareness of existing self-service consumption management tools
   c. Provide more communication on outages
   d. Improve FCR and identify opportunities for additional Customer Service training

### 1.5.5 Addressing Customer Needs and Preferences

Many of the customer engagement process findings corroborated what EPI had been hearing recently from customers, via the ongoing dialogue through the day-to-day engagement described in Section 1.4.3 (under Customer and Community Focus / Approach & Actions) above. However, some new key learnings emerged, particularly around the need to drive more awareness of existing Customer Service tools. Accordingly, while a number of the associated solutions have either launched or are in development, other new and planned solutions were identified through this process.

Above all, EPI recognizes the need to keep distribution rates affordable for its customers. This message has been heard clearly from customers, and EPI believes it has addressed this by budgeting efficiently and carefully for the future in this Application. This is evident by the proposed bill impacts shown in Section 1.6.9 below, which would result in many customers experiencing flat or declining distribution rates starting on May 1, 2016.

At the same time, customers are telling EPI to maintain or improve reliability. As noted by INNOVATIVE, some interpretation is required here because it is paradoxical to improve reliability while decreasing costs. However, EPI believes that the enhanced "engineering science" of its risk-based DSP will allow for maintenance, or improvement, of reliability and power quality while maintaining a prudent and consistent capital spend level in accordance with recent historical years. Further, the EPI DSP incorporates asset replacement, as well as elements of grid modernization that EPI's communities will need to remain economically competitive. The DSP is attached as Exhibit 2, Attachment 2-D.

EPI has committed to implementing a new power quality program to address the concerns of commercial and industrial customers with regard to power quality issues. Power quality is defined as any disturbance in the supply of electrical power that may cause connected equipment to malfunction or be damaged. Power based on customer quality disturbances include a wide range of detrimental effects including: voltage sags and swells, harmonics, voltage flicker, voltage imbalance and other brief disturbances. Power quality is a key focus because the EPI service territory has a large number of manufacturing facilities, in particular, automotive parts suppliers. Customers are indicating that their increasingly complex modern production machinery has very low tolerances for voltage variations. Momentary outages, or minute voltage variations (within traditional specification levels), can result in time consuming stoppages to the manufacturing process. The new program will involve investment in portable enhanced power quality metering that can be set up at various sites to be deployed as issues arise, and additional engineering resources, to help customers resolve power quality issues and better understand and control their energy usage. For more details about power quality, please refer to the DSP, which is attached as Exhibit 2, Attachment 2-D.

In order to assist customers with energy and billing literacy, EPI will continue to leverage its website and particularly the educational videos originally created to help customers digest the online customer workbook. INNOVATIVE noted the feedback on these videos to be "quite positive" (see INNOVATIVE report, page 77). EPI is also exploring ongoing annual customer focus groups, in order to: (a) to provide an avenue to educate customers on a one-on-one basis, (b) understand evolving needs and preferences.

In terms of enhanced customer communication, EPI took key steps toward improving its digital communication channels in 2014 with: the redesign of the EPI website, the launch of the new "My Account" self-service portal platform, and the launch of social media channels on Facebook, Twitter and YouTube. Based on customer feedback, the My Account platform will be further enhanced to allow access to customers in all rate classes (currently, only available to low volume classes) and provide more timely information and demand data. Further, it became apparent from the customer engagement activities that a portion of customers are still not aware of the existing digital offerings. Accordingly, EPI will launch a marketing plan to drive additional customer awareness.

In regard to better communication on outages, the 2014 digital communication enhancements include after hours, up-to-date, social media and website outage notification. However, the customer engagement process indicates that customers want more information, including mapping and anticipated restoration time frames. In response, EPI is in the process of enhancing its Outage Management System ("OMS"), such that it will update the website and social media interfaces with user friendly mapping and restoration communications on a timely basis. This project is expected to launch in late 2015.

Lastly, EPI will continue to work with Convergys on First Call Resolution and enhanced Customer Service training. As part of this effort, starting in September 2015, all EPI Customer Service Representatives will have access to an on-line portal of continuous transactional survey updates. This portal will provide management and CSRs with a weekly view of their key measureables including: Customer Satisfaction, Call Satisfaction, Rep Satisfaction, Resolution and First Call Resolution. The portal will also identify which type of issues CSRs in general are handling well, and which type of issues have opportunities for training improvement. This will be complimented by hard skills training on specific topic areas.

### 1.5.6 CONSULTATIONS WITH OTHER PARTIES

#### MUNICIPAL GOVERNMENT CONSULTATIONS

EPI frequently participates in the Municipality of Chatham-Kent's bi-weekly Council meetings. Each year, EPI holds an Annual General Meeting with Council and conducts a general overview of the prior year results. In addition, the EPI CEO periodically meets with the Mayors and other key decision makers in the other communities served by EPI, including Strathroy-Caradoc and others.

EPI regularly consults with the Chatham-Kent Economic Development team, in order to share planning and development information that will aid in the timely, coordinated and cost effective delivery of services for both EPI and the Municipality. Further, during the normal course of business, the EPI Engineering department consults with builders and developers in all of the communities that it serves in order to gather information on development trends.

#### CONSULTATIONS WITH CDM STAKEHOLDERS

EPI has offered the OPA/IESO save-ON-energy CDM programs since their inauguration in 2006. As per the Minister of Energy's directive on Conservation and Demand Management dated March 31, 2015, EPI will continue to engage and consult with its stakeholders, in order to develop a refined delivery model that best suits regional needs. An example of such consultation with stakeholders was EPI's May 2015 conference delivered to Commercial, Industrial and Institutional customers entitled "Power Play: Profiting from Sustainability & Electricity Conservation Strategies". This conference is further described above in Section 1.4.3 (under Customer and Community Focus / Approach & Actions).

Further, EPI CDM staff participates in daily face-to-face interactions with its large customers. This interaction allows EPI to customize its delivery methods to meet the specific needs of those customers. This interaction also allows EPI to receive feedback from stakeholders allowing two way communications between the IESO, EPI and end users potentially affecting the attributes of individual programs. Finally, consultation with regional local distribution companies is continuous and ongoing and used to identify and pursue opportunities for regional collaboration on design and implementation of programs that satisfy regional needs and requirements as well creating efficiencies for multiple processes in order to provide cost effective solutions to EPI's customers.

Such stakeholder consultation will be a key component to the new conservation delivery model. This will include ongoing consultation with the IESO and distributors to identify programs best suited to be delivered at a provincial scale versus programs that are specific to meeting regional needs. Evaluation of conservation delivery experience, impact of anticipated load growth, benefits of collaboration with regional electrical and gas distributors, and market research will be key considerations in the implementation of individual and regional CDM programs.

## Consultations with the Transmitter (Hydro One)

EPI regularly consults with HONI transmission staff to share planning and operational information. These consultations can be initiated by either party and vary in format and timing.

Given the broad geographic region that EPI serves, it belongs to four regional planning areas, for which HONI is the lead transmitter. As lead transmitter, HONI is primarily responsible for steering the regional planning in these regions. The statuses of the planning activity for each of these regions, along with the associated EPI communities, are described in the Table 1-10 below.

TABLE 1-10: EPI REGIONAL PLANNING AREAS AND STATUSES

| Region | Status | EPI Community |
|---|---|---|
| Windsor-Essex | Group 1 (one active plan) | Wheatley |
| London Area | Group 2 (currently scheduled for next planning activity) | Strathroy, Mt. Brydges, Dutton, Newbury |
| Chatham/Lambton/Sarnia | Group 3 (currently scheduled for future planning activity) | Chatham-Kent (except Wheatley) |
| Greater Bruce/Huron | Group 3 (currently scheduled for future planning activity) | Parkhill |

## Consultations with the Host and Embedded Distributor (Hydro One)

A significant portion of the EPI distribution system is embedded in HONI’s distribution system. Accordingly, EPI regularly consults with HONI distribution staff on various operational matters.

EPI has consulted with HONI with respect to the Embedded Distributor rates proposed in this application and came to an agreement. These consultations are further discussed in Exhibit 3 and Exhibit 7.

## CONSULTATIONS WITH OTHER STAKEHOLDERS

In April 2014, EPI staff initiated and attended a meeting with Board Staff at the Board Offices to obtain for planning purposes a preliminary understanding of filing requirements as relating to EPI and this Application.

In July 2015, EPI hosted a meeting with its Board Staff Case Manager and the intervenors of record from the CKH 2010 Cost of Service application (EB-2009-0261). The meeting provided a high level overview of the evolution of EPI and other matters relating to this Application.

## 1.6 Executive Summary

Throughout this Application, EPI uses the concept of 2010 Board-Approved Proxy ("2010 BAP") figures. This concept attempts to recognize that EPI's previous Cost of Service application (EB-2009-0261) included only the CKH component of the legacy entities which now comprise EPI. As described in Section 1.2 above, EPI has undergone an evolution since 2010 involving amalgamation and the transfer of employees from an affiliate.

At a high level, the 2010 Board-Approved Proxy Figures were calculated as the aggregate of the following components:

- The CKH 2010 Board-Approved figures, as approved in EB-2009-0261;
- The MPDC 2006 EDR (EB-2005-0351) Board-Approved figures, as inflated for 2007, 2008, 2009 and 2010 utilizing the Board IRM inflation factors as applicable for each of those years;
- The Dutton 2006 EDR (EB-2009-0177) Board-Approved figures, as inflated for 2007, 2008, 2009 and 2010 utilizing the Board IRM inflation factors as applicable for each of those years; and,
- The Newbury 2006 EDR (EB-2005-0392) Board-Approved figures, as inflated for 2007, 2008, 2009 and 2010 utilizing the Board IRM inflation factors as applicable for each of those years.

Further details on the calculation of Board-Approved figures for each Application component are discussion in the various exhibits of this Application. EPI wishes to stress that the use of 2010 BAP figures does not represent an attempt to revisit or deviate from the CKH (EB-2009-0261) OM&A figures previously approved by the Board. Rather, it is an attempt to facilitate an "apples to apples" comparison of 2010 Board-Approved figures in a manner consistent with the current EPI corporate structure and Board Filing Requirements.

### 1.6.1 Revenue Requirement

EPI is requesting the approval of its proposed service revenue requirement of $19,429,174, an increase of $575,560 or 3.1% in comparison to the 2010 Board-Approved Proxy, as shown below in Table 1-11. This increase is less than EPI's cumulative IRM escalation of 5.2% between 2010 and 2015.

TABLE 1-11: SERVICE REVENUE REQUIREMENT

| Line No. | Description | 2010 BAP | 2016 Test Year | Variance |
|---|---|---|---|---|
| | | A | B | C = B - A |
| **1** | **Revenue Requirement:** | | | |
| 2 | OM&A | $7,896,250 | $9,495,813 | $1,599,563 |
| 3 | Depreciation | $4,546,796 | $3,849,791 | -$697,005 |
| 4 | Property Tax | $309,686 | $243,162 | -$66,524 |
| 5 | Income Tax | $1,158,999 | $159,910 | -$999,089 |
| 6 | LEAP | $0 | $23,040 | $23,040 |
| 7 | Return on Rate Base | $4,941,883 | $5,606,789 | $664,905 |
| **8** | **Total** | **$18,853,614** | **$19,378,505** | **$524,891** |
| **9** | **Rate Base** | | | |
| 10 | Rate Base | $66,672,028 | $86,556,573 | $19,884,545 |

The main drivers of this increase are described as follows:

- **Operating Maintenance & Administration ("OM&A") Expense Increase:** EPI's OM&A component has increased by approximately $1.6M, as explained in Exhibit 4, Table 4-3. This includes an increase of $600k related to the transition from CGAAP to MIFRS, which results in costs that were previously capitalized now being expensed as OM&A (as shown in Section 1.7.7 below).

- **Depreciation Decrease:** Under normal circumstances, the growth in rate base between 2010 BAP and 2016 Test Year would have driven an increase to EPI's depreciation expense. However, EPI's depreciation component has decreased by approximately $700k. This decrease in depreciation, which occurs despite the increase in Rate Base, is the result of EPI adopting IFRS-compliant depreciation accounting policies in 2013. These new policies (e.g. longer useful asset lives) have resulted in a $1.9M decrease in what the 2016 Test Year depreciation would have otherwise been under CGAAP. For additional details, refer to Section 1.7.7 below.

- **Payments-in-Lieu of Taxes ("PILs") Decrease:** The decrease in the PILs component by approximately $1.0M is consistent with the decrease in accounting depreciation due to the adoption of longer useful asset lives (accounting for $600k of the decrease) , as well as a decrease in tax rates since EPI's previous rebasing. The result is that EPI's Capital Cost

Allowance (i.e. depreciation for tax purposes) is now higher than accounting depreciation, which has reduced PILs. For further details on PILS, please refer to Exhibit 4, Section 4.12.1.

- **Return on Rate Base:** The increase in Return on Rate Base component by approximately $700k is driven by an increase in Rate Base of $19.9M. The Net Book Value of EPI's assets increased by approximately $21.2M between the 2010 Board-Approved Proxy and the 2016 Test Year, as shown in Exhibit 2, Table 2-4. This resulting increase in Return on Rate Base has been partially offset by two factors:
  - A decrease in the percentage factor used in the calculation of the Working Capital Allowance from the 2010 Default Value of 15% to the 2016 EPI Lead/Lag Study value of 8.22%; and,
  - A decrease in EPI's Weighted Average Cost of Capital ("WACC") from approximately 7.43% in 2010 to 6.48% in the 2016 Test Year, based on Board capital parameters. EPI acknowledges that these parameters are subject to further update.

### 1.6.2 Budgeting and Accounting Assumptions

The development of EPI's budget is a key process, as it identifies past successes as well as future initiatives and projections for capital and operating costs. Each department manager or supervisor develops capital and operating plans, which are reviewed and tested by senior management (and ultimately reviewed by the Board of Directors) to ensure they support EPI's strategic initiatives, as well as being prudent and financially sustainable.

Both the 2015 Bridge and 2016 Test Years have been compiled using the MIFRS method of presentation. Impacts flowing from changes to depreciation and overhead capitalization changes normally required under MIFRS were recognized in 2013 upon conversion to Revised CGAAP. The 2015 Bridge Year Forecast is based on a combination of actual and forecasted balances. EPI provides detailed explanations in the applicable sections of the Application for the major components of the budget: Revenue, OM&A and Capital. Assumptions and methods of calculation from these exhibits for the 2016 Test Year are as follows:

## REVENUE

- The Total Customer/Connections are forecasted to increase slightly based on the forecast by rate class which is reflective of current conditions in EPI's service area; and,

- Other revenues were viewed on an item-by-item basis and were either based on a historical indicators and business plans moving forward.

## OPERATING MAINTENANCE AND ADMINISTRATION EXPENSES

- OM&A expenses have been developed based on managers' or supervisor's operating plans, using a bottom up approach. These plans are reviewed by senior management, and are prepared with a mindset of containing costs while still providing an acceptable level of service and reliability;
- Staffing levels are based on the estimated time required to complete the operating plans, as well as hiring for future requirements. The 2016 Test Year full time equivalent ("FTE") employee complement is forecasted to increase by three (3) from the 2015 Bridge Year level of 73.5 FTEs;
- Union wage increases are based on EPI's three (3) union contacts, which are effective January 1, 2015, expire on December 31, 2018, and provide for an annual wage increase of 2.25%. Non-union management wage increases are also estimated to increase at 2.25% annually;
- Regulatory costs for this Application and other One-Time Costs have been normalized over the five year life of the application; and,
- EPI used an inflation rate of 1.6% for 2015 and 2016 where the expense increase could not be specifically identified.

## AMORTIZATION

- Amortization has been calculated based on the revised useful lives in accordance with MIFRS requirements.

### PILs

- Regulatory PILS have been calculated using the Board Approved Model ; and,
- PILS are forecasted to decrease mainly due to the decrease in depreciation resulting from the change in useful lives and an increase in capital cost allowance which is not affected by the change in useful lives.

### Capital

- The Capital Budget was formulated on a project by project basis
- Distribution asset related projects were prioritized based on multiple factors as explained in the DSP
- General Asset related projects were submitted by managers and supervisors on a project- by-project basis. Major projects were based on fleet replacement scheduling, work equipment requirements and Information Technology assessments.

## 1.6.3 Load Forecast Summary

EPI's load forecast is weather normalized and considers factors such as historical power purchased load, weather conditions, time and local economic conditions.

As outlined in Exhibit 3, EPI has used the same regression analysis methodology utilized in the CKH 2010 Cost of Service Application (EB-2009-0261). The regression analysis was conducted on historical electricity purchases to produce an equation that will predict weather normalized power purchases in 2016. The weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast which is allocated to rate class using historical billing data.

Based on the load forecast methodology, the Total 2016 Test Year kWh forecast is 909,926,173 kWh. By comparison, in 2010 CKH had a Board Approved 2010 load forecast in EB-2009-0261 of 666,474,876 kWh, and MPDC reported an actual of 211,490,123 kWh, for an aggregate proxy total of 877,964,999 kWh. The 2016 Test Year kWh forecast represents a 3.6% increase over this 2010 Proxy.

The forecast of customers by rate class was determined primarily using geometric mean analysis, which resulted in an expected number of customers/connections for the 2016 Test Year of 55,013. By comparison, the CKH portion of EPI's service territory had Board Approved 2010 customers/connections of 43,404, and MPDC reported actual customers/connections of 10,212, for an aggregate proxy total of 53,616. The 2016 Test Year forecast represents a 2.6% increase over this 2010 Proxy.

### 1.6.4 RATE BASE & CAPITAL PLAN

#### DISTRIBUTION SYSTEM PLAN

In creating the DSP (refer to Exhibit 2, Attachment 2-D), EPI believes the objective and scope of this 2016 – 2020 investment plan speaks directly to the RRFE and EPI's core values and also to the Board's DSP evaluation criteria of efficiency, customer value and reliability. The main drivers in the DSP are voltage conversion, system renewal of overhead lines and underground plant, investments in resources to increase EPI's ability to detect and troubleshoot power quality concerns, and investments in distribution automation. The DSP and EPI's Capital Expenditure Plan seeks to find the right balance between capital investments in new infrastructure, and operating and maintenance costs so that the combined total cost over the life of an asset is minimized.

As will be demonstrated in the DSP as well as the remainder of this summary, the proposed levels of capital investment, for each category and in total, are relatively consistent and slightly declining from the 2016 Test Year onwards. This is reflective of the EPI's belief that over the forecast period, investment drivers will remain characteristically similar to 2016 and that there are no foreseen extraordinary expenditures. These capital expenditures are spread out over four categories (as seen in Table 1-12 below): System Renewal (SR), System Access (SA), System Service (SS) and General Plant (GP).

TABLE 1-12: PROPOSED CAPITAL INVESTMENTS

| Line No. | Category | 2015 Plan | 2016 Plan | 2017 Plan | 2018 Plan | 2019 Plan | 2020 Plan |
|---|---|---|---|---|---|---|---|
| 1 | System Access | $853 | $813 | $774 | $786 | $797 | $809 |
| 2 | System Renewal | $4,750 | $4,314 | $4,461 | $4,773 | $4,759 | $4,406 |
| 3 | System Service | $941 | $1,192 | $1,244 | $1,076 | $1,083 | $1,141 |
| 4 | General Plant | $1,683 | $1,519 | $1,234 | $1,023 | $1,036 | $1,106 |
| **5** | **Total** | **$8,227** | **$7,839** | **$7,713** | **$7,657** | **$7,675** | **$7,461** |

## CAPITAL EXPENDITURES FOR THE 2016 TEST YEAR

In the 2016 Test Year, EPI is forecasting a decrease in total capital spending in comparison to the 2015 Bridge Years. Forecasted capital expenditures then decrease slightly through to 2020. The decrease in the 2016 Test Year from the 2015 Bridge Year is primarily driven by a decrease in the System Renewal investment, related to the completion of several ongoing voltage conversion projects, as well as a decrease in General Plant investment, related to the timing of fleet purchases driven by the fleet purchasing policy and asset condition assessments.

As outlined in EPI's DSP, system renewal projects represent investments required due to assets reaching the end of their Typical Useful Life ("TUL") or found to be in poor condition. The majority of this work for 2016 involves the replacement of wood poles, switches, transformers and underground cable as identified by EPI's Asset Management Plan. Generally, the lines that are the oldest and in poorest condition, also operate at the 4.16 kV and 8.32 kV voltage levels. As part of EPI's asset renewal plans, the lower voltage assets when replaced are also upgraded to higher and more efficient voltages or capacities at 27.6 kV. EPI forecasts $1.49M in major projects for voltage conversion, and an additional $1.3M to replace underground cables, submersible transformers, switches and so forth that have been identified for replacement based on the Asset Condition Assessment ("ACA") completed in 2014.

System Service expenditures include $400k required for Distribution Automation expenditures and $250k for the installation of advanced fault indicators, to improve EPI's ability to detect and troubleshoot system faults. This is part of EPI's plan to modernize its distribution system into a Smart Grid (see Exhibit 2, Attachment 2-D, Appendix XI).

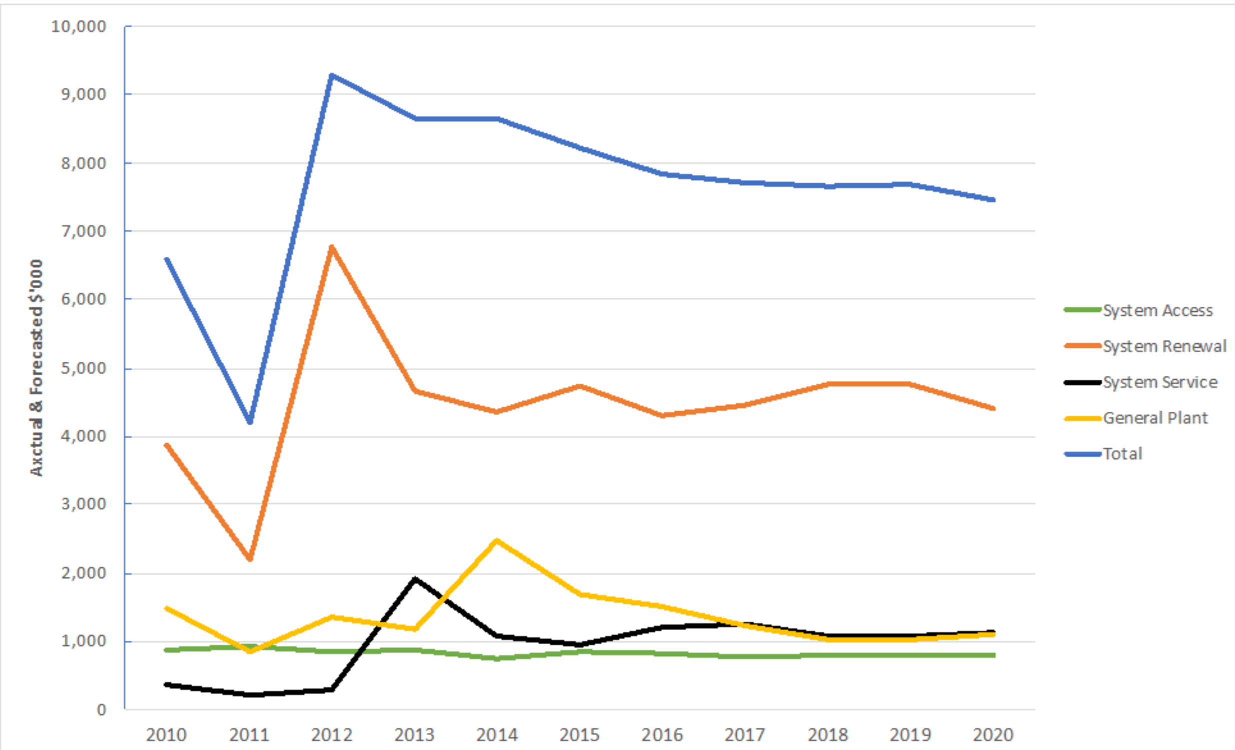
EPI notes that the term 'Capital Expenditures' has been reflected as Capital Additions in this Application, Work in Process is not recorded in the year spent, it is recorded when the asset is in service.

## Capital Expenditures for the Forecast Period

For the forecast period of 2017-2020, EPI does not have specific project listings. The Capital Expenditures for this period are anticipated to remain relatively consistent.

Chart 1-2, shown below, depicts both historical and proposed capital expenditure levels by category.

**Chart 1-2: Historic and Proposed Capital Expenditures**




Major investments, in System Access ("SA"), are expected to be customer centric and are based on historical levels and municipal and developer consultation outcomes. SA capital investments continue to remain steady for the 2017 to 2020 forecast. Any year-to-year increases remain within the materiality threshold.

System Renewal ("SR") investments over the forecast period represent the largest group of investments. From Chart 1-2 above, it can be seen that average annual investments in SR is trending higher by an average of $1.1 mil annually from historical levels. This is in keeping with an increased focus to replace aging and failing assets as identified in the ACA.

In addition, major investments continue to be related to voltage conversion projects and the replacement of aging and failing underground cable, transformers, switches and poles.

System Service ("SS") investments are the second highest group of investments and show a slight increase over the forecast period. The majority of the investments are reliability centric in Distribution Automation, power quality monitoring and troubleshooting capabilities and fault indicating devices. This increased focus on developing the Smart Grid is in accordance with EPI's Smart Grid Plan (see Exhibit 2, Attachment 2-D, Appendix XI) and in response to a growing customer concern about reliability and power quality as well as general corporate alignment of EPI's capital plans with corporate values and objectives.

General Plant ("GP") investments represent the third largest group of investments over the forecast period. From Table 1-12 and Chart 1-2 above, it can be seen that average annual investments in GP are trending at the same rate as historic levels.

EPI is applying considerable effort to level out expenditures related to fleet purchases and building refurbishments. There are no planned major changes to either. Costs are therefore expected to be level year-over-year beyond the 2016 Test Year.

## COMPARISON TO 2010 BOARD APPROVED PROXY CAPITAL EXPENDITURES

Please refer to Table 1-13 below for a comparison of 2010 Board Approved Proxy Capital Expenditures to 2016 Test Year Capital Expenditures

As described throughout this Application, since CKH and MPDC operated separately until 2012, the CKH 2010 Cost of Service (EB-2009-0261) Board Approved figures do not include MPDC (e.g. the rate zones of SMP, Dutton and Newbury, which last rebased under the 2006 EDR). In order to facilitate comparison, throughout the various exhibits, EPI has developed Board Approved Proxies. In general, the methodology involves adding the CKH EB-2009-0261 Board Approved figures to the SMP, Dutton and Newbury 2006 EDR figures, with escalation of the latter figures for the 2007-2010 IRM escalation factors. This calculation is shown for Rate Base in Column B of Table 1-13 below for information purposes only. However, the MPDC component of the 2010 BAP is only $48k due to the low capital investment amounts included in the 2006 EDR applications of the MPDC entities. At that point in time, the MPDC entities followed the asset management practices of previous ownership.

Subsequent to the acquisition of MPDC in 2005, management embarked on a rigorous environmental and asset risk assessment process to identify and prioritize capital requirements. As a result, significant focus was put on capital investments required to bring the MPDC system up to standard, which necessitated capital investment beyond the levels included in rates. Similarly, management focused on system enhancements subsequent to the acquisition of Dutton and Newbury in 2009, including the prompt remedying of ESA non-compliance orders issued to the previous ownership of Dutton, which required pole replacement and other items. The above-noted actions allowed MPDC, Dutton and Newbury customers to enjoy a period of stable rates while benefitting from additional capital investments and improved service and reliability.

Accordingly, for the purposes of this summary, EPI has provided an alternative comparative view in Table 1-13 below. This alternative view is shown in Column C, and represents the CKH EB-2009-0261 Board Approved figures added to the 2010 actual capital expenditures for SMP, Dutton and Newbury. As illustrated, applying this view shows that the 2016 Test Year Capital Expenditures are $1,667,245 higher than the 2010 comparative view (in Column C).

**TABLE 1-13: BOARD APPROVED PROXY AND COMPARATIVE EXPENDITURES VS. 2016 TEST YEAR CAPITAL EXPENDITURES**

| Investment Category | 2010 BAP Proxy | 2010 CK BAP + MPDC Actual | 2016 Test Year | Variance |
|---|---|---|---|---|
| A | B | C | D | E = D - C |
| General Plant | $1,330,569 | $1,418,256 | $1,518,500 | $100,244 |
| System Access | $862,761 | $1,087,487 | $813,246 | -$274,241 |
| System Renewal | $2,537,140 | $3,096,723 | $4,314,464 | $1,217,742 |
| System Service | $559,504 | $568,978 | $1,192,479 | $623,501 |
| Grand Total | $5,289,974 | $6,171,443 | $7,838,689 | $1,667,245 |

The following factors contribute to the increase in investment between the 2010 comparative (shown in Column C) and the 2016 Test Year (shown in Column D):

## SYSTEM RENEWAL

- The 2010 Board Approved capital expenditures included, just as in 2016, significant investment in voltage conversion projects;
- The increased focus on voltage conversion is a means of achieving several goals related to Asset Management and system operational efficiencies (see Section 5.4.2.1 of the DSP, attached as Exhibit 2, Attachment 2-D, Appendix XI), complemented by a better understanding acquired from the Asset Condition Asset ("ACA") exercise and a better understanding of Asset Management techniques. Any variations from year-to-year are as the result of the peculiarities of the work planned in each year and the complexity of each phase of a project; and,
- EPI increasingly intensified its voltage conversion and asset replacement programs to replace aging and failing equipment. With the completion of the ACA, in 2014, this approach was confirmed and planned expenditures in SR will continue to be near 2016 levels into the forecast period.

## SYSTEM ACCESS

- 2016 Test Year costs for demand related work in SA are based on historical trending and are lower than 2010 comparative figure by $274,241; and,
- EPI believes this is primarily due to struggling local economic conditions since the 2009 economic downturn.

## SYSTEM SERVICE

- The increased expenditure in SS versus the 2010 comparative, by $623,501, is a reflection of the increased development of the Smart Grid, starting in 2015, but leveling and declining again after 2017. This increased investment is related to the town-by-town rollout of Smart Grid technology. More specifically, in 2016 the town of Wallaceburg will be the recipient of this technology in an effort to manage the growing reliability issues and feedback from customers. Subsequently, other EPI communities will receive Smart Grid rollout based on their degree of need and feedback from customers. These investments may have to be deployed in phases, depending on the size and complexity of the distribution in each town.

## GENERAL PLANT

- GP spending is heavily influenced by the replacement and upkeep of rolling stock and building. Cost in this category have fluctuated throughout the historic period but are forecast to level as EPI enters into a period of relative stability with regards to fleet and building requirements.
- There continues to be modernization and enhancement to EPI's IT infrastructure as customer expectations change and the demand for greater computational power and storage grows as an offshoot of EPI's grid modernization efforts.

## RATE BASE

Table 1-14 below outlines the summary of rate base from 2010 Board-Approved Proxy as compared to the 2016 Test Year.

**TABLE 1-14: SUMMARY OF RATE BASE**

| Line No. | Description | 2010 BAP | 2010 Actual | 2011 Actual | 2012 Actual | 2013 Actual | 2013 Actual | 2014 Actual | 2015 Bridge | 2016 Test |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Accounting Standard | CGAAP | CGAAP | CGAAP | CGAAP | CGAAP | RCGAAP | MIFRS | MIFRS | MIFRS |
| 2 | Gross Fixed Assets | $96,892,535 | $100,790,407 | $104,997,721 | $114,279,741 | $123,432,009 | $122,921,468 | $131,584,123 | $139,810,780 | $147,649,469 |
| 3 | Accumulated Depreciation | -$40,818,534 | -$44,133,706 | -$47,761,263 | -$53,052,143 | -$58,432,574 | -$57,319,702 | -$60,804,052 | -$64,884,552 | -$69,297,605 |
| 4 | Net Book Value | $56,074,001 | $56,656,702 | $57,236,458 | $61,227,598 | $64,999,435 | $65,601,767 | $70,780,071 | $74,926,228 | $78,351,864 |
| **5** | **Average Net Book Value** | **$55,448,194** | **$55,677,004** | **$56,946,580** | **$59,232,028** | **$63,113,517** | **$65,300,601** | **$68,190,919** | **$72,853,150** | **$76,639,046** |
| 6 | Total Working Capital | $74,825,559 | $88,512,232 | $91,948,855 | $96,982,003 | $105,484,108 | $105,673,269 | $112,875,386 | $120,510,073 | $120,651,183 |
| 7 | Working Capital Allow. Factor | 15.00% | 15.00% | 15.00% | 15.00% | 15.00% | 15.00% | 15.00% | 15.00% | 8.22% |
| **8** | **Working Capital Allowance** | **$11,223,834** | **$13,276,835** | **$13,792,328** | **$14,547,300** | **$15,822,616** | **$15,850,990** | **$16,931,308** | **$18,076,511** | **$9,917,527** |
| **9** | **Rate Base** | **$66,672,028** | **$68,953,839** | **$70,738,908** | **$73,779,328** | **$78,936,133** | **$81,151,591** | **$85,122,227** | **$90,929,661** | **$86,556,573** |

As shown above, the 2016 Test Year Rate Base is $86,556,573, compared to the 2010 Board-Approved Proxy Rate Base of $66,672,028. This represents an increase of $19.9M (or 30%), which is driven by an increase in Net Book Value of $21.2M.

EPI engaged Navigant Consulting to conduct a Lead Lag Study in order to establish EPI's proposed Working Capital Allowance ("WCA") Factor of 8.22%. Please refer to Exhibit 2, Attachment 2-B for the EPI Lead/Lag Study. The decrease in the WCA Factor since 2010 triggers a decrease in WCA, which modestly offsets the growth in Net Book Value, as discussed in Section 1.6.1 above. The variance in Rate Base is further described in Exhibit 2.

Much of the increase in rate base is as a result of the increased focus asset renewal, such as voltage conversion, cable replacement, pole replacement, etc., as a result of the realization that many of these assets were approaching end of life. This increase in capital investment was confirmed through the results of the ACA conducted in 2014.

## Renewable Energy Connections and Regional Planning

EPI uses a comprehensive approach to its Distribution System Planning which includes all categories of investments including System Renewal and expansion, Renewable Generation Connection, and Regional Planning as required. This comprehensive approach ensures the investments made by EPI are efficient and that they support the goals identified by the Board in the Filing Requirements.

Given the large geographic area served by EPI, it is a member of four regional planning groups. Additional details are provided in Section 1.5.6 above.

## Renewable Energy Investments

EPI's distribution system has been planned and proactively built and equipped to handle forecasted renewable generation. As part of the DSP, EPI prepared a Renewable Energy Generation Investments Plan and has submitted this plan to the IESO (formerly the OPA). Based on the evaluation of the distribution system to accept green energy generation connections, no constraints have been identified in the system, preventing the connection of renewable energy generation installations. On this basis, EPI is not proposing any capital investments for capacity upgrades on its distribution system to accommodate the applications for the connection of any Renewable Energy Generation (“REG”) plant over the forecast period of the DSP.

EPI has been involved in meetings with the other distributors and HONI with regard to Regional Supply Planning for many years prior to the process being formalized into the IRRP.

The IESO’s response to EPI’s Renewable Energy Generation Investments Plan is shown in the DSP (see Exhibit 2, Attachment 2-D, Appendix II).

### 1.6.5 Operations, Maintenance and Administration Expense

EPI is proposing the recovery through distribution rates of $9,495,813 in OM&A expenses for the 2016 Test Year. These 2016 OM&A expenses represent an increase of $1,599,563 or 20% over the 2010 Board Approved Proxy amount of $7,896,250 (adjusted for $23,040 of LEAP). Table 1-15 below summarizes the changes.

**Table 1-15: Changes in OM&A Between 2010 Board-Approved Proxy and 2016 Test Year**

| Item | Amount | Core Value Reference |
|---|---|---|
| **2010 Board-Approved Proxy OM&A** | $7,896,250 | |
| Increase in Operating Portion of Salaries, Wages and Benefits | $580,708 | All |
| Community Relations - Website, Social Media, Literacy Videos | $55,020 | CC |
| Customer Service - My Account Upgrades, Outage Management System, First Call Resolution | $144,870 | CC, IE |
| Impact of IFRS Capitalization Changes on OM&A | $625,688 | All |
| Power Quality | $102,381 | OE |
| Smart Meter Maintenance and Re-Verification | $126,831 | OE |
| Transformer Capital Replacement | ($236,901) | OE |
| Additional Engineering Software Licensing to Support DSP Updates | $100,000 | SF, OE |
| Inflation on Non-Labour Items | $439,149 | All |
| Other Immaterial Items | ($338,183) | All |
| **2016 Test Year OM&A** | **$9,495,813** | |

**Core Value Legend:**
SF - Safety
CC - Customer and Community Focus
OE - Operational Excellence
SG - Sustainable Growth
IE - Inspired and Empowered People

The proposed OM&A expenditures for the 2016 Test Year have been derived through a detailed budgeting and business planning process aligned with EPI's strategy and Core Values. These expenditures are required so that EPI can maintain the distribution business service quality and reliability standards in compliance with the Distribution System Code and other regulatory bodies (IESO, Ministry of Energy, ESA, etc.) while also responding to customer needs and preferences.

Between 2010 and 2016, EPI experienced an increase in its OM&A workload as a result of increased demand by its customers for services. New provincial policy initiatives have been introduced over this timeframe as well, resulting in increased OM&A workloads. Some of these initiatives include new service rules for low income customers, LEAP, the RRFE with its increased regulatory requirements, the introduction of Smart Meters, the conversion to Time-of-Use ("TOU") rates, renewable generator connection and settlement obligations, increased customer engagement requirements on local and provincial industry issues and the introduction of Regional Planning. EPI has willingly embraced these initiatives and worked hard to implement them at minimal cost, without adversely impacting customer service.

Further, the OM&A costs in the 2016 Test Year address the "greying" workforce issue that EPI faces. Overall, 21% of the EPI workforce is 56 years of age or older and over 35% of the workforce is eligible to retire in the next five years, including 50% of the Lines Department. Further, additional engineering resources are required for EPI to remain technologically relevant and continually update and execute its DSP, as further described in Section 4.4.2. Given the specialization of the industry, it can take several years for new staff to become proficient in completing tasks safely.

In this context, the primary drivers for the increased OM&A costs shown in Table 1-15 above are more fully described as follows:

- The inclusion of IFRS-compliant capitalization and depreciation policies in accordance with the Board's letter dated July 17, 2012 has resulted in increased OM&A expenses. EPI adopted the changes effective 2013, with the result that certain overheads previously capitalized are now required to be expensed as OM&A cost. The OM&A increase for the 2016 Test Year versus the 2010 Board-Approved Proxy relating to these changes is $625,688;

- Increased salaries, wages and benefit costs charged to OM&A. Wages for unionized staff have been trending upwards at 2.29% per year. Benefit costs have increased in particular as a result of significantly higher OMERS pension costs. In total, compensation charged to OM&A has increased by $580,708 from the 2010 Board Approved Proxy amount; and,

- Inflation on Non-Labour items of $439,149, as discussed in Exhibit 4.1.3

The other drivers shown in Table 1-15 above are further described in Exhibit 4.1.3.

When normalized for the impact of IFRS-compliant capitalization ($625,688), OM&A has increase by $973,875 between the 2010 Board-Approved Proxy and the 2016 Test Year. This equates to a 12.3%

increase over a 6 year period since the 2010 Board-Approved Proxy amount of $7,896,250. In turn, this translates to a 2.1% average annual increase in OM&A. EPI submits that this rate of increase in its OM&A requirements reflects a responsible approach to controlling costs.

### 1.6.6 Cost of Capital

EPI has prepared its Application in accordance with the Board's guidelines provided in the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities* (the "Cost of Capital Report") dated December 11, 2009. For the purposes of preparing this Application, NBHDL has used the cost of capital parameters issued by the Board on November 20, 2014 for 2015 Cost of Service rate applications for rates with effective dates in 2015.

EPI will update its evidence to reflect future Board cost of capital parameters for rates with effective dates in 2016, prior to the issuance of the Board's decision for its Application. EPI proposes no deviations from the Board's Cost of Capital Methodology.

### 1.6.7 Cost Allocation and Rate Design

The data used in the updated cost allocation study is consistent with EPI's cost data supporting the proposed 2016 revenue requirement outlined in this Application. The breakout of Assets, Capital Contributions, Depreciation, Accumulated Depreciation, Customer Data and Load Data by Primary, Line Transformer and Secondary categories were developed from the best data available to EPI, its Engineering Records, and its Customer and Financial Information Systems.

In accordance with the Report of the Board "Review of Electricity Distribution Cost Allocation Policy, dated March 31, 2012", whereby the Board stated that "default weighting factors should now be utilized only in exceptional circumstances", EPI has developed and utilized its own weighting factors for the purposes of preparing the Cost Allocation Model. The 2016 Cost Allocation Study has resulted in a change in the cost allocations by rate class using EPI's weighting factors.

As shown in Table 1-16 below, the resulting 2016 Cost Allocation Study indicates the Revenue to Cost ("RTC") Ratios for the Unmetered Scattered Load and Large Use rate classes are outside the Board's range. For 2016, it is proposed these ratios be brought within the Board's range and Residential, General

Service < 50-4,999 kW and Street Light rate classes be adjusted downward within the Board's range in order to maintain revenue neutrality.

**TABLE 1-16: PROPOSED REVENUE TO COST RATIOS**

| Line No. | Rate Class | Previously Approved Ratios (Note 1) | Status Quo Ratios (Per CA Model) | Proposed Ratios | Policy Range |
|---|---|---|---|---|---|
| 1 | Residential | 94.7% | 98.0% | 98.9% | 85% to 115% |
| 2 | GS<50 | 106.6% | 114.3% | 105.1% | 80% to 120% |
| 3 | GS>50 | 113.4% | 104.2% | 104.2% | 80% to 120% |
| 4 | Large Use **Note 2** | n/a | 26.8% | 60.6% | 85% to 115% |
| 5 | USL | 90.2% | 136.9% | 105.1% | 80% to 120% |
| 6 | Sentinel | 79.0% | 83.4% | 83.4% | 80% to 120% |
| 7 | Street | 79.0% | 124.4% | 105.1% | 80% to 120% |
| 8 | Embedded **Note 3** | n/a | 180.9% | 100.0% | n/a |

**Note 1**: These Revenue to Cost ratios relate to the former CKH, as approved in EB-2009-0261 and EB-2010-0074.
**Note 2:** The Large Use rate class is currently applicable only to SMP, which was last rebased under the 2006 EDR (MPDC application EB-2005-0351). At such time, current cost allocation and Revenue to Cost Ratio practices had not yet been established. Accordingly, there is no current Revenue to Cost Ratio for this rate class
**Note 3:** Currenty, a separate rate class does not exist for Embedded Distributor. Accordingly, there is no current Revenue to Cost ratio for this rate class.

In the Application, EPI proposes the creation of an Embedded Distributor Rate Class. This rate class is not currently included in the Board's RTC Ratio ranges. Accordingly, EPI proposes applying an RTC Ratio of 100% for the Embedded Distributor Rate Class. The proposed Distribution Revenue is $814 per annum for the Embedded Distributor rate class.

## RATE DESIGN

In this Application, EPI seeks to harmonize distribution rates across its existing four rate zones. This will assist in meeting EPI's goal of assisting with customer energy literacy by simplifying EPI's tariff sheet.

As described in Section 1.5.3 above, EPI consulted with customers on the proposed rate harmonization for this Application. In this regard, survey results showed that a strong majority of both residential (72%) and general service customers (69%) agree with the concept of rate harmonization.

As part of the proposed harmonization, EPI is seeking the elimination of two rate classes: the CK Intermediate rate class, and the CK Intermediate with Self Generation Classes. The customers from the former class would migrate to the GS>50-4,999 kW rate class and the sole customer from the latter class would migrate to the Large Use rate class. Further, EPI proposes setting a standby charge for the GS<50-4,999 kW and Large Use rate classes equivalent to the respective variable charges for those rate classes. These proposals are detailed in Exhibit 7.

EPI proposes to design its 2016 distribution rates to maintain the current weighted average Fixed/Variable proportions assumed in its current rates, with the exception of the Residential and Large Use rate classes. These exceptions are due to: (a) the implementation of fixed rates for the Residential rate class, consistent with implementation of the recent Board Policy entitled "*A New Distribution Rate Design for Residential Electricity Customers (EB-2012-0140)*", and (b) the proposed mitigation plan for the former sole SMP Large Use customer who will now reside in the proposed Large Use rate class.

The transition to fixed Residential rates is described in Exhibit 8, Section 8.1.4. EPI notes that it has a wide range of fixed/variable proportions for each of its current four rate zones, and that the transition is occurring simultaneously with rate harmonization. Accordingly, EPI is proposing that all Residential customers start by moving to a 76% fixed rate in 2016, as consistent with the already highly fixed CK Residential rates. This avoids the need for the CK Residential customers (EPI's largest customer segment) to first backtrack to a greater proportion of variable rates before starting their transition to fully fixed rates.

The proposed mitigation plan for the SMP Large Use customer is described in Exhibit 7, Section 7.5, and involves a 3 year phase in transition to an 85% RTC Ratio, with the offsetting amount being collected from the Residential Rate Class. The RTC Ratio for the Residential rate class is currently below 100%, and will remain so throughout the mitigation period.

Table 1-17 below provides a comparison of the 2015 Current Distribution Rates (by rate class) to the harmonized 2016 Proposed Distribution Rates.

TABLE 1-17: COMPARISON OF CURRENT AND PROPOSED DISTRIBUTION RATES

| Line No. | Rate Class | Monthly Service Charge | | | Distribution Volumetric Charge | | | |
|---|---|---|---|---|---|---|---|---|
| | | 2015 Approved | 2016 Proposed | % Difference | Unit | 2015 Approved | 2016 Proposed | % Difference |
| 1 | **CK Rate Zone** | | | | | | | |
| 2 | Residential | $18.98 | $18.98 | 0.00% | kWh | $0.0088 | $0.0093 | 5.68% |
| 3 | General Service <50 kW | $34.84 | $29.41 | -15.59% | kWh | $0.0118 | $0.0097 | -17.80% |
| 4 | General Service 50-4,999 kW | $122.86 | $100.49 | -18.21% | kW | $3.4827 | $3.3220 | -4.61% |
| 5 | Intermediate | $99.74 | *to cease in 2016* | n/a | kW | $4.7298 | *to cease in 2016* | n/a |
| 6 | Intermediate with Self Generation | $1,385.39 | *to cease in 2016* | n/a | kW | $3.4954 | *to cease in 2016* | n/a |
| 7 | Large User | n/a | $1,390.17 | n/a | kW | n/a | $2.4042 | n/a |
| 8 | Unmetered Scattered Load Connections | $11.06 | $8.19 | -25.95% | kWh | $0.0008 | $0.0015 | 87.50% |
| 9 | Sentinel Lighting Connections | $8.71 | $7.54 | -13.43% | kW | $0.6185 | $0.6762 | 9.33% |
| 10 | Street Lighting Connections | $1.73 | $1.20 | -30.64% | kW | $1.2859 | $1.0076 | -21.64% |
| 11 | Embedded Distributor | *new in 2016* | $67.85 | n/a | kW | *new in 2016* | $0.0000 | n/a |
| 12 | **SMP Rate Zone** | | | | | | | |
| 13 | Residential | $14.43 | $18.98 | 31.53% | kWh | $0.0146 | $0.0093 | -36.30% |
| 14 | General Service <50 kW | $19.06 | $29.41 | 54.30% | kWh | $0.0051 | $0.0097 | 90.20% |
| 15 | General Service 50-4,999 kW | $45.55 | $100.49 | 120.61% | kW | $1.5094 | $3.3220 | 120.09% |
| 16 | Large User | $3,845.43 | $381.67 | -90.07% | kW | $0.0567 | $1.4814 | 2512.70% |
| 17 | Unmetered Scattered Load Connections | $9.54 | $8.19 | -14.15% | kWh | $0.0055 | $0.0015 | -72.73% |
| 18 | Sentinel Lighting Connections | $0.18 | $7.54 | 4088.89% | kW | $1.0357 | $0.6762 | -34.71% |
| 19 | Street Lighting Connections | $0.14 | $1.20 | 757.14% | kW | $0.6069 | $1.0076 | 66.02% |
| 20 | **Dutton Rate Zone** | | | | | | | |
| 21 | Residential | $13.44 | $18.98 | 41.22% | kWh | $0.0127 | $0.0093 | -26.77% |
| 22 | General Service <50 kW | $27.45 | $29.41 | 7.14% | kWh | $0.0061 | $0.0097 | 59.02% |
| 23 | Sentinel Lighting Connections | $0.98 | $7.54 | 669.39% | kW | $5.2239 | $0.6762 | -87.06% |
| 24 | Street Lighting Connections | $0.66 | $1.20 | 81.82% | kW | $3.0966 | $1.0076 | -67.46% |
| 25 | **Newbury Rate Zone** | | | | | | | |
| 26 | Residential | $12.52 | $18.98 | 51.60% | kWh | $0.0126 | $0.0093 | -26.19% |
| 27 | General Service <50 kW | $22.91 | $29.41 | 28.37% | kWh | $0.0114 | $0.0097 | -14.91% |
| 28 | General Service 50-4,999 kW | $279.02 | $100.49 | -63.98% | kW | $1.4026 | $3.3220 | 136.85% |
| 29 | Street Lighting Connections | $0.85 | $1.20 | 41.18% | kW | $3.5494 | $1.0076 | -71.61% |

In addition, the proposed rate design provides a substantial improvement for SMP, Dutton and Newbury customers in terms of loss factors. Beyond harmonization, this benefit is consistent with the significant investments made to bring the SMP, Dutton and Newbury distribution systems up to standard after their acquisition, as described above in Section 1.6.4. The proposed loss factors are shown in Table 1-18 below.

TABLE 1-18: COMPARISON OF CURRENT AND PROPOSED LOSS FACTORS

| Line No. | Description | 2015 Approved | | | | 2016 Proposed |
|---|---|---|---|---|---|---|
| | | CK | SMP | Dutton | Newbury | |
| 1 | Total Loss Factor - Secondary Metered Customer < 5,000 kW | 1.0428 | 1.0608 | 1.0662 | 1.0580 | 1.0432 |
| 2 | Total Loss Factor - Secondary Metered Customer > 5,000 kW | 1.0430 | 1.0145 | | | 1.0149 |
| 3 | Total Loss Factor - Primary Metered Customer < 5,000 kW | 1.0324 | 1.0501 | | 1.0475 | 1.0328 |
| 4 | Total Loss Factor - Primary Metered Customer > 5,000 kW | 1.0141 | 1.0045 | | | 1.0049 |

### 1.6.8 Deferral and Variance Accounts

As outlined in Exhibit 9, EPI is requesting approval of the disposition of Group 1, Group 2 and Other Deferral and Variance Accounts (“DVAs”) in the amount of $35,428.37 refunded to customers. This includes an RSVA – Global Adjustment amount of $1,812.670.48 owed to EPI by Non-RPP customers only. The remaining amount of $1,848,098.85 is to be refunded to all customers.

EPI is proposing a one year disposition period for all DVAs, with the exception of Account 1576 (Accounting Changes under CGAAP), where a two year disposition period is proposed. EPI is not requesting any new Deferral and Variance Accounts.

As part of its proposal to harmonize the existing four EPI rate zones, EPI proposes to dispose of all Group One and Group Two DVA balances on a harmonized basis, effective May 1, 2016. The reasoning behind this request is described in Exhibit 9, Section 9.3. Further, EPI proposes that future dispositions of all DVAs balances be accounted for and completed on a consolidated basis. This methodology would ensure consistency among the dispositions proposed in this Application and future balances.

### 1.6.9 Bill Impacts

In preparing for this Application, EPI undertook customer engagement activities which emphasized to EPI the importance of focusing on affordable distribution rates.

EPI has carefully considered the effects of bill impacts on its customers, with a goal of minimizing those impacts. The majority of bill impacts are flat or declining in 2016. These customer bill impacts, as summarized in Table 1-19 below, include the proposed (and previously discussed) rate mitigation for the former sole SMP Large Use customers.

**TABLE 1-19: PROPOSED BILL IMPACTS**

| Line No. | Rate Class | Type | Typical kWh | Typical kW | 2015 Final Rates by Rate Zone | 2016 Proposed Rates Combined | $ Increase (Decrease) | % Increase (Decrease) |
|---|---|---|---|---|---|---|---|---|
| **1** | **CK** | | | | | | | |
| 2 | Residential | RPP | 800 | - | $137.72 | $137.80 | $0.08 | 0.06% |
| 3 | General Service < 50 kW | RPP | 2,000 | - | $342.08 | $322.38 | -$19.70 | -5.76% |
| 4 | General Service > 50 - 4,999 kW | Non-RPP | 162,500 | 500 | $23,971.55 | $25,042.79 | $1,071.23 | 4.47% |
| 5 | General Service > 50 - 4,999 kW (From Intermediate) | Non-RPP | 1,825,000 | 2,500 | $252,413.68 | $247,842.30 | -$4,571.37 | -1.81% |
| 6 | Large Use (From Intermediate w/Self Gen) | Non-RPP | 2,763,935 | 7,200 | $406,026.52 | $395,377.43 | -$10,649.09 | -2.62% |
| 7 | Unmetered Scattered Load | RPP | 150 | - | $31.98 | $29.08 | -$2.90 | -9.06% |
| 8 | Sentinel Lighting | RPP | 150 | 1 | $32.23 | $30.97 | -$1.26 | -3.91% |
| 9 | Street Lighting | Non-RPP | 150 | 1 | $27.03 | $25.99 | -$1.04 | -3.84% |
| 10 | Embedded Distribution (From General Service > 50 kW) | Non-RPP | 368,500 | 14 | $49,881.06 | $49,832.37 | -$48.69 | -0.10% |
| **11** | **SMP** | | | | | | | |
| 12 | Residential | RPP | 800 | - | $140.96 | $137.80 | -$3.16 | -2.24% |
| 13 | General Service < 50 kW | RPP | 2,000 | - | $316.43 | $322.38 | $5.95 | 1.88% |
| 14 | General Service > 50 - 4,999 kW | Non-RPP | 162,500 | 500 | $23,322.91 | $25,042.79 | $1,719.87 | 7.37% |
| 15 | Large Use | Non-RPP | 2,631,117 | 5,500 | $360,296.17 | $358,769.69 | -$1,526.47 | -0.42% |
| 16 | Unmetered Scattered Load | RPP | 150 | - | $31.35 | $29.08 | -$2.27 | -7.25% |
| 17 | Sentinel Lighting | RPP | 150 | 1 | $70.09 | $30.97 | -$39.13 | -55.82% |
| 18 | Street Lighting | Non-RPP | 150 | 1 | $23.28 | $25.99 | $2.71 | 11.63% |
| **19** | **Dutton** | | | | | | | |
| 20 | Residential | RPP | 800 | - | $142.11 | $138.13 | -$3.98 | -2.80% |
| 21 | General Service < 50 kW | RPP | 2,000 | - | $328.59 | $323.19 | -$5.40 | -1.64% |
| 22 | General Service > 50 - 4,999 kW (From General Service < 50 kW) | RPP | 440,000 | 96 | $63,341.66 | $54,434.57 | -$8,907.09 | -14.06% |
| 23 | Sentinel Lighting | RPP | 150 | 1 | $30.29 | $30.97 | $0.67 | 2.23% |
| 24 | Street Lighting | Non-RPP | 150 | 1 | $30.26 | $28.85 | -$1.41 | -4.66% |
| **25** | **Newbury** | | | | | | | |
| 26 | Residential | RPP | 800 | - | $145.03 | $139.67 | -$5.36 | -3.69% |
| 27 | General Service < 50 kW | RPP | 2,000 | - | $347.89 | $327.06 | -$20.83 | -5.99% |
| 28 | General Service > 50 - 4,999 kW | Non-RPP | 162,500 | 500 | $25,258.36 | $24,790.16 | -$468.20 | -1.85% |
| 29 | Street Lighting | Non-RPP | 150 | 1 | $31.14 | $27.84 | -$3.30 | -10.59% |

As discussed in Exhibit 8, Section 8.13 (see Attachment 8-G), EPI performed a detailed analysis of proposed bill impacts, both from a summary level and a discrete customer group level. The starting point for this analysis was the current rate classes for each of EPI's rate zones (the names of these current rate classes are shown in the Rate Class Column of Table 1-19 above). Each existing rate class was then compared to the corresponding proposed harmonized rate class, which were then analyzed according to various kWh and kW assumptions. These assumptions are representative of discrete customer groups, and are shown below by rate class:

- Residential (kWh): 100, 250, 500, 800, 1000, 1500, 2000
- GS<50 kW (kWh): 1000, 2000, 5000, 10000, 15000

- GS>50 kW (kW): 60, 100, 500, 1000
- Large User (kW): 5500, 7200
- Street Lighting (kW): 1
- Sentinel Lighting (kW): 1
- USL (kWh): 150
- Embedded Distributor (kWh): 368,500

Based on this analysis, EPI notes that the majority of the proposed bill impacts at a discrete customer group level are decreasing (i.e. more favourable to customers), and that no discrete customer group exceeds the 10% overall bill impact threshold, except for SMP Street Lights, which are addressed in Exhibit 8, Section 8.14.

As described in Section 1.5.3 above, EPI customer engagement consultations included feedback on the preliminary estimated bill impacts for this Application. In general, the bill impacts at the time of that the consultation was conducted were higher (i.e. less favourable to customers) in comparison to those shown in Table 1-19 above. The resulting generalizable survey results from the INNOVATIVE telephone surveys showed that 74% of residential customers accepted EPI's proposed rate increase, while 75% of general service customers accepted the proposed rate increase. Additional detail on social permission regarding the rate proposal is shown in Table 1-8 of Section 1.5.3 above.

Taking this all into account, EPI submits that the bill impacts of its proposed 2016 distribution rates are reasonable and do not require rate mitigation, beyond the proposed mitigation plan for the SMP Large Use customer described in Section 1.6.7 above.

# 1.7 Financial Information

## 1.7.1 Audited Financial Statements

Copies of EPI's 2013 and 2014 Audited Financial Statements are provided in Attachment 1-L.

## 1.7.2 Reconciliation Between Audited Financial Statements and Regulatory Accounting

Reconciliations of EPI's Audited Financial Statements to the annual RRR Trial Balance for 2012, 2013 and 2014 are provided as Attachment 1-M.

EPI has a limited amount of non-utility services, including Conservation & Demand Management, and some Renewable Generation (a 10 kW solar array and 50% ownership in a 250 kW biogas facility). For more details regarding the non-utility services see Exhibit 3, Section 3.4 regarding Other Revenue.

## 1.7.3 Annual Report

Neither EPI, nor its parent company, Entegrus Inc., issues an Annual Report.

## 1.7.4 Rating Agency Report

The June 2, 2015, Standard & Poor's rating agency report on EPI's parent company, Entegrus Inc., accompanies this application as Attachment 1-N.

## 1.7.5 Prospectuses or Information Circulars

EPI has no past or planned prospectuses, information circulars, or other similar documents.

## 1.7.6 Changes in Tax Status

EPI is a corporation incorporated pursuant to the Ontario *Business Corporations Act* and has not had a change in tax status since its last Cost of Service Application.

### 1.7.7 STATEMENT OF ACCOUNTING STANDARD USED

#### EXISTING/PROPOSED ACCOUNTING ORDERS

The Accounting Standards Board ("AcSB") deferred mandatory adoption of IFRS for qualifying rate regulated entities to January 1, 2015. However, per the Board's letter of July 17, 2012, electricity distributors electing to remain on CGAAP were required to implement regulatory accounting changes for depreciation and capitalization policies by January 1, 2013.

EPI confirms that it implemented the regulatory accounting changes for depreciation and overhead capitalization in 2013. EPI has prepared this Application on an MIFRS accounting basis, as required.

EPI has no further existing or proposed accounting orders.

#### ACCOUNTING STANDARD USED IN APPLICATION

In accordance with the Filing Requirements, EPI has provided information for the historic years using the CGAAP method of presentation. As directed by the Board, EPI has provided the 2013 to 2016 Years on both a CGAAP basis and a MIFRS basis, this can be found in Exhibit 9.

EPI has made the required changes to the capitalization policy, including overhead costs. Details with respect to these changes are provided in Exhibit 2. Details with respect to the new useful lives applied to capital assets and the resulting impact on depreciation, are provided in Exhibit 4.

EPI is also required to make changes related to employee future benefits upon adoption of IFRS since under IAS 19, the deferral and amortization of actuarial gains/losses has been eliminated. Please refer to Section 4.4 for more information.

EPI has presented the impact on the 2016 Revenue Requirement related to these depreciation and capitalization changes in Board Appendix 2-Y, which is shown below as Table 1-20 and is included in Attachment 1-P. This table is in the format of the Board's Appendix 2-Y.

**TABLE 1-20: APPENDIX 2-Y – SUMMARY OF IMPACTS TO REVENUE REQUIREMENT FROM TRANSITION TO MIFRS**

| Revenue Requirement Component | 2016 MIFRS | 2016 CGAAP without policy changes | Difference | Reasons why the revenue requirement component is different under |
|---|---|---|---|---|
| Closing NBV 2015 | $ 74,926,228 | $ 71,340,808 | $ 3,585,420 | Depreciation - decrease in depreciation expense under MIFRS; Capitalization - decrease in capital under MIFRS |
| Closing NBV 2016 | $ 78,351,864 | $ 73,516,117 | $ 4,835,747 | Depreciation - decrease in depreciation expense under MIFRS; Capitalization - decrease in capital under MIFRS |
| Average NBV | $ 76,639,046 | $ 72,428,463 | $ 4,210,583 | |
| Working Capital | $ 9,917,527 | $ 9,866,856 | $ 50,671 | Capitalization - increase in OM&A under MIFRS |
| Rate Base | $ 86,556,573 | $ 82,295,318 | $ 4,261,255 | |
| | | | | |
| **Return on Rate Base** | $ 5,606,789 | $ 5,330,659 | $ 276,129 | Impact of above-noted changes to capitalization and depreciation policies |
| | | | $ - | |
| OM&A | $ 9,495,813 | $ 8,879,372 | $ 616,441 | Capitalization - increase in OM&A under MIFRS |
| Depreciation | $ 3,849,791 | $ 5,716,559 | $ (1,866,768) | Depreciation - decrease in depreciation expense under MIFRS |
| PILs or Income Taxes | $ 159,910 | $ 724,256 | $ (564,346) | Depreciation - increase in Schedule 1 addback under CGAAP; Capitalization - increase CCA for higher capital under CGAAP |
| Property Taxes | $ 243,162 | $ 243,162 | $ - | |
| Other Expenses | $ 23,040 | $ 23,040 | $ - | |
| | | | $ - | |
| Less: Revenue Offsets | $ (1,188,521) | $ (1,188,521) | $ - | |
| | | | $ - | |
| | | | $ - | |
| | | | $ - | |
| **Total Base Revenue Requirement** | $ 18,189,984 | $ 19,728,528 | $ (1,538,544) | |

## 1.7.8 NON-UTILITY BUSINESS ACCOUNTING

EPI engages in water billing, street light maintenance and a limited amount of renewable generation activities (the latter since 2011). EPI confirms that accounting for these activities was segregated from EPI's rate regulated activities in accordance with the Board's Guidelines: Regulation and Accounting Treatments for Distributor-Owned Generation Facilities G-2009-0300 dated September 15, 2009.

Further, EPI is engaged in the delivery of the Ontario Power Authority's CDM programs. The accounting for these activities is segregated from EPI's rate regulated activities in accordance with the Board's Accounting Procedures Handbook for Electricity Distributors.

## 1.8 MATERIALITY THRESHOLD

Chapter 2 of the Filing Requirements issued by the Board on July 16, 2015 sets out the materiality levels based on the magnitude of the revenue requirement. EPI's revenue requirement is greater than $10 million and less than $200 million, therefore its materiality level is 0.5% of distribution revenue requirement. EPI's materiality threshold for the 2016 Test Year is $90,620 as provided in Table 1-21 below. EPI has used a threshold of $90,000 for assessing materiality for the purposes of this Application.

TABLE 1-21: EPI'S MATERIALITY THRESHOLD FOR THE 2016 TEST YEAR

| Description | 2016 Test Year |
|---|---|
| Distribution Revenue Requirement | $ 18,189,984 |
| Materiality Threshold | 0.5% |
| Materiality Calculated | $ 90,950 |
| Materiality Used | $ 90,000 |

# 1.9 Administrative

## 1.9.1 Table of Contents

The Table of Contents has been included on page 2 of this Exhibit.

## 1.9.2 Contact Information

**The Applicant's Address for Service:**

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### 1.9.3 Legal Representation

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### 1.9.4 Internet Address & Social Media

The Application and related materials will be posted on the EPI website, and will be available for viewing at the following internet address: http://www.entegrus.com/regulatory. The Application will further be communicated to customers and media via Facebook and Twitter. In addition, various aspects of the application are explained in videos on the EPI YouTube channel. EPI social media channel addresses are as follows:

www.facebook.com/entegrus

www.twitter.com/entegrus

www.youtube.com/entegrus

The Application will also be available on the Board's website at www.ontarioenergyboard.ca, under Board File Number EB-2015-0061.

### 1.9.5 Affected Customers & Publication

Residents, businesses and institutions in the EPI service territory described above who receive electricity distribution services from EPI will be affected by the Application.

EPI proposes to publish the Notice of Application in the primary publications for both Chatham and Strathroy in order to reach the affected customers. EPI considers these primary publications to be:

- The Chatham Daily News, a paid publication serving the Chatham-Kent communities with an average circulation of approximately 7,000 per day; and,
- The Strathroy Age Dispatch, a paid weekly publication serving the Strathroy, Mount Brydges, Parkhill, Dutton and Newbury communities.

### 1.9.6 Bill Impacts for Publication

As noted in Section 1.9.6 above, in order to reflect EPI's current four rate zones and depict the impacts of the rate harmonization proposed in this Application, EPI has created customized models for bill impacts (Exhibit 8).

In order to provide bill impacts for publication, EPI has performed additional calculations using the methodology of Sub-Total A of the Board's Appendix 2-W for each of its current four rate zones. This methodology isolates the distribution impact of the proposed rate changes, excluding commodity and losses. These calculations, in their standard form, are shown on lines 2 and 3 (for CK and SMP) and lines 11 and 12 (for Dutton and Newbury) of Table 1-22 below. The table also includes two alternative bill impact views that are described below.

### Table 1-22: Bill Impacts for Publication - Alternatives

| Line No. | Consumption | Type | Chatham-Kent | | | | Strathroy, Parkhill & Mt. Brydges | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | 2015 Final Rates by Rate Zone | 2016 Proposed Rates Combined | $ Increase (Decrease) | % Increase (Decrease) | 2015 Final Rates by Rate Zone | 2016 Proposed Rates Combined | $ Increase (Decrease) | % Increase (Decrease) |
| **1** | **Alternative A: Sub-total A of Appendix 2-W Basis** | | | | | | | | | |
| 2 | Residential (@ 800 kWh) | RPP | $26.30 | $25.00 | -$1.30 | -4.94% | $28.49 | $25.00 | -$3.49 | -12.25% |
| 3 | GS < 50 (@ 2,000 kWh) | RPP | $67.05 | $44.41 | -$22.64 | -33.77% | $39.96 | $44.41 | $4.45 | 11.14% |
| **4** | **Alternative B: 'A' Above with Line Loss Impact Included** | | | | | | | | | |
| 5 | Residential (@ 800 kWh) | RPP | $29.80 | $28.52 | -$1.28 | -4.28% | $33.46 | $28.52 | -$4.94 | -14.75% |
| 6 | GS < 50 (@ 2,000 kWh) | RPP | $75.79 | $53.21 | -$22.58 | -29.79% | $52.38 | $53.21 | $0.83 | 1.59% |
| **7** | **Alternative C: Overall Basis (consistent with Table 1-19)** | | | | | | | | | |
| 8 | Residential (@ 800 kWh) | RPP | $137.72 | $137.72 | $0.00 | 0.00% | $140.96 | $137.72 | -$3.25 | -2.30% |
| 9 | GS < 50 (@ 2,000 kWh) | RPP | $342.08 | $322.38 | -$19.70 | -5.76% | $316.43 | $322.38 | $5.95 | 1.88% |

| Line No. | Consumption | Type | Dutton | | | | Newbury | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | 2015 Final Rates by Rate Zone | 2016 Proposed Rates Combined | $ Increase (Decrease) | % Increase (Decrease) | 2015 Final Rates by Rate Zone | 2016 Proposed Rates Combined | $ Increase (Decrease) | % Increase (Decrease) |
| **10** | **Alternative A: Sub-total A of Appendix 2-W Basis** | | | | | | | | | |
| 11 | Residential (@ 800 kWh) | RPP | $27.13 | $25.00 | -$2.13 | -7.85% | $25.77 | $25.00 | -$0.77 | -2.99% |
| 12 | GS < 50 (@ 2,000 kWh) | RPP | $45.70 | $44.41 | -$1.29 | -2.82% | $50.01 | $44.41 | -$5.60 | -11.20% |
| **13** | **Alternative B: 'A' Above with Line Loss Impact Included** | | | | | | | | | |
| 14 | Residential (@ 800 kWh) | RPP | $32.54 | $28.52 | -$4.02 | -12.35% | $30.51 | $28.52 | -$1.99 | -6.51% |
| 15 | GS < 50 (@ 2,000 kWh) | RPP | $59.22 | $53.21 | -$6.01 | -10.15% | $61.86 | $53.21 | -$8.64 | -13.97% |
| **16** | **Alternative C: Overall Basis (consistent with Table 1-19)** | | | | | | | | | |
| 17 | Residential (@ 800 kWh) | RPP | $142.11 | $138.04 | -$4.07 | -2.86% | $145.03 | $139.59 | -$5.44 | -3.75% |
| 18 | GS < 50 (@ 2,000 kWh) | RPP | $328.59 | $323.19 | -$5.40 | -1.64% | $347.89 | $327.06 | -$20.83 | -5.99% |

In terms of Alternative A, the highlighted standard calculation on line 2 and line 3 above shows an increase of approximately 11% for the SMP GS < 50 kW rate class. EPI believes that publishing a proposed 11% distribution rate increase for this rate class may be unintentionally misleading to a publication reader, since this percentage does not incorporate the proposed loss benefit that SMP GS < 50 kW (and other) customers would realize from the Application.

As noted in Section 1.6.7 above, the line loss factors proposed in this Application represent a substantial improvement for SMP, Dutton and Newbury customers. Alternative B, shown on Lines 5 and 6 (for CK and SMP) and lines 14 and 15 (for Dutton and Newbury), adjusts the calculation to include the proposed loss factors. For the SMP GS<50 kW rate class, Alternative B results in an increase of approximately 2%, instead of the 11% increase shown under Alternative A.

EPI has also included the total bill impact on an overall basis as Alternative C above. This is shown on lines 8 and 9 (for CK and SMP) and lines 17 and 18 (for Dutton and Newbury).

EPI submits that Alternative B should be used as the basis of bill impacts for publication.

### 1.9.7 Form of Hearing

The majority of bill impacts resulting from this Application are flat or decreasing, as shown in Section 1.6.9 above. Accordingly, EPI requests that this Application be disposed of by way of a written hearing in order to expedite the proceeding.

### 1.9.8 Effective Date

EPI requests that the Board make its Rate Order effective May 1, 2016 in accordance with the Filing Requirements.

In the event that the Board is unable to provide a Decision and Order in this application for implementation by the Applicant as of May 1, 2016, the Applicant requests that the Board declare its current rates interim, effective May 1, 2016, pending the implementation of the Board's Rate Order for the 2016 rate year.

### 1.9.9 Approvals Requested

In this proceeding, EPI is requesting the following approvals:

1. Approval to charge distribution rates effective May 1, 2016 to recover a service revenue requirement of $19,429,174 which includes a Revenue Deficiency of $155,997 as detailed in Exhibit 6. The schedule of proposed rates is set out in Exhibit 8.

2. Approval of the DSP as outlined in Exhibit 2, Attachment 2-D.

3. Approval to harmonize the four existing EPI rate zones into one common EPI tariff sheet, effective May 1, 2016, including harmonized disposition of all DVAs as of May 1, 2016, as explained in Exhibit 9, Section 9.3.

4. Approval of revised Low Voltage rates as proposed and described in Exhibit 8.

5. Approval to adjust the Retail Transmission Rates – Network and Connection as detailed in Exhibit 8.

6. Approval to continue to charge Wholesale Market and Rural Rate Protection Charges approved in the Board Decision and Order in the matter of EPI's 2015 Distribution Rates (EB-2014-0064).

7. Approval to continue the Specific Service Charges and Transformer Allowance approved in the Board Decision and Order in the matter of EPI's 2015 Distribution Rates (EB-2014-0064).

8. Approval of the proposed loss factors as detailed in Exhibit 8.

9. Approval of the rate riders for a one year disposition of the Group 1 and Group 2 and Other Deferral and Variance Accounts as detailed in Exhibit 9.

10. Approval of the rate riders for a two year period to dispose of the difference in 2015 Net Book Value of Property, Plant and Equipment, as a result of EPI's changes to depreciation rates and capitalization policy recorded in Account 1576, CGAAP Accounting Changes as explained in Exhibit 9.

11. Approval of the rate riders for a one year disposition of the Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") and Lost Revenue Adjustment Mechanism ("LRAM") for lost revenue as follows:

    - CK Hydro Rate Zone: LRAMVA for the 2011-2014 program years, with persistence from January 1, 2014 to December 31, 2014.
    - MPDC Rate Zone: LRAM for the 2006-2010 program years, with persistence from January 1, 2014 to December 31, 2014.
    - MPDC Rate Zone: LRAMVA for the 2011-2014 program years, with persistence from January 1, 2014 to December 31, 2014.

Previous LRAMVA and LRAM claims, up to an including December 31, 2013, have been claimed in previous applications. For additional information, please refer to Exhibit 4. Approval of the rate riders to address the recovery of stranded meters over a one year period as outlined in Exhibit 2.

12. Approval to charge HONI, an Embedded Distributor, as per the rates proposed in Exhibit 7. HONI has been consulted and supports the proposed rates.

13. Approval of the rate mitigation plan described in Exhibit 8 for the former sole SMP Large Use customer.

EPI may request such other approvals as counsel for EPI may submit and the Board may allow.

### 1.9.10 Deviations from Filing Requirements

EPI has not, to the best of its knowledge, deviated from the final Board's Filing Requirements for Electricity Distribution Rate Applications.

As a result of the acquisitions, mergers and organizational evolution of EPI (which are more fully described below), for the purposes of this Application, EPI has developed 2010 Board-Approved Proxy Figures. This approach recognizes that the previous EPI rebasing application (the 2010 Chatham-Kent Hydro application, EB-2009-0261) reflected what now comprises only a portion of EPI. This Proxy approach is further described throughout the respective Application Exhibits.

Further, in order to reflect EPI's current four rate zones and depict the impacts of the rate harmonization proposed in this Application, EPI has created a custom bill impact model (see Exhibit 8) and DVA disposition (see Exhibit 9).

### 1.9.11 Methodology Changes

The pro-forma projections for the 2016 Test Year have been prepared in accordance with EPI's usual process (including the use of MIFRS accounting), with the following exceptions:

- Rates for distribution and sales of electricity are assumed to be constant for the entire 2016 Test Year; and,
- Regulatory costs have been normalized over the five year application period.

### 1.9.12 Board Directives

EPI has not received any other utility-specific directions from the Board since submitting its last Cost of Service application (EB-2009-0261) for May 1, 2010 distribution rates, and nor have the other predecessor distributors that now constitute EPI, and no such directions are outstanding presently.

### 1.9.13 Conditions of Service

The current version of EPI's Conditions of Service is available on EPI's website at http://www.entegrus.ca/conditions-service

Rates and charges which are the subject of this rate Application are not contained in the Conditions of Service.

# 1.10 Corporate Governance

## 1.10.1 Corporate and Utility Organizational Structure

Entegrus Inc., incorporated September 22, 2000 (originally as Chatham-Kent Energy Inc.) under the Business Corporation Act (Ontario), is the parent holding company of EPI. The Municipality of Chatham-Kent (the "Muni") holds 90% of the shares of Entegrus Inc. and Corix holds the remaining 10%.

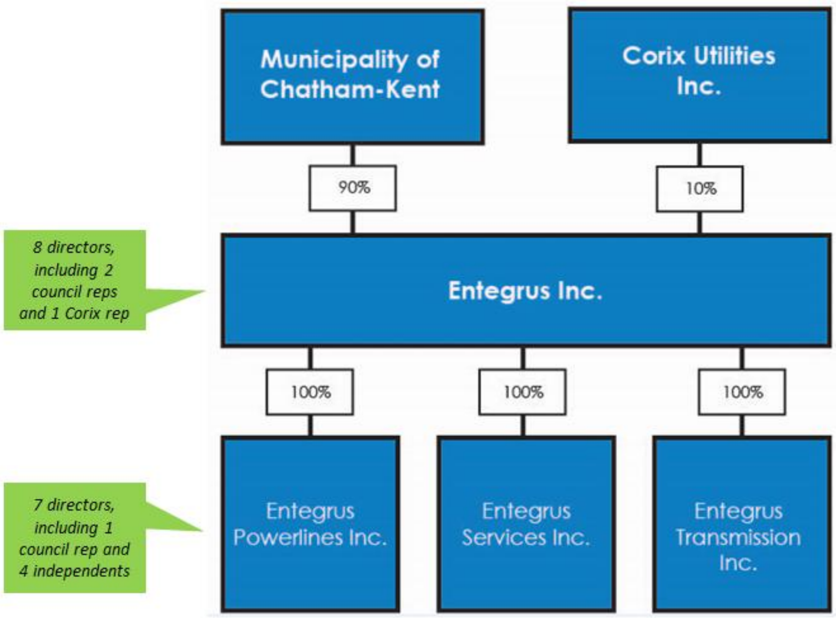
Corix is a privately held Canadian corporation principally owned by British Columbia Investment Management Corporation and the Corix executive management team. Corix is a British Columbia company and is extra-provincially registered in Alberta, Saskatchewan, Manitoba, Ontario and Quebec. Corix specializes in providing products and utility solutions for sustainable infrastructure in the water, wastewater and energy sectors for clients across North America. It has over 1,800 employees in 60 locations across North America.

Corix has the right to appoint one director to the Board of Directors of Entegrus Inc. Should Corix increase its non-equity interest in Entegrus Inc., Corix would then have the right to appoint one additional Director. The Muni has the right to appoint the remaining Directors of Entegrus Inc., which may include the appointment of up to two (2) two Municipal Council representatives.

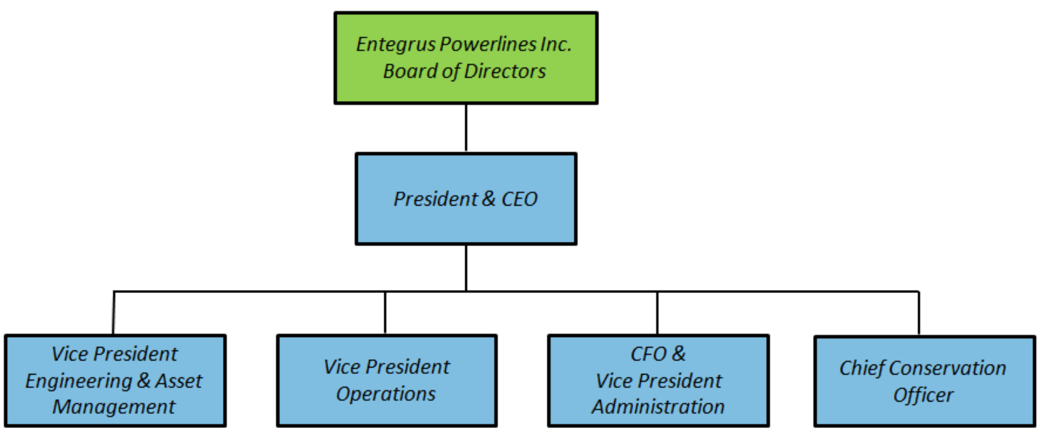
The EPI Directors are appointed by the Board of Directors of Entegrus Inc. There has always been one (1) Director on the EPI Board who also serves as a Muni Council representative on the Entegrus Inc. Board, although it is not a requirement. A corporate entities relationship chart is shown below as Chart 1-3. Further, Chart 1-4 shows a high level organizational chart.

Entegrus Inc. and EPI are not planning on any changes to its corporate or operational structure at this time.

### CHART 1-3: CORPORATE ENTITIES RELATIONSHIP CHART




### CHART 1-4: EPI HIGH LEVEL ORGANIZATIONAL CHART



### 1.10.2 Board of Directors and Independence

The Entegrus Inc. Board of Directors consists of eight (8) Directors, while the EPI Board of Directors consists of seven (7) Directors. The respective Board of Directors manages the respective business affairs of Entegrus Inc. and EPI, and each Board of Directors is responsible for overseeing and monitoring all significant aspects of the management of the business and affairs of the corresponding corporations.

Four of the seven EPI Directors are independent, in accordance with the Ontario Energy Board requirement and EPI policy that one third of Directors be independent. In practice, EPI has ensured the facilitation of independent judgment by having a higher percentage of independent Board members who are strong professionals. Further, it has been a practice that the Muni Council representative on the EPI Board is never the chair of the Board or any of its committees. Figure 1-1 above further describes the composition and independence of Directors.

Additional independence is facilitated by the involvement of the minority shareholder (Corix) at the Entegrus Inc. board level.

### 1.10.3 Board Mandate

The most recent version of the EPI Board of Directors Mandate and Charter is shown as Attachment 1-O. This document contains appendices which include the Board Orientation Process and Code of Conduct.

### 1.10.4 Board Meetings

Annually, the Board of Directors establishes a schedule of meetings for the upcoming fiscal year. The 2015 schedule is summarized as follows:

- February 9, 2015
- April 24, 2015
- June 19, 2015
- September 10, 2015

- September 11, 2015
- October 30, 2015
- November 20, 2015

In addition, the EPI Board of Directors has three Committees which hold separate meetings throughout the year, as further described below under Section 1.10.8. The Board may also hold additional ad hoc meetings as required.

### 1.10.5 Orientation and Continuing Education

EPI believes in the importance of Directors having the opportunity to take part in professional development to enhance their skills and knowledge, in order to assist in providing good oversight.

EPI provides new Directors with an orientation program that includes providing a Board Orientation / Onboarding Manual, which includes: organizational charts, Board and committee charters, the Shareholder Agreement, the EPI Mission, Vision and Values, the Business Plan, the latest AGM report, regulatory environment information and background on the other Directors and senior management.

The President and CEO and the other executives facilitate an orientation meeting with new Directors in order to review the Board Orientation / Onboarding Manual, which includes:

- Review of the background and evolution of EPI;
- Review of the EPI mission, vision and core values;
- Review of the Ontario regulatory framework and current industry issues;
- Review of biographical information on other Directors and key personnel, including introductions as appropriate; and,
- A tour of the EPI facilities.

Additional details on the orientation process are included as Appendix A to the EPI Board of Directors Mandate and Charter, which accompanies this Application as Attachment 1-O, and in The Board of Directors Education and Training Policy, shown herein as Attachment 1-O.

Role descriptions for Directors are provided in Attachment 1-O.

Further, a small budget is established for the continuing education of Directors. Directors may request additional Director Education and Training funding with approval by the Board of Directors.

Recent examples of Director continuing education include:

- An Entegrus Inc. Director (and Audit Committee Chair) and the President & CEO received their Chartered Director designations from the Directors College (a joint venture between the DeGroote School of Business and the Conference Board of Canada) in March 2015

- An EPI Director (and Audit Committee Member) and the CFO attended the Audit Committee Program at the Directors College in May 2015

### 1.10.6 Code of Conduct

The Board of Directors of Entegrus Inc. has adopted a written Code of Conduct for Directors that applies to Entegrus Inc. and EPI. The Code of Conduct is Appendix B to the EPI Board of Directors Mandate and Charter, included in Attachment 1-O.

The Board is a self-monitoring body that is accountable to the shareholder. Any infractions would be dealt with by the Chair.

### 1.10.7 Nomination of Directors

The Governance and Compensation Committee is responsible for the recruitment of new directors, including advertisement, interview and recommendation of nominees to the Board of Directors for approval.

In 2014, Entegrus Inc. engaged a national consulting firm to conduct a survey of Entegrus Inc. and EPI Board members, in order to assess competencies and provide a gap analysis. Subsequently, a second consulting firm was retained to assist the Governance and Compensation Committee in screening and evaluation of new Board members. This process led to the appointment of three new Directors in 2014 that bring complimentary skill sets to the EPI Board.

### 1.10.8 Board Committees

The Entegrus Inc. Board of Directors established three Board Committees relating to governance of Entegrus Inc. and EPI. These Board Committees, along with their 2015 meetings dates, are as follows:

- Governance & Compensation Committee: Mar 19, Mar 26, Jun 22, Dec 16
- Environmental Health & Safety Committee: Jan 30, Apr 2, Jun 5, Sep 4, Nov 19
- Audit Committee: Mar 25, Jun 4, Nov 6

The above-noted Board Committee meetings are separate and distinct from the recurring Board Meetings described in Section 1.10.4 above.

Board Committee member appointments are made from Directors on both Entegrus Inc. Board and the EPI Board. The members of the Audit Committee are required to be financially literate. Currently, three of the four Audit Committee members hold CPA designations.

The Board Committees have the authority to engage external experts to assist the Directors in conducting their fiduciary duty, subject to approval by the Board of Directors.

The Charters for each of the above-described Board Committees are shown in Attachment 1-O and Attachment 1-O.

## 1.11 Letters of Comment

As of the date of filing this Application, no letters of comment have been received.

EPI will file all responses to matters raised in letters of comment filed with the Board during the course of the proceeding in this Exhibit 1, in accordance with Section 2.4.9 of the Filing Requirement.

# ATTACHMENT 1-A

## Certification of Evidence

**Entegrus Powerlines Inc.**
320 Queen St. (P.O. Box 70)
Chatham, ON N7M 5K2
Phone: (519) 352-6300
Toll Free: 1-866-804-7325
entegrus.com

# Certification of Evidence

As President & CEO of Entegrus Powerlines Inc., I certify that the evidence filed in this Application is accurate, consistent and complete to the best of my knowledge and belief.

**Jim Hogan**
President & CEO
Entegrus Powerlines Inc.

# ATTACHMENT 1-B

## 2016 Cost of Service

## Filing Checklist

# 2016 Cost of Service Checklist

## Entegrus Powerlines Inc.

## EB-2015-0061

**Date:** August 28, 2015

| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| **GENERAL** | | | |
| Ch 1 p4 & 5 | Confidential Information - Practice Direction has been followed | N/A | No confidential information as filed |
| 2 | Chapter 2 appendices in live Microsoft Excel format | Yes | |
| 4 | Text searchable and bookmarked PDF documents | Yes | |
| RESS Guideline | Two hardcopies of application sent to OEB the same day as electronic filing (p10 of RESS Guideline) | Yes | |
| **EXHIBIT 1 - ADMINISTRATIVE DOCUMENTS** | | | |
| *Management Discussion and Analysis* | | | |
| 9 | Plain language description of objectives and business plan and how they relate to the application and the RRFE objectives. Description of how customer feedback is reflected. | Yes | Section 1.4 |
| *Executive Summary* | | | |
| 10 | Revenue Requirement - service RR, change from previously approved, main drivers | Yes | Section 1.6 |
| 10 | Budgeting Assumptions - economic overview and identification of accounting standard used for test year and brief explanation of impacts arising from any change in standards | Yes | Section 1.6.2 |
| 10 | Load Forecast Summary - load and customer growth, change in kWh and customer numbers, methodology description | Yes | Section 1.6.3 |
| 10 & 11 | Rate Base and Capital Plan - major drivers of DSP, rate base for test year, change from last approved, capex for test year, change from last approved, costs for any REG-related, smart grid, regional planning projects, any O.Reg 339/09 planned recovery | Yes | Section 1.6.4 |
| 11 | OM&A for test year and change from last approved, summary of drivers, inflation assumed, total compensation for test year and change from last approved. | Yes | Section 1.6.5 |
| 11 | Statement regarding use of OEB's cost of capital parameters; summary of any deviations | Yes | Section 1.6.6 |
| 11 | Cost Allocation & Rate Design - summary of any deviations from OEB methodologies, significant changes and summary of proposed mitigation plans | Yes | Section 1.6.7 |
| 11 | Deferral and Variance Accounts - total disposition (RPP and non-RPP), disposition period, new accounts requested | Yes | Section 1.6.8 |
| 10 & 11 & 59 | Bill Impacts - total impacts ($ and %)for all classes for typical customers; all proposed changes that will have material impact on customers or discrete customer groups | Yes | Section 1.6.9 |
| *Customer Engagement* | | | |
| 12 | Overview of customer engagement activities; description of plans and how customer needs have been reflected in the application. | Yes | Section 1.5 |
| 12 | Discuss how customers were informed of the proposals being considered for inclusion in the application and the value of those proposals to customers i.e. costs, benefits, and the impact on rates | Yes | Sections 1.5.2, 1.5.3 and 1.5.4 |
| 12 | Discuss any feedback provided by customers and how the feedback shaped the final application | Yes | Section 1.5.5 |
| 12 | Reference any other communication sent to customers about the application i.e. bill inserts, town hall meetings or other forms of out reach and the feedback received from customers through these engagement activities | Yes | Section 1.5.3 and Attachment 1-K |
| 12 | Complete Appendix 2-AC Customer Engagement Activities Summary - identify how outcomes have shaped the application | Yes | Section 1.5 and Attachment 1-G |
| *Financial Information* | | | |
| 12 & 42 | Non-consolidated Audited Financial Statements for 2 most recent years (i.e. 3 years of historical actuals) | Yes | Section 1.7.1 and Attachment 1-L |
| 12 & 13 | Detailed reconciliation of AFS with regulatory financial results filed in the application, with identification of any deviations that are being proposed | Yes | Section 1.7.2 and Attachment 1-M |
| 13 | Annual Report and MD&A for most recent year of parent company, if applicable | N/A | Confirmed that there are none in Section 1.7.3 |
| 13 | Rating Agency Reports, if available; Prospectuses, etc. for recent and planned public issuances | Yes | Section 1.7.4 and Attachment 1-N |
| 13 | Any change in tax status | N/A | Confirmed that there are no changes in Section 1.7.6 |
| 13 | Existing accounting orders and departures from USoA including references to the accounting orders | Yes | Section 1.7.7 |
| 13 | Accounting Standards used for financial statements and when adopted | Yes | Section 1.7.7 |
| 2 & 13 | Confirmation that accounting treatment of any non-utility business has segregated activities from rate regulated activities | Yes | Section 1.7.8 |
| *Accounting Standards and Modified IFRS Applications* | | | |
| 6 | State accounting standard(s) used in historical, bridge and test years | Yes | Section 1.7.7 |
| 6 | Summary of changes to accounting policies and quantification of revenue requirement impact (Appendix 2-Y) | Yes | Section 1.7.7 |
| 7 | Identify all material changes, quantify and explain the changes in the adoption of IFRS, if none state that and explain why it would not be material | Yes | Section 1.6.1 and Section 1.7.7. |

# 2016 Cost of Service Checklist

## Entegrus Powerlines Inc.

## EB-2015-0061

**Date: August 28, 2015**

| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| *Materiality Thresholds* | | | |
| 13 & 14 | Materiality threshold; additional details beyond the threshold if necessary | Yes | Section 1.8 |
| *Administration* | | | |
| Ch 1 p4 | Certification by senior officer that evidence is accurate, consistent and complete | Yes | Section 1.1.1 and Attachment 1-A |
| 14 | Table of Contents | Yes | Table of Contents |
| 14 | Primary contact information (name, address, phone, fax, email) | Yes | Section 1.9.2 |
| 14 | Identification of legal (or other) representation | Yes | Section 1.9.3 |
| 14 | Applicant's internet address for viewing of application and any social media accounts used by the applicant to communicate with customers | Yes | Section 1.9.4 |
| 14 | Statement identifying customers materially affected by the application | Yes | Section 1.9.5 |
| 14 | Statement identifying where notice should be published and why | Yes | Section 1.9.5 |
| 14 | Bill impacts - distribution only impacts for 800 kWh residential and 2000 kWh GS<50 (sub-total A of Appendix 2-W) to be used for notice | Yes | Section 1.9.6 |
| 15 | Form of hearing requested and why | Yes | Section 1.9.7 |
| 15 | Requested effective date | Yes | Section 1.9.8 |
| 15 | List of approvals requested (and relevant section of legislation), including accounting orders | Yes | Section 1.9.9 |
| 3 | In advance of scheduled application - meet threshold established in OEB letter (April 20, 2010) | N/A | EPI's filing is as scheduled |
| 3 | Aligning rate year with fiscal year - request for proposed alignment | N/A | Remaining on May 1 rate year |
| 2 & 15 | Statement identifying all deviations from Filing Requirements; identify concerns with models or changes to models | Yes | Section 1.9.10 |
| 15 | Statement identifying and describing any changes to methodologies used vs previous applications | Yes | Section 1.9.11 |
| 15 | Identification of OEB Directives from previous OEB Decisions, and how addressed | Yes | Section 1.9.12 |
| 15 | Reference to Conditions of Service - LDC does not need to file Conditions of Service, but must provide reference to website and confirm version is current; identify if there are changes to Conditions of Service (a) since last CoS application or (b) as a result of the current application | Yes | Section 1.9.13 |
| 15 | Description of Service Area (including map, communities served) | Yes | Section 1.3.1 |
| 15 & 16 | Identification of embedded and/or host distributors; if partially embedded provide %load from host distributor | Yes | Section 1.3.2 |
| 16 | Statement as to whether or not the distributor has had any transmission or high voltage assets deemed by the OEB as distribution assets and whether or not there are any such assets the distributor is seeking approval for in this application | Yes | Section 1.3.3 |
| 16 & 17 | Corporate Governance: Description of corporate and utility organizational structure, corporate entities relationship chart; identify any planned changes<br>- Number of Directors on Board, number of independent directors, how independent judgement is facilitated<br>- Board Mandate; Schedule of Board Meetings<br>- Continuing Education for directors<br>- Identify whether Board has adopted written code for directors, officers and employees; provide written code, where available, and describe how compliance is monitored<br>- Process for Nomination of Directors<br>- Committees - function and charter for each committee<br>- Audit Committee - number of independent members, whether members are financially literate | Yes | Section 1.9.10 |
| 17 | Responses to matters raised in letters of comment filed | Yes | Section 1.10.11 |
| *Scorecard Performance Evaluation* | | | |
| 9 | Discussion of performance for each scorecard measure over last five years | Yes | Section 1.4.1 & 1.4.2 |
| 9 | Explain performance drivers, discuss continuous improvement plans, include targets, discuss how self-assessment has informed business plan and application | Yes | Section 1.4.2 |
| **EXHIBIT 2 - RATE BASE** | | | |
| *Overview* | | | |
| 18 | Completed Fixed Asset Continuity Schedule (Appendix 2-BA) | Yes | Attachment 2-A |
| 4 & 18 | Opening and closing balances, average of opening and closing balances for gross assets and accumulated depreciation; working capital allowance (historical actuals, bridge and test year forecast) | Yes | Section 2.1.1, Table 2-1 |

# 2016 Cost of Service Checklist
## Entegrus Powerlines Inc.
## EB-2015-0061

**Filing Requirement Page # Reference**

**Date: August 28, 2015**

| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| **18** | Continuity statements (year end balance, including interest during construction and overheads).<br>Explanation for any restatement (e.g. due to change in accounting standards)<br>Year over year variance analysis; explanation where variance greater than materiality threshold<br>Hist. OEB-Approved vs Hist. Actual<br>Hist. Act. vs. preceding Hist. Act.<br>Hist. Act. vs. Bridge<br>Bridge vs. Test | **Yes** | Section 2.1.3, Section 2.2.2 and Section 2.4.4 |
| **18 & 19** | Opening and closing balances of gross assets and accumulated depreciation must correspond to fixed asset continuity statements. If not, an explanation must be provided (e.g.. WIP, ARO). Reconciliation must be between YE 2015 and YE 2016 net book value balances reported on Appendix 2-BA and balances included in rate base calculation | **Yes** | |
| *Gross Assets - PP&E and Accumulated Depreciation* | | | |
| **19** | Breakdown by function and by major plant account; description of major plant items for test year | **Yes** | Section 2.2.1, Table 2-9 |
| **19** | Summary of approved and actual costs for any ICM(s) approved in previous IRM applications | **Yes** | Section 2.3 |
| **19 & 40** | Continuity statements must reconcile to calculated depreciation expenses and presented by asset account | **Yes** | Section 2.1.2 |
| *Allowance for Working Capital* | | | |
| **20** | Working Capital - 7.5% allowance or Lead/Lag Study or Previous OEB Direction | **Yes** | Attachment 2-B |
| **20** | Cost of Power must be determined by split between RPP and non-RPP customers based on actual data, use most current RPP (TOU) price, use current UTR. Should include SME charge. | **Yes** | Section 2.4.3 |
| **20** | Lead/Lag Study - leads and lags measured in days, dollar-weighted | **Yes** | Attachment 2-B |
| *Treatment of Stranded Assets Related to Smart Meter Deployment* | | | |
| **21 & 22** | Stranded Meters - if the recovery of stranded conventional meters replaced by smart meters has not been reviewed and approved, a proposal for a Stranded Meter Rate Rider must be made<br>Explanation for approaches that are not the OEB approach<br>Completed Appendix 2-S. | **Yes** | Section 2.5 |
| *Capital Expenditures/Planning* | | | |
| **23** | As applicable - file evidence that demonstrates that regional issues have been appropriately considered and where applicable addressed in developing the applicant's proposed capital expenditure plan. As part of its planning an applicant should consider municipal planning, including any plans for expansion of boundaries from a regional perspective to demonstrate the most cost effective solutions are being considered. | **Yes** | Section 2.6.1 |
| *Capital Expenditures/Distribution System Plan* | | | |
| **24** | DSP filed as a stand-alone document; a discrete element within Exhibit 2 | **Yes** | Attachment 2-D |
| **Ch 5 p9** | Where applicable, explanation for section headings other than Chapter 5 headings; cross reference table | **Yes** | Section 5.2 |
| **Ch 5 p9-10** | Distribution System Plan Overview - key elements, sources of cost savings, period covered, vintage of information on investment drivers, changes to asset management process since last DSP filing, dependencies | **Yes** | 5.1.2, 5.2.1.2, 5.2.1.4, 5.2.1.5, |
| **Ch 5 p10-11** | Coordinated Planning with 3rd parties - description of consultations<br>- deliverables of the Regional Planning Process, or status of deliverables<br>- OPA letter in relation to REG investments (Ch 5 p8&9) and Dx response letter | **Yes** | 5.2.2, 5.1.4, 5.1.4.1, 5.1.4.2, Appendix I & II |
| **Ch 5 p11** | Performance Measurement - identify and define methods and measures used to monitor DSP performance<br>- summary of performance and trends over historical period. Must include SAIFI and SAIDI for all interruptions and all interruptions excluding loss of supply<br>- explain how information has affected DSP | **Yes** | 5.2.3 |
| **Ch5 p12** | Asset Management Process Overview - description of AM objectives/corporate goals and how Dx ranks objectives for prioritizing investments | **Yes** | 5.3 |
| **Ch5 p12** | Inputs/Outputs of the AM process and information flow for investments; flowchart recommended | **Yes** | Figure 5.3-35 |
| **Ch 5 p13** | Overview of Assets Managed - description of service area (including evolution of features in forecast period affecting DSP),<br>- description of system configuration<br>- service profile and condition by asset type (tables and/or figures) - date data compiled<br>- assessment of degree the capacity of system assets is utilized | **Yes** | 5.3.2 |
| **Ch 5 p13-14** | Asset Lifecycle Optimization - description of asset lifecycle optimization policies and practices, including asset replacement and refurbishment, maintenance planning criteria and assumptions<br>- description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation | **Yes** | 5.3.3 |

# 2016 Cost of Service Checklist

## Entegrus Powerlines Inc.

## EB-2015-0061

**Filing Requirement Page # Reference**

**Date: August 28, 2015**

| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| **Ch 5 p14-15** | Capital Expenditure Plan Summary for significant projects and activities to be undertaken - capability to connect new load or Gx customers, total annual capex over forecast period by investment category, description of how AMP and Capex planning have affected capital expenditures for each category<br>- list, description and total capital cost of material capital expenditures sorted by category (table recommended)<br>- information related to Regional Planning Process (Needs Assessment Report, Regional Planning Status Letter, Regional Infrastructure Plan - as appropriate)<br>- description of customer engagement<br>- Dx expectations of system development over next 5 years<br>- list, description and total capital cost of projects planned in response to customer preferences, to take advantage of technology based opportunities, to study innovative processes (table recommended) | **Yes** | 5.4 |
| **Ch 5 p15** | Capital Expenditure Planning Process Overview - description of capex planning objectives/criteria/ assumptions, relationship with AM objectives, policy on consideration of non-distribution alternatives, processes used to identify projects in each investment category, customer feedback and impact on plan, method and criteria used to prioritise REG investments | **Yes** | 5.4.2 |
| **Ch 5 p16** | System Capability Assessment for REG - REG applications > 10 kW, number and MW of REG connections for forecast period, capacity of Dx to connect REG, connection constraints | **Yes** | 5.4.3 |
| **Ch 5 p16-18**<br>**Ch 2 p24** | Capital Expenditure Summary by Investment Category - completed Table 2 of Ch 5 for historical and forecast period, explanation of markedly different variances plan vs actual, explanation of markedly different variances year over year<br>Table 2 of Ch 5 is provided in Excel format in Appendix 2-AB (must provide actual totals for historical years, as a minimum) | **Yes** | 5.4.4 |
| **Ch5 p19** | Overall Plan - comparative expenditures by category over historical period, forecast impact of system investment on O&M, drivers of investments by category, information related to Dx system capability assessment | **Yes** | 5.4.5.1 |
| **Ch 5 p19-25** | Material Investments - For each project that meets materiality threshold set in Ch 2 p10<br>- general information - total capital, customer attachments, dates, risks, variances, REG investments<br>- evaluation criteria - may include: efficiency, customer value, reliability, etc.<br>- category specific requirements for each project - system access, system renewal, system service, general plant (as applicable) | **Yes** | Appendix VIII |
| **24** | Capital Expenditures - completed Appendix 2-AA showing capex on a project specific basis for 4 historical years, bridge and test; explanation of variances, accounting treatment for projects with life cycle greater than one year | **Yes** | Section 2.6.4, Attachment 2-F |
| **24** | Non-distribution activities - capital expenditures and reconciliation to total capital budget | **Yes** | Section 2.1.1 |
| **8 & 25** | Capitalization policy, changes to capitalization since previous rebasing - explanations must be provided. The changes must be identified and the causes of the changes must also be identified, e.g. changes to depreciation expense and capitalization policy in 2012 or 2013 per the OEB July 17, 2012 letter. | **Yes** | Section 2.5.3 |
| **25** | Capitalization of overhead - Completed Appendix 2-D regarding overhead costs on self-constructed assets<br>Burden rates must be identified; changes from last rebasing must be identified; LDC must identify burden rates prior to and after the change | **Yes** | Section 2.5.4 |
| *Costs of Eligible Investments for Connection of Qualifying Generation Facilities* | | | |
| **25** | For Eligible Investments - proposal to divide costs per O.Reg. 330/09 | **Yes** | Section 2.6.7 |
| **25** | Where applicable, file a draft accounting order to establish variance account tracking IESO payment revenues against actual spending | **N/A** | |
| **26** | As applicable Appendices 2-FA through 2-FC must be filed identifying eligible investments | **N/A** | |
| *New Policy Options for the Funding of Capital* | | | |
| **26** | Distributor may propose ACM capital project coming into service during Price Cap IR (a discrete project documented in DSP). Provide cost and materiality calculations to demonstrate ACM qualification | **Yes** | Section 2.6.8 |
| *Addition of ICM Assets to Rate Base* | | | |
| **27** | Distributor with previously approved ICM(s) - schedule of ICM amounts, variances and explanation | **Yes** | Section 2.6.9 |
| **27 & 28** | Balances in Account 1508 sub-accounts, reconciliation with proposed rate base amounts; recalculated revenue requirement should be compared with rate rider revenue | **N/A** | |
| *Service Quality and Reliability* | | | |
| **28** | 5 historical years of ESQRs, explanation for any under-performance vs standard and actions taken | **Yes** | Section 2.6.10 |
| **28** | 5 historical years of SAIDI and SAIFI - for all interruptions and all interruptions excluding loss of supply, explanation for any under-performance vs 5 year average and actions taken | **Yes** | Section 2.6.10 |
| **28** | Distributors may propose SAIDI and SAIFI benchmarks different than 5 year average; provide rationale | **N/A** | |
| **28** | Completed Appendix 2-G | **Yes** | Attachment 2-H |

# 2016 Cost of Service Checklist

## Entegrus Powerlines Inc.

## EB-2015-0061

**Date:** **August 28, 2015**

| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| **EXHIBIT 3 - OPERATING REVENUE** | | | |
| *Load and Revenue Forecasts* | | | |
| 28 | Customer, volume and revenue forecast methodologies and data | Yes | Section 3.2 |
| 29 | Explanation of causes, assumptions and adjustments for volume forecast. Economic assumptions and data sources for customer and load forecasts | Yes | Section 3.2.2 |
| 29 | Explanation of weather normalization methodology. | Yes | Section 3.2.2 |
| 29 | Completed Appendix 2-IA | Yes | Attachment 3-D |
| 29 & 30 | Multivariate Regression Model - rationale for choice, regression statistics, explanation for any unintuitive relationships, explanation of modeling approaches and alternative models tested, explanation of weather normalization methodology, sources of data for endogenous and exogenous variables, explanation of any constructed variables; data used in load forecast must be provided in Excel format, including derivation of constructed variables | Yes | Section 3.2 |
| 30 & 31 | NAC Model - rationale for choice, data supporting NAC variables, description of accounting for CDM including licence conditions, discussion of weather normalization considerations | N/A | |
| 29 & 31 | CDM Adjustment - account for CDM in 2016 load forecast. Consider impact of persistence of historical CDM and impact of new programs. Adjustments may be required for IESO reported results which are full year impacts. | Yes | Section 3.2.8 |
| 31 | CDM savings for 2016 LRAMVA balance and adjustment to 2016 load forecast; data by customer class. Provide rationale for level of CDM reductions in 2016 load forecast. | Yes | Section 3.2.9 |
| 31 & 32 | Completed Appendix 2-I | Yes | Attachment 3-B |
| *Accuracy of Load Forecast and Variance Analyses* | | | |
| 32 | Schedule of volumes, revenues, customer/connection count by class and total system load: 5 years historical, OEB approved, 5 years historical weather normalized, bridge year and test year. | Yes | Section 3.3.3 |
| 32 | Customer count increases or decreases for test year - explanation by class; confirmation of year end or average format | Yes | Section 3.2.5 |
| 32 | Explanation for any changes in definition or composition of class | Yes | Section 3.2.4 |
| 32 | Weather normalized average consumption per customer for historical 5 years, bridge and test | N/A | Section 3.3.1 |
| 33 | Explanation of net change in average consumption from last OEB approved, and actual historical, bridge and test - for each rate class | Yes | Section 3.3.3 |
| 33 | Details of development of billed kW | Yes | Section 3.2.7 |
| 33 | Revenues on existing and proposed rates for the test year | Yes | Section 3.3.5 |
| 33 | Variance analysis of volumes, revenues, customer/connection count and total system load:<br>Hist. OEB-Approved vs Hist. Actual<br>Hist. OEB-Approved vs Hist. Actual (weather normalized)<br>Hist. Act. vs. preceding Hist. Act. (weather normalized)<br>Hist. Act. vs. Bridge (weather normalized)<br>Bridge vs. Test (weather normalized) | Yes | Section 3.3 |
| 33 | Data used to determine forecasts must be filed as live Excel spreadsheet | Yes | |
| *Other Revenue* | | | |
| 33 | Completed Appendix 2-H | Yes | Attachment 3-E |
| 33 | Variance analysis - year over year, historical, bridge and test | Yes | Section 3.4.3 |
| 33 | Any new proposed specific service charges, or proposed changes to rates or application of existing specific service charges | Yes | Section 3.4.4 |
| 33 | Revenue from affiliate transactions, shared services, corporate cost allocation | Yes | Section 3.4.5 |
| **EXHIBIT 4 - OPERATING COSTS** | | | |
| *Overview* | | | |
| 35 | Brief explanation of test year OM&A levels, cost drivers, significant changes, trends, inflation rate assumed, business environment changes | Yes | Section 4.1.1, 4.1.2 and 4.1.3 |
| *Summary and Cost Driver Tables* | | | |
| 35 | Summary of recoverable OM&A expenses; Appendix 2-JA | Yes | Section 4.2.2 |
| 35 | OM&A cost drivers; Appendix 2-JB | Yes | Section 4.2.3 |
| 35 | Recoverable OM&A Cost per customer and per FTE; Appendix 2-L | Yes | Section 4.2.4 |
| 35 | Identification of change in OM&A in test year in relation to change in capitalized overhead. | Yes | Section 4.2.4 |
| 35 | OM&A variance analysis for test year with respect to bridge and historical years; Appendix 2-D | Yes | Section 4.2.4 |

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## Entegrus Powerlines Inc.
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**Date: August 28, 2015**

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|---|---|---|---|
| *Program Delivery Costs with Variance Analysis* | | | |
| **35 & 36** | Completed Appendix 2-JC OM&A Programs Table - completed by program or major functions; include variance analysis limited to variances that are outliers, between test year and last OEB approved and most recent actuals, including an explanation for each significant change whether the change was within or outside the applicant's control and explanation of why. | **Yes** | Section 4.3.1 |
| **36** | For each significant change within the applicant's control describe business decision that was made to manage the cost increase/decrease and the alternatives | **Yes** | Section 4.3.2 |
| *Compensation* | | | |
| **36** | Employee Compensation - completed Appendix 2-K | **Yes** | Section 4.4.3 and Attachment 4-F |
| **36** | Description of compensation strategy | **Yes** | Section 4.4.1 |
| **36 & 37** | Explanation for material changes to head count and compensation: year over year variances, inflation, plans for new employees, details on collective agreements, basis for performance pay, filing of any relevant studies | **Yes** | Sections 4.4.2, 4.4.3, 4.4.4 & 4.4.5 |
| **37** | Details of employee benefit programs including pensions for last OEB approved, historical, bridge and test; must agree with tax section | **Yes** | Section 4.4.6 |
| **37** | Most recent actuarial report on employee benefits, pension and OPEBs | **Yes** | Section 4.4.6 and Attachment 4-G |
| *Shared Services and Corporate Cost Allocation* | | | |
| **37** | Identification of all shared services among affiliates and parent company | **Yes** | Section 4.5.1 |
| **37** | Allocation methodology for corporate and shared services, list of costs and allocators, including any third party review | **Yes** | Section 4.5.1 |
| **38** | Completed Appendix 2-N for service provided or received for historical, bridge and test; including reconciliation with revenue included in Other Revenue | **Yes** | Section 4.5.1 |
| **38** | Shared Service and Corporate Cost Variance analysis - test year vs last OEB approved and most recent actual | **Yes** | Section 4.5.6 |
| **38** | Identification of any Board of Director costs for affiliates included in LDC costs | **Yes** | Section 4.5.5 |
| *Non-Affiliate Services, One-Time Costs, Regulatory Costs* | | | |
| **38** | Purchased Non-Affiliated Services - file a copy of procurement policy (signing authority, tendering process, non-affiliate service purchase compliance) | **Yes** | Section 4.6 |
| **38** | Explanation for procurements above materiality threshold without competitive tender | **Yes** | Section 4.6 |
| **38** | Identification of one-time costs in historical, bridge, test; explanation of cost recovery in test (or future years) | **Yes** | Section 4.7 |
| **39** | Regulatory costs - breakdown of actual and forecast, supporting information related to CoS application, proposed recovery (i.e. amortized?). Completed Appendix 2-M | **Yes** | Section 4.7 and Attachment 4-H |
| *LEAP, Charitable and Political Donations* | | | |
| **39** | LEAP - the greater of 0.12% of forecasted service revenue requirement or $2,000 should be included in OM&A and recovered from all rate classes | **Yes** | Section 4.9 |
| **39** | Statement whether test year revenue requirement includes legacy low income energy assistance programs. If yes, identify programs | **Yes** | Section 4.9 |
| **40** | Charitable Donations - amounts paid from last OEB approved rebasing application up to test year | **Yes** | Section 4.10.1 |
| **40** | Detailed information for any proposal to recover charitable donations (outside of assistance for payment of electricity bills). Any non-recoverable contributions identified and removed from revenue requirement. | **Yes** | Section 4.10.1 |
| **40** | Confirm that no political contributions have been included for recovery | **Yes** | Section 4.10.2 |
| *Depreciation, Amortization and Depletion* | | | |
| **40** | Explanations for any useful lives of an asset that are proposed that are not within the ranges contained in the Kinectrics Report | **Yes** | Section 4.11.3 |
| **19 & 40** | Depreciation, Amortization and Depletion details by asset group for historical, bridge and test years. Include asset amount and rate of depreciation/amortization. Must agree to accumulated depreciation in Appendix 2-BA under rate base. | **Yes** | Section 4.11.1 |
| **41** | Identify any Asset Retirement Obligations and associated depreciation | **Yes** | Section 4.11.2 |
| **41** | Identify historical depreciation practice and proposal for test year. Variances from half year rule must be documented and supporting rationale provided | **Yes** | Section 4.11.3 |
| **41** | Copy of depreciation/amortization policy, or equivalent written description; summary of changes to depreciation/amortization policy since last CoS | **Yes** | Section 4.11.3 |
| **41** | Explanation of any deviations from the practice of depreciating significant parts or components of PP&E separately | **N/A** | |

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**Date: August 28, 2015**

| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| **41 & 42** | Regulatory Accounting changes for depreciation expense<br>- use of Kinectrics study or another study to justify changes in useful life<br>- list detailing all asset service lives tied to USoA, detail differences in TUL from Kinectrics and explain differences outside of minimum and maximum TUL range from Kinectrics<br>- Appendix 2-BB<br>- recalculation to determine average remaining service life of opening balance on date of making depreciation changes<br>- If further depreciation expense policy changes or changes in asset service lives are made (subsequent to January 1, 2013) they must be identified and a detailed explanation of the changes provided<br>-File applicable depreciation appendices as provided in Chapter 2 MIFRS Appendices (Appendix 2-CA to 2-CK) | **Yes** | Sections 4.11.3 and 4.11.4 |
| *PILs and Property Taxes* | | | |
| **42** | Completed version of the PILs model (PDF and Excel); derivation of adjustments for historical, bridge, test years | **Yes** | Attachment 4-S |
| **42** | Supporting schedules and calculations identifying reconciling items | **Yes** | Section 4.12.1 |
| **42** | Most recent federal and provincial tax returns | **Yes** | Attachment 4-R |
| **12 & 42** | Financial Statements included with tax returns if different from those filed with application | **N/A** | |
| **42** | Calculation of Tax Credits; redact where required (filing of unredacted versions is not required) | **Yes** | Section 4.12.1 |
| **42** | Supporting schedules, calculations and explanations for other additions and deductions | **Yes** | Section 4.12.1 |
| **42** | Explanation of how property tax amounts are derived | **Yes** | Section 4.12.2 |
| **43** | Exclude from regulatory tax calculation any non-recoverable or disallowed expenses | **Yes** | Section 4.13 |
| **43** | Completion of Integrity checks listed on p.43; statement confirming completion | **Yes** | Section 4.14 |
| *Conservation and Demand Management* | | | |
| **45** | LRAMVA - disposition of balance<br>- statement indicating use of most recent input assumptions when calculating lost revenue<br>- statement indicating reliance on most recent CDM evaluation report from IESO; copy of report<br>- Tables for each rate class showing lost revenue by year; list of programs applicable to rate class<br>- lost revenue calculations - energy savings by class and OEB-approved variable charge<br>- statement that indicates if carrying charges are requested<br>- Third party report for any OEB-approved programs | **Yes** | Section 4.15, Attachments 4-U to 4-X |
| **EXHIBIT 5 - COST OF CAPITAL AND CAPITAL STRUCTURE** | | | |
| *Capital Structure and Cost of Capital* | | | |
| **46** | Statement that LDC adopts OEB's guidelines for cost of capital and confirms that updates will be done. Alternatively - utility specific cost of capital with supporting evidence | **Yes** | Section 5.1.1 |
| **46** | Completed Appendix 2-OA for last OEB approved and test year; total capitalization (debt and equity) must equate to total rate base | **Yes** | Attachment 5-G |
| **46** | Completed Appendix 2-OB for historical, bridge and test years | **Yes** | Attachment 5-H |
| **46** | Explanation for any changes in capital structure | **Yes** | Section 5.1.1 |
| **46** | Calculation of cost for each capital component | **Yes** | Section 5.2 |
| **46** | Profit or loss on redemption of debt | **Yes** | Section 5.2.4 |
| **46** | Copies of promissory notes or other debt arrangements with affiliates | **Yes** | Attachments 5-A to 5-F |
| **47** | Explanation of debt rate for each existing debt instrument | **Yes** | Section 5.2 |
| **47** | Forecast of new debt in bridge and test year - details including estimate of rate | **Yes** | Section 5.2.1, Table 5-6 |
| **47** | Notional Debt - difference between actual debt thickness and deemed debt thickness attracts the weighted average cost of actual long-term debt rate (unless 100% equity financed) | **Yes** | Section 5.2.5 |
| *Not-for-Profit Corporations* | | | |
| **48** | Not for Profit Corporations - evidence that excess revenue is used to build up operating and capital reserves | **N/A** | |
| **48** | Detailed calculation for test year revenue requirement based on its Reserve Requirement | N/A | |
| **48** | The proposed reserves and rationale for the need to establish each reserve, the time period of building up the reserves, and the procedure and policy of each reserve | N/A | |
| **48** | Description of the governance of the not-for-profit corporation | N/A | |

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## Entegrus Powerlines Inc.

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|---|---|---|---|
| 49 | If there are approved reserves from previous OEB decisions provide the following:<br>-any changes to the reserve policies and rationale for the changes since last CoS<br>-limits of any capital and/or operating reserves as approved by the OEB and identify decisions<br>-current balances of any established capital and/or operating reserves<br>-list withdrawals from capital and operating reserves, identify amounts and purpose of withdrawal<br>-if limits on capital and operating reserves achieved provide a proposal for utilization of amounts<br>-if limits on reserves not achieved provide rationale and the detail for its forecast of the Reserve Requirement for the test year | N/A | |
| **EXHIBIT 6 - REVENUE DEFICIENCY/SUFFICIENCY** | | | |
| 49 | Calculation of delivery-related Revenue Deficiency/Sufficiency (excluding cost of power and associated costs): net utility income, rate base, actual return on rate base, indicated rate of return, requested rate of return, deficiency/sufficiency, gross deficiency/sufficiency. Deficiency/sufficiency must also be net of other costs (e.g. LV costs, RSVAs, smart meter and other DVA balances). | Yes | Section 6.1 |
| 50 | Summary of drivers for test year deficiency/sufficiency, how much each driver contributes; references in application evidence mapped to drivers | Yes | Section 6.7 |
| 50 | Impacts of any changes in methodologies to deficiency/sufficiency | Yes | Section 6.7 |
| *Revenue Requirement Work Form* | | | |
| 50 | RRWF - in PDF and Excel. Revenue requirement, def/sufficiency, data entered in RRWF must correspond with other exhibits | Yes | Attachment 6-A |
| **EXHIBIT 7 - COST ALLOCATION** | | | |
| *Cost Allocation Study Requirements* | | | |
| 51 | Completed cost allocation study reflecting test year loads and costs. Live Excel version of 2015 cost allocation model will be filed (updated load profiles or scaled version of HONI CAIF). Model must be consistent with test year load forecast, changes to customer classes and load profiles. | Yes | |
| 51 | Description of weighting factors, and rationale for use of default values (if applicable) | Yes | Section 7.3.6, Section 7.3.9 and Section 7.3.10 |
| 51 | Hard copy of sheets I-6, I-8, O-1 and O-2 (first page) | Yes | Attachment 7-A |
| 52 | Host Distributor - evidence of consultation with embedded Dx<br>- Statement regarding embedded Dx support for approach to allocation of costs<br>- If embedded Dx is separate class - class in cost allocation study and Appendix 2-P<br>- If new embedded Dx class - rationale and supporting evidence (cost of serving, load served, asset ownership information, distribution charges); include in cost allocation study and Appendix 2-P<br>- If embedded Dx billed as GS customer - , include with the GS class in cost allocation model and Appendix 2-P. Provide cost of serving, load served, asset ownership information, distribution charges, appropriateness of rate class. File Appendix 2-Q. | Yes | Section 7.2.4 |
| 53 | Unmetered Loads (including Street Lighting) - Confirmation of communication with unmetered load customers when proposing changes to the level of the rates and charges or the introduction of new rates and charges | Yes | Section 7.2.2 |
| 53 | Standby Rates - if seeking approval on final basis, provide evidence that affected customers have been advised. If seeking changes to standby charges, provide rationale and evidence that affected customer have been advised. | Yes | Section 7.2.3 |
| 54 | New customer class or eliminated customer class - rationale and restatement of revenue requirement from previous CoS | Yes | Section 7.2.1 |
| *Class Revenue Requirements and Revenue to Cost Ratios* | | | |
| 54 | Completed Appendix 2-P; supporting information for any proposal to re-balance rates | Yes | Section 7.5 and Attachment 7-E |
| 55 | Proposal to re-balance to bring R:C ratio within OEB policy ranges; any proposal to for further re-balancing beyond test year. | Yes | Section 7.5 |
| 55 | If Cost Allocation Model other than OEB model used - exclude LV, exclude DVA such as smart meters | N/A | |
| **EXHIBIT 8 - RATE DESIGN** | | | |
| 56 | Monthly fixed charges - 2 decimal places; variable charges - 4 decimal places | Yes | |
| 56 | Current and Proposed F/V proportion with explanation for any changes (billing determinants from proposed load forecast). Analysis must be net of adders and riders. | Yes | Section 8.1.2 |
| 56 | Table comparing current and proposed fixed charge with floor and ceiling from cost allocation study. | Yes | Section 8.1.2, Table 8-7 |
| 57 | Rate Design Policy - LDCs filing in first half of 2015 for Jan 1, 2016 rates may request a transition beginning with 2017 rates. Otherwise, LDCs will propose changes to residential rates consistent with policy to transition to fully fixed monthly distribution service charge. Completed Appendix 2-PA | Yes | Section 8.1.4, Attachment 8-A |

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|---|---|---|---|
| *RTSRs and Other Charges* | | | |
| **58** | Retail Transmission Service Rate Work Form - PDF and Excel | **Yes** | Section 8.4, Attachment 8-C |
| **58** | RTSR information must be consistent with working capital allowance calculation | **Yes** | |
| **58** | If proposing changes to Retail Service Charge - evidence of consultation and notice | **Yes** | Section 8.9 |
| **58 & 59** | Wholesale Market Service Rate - reflect $0.0057/kWh in application or justify otherwise | **Yes** | Section 8.5 |
| **59** | Smart Metering Entity Charge - reflect $0.79/month in application for Residential and GS<50 | **Yes** | Section 8.2 |
| **59** | Specific Service Charge description/purpose/reason for new and revised SSC; calculations to support charges | **Yes** | Section 8.8 |
| **59** | Identify any rates and charges in Conditions of Service that do not appear on tariff sheet. Explain nature of costs, provide schedule outlining revenues or capital contributions 2011-2014, bridge and test years. Whether these charges should be included on tariff sheet | **Yes** | Section 8.11 |
| **60** | Ensure revenue from SSCs corresponds with Operating Revenue evidence | **Yes** | Section 8.8 |
| **60** | If not on monthly billing, provide details of plan to transition by Dec 31, 2016 to monthly billing. | **N/A** | |
| **60** | Forecast of LV cost, sum of host distributors charges | **Yes** | Section 8.3.1 |
| **60** | Low Voltage Cost (historical, bridge, test), variances and explanations for substantive changes | **Yes** | Section 8.3.2 |
| **60** | Support for forecast LV, e.g. Hydro One Sub-Transmission charges | **Yes** | Section 8.3.2 |
| **60** | Allocation of LV cost to customer classes (typically proportional to Tx connection revenue) | **Yes** | Section 8.3.3 |
| **60** | Proposed LV rates by customer class | **Yes** | Section 8.3.3 |
| *Loss Factors* | | | |
| **60** | Proposed SFLF and Total Loss Factor for test year | **Yes** | Section 8.10 |
| **60** | Statement as to whether LDC is embedded including whether fully or partially | **Yes** | Section 8.10 |
| **61** | Study of losses if required by previous decision | **N/A** | |
| **61** | 3-5 years of historical loss factor data - Completed Appendix 2-R | **Yes** | Section 8.10.2, Attachment 8-D |
| **61** | Explanation of losses >5% | **Yes** | Section 8.10 |
| **61** | If proposed loss factor >5%, action plan to reduce losses going forward | **Yes** | Section 8.10 |
| **61** | Explanation of SFLF if not standard | **Yes** | Section 8.10.2, Attachment 8-D |
| *Rates and Bill Impacts* | | | |
| **61** | Current Tariff of Rates and Charges | **Yes** | Attachment 8-E |
| **61** | Proposed Tariff of Rates - Appendix 2-Z; ensure each change is explained and supported in appropriate section of the application | **Yes** | Attachment 8-F |
| **61** | Explanation of changes to terms and conditions of service if changes affect application of rates | **N/A** | |
| **61** | Calculations of revenue per class under current and proposed rates; reconciliation of rate class revenue and other revenue to total revenue requirement | **Yes** | Section 8.1.5 |
| **61** | Completed Appendix 2-V (Revenue Reconciliation) | **Yes** | Attachment 8-B |
| **62** | Bill Impacts - completed Appendix 2-W for all classes for representative samples of end-users. Must provide residential 800 kWh and GS<50 2,000 kWh. Commodity and regulatory charges held constant | **Yes** | Attachment 8-G |
| *Rate Mitigation* | | | |
| **63** | Default number of transition years for rate design policy change is 4. Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year. LDC may propose an alternative in the event an additional transition year is insufficient. | **Yes** | Section 8.1.4, Attachment 8-A |
| **63** | Assessment of combined effect of rate design policy change and other impacts from rebasing - LDC must evaluate bill impact for residential customer at 10th consumption percentile. Describe methodology for determination of 10th consumption percentile. File mitigation plan for whole residential class if impact >10% for these customers. | **Yes** | Attachment 8-A |
| **63 & 64** | Mitigation plan if total bill increase for any customer class is >10% including: specification of class and magnitude of increase, description of mitigation measures, justification, revised impact calculation. Appendix 2-W must reflect any mitigation plan proposed. | **Yes** | Section 8.13 and Section 8.14 |
| **64** | Rate Harmonization Plans, if applicable - including impact analysis | **Yes** | Section 14 |

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|---|---|---|---|
| **EXHIBIT 9 - DEFERRAL AND VARIANCE ACCOUNTS** | | | |
| 65 | List of all outstanding DVA and sub-accounts; provide description of DVAs that were used differently than as described in the APH | Yes | Section 9.4 and Section 9.5 |
| 65 | Completed DVA continuity schedule for period following last disposition to present - live Excel format | Yes | |
| 65 | Interest rates applied to calculate carrying charges (month or quarter) | Yes | Section 9.2.3 |
| 65 | Explanation if account balances in continuity schedule differs from trial balance in RRR and AFS | Yes | Section 9.2.1 |
| 65 | Identification of Group 2 accounts that will continue/discontinue going forward, with explanation | Yes | Section 9.6.2 and Section 9.6.3 |
| 65 | Statement as to any new accounts, and justification. | Yes | Section 9.6.1 |
| 65 | Statement whether any adjustments made to DVA balances previously approved by OEB on final basis; explanation, amount of adjustment and supporting documents | Yes | Section 9.1 |
| 65 | Breakdown of energy sales and cost of power by USoA - as reported in AFS mapped and reconciled to USoA. Provide explanation if making a profit or loss on commodity. | Yes | Section 9.2.2 |
| 65 | Statement confirming that IESO GA charge is pro-rated into RPP and non-RPP; provide explanation if not pro-rated. | Yes | Section 9.1 |
| 66 | If not addressed previously, disposition of Account 1592 - Completed Appendix 2-TA | N/A | Section 9.5.9 |
| 66 | If not addressed previously, disposition of Account 1592 sub-account HST/OVAT ITC - analysis that supports conformity with Dec 2010 APH FAQ (particularly #4)<br>Applicant must state the period that the account covers (i.e. Jul 1-2010 up to start of new rate year (year of rebasing)).<br>Completed Appendix 2-TB | Yes | Section 9.5.9 |
| 67 | Request for disposition of Account 1508 sub-account IFRS transition costs<br>- completed Appendix 2-U<br>- statement whether any one time IFRS transition costs are embedded in 2016 revenue requirement, where and why it is embedded, and the quantum<br>- explanation for each category of cost recorded in 1508 sub-account, how it meets criteria of one time IFRS admin incremental costs<br>- explanation for material variances in Account 1508 sub-account IFRS Transition Costs Variance<br>- statement that no capital costs, ongoing IFRS compliance costs are recorded in 1508 sub-account; provide explanation if this is not the case | Yes | Section 9.5.1 |
| 68 & 69 | 1575 IFRS-CGAAP PP&E account<br>- Account 1575 and 1576 can't be used interchangeably<br>- breakdown of balance, Appendix 2-EA<br>- listing and quantification of drivers<br>- a breakdown for quantification of any accounting changes arising from IFRS in relation to PP&E<br>- volumetric rate rider to clear 1575;<br>- rate of return component is to be applied to 1575 but not recorded in 1575<br>- statement confirming no carrying charges applied to 1575<br>explanation for the basis of the proposed disposition period to clear Account 1575 rate rider<br>- show the balance in DVA continuity schedule | N/A | |
| 69 & 70 | Changes to depreciation and capitalization in 2012 or 2013 - 1576 IFRS-CGAAP PP&E account<br>- Appendix 2-BA must not be adjusted for 1576<br>- breakdown of balance related to 1576, Appendix 2-EB or 2-EC<br>- volumetric rate rider to clear 1576;<br>- rate of return component is to be applied to 1576 but not recorded in 1576<br>- statement confirming no carrying charges applied to 1576<br>- explanation for the basis of the proposed disposition period to clear Account 1576 rate rider<br>- show the balance in DVA continuity schedule | Yes | Section 9.5.6 |
| 70 | Retail Service Charges - material balance in 1518 or 1548<br>- confirm variances are incremental costs of providing retail services; identify drivers for balances<br>- provide schedule identifying all revenues and expenses listed by USoA for 2013, actual/forecast for bridge and test year<br>- state whether Article 490 of APH has been followed; explanation if not followed | Yes | Section 9.5.2 and Section 9.5.4 |
| 71 | Retail Service Charges - zero balance in 1518 or 1548 - state whether Article 490 of APH has been followed; explanation if not followed | N/A | |
| 71 | Identify all accounts for which LDC is seeking disposition; identify DVA for which LDC is not proposing disposition and the reasons why | Yes | Section 9.3 |
| 71 | Statement whether DVA balances before forecasted interest match the last AFS; explain any variances | Yes | Section 9.2.1 |

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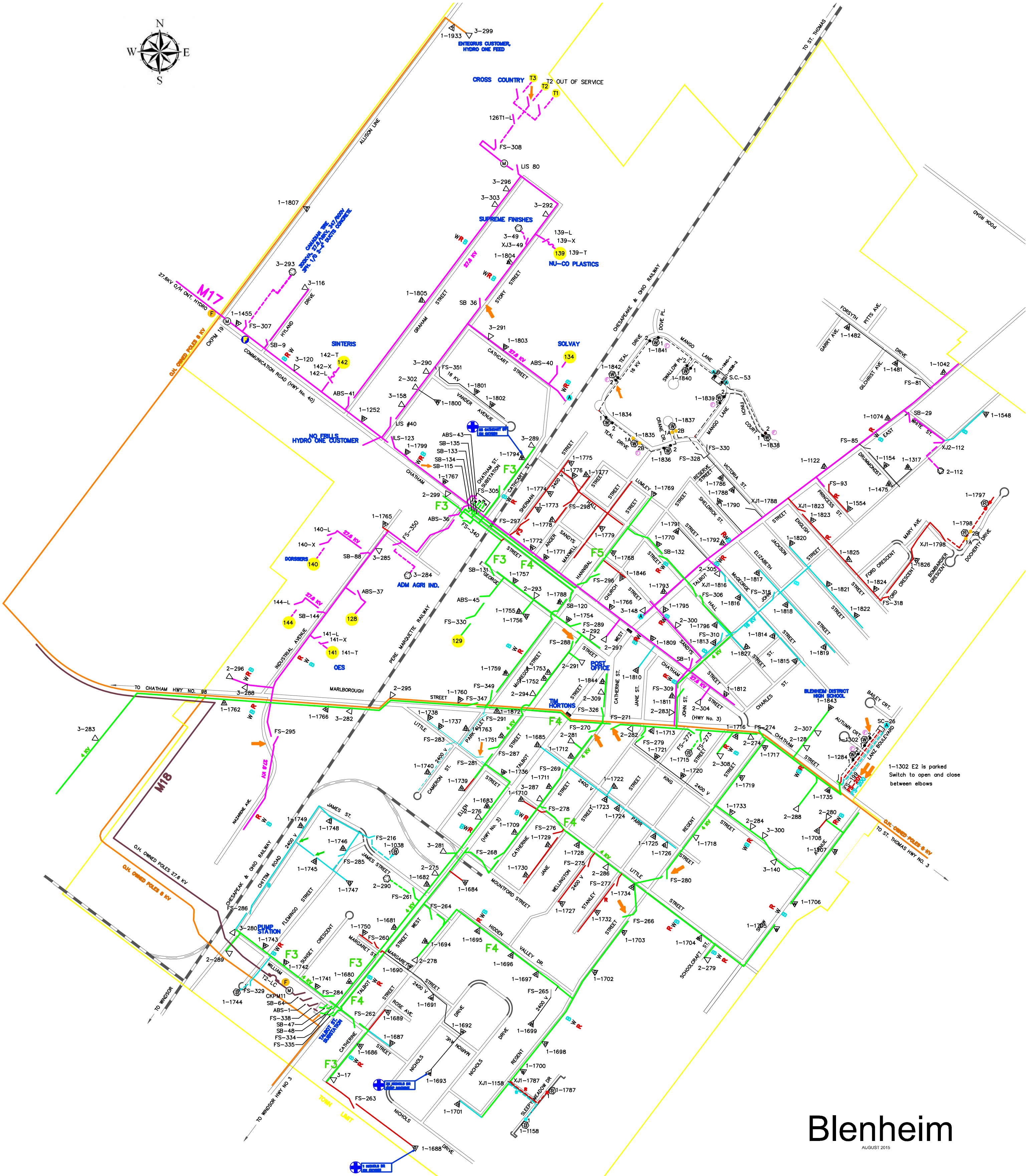
| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| 71 | Provide an explanation of variance > 5% between amounts proposed for disposition and amounts reported in RRR for each account. | N/A | |
| 71 | Provide explanations if variances are < 5% threshold if the variances in question relate to: (1) matters of principle (i.e. conformance with the APH or prior OEB decisions, and prior period adjustments); and/or, (2) the cumulative effect of immaterial differences over several accounts total to a material difference between what is proposed for disposition in total before forecasted interest and what is recorded in the RRR filings | N/A | |
| 71 | Show relevant calculations: rationale for allocation of each account, proposed billing determinants and length of disposition period. | Yes | Section 9.7 |
| 71 | Propose charge type (fixed or variable) for recovery purposes in accordance with Rate Design Policy | Yes | Section 9.7 |
| 71 | Propose rate riders for recovery or refund of balances that are proposed for disposition. The default disposition period is one year; if the applicant is proposing an alternative recovery period must provide explanation. | Yes | Section 9.7 |
| 71 | Establish separate rate riders to recover balances in the RSVA's from Market Participants who must not be allocated the RSVA balances related to charges for which the MP's settle directly with the IESO. | Yes | Section 9.7 |
| 72 | New DVA - must meet causation, materiality, prudence criteria; include draft accounting order | N/A | |
| *Global Adjustment* | | | |
| 72 & 73 | Description of settlement process with IESO or host distributor, specify GA rate used for each rate class, itemize process for providing estimates and describe true-up process, details of method for estimating RPP and non-RPP consumption, treatment of embedded generation/distribution. LDCs are expected to use accrual accounting. | Yes | Section 9.4.8 |
| 73 | Identify number of Class A customers served in 2014 and on July 1, 2015. Provide combined peak demand facotr for each period. Propose allocation for recovery of GA variance balance. | Yes | Section 9.4.8 |

| | | |
|---|---|---|
| **TOTAL "NO"** | **0** | |

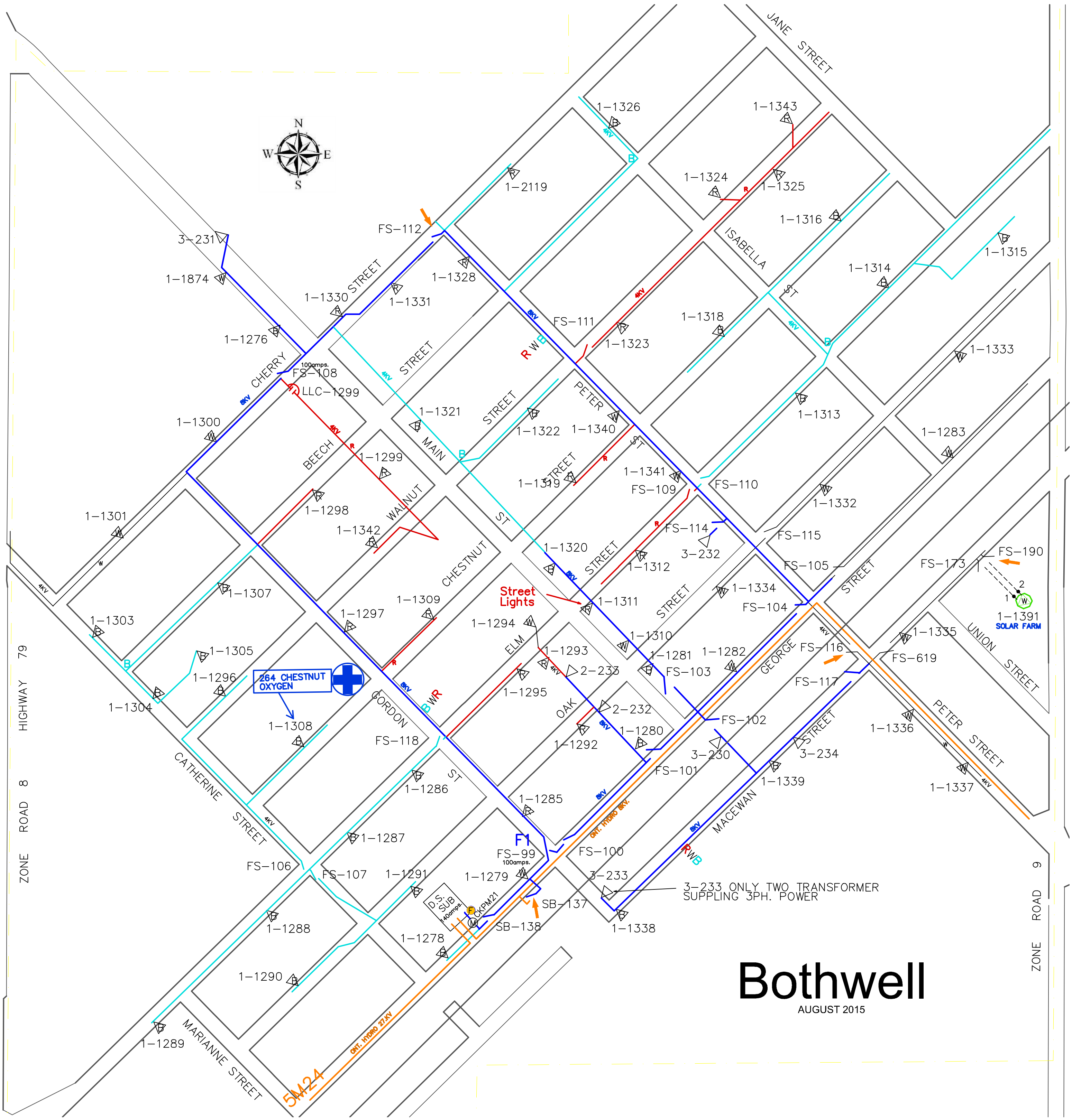
# ATTACHMENT 1-C

Maps of Communities

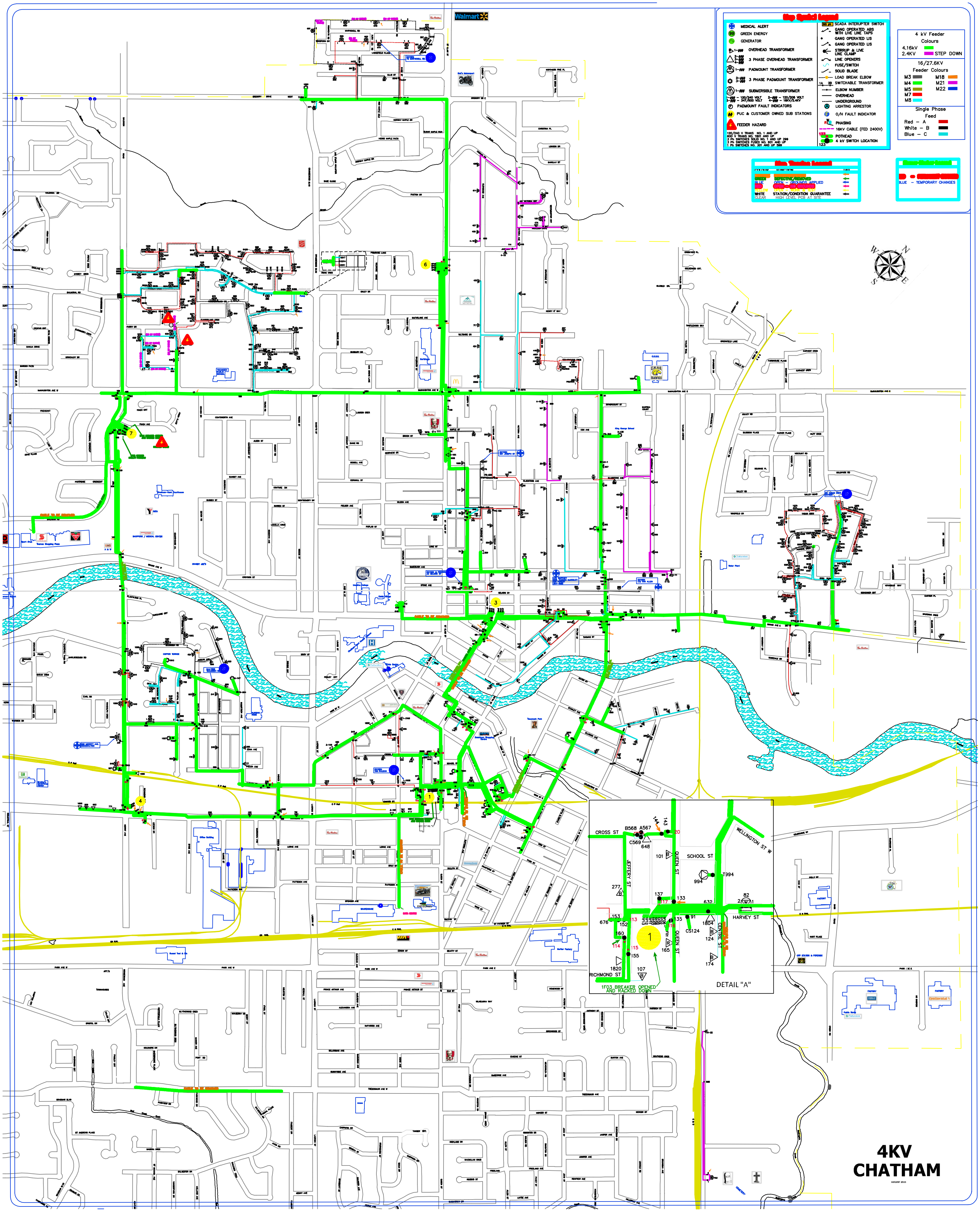
Served by EPI

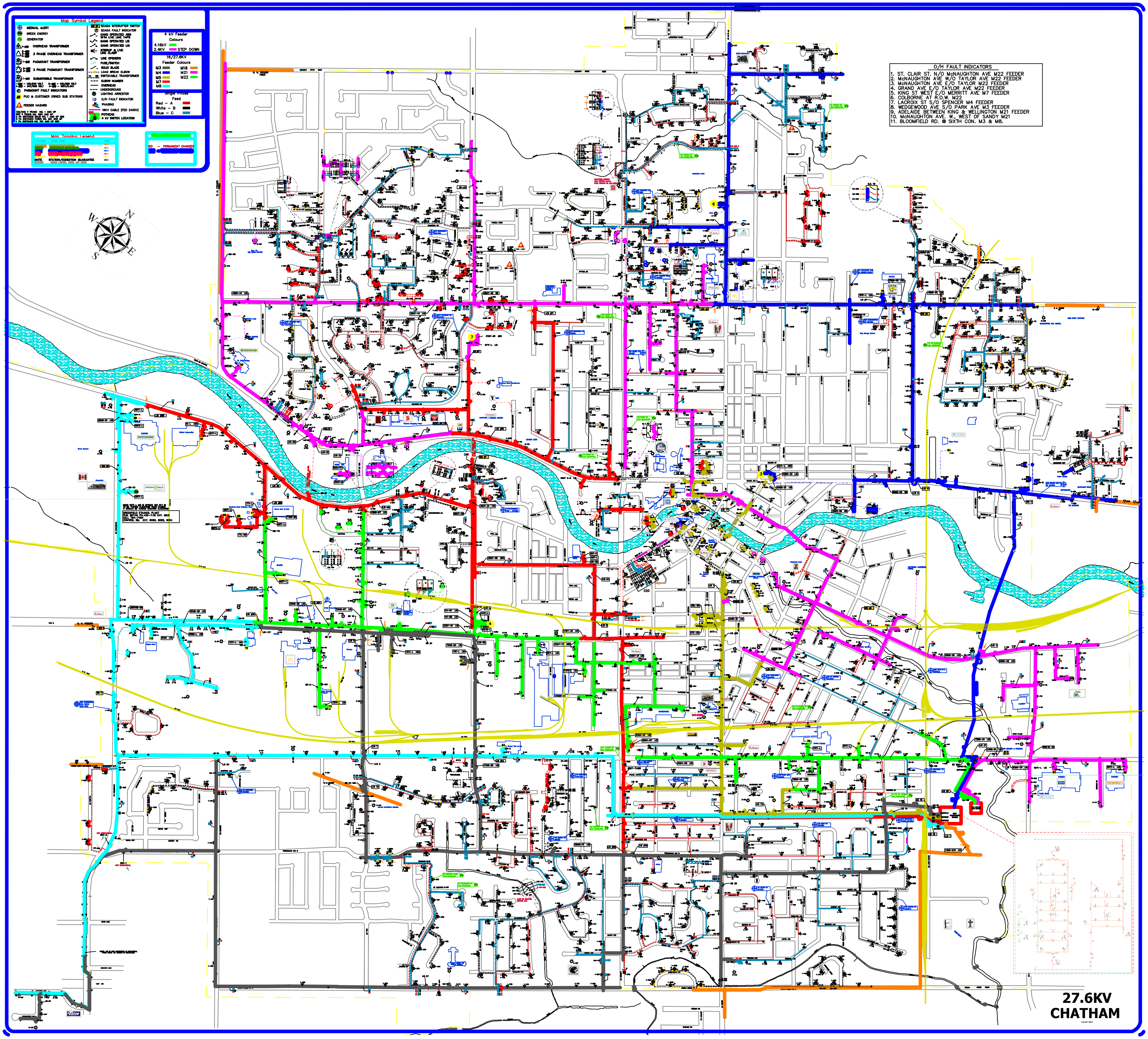


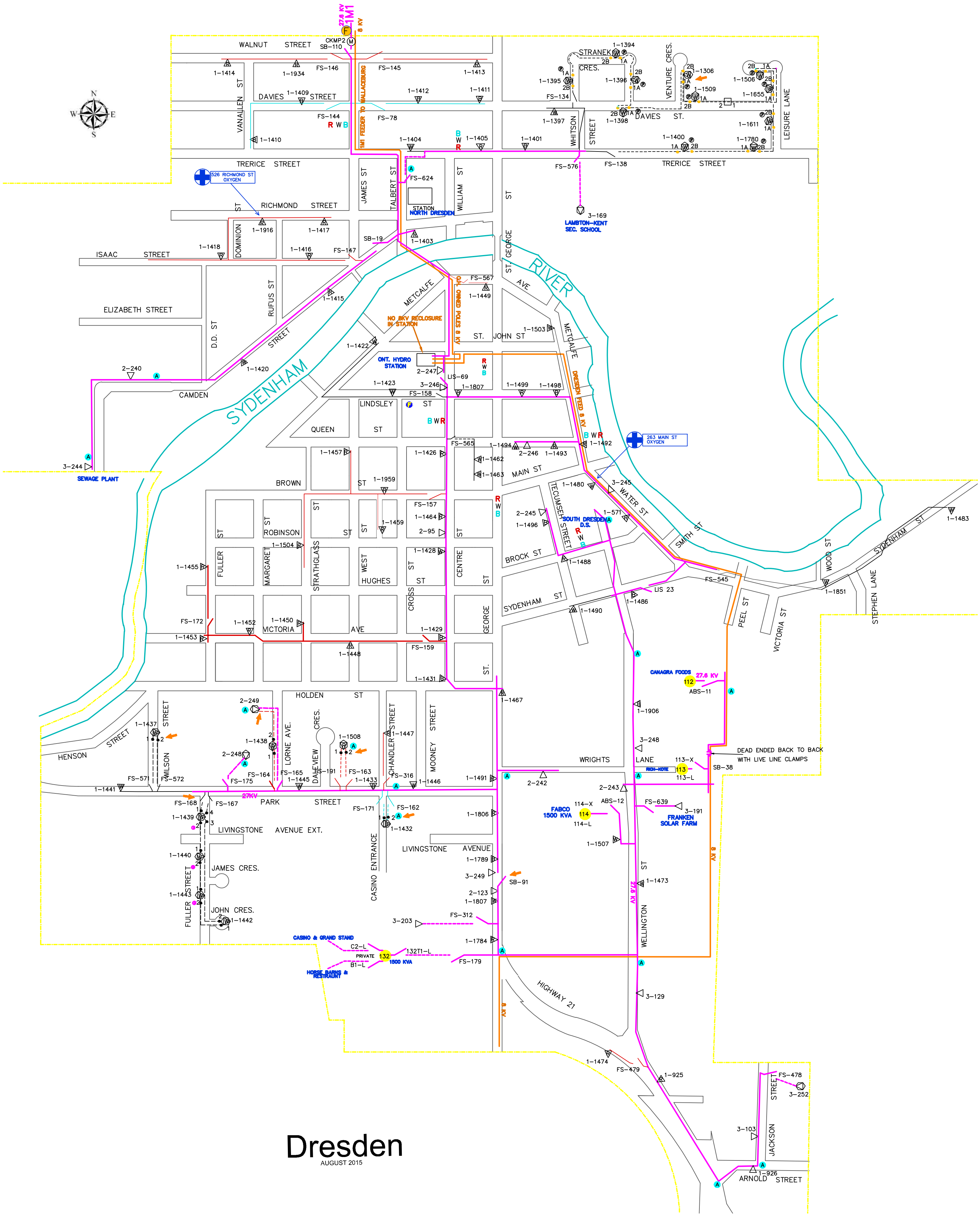
Blenheim
AUGUST 2015
ENTEGRUS CUSTOMER, HYDRO ONE FEED
CROSS COUNTRY
T2 OUT OF SERVICE
SUPREME FINISHES
NU-CO PLASTICS
SINTERIS
SOLVAY
NO FRILLS HYDRO ONE CUSTOMER
DORSSERS
ADM AGRI IND.
OES
M17
M18
27.6KV O/H ONT. HYDRO
COMMUNICATION ROAD (HWY No. 40)
ALLISON LINE
GRAHAM STREET
STORY STREET
CATHCART STREET
VANDER AVENUE
CHATHAM ST. SUBSTATION
CHESAPEAKE & OHIO RAILWAY
PERE MARQUETTE RAILWAY
TO CHATHAM HWY NO. 98
MARLBOROUGH STREET
INDUSTRIAL AVENUE
NAZARENE AVE.
O.H. OWNED POLES 27.6 KV
O.H. OWNED POLES 8 KV
MANGO LANE
TEAL DRIVE
DOVE PL.
SWALLOW PL.
FINCH COURT
CRANE DR.
VICTORIA ST.
TIM HORTONS
POST OFFICE
CATHERINE ST.
JANE ST.
JOHN ST.
CHATHAM STREET
(HWY No. 3)
BLENHEIM DISTRICT HIGH SCHOOL
AUTUMN CRT.
BAILEY CRT.
LANE BOULEVARD
1-1302 E2 is parked Switch to open and close between elbows
TO ST. THOMAS HWY NO. 3
TO ST. THOMAS
FORSYTH
PITTS AVE.
GARRY AVE.
GILCHRIST AVE.
WHITE ST.
DRUMMOND
PRINCESS ST.
ENGLISH
ELIZABETH
JACKSON
FORD CRESCENT
MARY AVE.
DOCHERTY DRIVE
BOMBARDIER CRESCENT
POOK ROAD
PUMP STATION
TALBOT ST. SUBSTATION
WILLIAM
JAMES ST.
CHITTIM ROAD
FLEMINGO STREET
SUNSET CRESCENT
MARGARET ST.
ROSE AVE.
HIDDEN VALLEY DR.
MOUNTFORD STREET
WELLINGTON
STANLEY STREET
LITTLE STREET
REGENT
NICHOLS DRIVE
NORMAN AVE.
SLEEPY MEADOW DR
SCHOOLCRAFT ST.
TO WINDSOR
TO WINDSOR HWY NO 3
TOWN LIMIT



Bothwell
AUGUST 2015
3-233 ONLY TWO TRANSFORMER SUPPLING 3PH. POWER
264 CHESTNUT OXYGEN
Street Lights
SOLAR FARM
D.S. SUB
5M24
ONT. HYDRO 27.6KV
ONT. HYDRO 8KV
F1
CHERRY STREET
BEECH STREET
WALNUT STREET
CHESTNUT STREET
GORDON ST
CATHERINE STREET
MARIANNE STREET
MAIN STREET
PETER STREET
ELM STREET
OAK STREET
ISABELLA ST
JANE STREET
GEORGE STREET
MACEWAN STREET
UNION STREET
HIGHWAY 79
ZONE ROAD 8
ZONE ROAD 9
FS-112
FS-108
FS-111
FS-110
FS-109
FS-114
FS-115
FS-105
FS-104
FS-103
FS-102
FS-101
FS-100
FS-99
FS-116
FS-117
FS-619
FS-173
FS-190
FS-118
FS-106
FS-107
SB-137
SB-138
LLC-1299
CKPM21


MEDICAL ALERT
GREEN ENERGY
GENERATOR
OVERHEAD TRANSFORMER
3 PHASE OVERHEAD TRANSFORMER
PADMOUNT TRANSFORMER
3 PHASE PADMOUNT TRANSFORMER
SUBMERSIBLE TRANSFORMER
1-### - 120/240 VOLT 2-### - 120/208 VOLT
3-### - 347/600 VOLT 4-### - 16KV/2.4KV
PADMOUNT FAULT INDICATORS
PUC & CUSTOMER OWNED SUB STATIONS
FEEDER HAZARD
120/240 V TRANS NO. 1 AND UP
600 V TRANS NO. 1601 AND UP
3 Ph SWITCHES SOLID NO. 1 AND UP 299
3 Ph SWITCHES FUSED NO. 601 AND UP
1 Ph SWITCHES NO. 301 AND UP 599
SCADA INTERUPTER SWITCH
GANG OPERATED ABS WITH LIVE LINE TAPS
GANG OPERATED LIS
GANG OPERATED LIS
STIRRUP & LIVE LINE CLAMP
LINE OPENERS
FUSE/SWITCH
SOLID BLADE
LOAD BREAK ELBOW
SWITCHABLE TRANSFORMER
ELBOW NUMBER
OVERHEAD
UNDERGROUND
LIGHTING ARRESTOR
O/H FAULT INDICATOR
PHASING
16KV CABLE (FED 2400V)
POTHEAD
4 kV SWITCH LOCATION
4 kV Feeder Colours
4.16kV
2.4KV STEP DOWN
16/27.6KV Feeder Colours
M3 M18
M4 M21
M5 M22
M7
M8
Single Phase Feed
Red – A
White – B
Blue – C
GREEN DEFECTIVE/REMOVED
BLUE OPEN – GROUNDS APPLIED
WHITE STATION/CONDITION GUARANTEE
CLEAR HIGH LEVEL PCB AT SITE
BLUE – TEMPORARY CHANGES
Walmart
CROSS ST
B568
A567
C569
648
101
QUEEN ST
SCHOOL ST
WELLINGTON ST W
JEFFERY ST
994
T994
277
137
133
632
82
HARVEY ST
153
676
152
135
91
1804
CS124
CENTRE ST
160
165
124
155
174
1820
RICHMOND ST
107
1F03 BREAKER OPENED AND RACKED DOWN
DETAIL "A"
4KV
CHATHAM

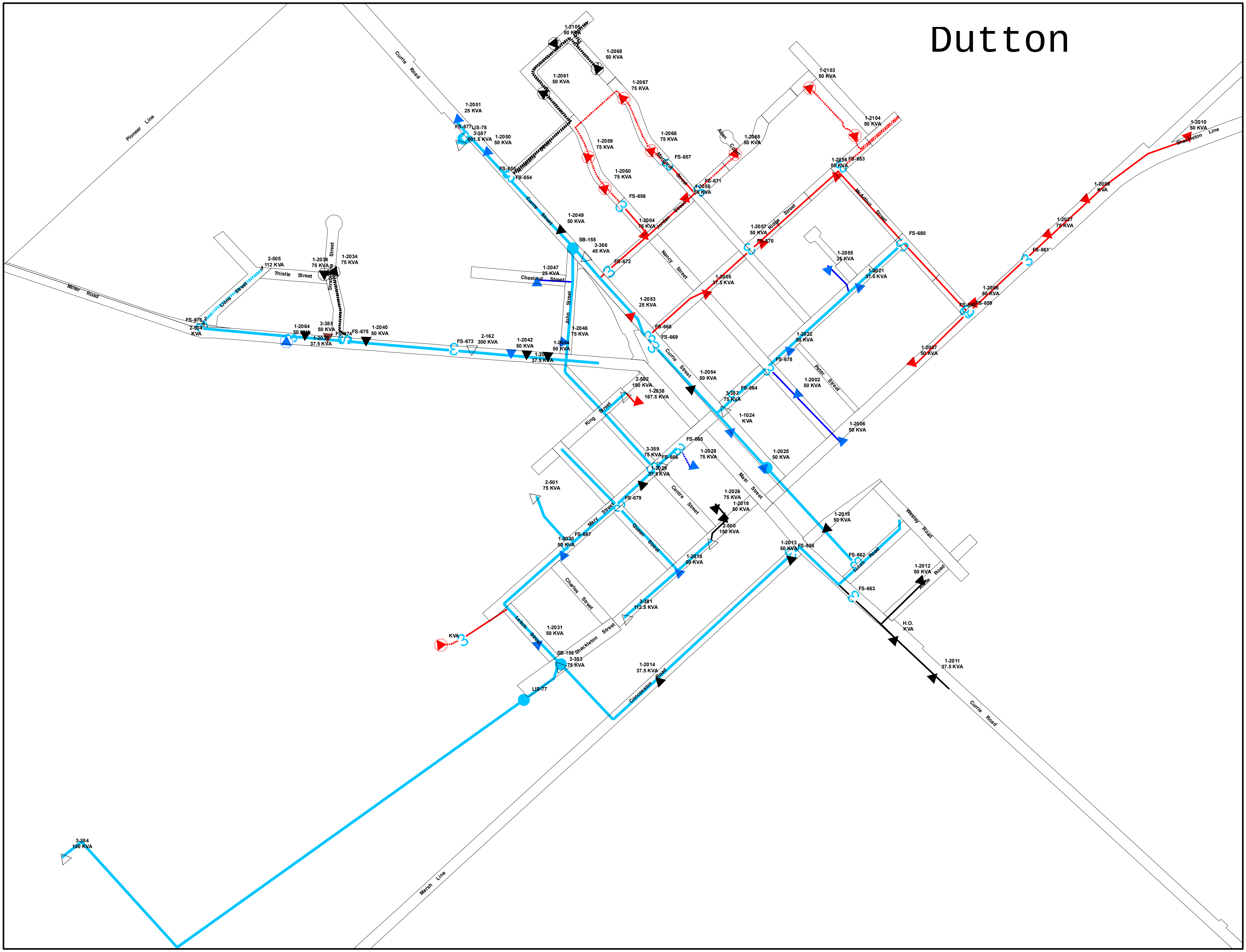

27.6KV
CHATHAM
Map Symbol Legend
MEDICAL ALERT
GREEN ENERGY
GENERATOR
OVERHEAD TRANSFORMER
3 PHASE OVERHEAD TRANSFORMER
PADMOUNT TRANSFORMER
3 PHASE PADMOUNT TRANSFORMER
SUBMERSIBLE TRANSFORMER
PADMOUNT FAULT INDICATORS
PUC & CUSTOMER OWNED SUB STATIONS
FEEDER HAZARD
SCADA INTERUPTER SWITCH
SCADA FAULT INDICATOR
GANG OPERATED ABS WITH LIVE LINE TAPS
GANG OPERATED LIS
GANG OPERATED LIS
STIRRUP & LIVE LINE CLAMP
LINE OPENERS
FUSE/SWITCH
SOLID BLADE
LOAD BREAK ELBOW
SWITCHABLE TRANSFORMER
ELBOW NUMBER
OVERHEAD
UNDERGROUND
LIGHTING ARRESTOR
O/H FAULT INDICATOR
PHASING
16KV CABLE (FED 2400V)
POTHEAD
4 kV SWITCH LOCATION
4 kV Feeder Colours
4.16kV
2.4KV STEP DOWN
16/27.6KV Feeder Colours
M3
M4
M5
M7
M8
M18
M21
M22
Single Phase Feed
Red - A
White - B
Blue - C
Map Tagging Legend
STATION/CONDITION GUARANTEE
PERMANENT CHANGES
O/H FAULT INDICATORS
1. ST. CLAIR ST. N/O McNAUGHTON AVE M22 FEEDER
2. McNAUGHTON AVE W/O TAYLOR AVE M22 FEEDER
3. McNAUGHTON AVE E/O TAYLOR M22 FEEDER
4. GRAND AVE E/O TAYLOR AVE M22 FEEDER
5. KING ST WEST E/O MERRITT AVE M7 FEEDER
6. COLBORNE AT R.O.W. M22
7. LACROIX ST S/O SPENCER M4 FEEDER
8. WEDGEWOOD AVE S/O PARK AVE M3 FEEDER
9. ADELAIDE BETWEEN KING & WELLINGTON M21 FEEDER
10. McNAUGHTON AVE. W., WEST OF SANDY M21
11. BLOOMFIELD RD. @ SIXTH CON. M3 & M8.



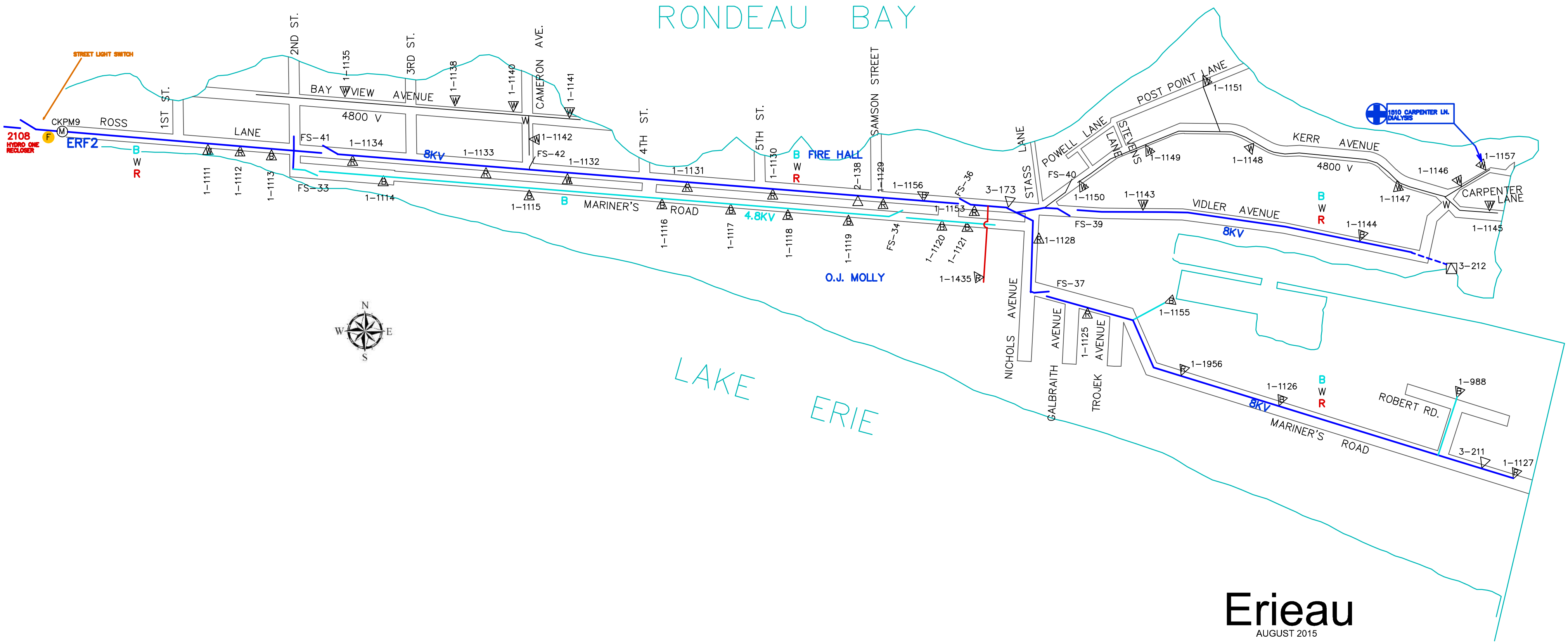

# Dresden

AUGUST 2015

# Dutton

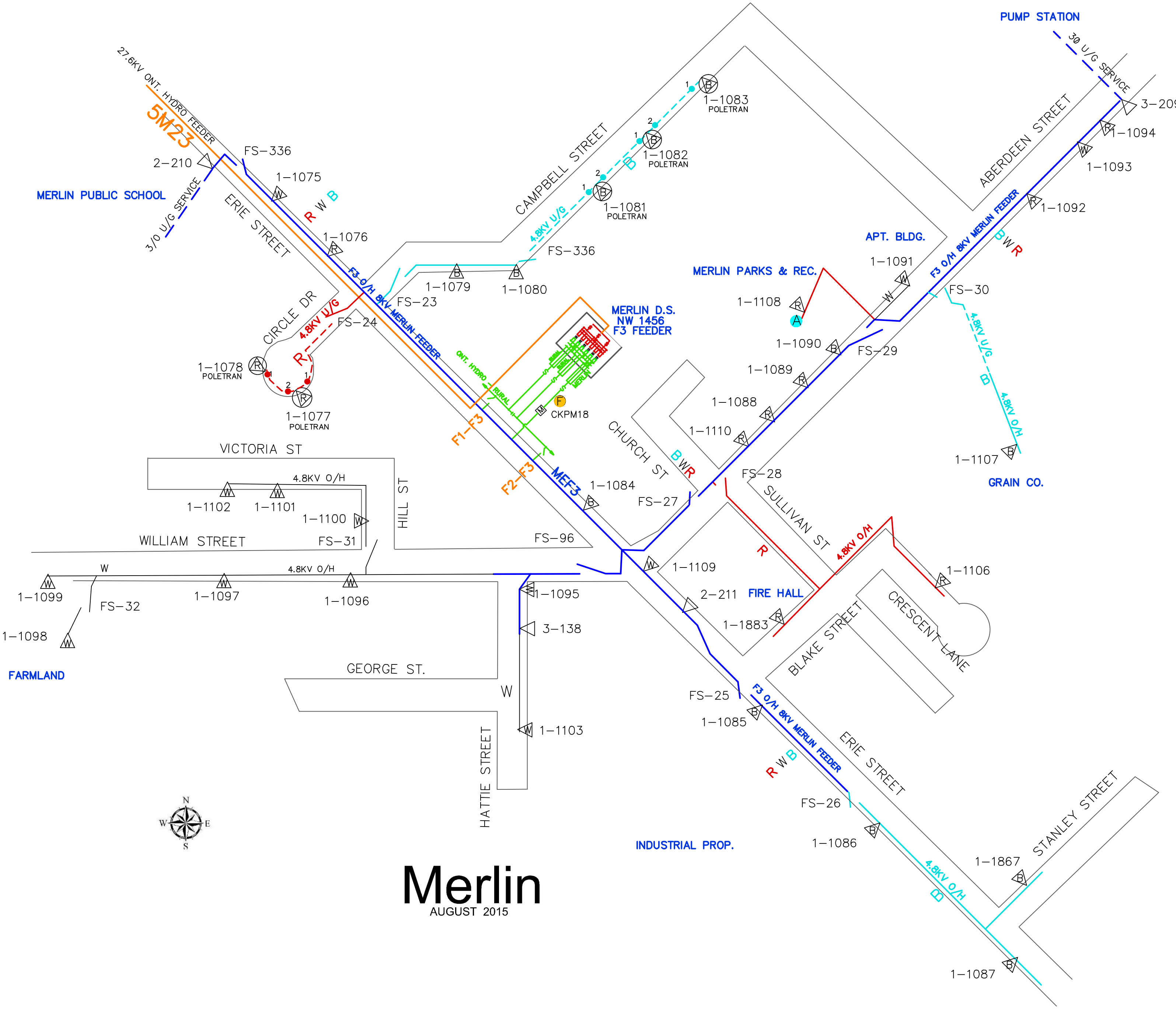


Pioneer Line
Currie Road
Miller Road
Marsh Line
Shackleton Line
Thistle Street
Lions Street
Chestnut Street
John Street
Currie Street
Nancy Street
Jordan Street
Ridge Street
McArthur Street
Peter Street
King Street
Main Street
Centre Street
Mary Street
Queen Street
Charles Street
Leitch Street
Shackleton Street
Concession Road
Wesley Road
Lutten Road
Allan Court
1-2105 50 KVA
1-2068 50 KVA
1-2061 50 KVA
1-2067 75 KVA
1-2103 50 KVA
1-2104 50 KVA
1-2051 25 KVA
FS-677
LIS-78
3-387 601.5 KVA
1-2050 50 KVA
1-2059 75 KVA
1-2066 75 KVA
1-2065 50 KVA
1-2010 50 KVA
FS-655
FS-654
FS-657
1-2056 50 KVA
FS-653
1-2060 75 KVA
FS-671
1-2058 50 KVA
1-2009 75 KVA
FS-656
1-2049 50 KVA
1-2004 75 KVA
1-2057 50 KVA
FS-670
FS-680
1-2027 75 KVA
SB-155
3-386 45 KVA
1-2055 25 KVA
FS-661
2-505 112 KVA
1-2036 75 KVA
1-2034 75 KVA
1-2047 25 KVA
FS-672
1-2005 37.5 KVA
1-2021 37.5 KVA
1-2008 50 KVA
FS-660
FS-659
1-2053 25 KVA
FS-676
2-504 KVA
1-2064 50 KVA
3-385 50 KVA
FS-674
FS-675
1-2040 50 KVA
1-2039 37.5 KVA
FS-673
2-162 300 KVA
1-2042 50 KVA
1-2044 50 KVA
37.5 KVA
1-2046 75 KVA
FS-668
FS-669
1-2022 50 KVA
1-2007 50 KVA
FS-678
1-2054 50 KVA
2-502 150 KVA
1-2038 167.5 KVA
FS-664
3-382 75 KVA
1-2002 50 KVA
1-1024 KVA
1-2006 50 KVA
FS-665
3-359 75 KVA
FS-666
1-2028 75 KVA
1-2029 37.5 KVA
1-2025 50 KVA
2-501 75 KVA
FS-679
1-2026 75 KVA
1-2019 50 KVA
2-500 150 KVA
1-2015 50 KVA
1-2030 50 KVA
FS-667
1-2018 50 KVA
1-2013 50 KVA
FS-658
FS-662
1-2012 50 KVA
FS-663
3-381 112.5 KVA
H.O. KVA
KVA
1-2031 50 KVA
SB-156
3-383 75 KVA
1-2011 37.5 KVA
1-2014 37.5 KVA
LIS-77
3-384 150 KVA



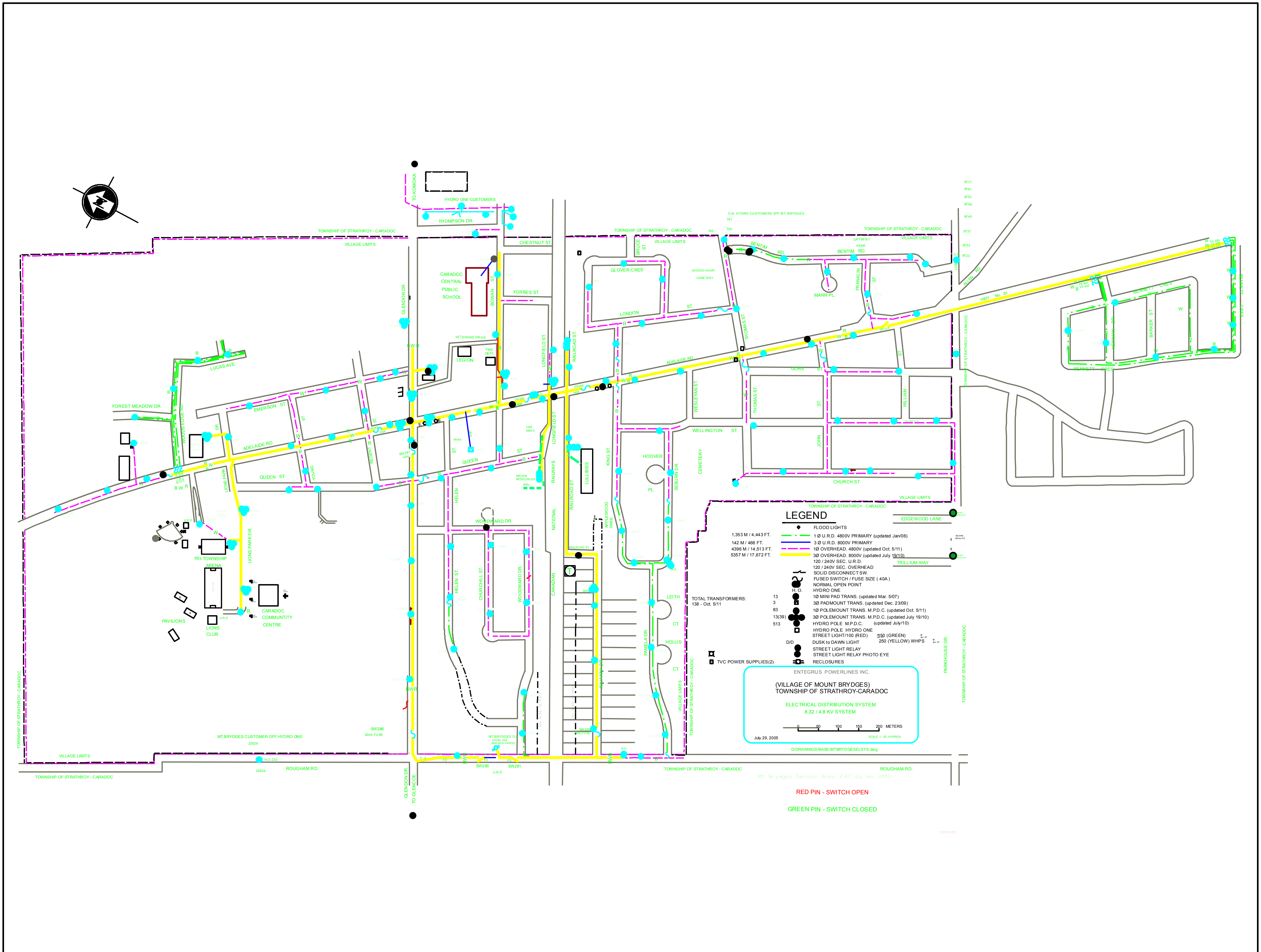

# Erieau

AUGUST 2015



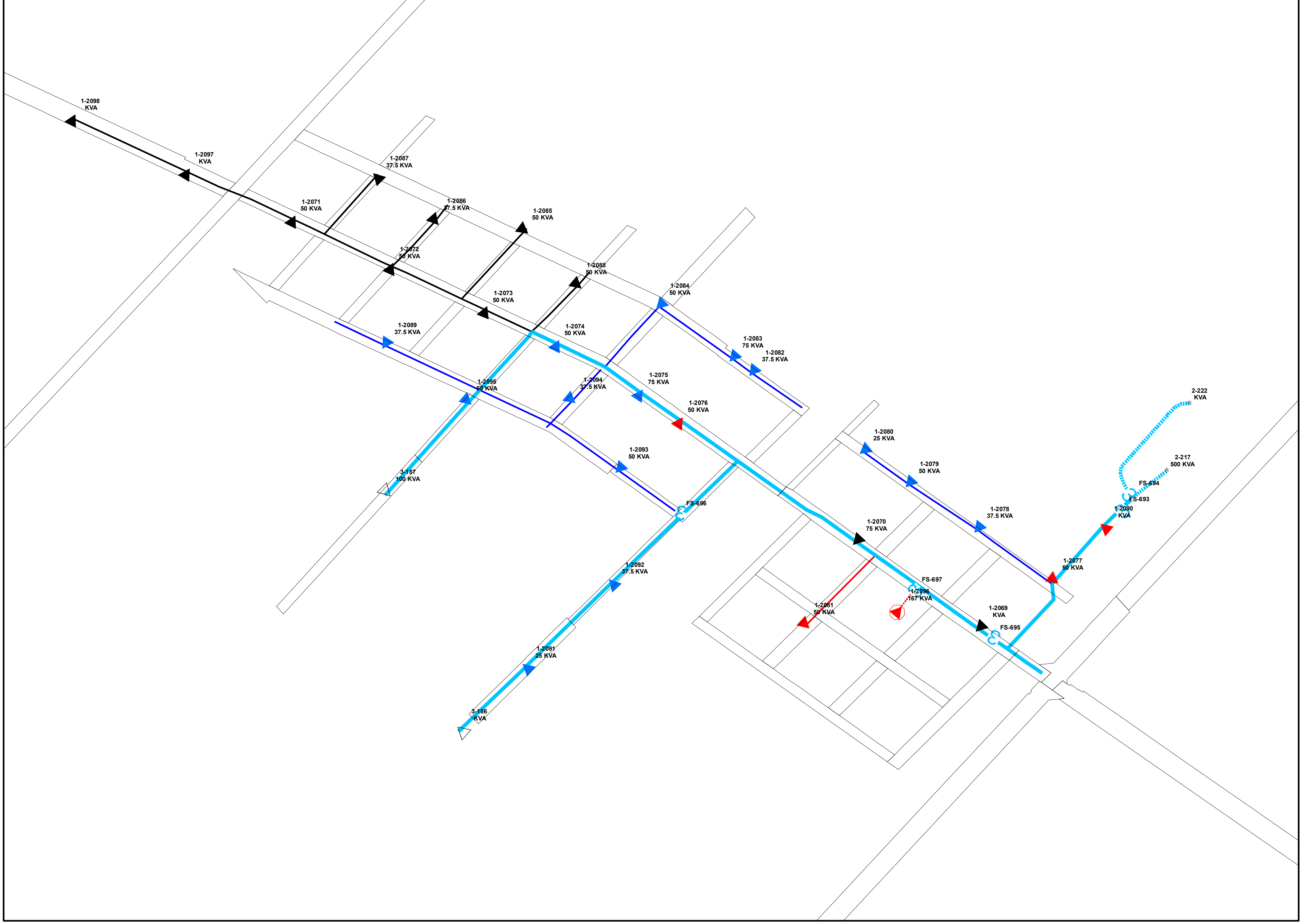

# Merlin

AUGUST 2015

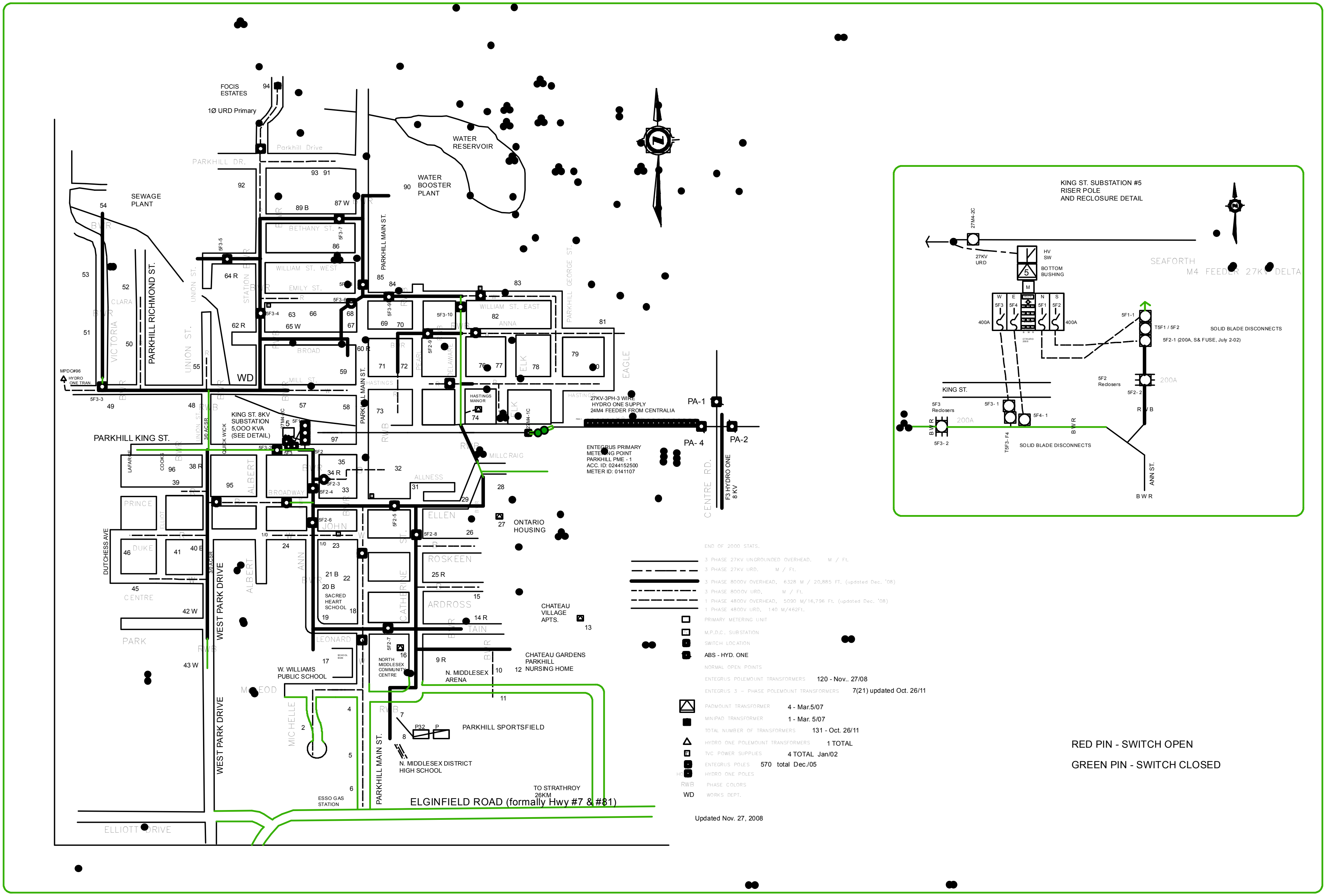


LEGEND
FLOOD LIGHTS
1,353 M / 4,443 FT. 1 Ø U.R.D. 4800V PRIMARY (updated Jan/06)
142 M / 466 FT. 3 Ø U.R.D. 8000V PRIMARY
4396 M / 14,513 FT. 1Ø OVERHEAD. 4800V (updated Oct. 5/11)
5357 M / 17,672 FT. 3Ø OVERHEAD. 8000V (updated July 19/10)
120 / 240V SEC. U.R.D.
120 / 240V SEC. OVERHEAD
SOLID DISCONNECT SW.
FUSED SWITCH / FUSE SIZE ( 40A )
NORMAL OPEN POINT
H. O. HYDRO ONE
13 1Ø MINI PAD TRANS. (updated Mar. 5/07)
3 3Ø PADMOUNT TRANS. (updated Dec. 23/09)
83 1Ø POLEMOUNT TRANS. M.P.D.C. (updated Oct. 5/11)
13(39) 3Ø POLEMOUNT TRANS. M.P.D.C. (updated July 19/10)
513 HYDRO POLE M.P.D.C. (updated July/10)
HYDRO POLE HYDRO ONE
STREET LIGHT/100 (RED) 150 (GREEN)
250 (YELLOW) WHPS
D/D DUSK to DAWN LIGHT
STREET LIGHT RELAY
STREET LIGHT RELAY PHOTO EYE
RECLOSURES
TVC POWER SUPPLIES(2)
TOTAL TRANSFORMERS:
138 - Oct. 5/11
ENTEGRUS POWERLINES INC.
(VILLAGE OF MOUNT BRYDGES)
TOWNSHIP OF STRATHROY-CARADOC
ELECTRICAL DISTRIBUTION SYSTEM
8.32 / 4.8 KV SYSTEM
0 50 100 150 200 METERS
July 29, 2005
SCALE 1 : 25. APPROX.
D/DRAWINGS/BASE/MTBRYDGESELSYS.dwg
Mt Brydges Service Area: 2.47 sq. km, 2003
RED PIN - SWITCH OPEN
GREEN PIN - SWITCH CLOSED
TOWNSHIP OF STRATHROY - CARADOC
VILLAGE LIMITS
HYDRO ONE CUSTOMERS
THOMPSON DR.
TO KOMOKA
CARADOC CENTRAL PUBLIC SCHOOL
CHESTNUT ST.
FORBES ST.
BOWAN ST.
GLENDON DR.
VETERANS DRIVE
LEGION
LUCAS AVE.
FOREST MEADOW DR.
EMERSON ST.
ADELAIDE RD.
QUEEN ST.
LIONS PARK DR.
TRI-TOWNSHIP ARENA
CARADOC COMMUNITY CENTRE
LIONS CLUB
PAVILIONS
HELEN ST.
CHURCHILL ST.
WOODWARD DR.
NATIONAL
CANADIAN
RAILWAYS
LONGFIELD ST.
RAILROAD ST.
GLOVER CRES.
BRUCE ST.
LONDON ST.
KING ST.
APPLEWOOD
HOOVER PL.
SEBURN DR.
CEMETERY
WESLEYAN ST.
WELLINGTON ST.
PAMELA DR.
LEITH CT.
HOLLIS CT.
THOMAS ST.
BENTIM RD.
MARR PL.
FRANKLIN ST.
GORE ST.
JOHN ST.
WILLIAM ST.
CHURCH ST.
HWY. No. 81
BARKER ST.
BENNETT CRES.
EDGEWOOD LANE
TRILLIUM WAY
PARKHOUSE DR.
ROUGHAM RD.
GLENDON DR. TO GLENCOE
MT.BRYDGES CUSTOMER OFF HYDRO ONE
SW286
SW281

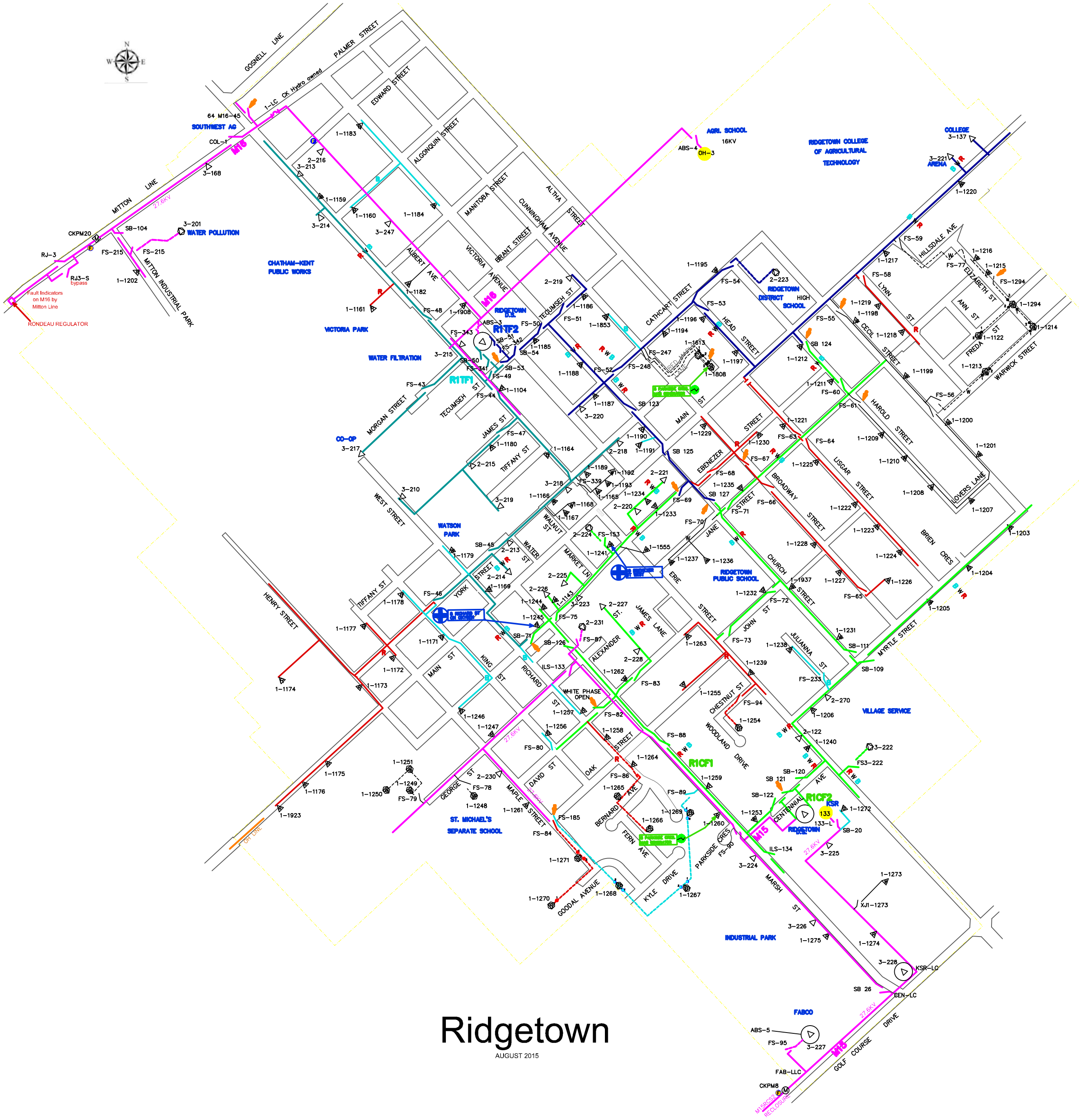
# Newbury



1-2098
KVA
1-2097
KVA
1-2087
37.5 KVA
1-2071
50 KVA
1-2086
37.5 KVA
1-2085
50 KVA
1-2072
50 KVA
1-2088
50 KVA
1-2084
50 KVA
1-2073
50 KVA
1-2089
37.5 KVA
1-2074
50 KVA
1-2083
75 KVA
1-2082
37.5 KVA
1-2095
50 KVA
1-2094
37.5 KVA
1-2075
75 KVA
1-2076
50 KVA
2-222
KVA
1-2080
25 KVA
3-187
100 KVA
1-2093
50 KVA
1-2079
50 KVA
2-217
500 KVA
FS-694
FS-693
FS-696
1-2078
37.5 KVA
1-2090
KVA
1-2070
75 KVA
1-2092
37.5 KVA
1-2077
50 KVA
FS-697
1-2096
167 KVA
1-2081
50 KVA
1-2069
KVA
FS-695
1-2091
25 KVA
3-186
KVA

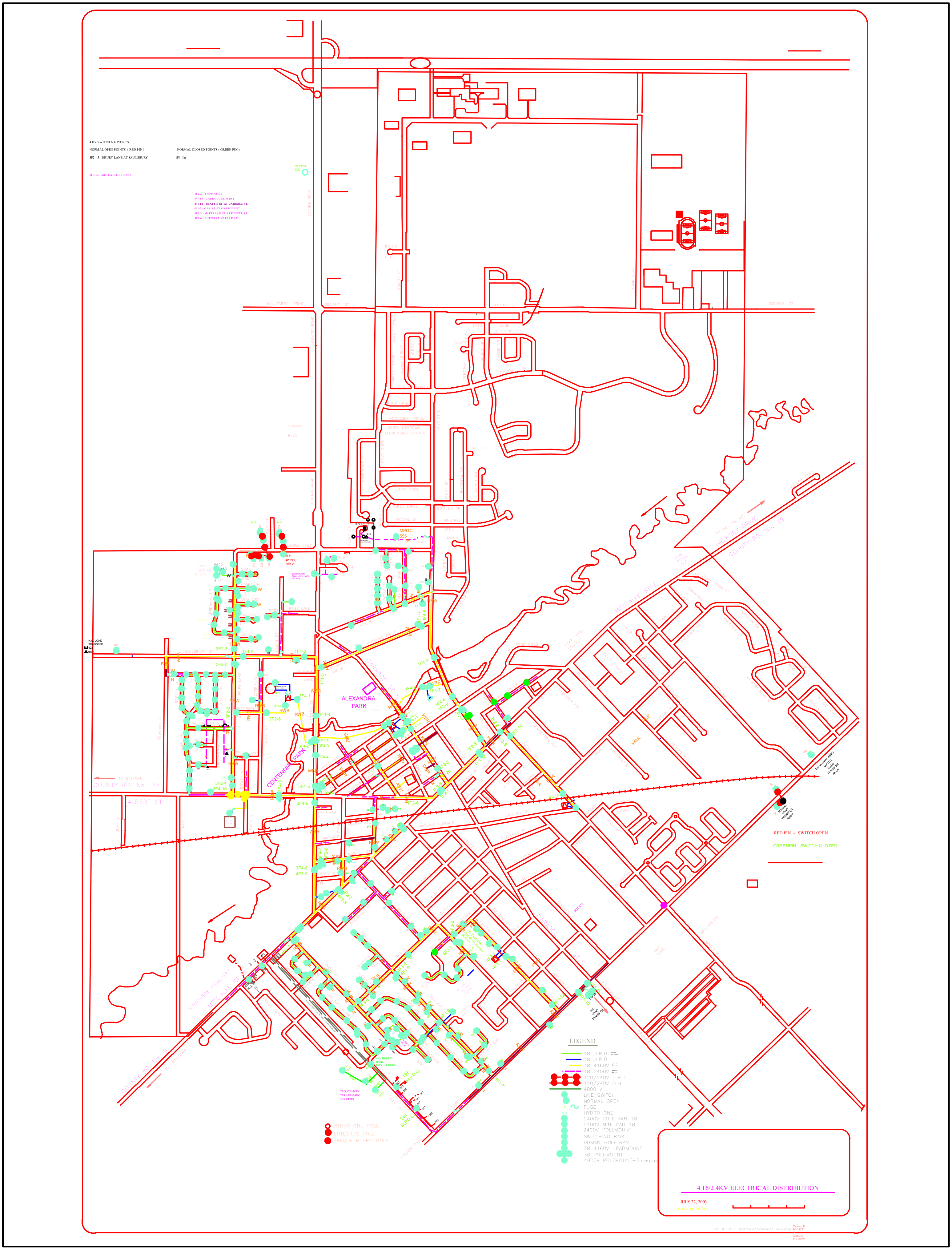


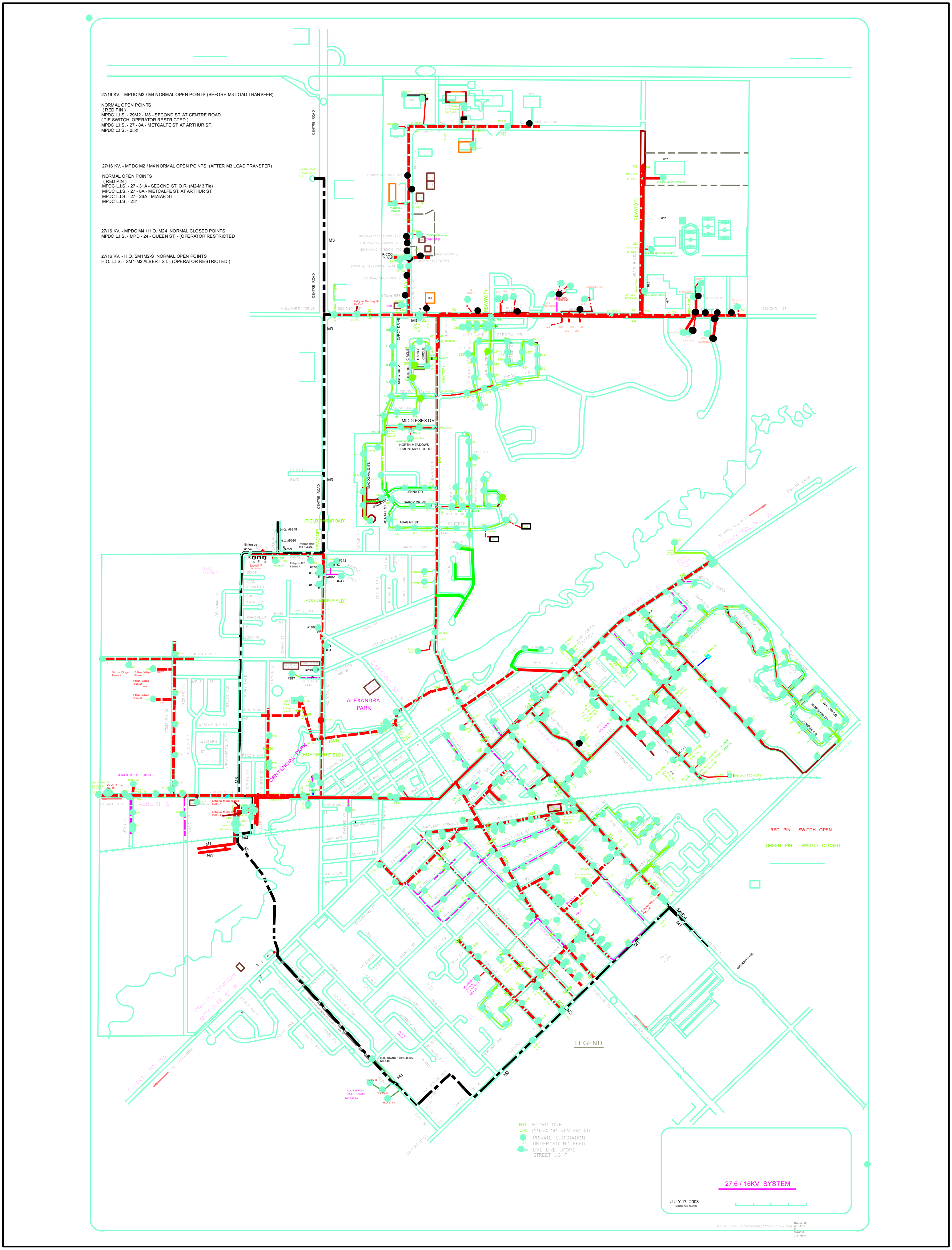
FOCIS ESTATES
1Ø URD Primary
SEWAGE PLANT
WATER RESERVOIR
WATER BOOSTER PLANT
PARKHILL RICHMOND ST.
PARKHILL MAIN ST.
PARKHILL KING ST.
KING ST. 8KV SUBSTATION 5,OOO KVA (SEE DETAIL)
WD
HASTINGS MANOR
27KV-3PH-3 WIRE HYDRO ONE SUPPLY 24M4 FEEDER FROM CENTRALIA
PA-1
PA-2
PA- 4
ENTEGRUS PRIMARY METERING POINT PARKHILL PME - 1 ACC. ID: 0244152500 METER ID: 0141107
F3 HYDRO ONE 8 KV
ONTARIO HOUSING
CHATEAU VILLAGE APTS.
CHATEAU GARDENS PARKHILL NURSING HOME
SACRED HEART SCHOOL
W. WILLIAMS PUBLIC SCHOOL
NORTH MIDDLESEX COMMUNITY CENTRE
N. MIDDLESEX ARENA
PARKHILL SPORTSFIELD
N. MIDDLESEX DISTRICT HIGH SCHOOL
ESSO GAS STATION
WEST PARK DRIVE
TO STRATHROY 26KM
ELGINFIELD ROAD (formally Hwy #7 & #81)
KING ST. SUBSTATION #5 RISER POLE AND RECLOSURE DETAIL
SEAFORTH M4 FEEDER 27KV DELTA
SOLID BLADE DISCONNECTS
KING ST.
ANN ST.
120 - Nov.. 27/08
7(21) updated Oct. 26/11
4 - Mar.5/07
1 - Mar. 5/07
131 - Oct. 26/11
1 TOTAL
4 TOTAL Jan/02
570 total Dec./05
ABS - HYD. ONE
RWB
WD
Updated Nov. 27, 2008
RED PIN - SWITCH OPEN
GREEN PIN - SWITCH CLOSED



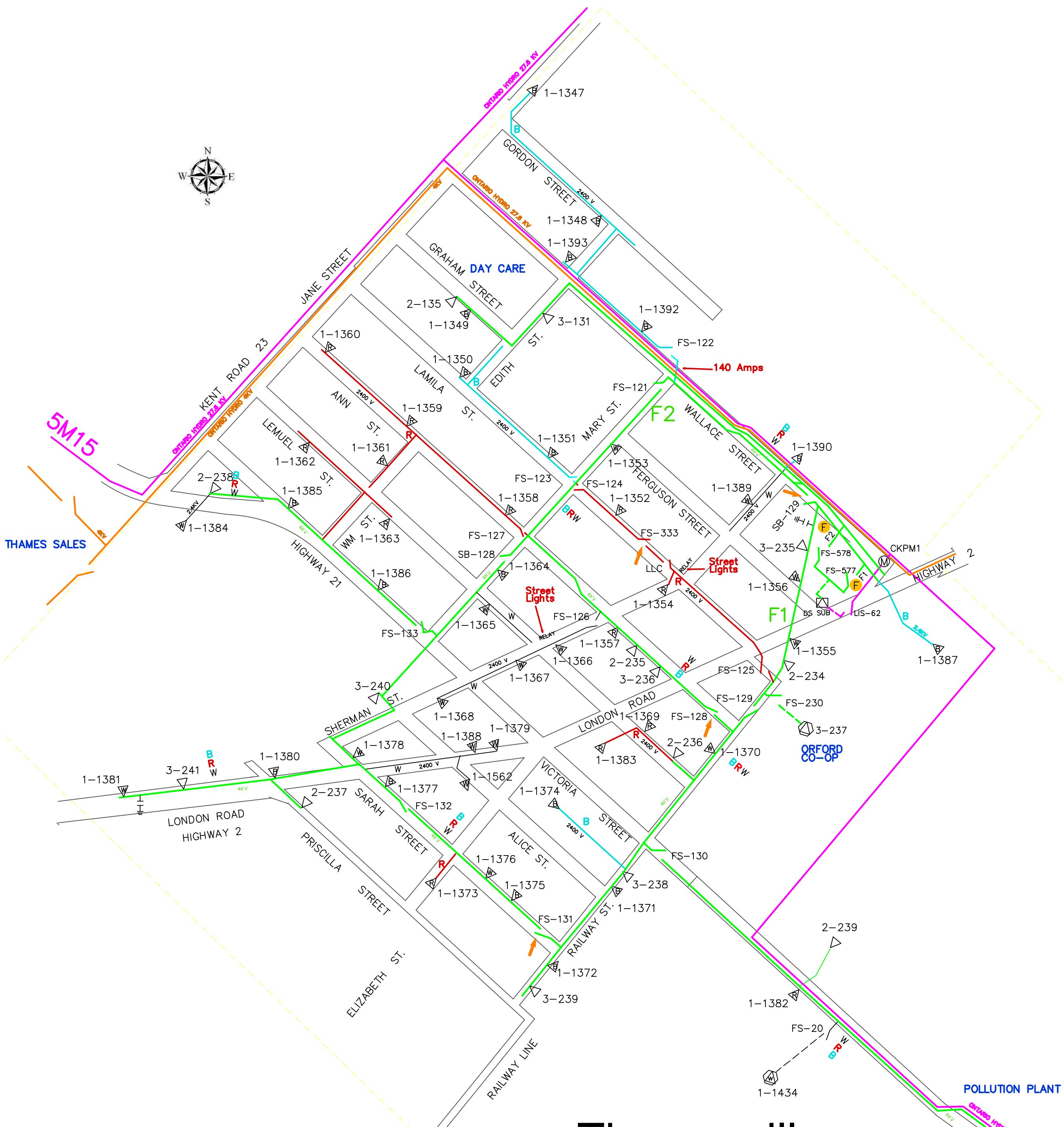

# Ridgetown

AUGUST 2015


4 KV SWITCHING POINTS
NORMAL OPEN POINTS ( RED PIN )
NORMAL CLOSED POINTS ( GREEN PIN )
3F2 - 5 - DRURY LANE AT SAULSBURY
1F1
1F3-12 - METCALFE ST. EAST
1F2-2 - THOMAS ST.
4F1-10 - CARROLL ST. WEST
4F1-12 - BEATTIE ST. AT CARROLL ST.
4F1-7 - OAK ST. AT CARROLL ST.
4F3-3 - McKELLAR ST. AT KEEFER ST.
4F3-6 - BURNS ST. AT PARK ST.
ALEXANDRA PARK
CENTENNIAL PARK
COUNTY RD. No. 39
ALBERT ST
METCALFE ST. E
MPDC
H.O. LOAD TRANSFER
COOP
RED PIN - SWITCH OPEN
GREENPIN - SWITCH CLOSED
LEGEND
1Ø U.R.D.
3Ø U.R.D.
3Ø 4160V
1Ø 2400V
120/240V U.R.D.
120/240V O.H.
4800 V
LINE SWITCH
NORMAL OPEN
FUSE
HYDRO ONE
2400V POLETRAN 1Ø
2400V MINI PAD 1Ø
2400V POLEMOUNT
SWITCHING BOX
DUMMY POLETRAN
3Ø 4160V PADMOUNT
3Ø POLEMOUNT
4800V POLEMOUNT–Entegrus
HYDRO ONE POLE
ENTEGRUS POLE
PRIVATE HYDRO POLE
4.16/2.4KV ELECTRICAL DISTRIBUTION
JULY 22, 2003
updated Apr. 16, 2015
File: M.P.D.C. d/drawings/base/4.16kv.dwg.
Cad no. D: ADCADD
9346010
416-24KV

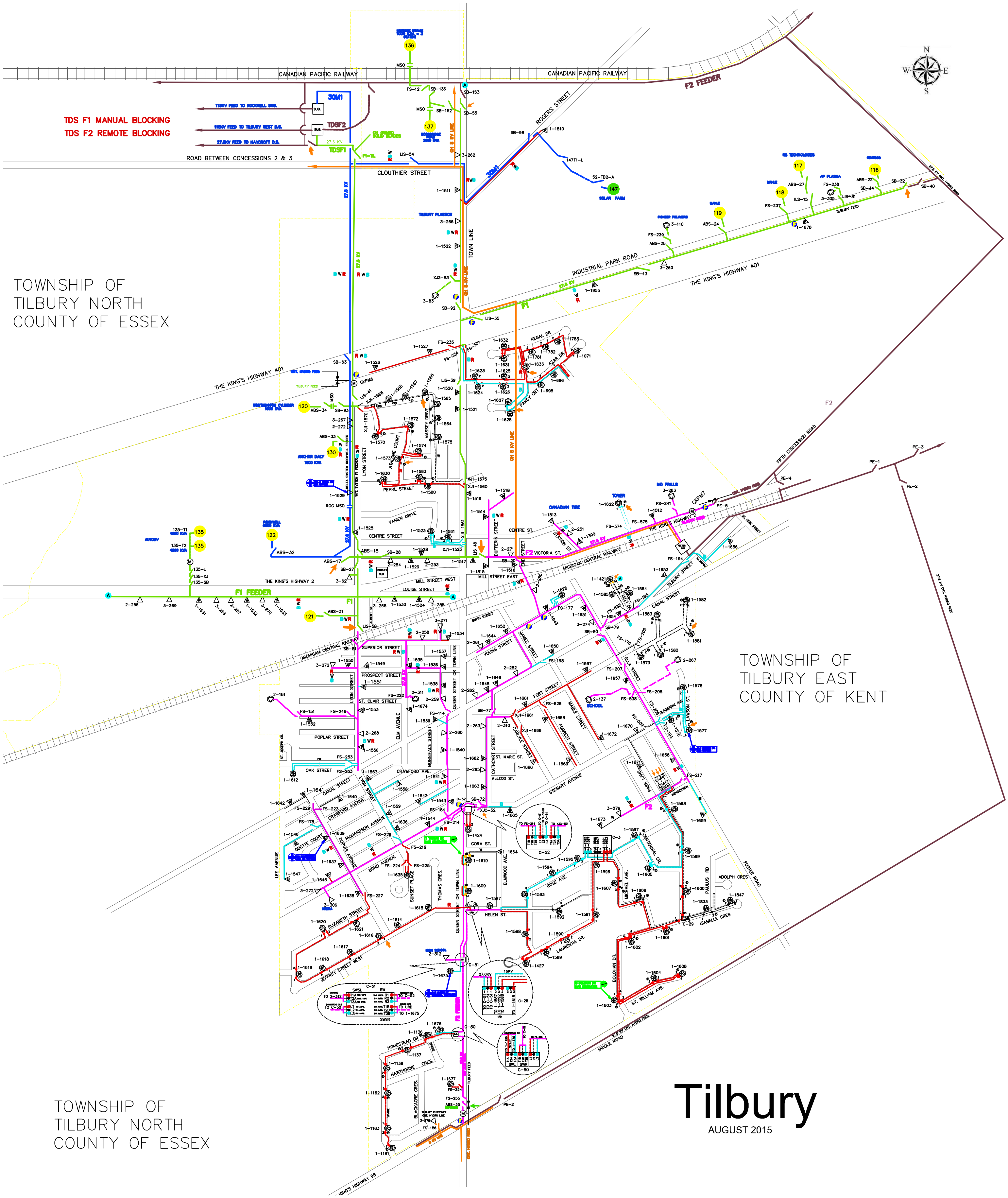


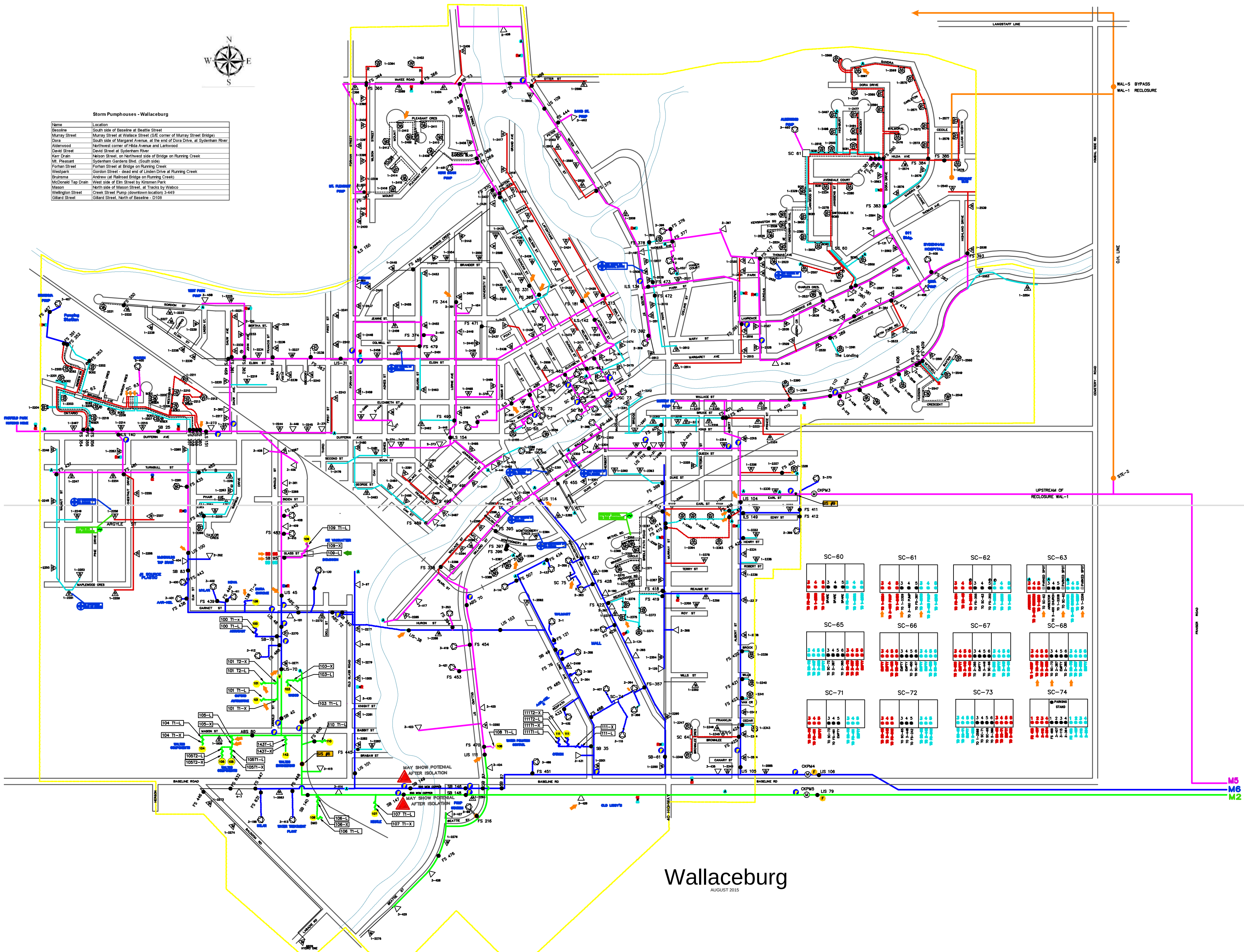
27/16 KV. - MPDC M2 / M4 NORMAL OPEN POINTS (BEFORE M3 LOAD TRANSFER)
NORMAL OPEN POINTS
( RED PIN )
MPDC L.I.S. - 29M2 - M3 - SECOND ST. AT CENTRE ROAD
( TIE SWITCH, OPERATOR RESTRICTED )
MPDC L.I.S. - 27 - 8A - METCALFE ST. AT ARTHUR ST.
27/16 KV. - MPDC M2 / M4 NORMAL OPEN POINTS (AFTER M3 LOAD TRANSFER)
NORMAL OPEN POINTS
( RED PIN )
MPDC L.I.S. - 27 - 31A - SECOND ST. O.R. (M2-M3 Tie)
MPDC L.I.S. - 27 - 8A - METCALFE ST. AT ARTHUR ST.
MPDC L.I.S. - 27 - 26A - McNAB ST.
27/16 KV. - MPDC M4 / H.O. M24 NORMAL CLOSED POINTS
MPDC L.I.S. - MPD - 24 - QUEEN ST. - (OPERATOR RESTRICTED
27/16 KV. - H.O. SM1M2-S NORMAL OPEN POINTS
H.O. L.I.S. - SM1-M2 ALBERT ST. - (OPERATOR RESTRICTED )
CENTRE ROAD
SECOND ST.
MIDDLESEX DR.
NORTH MEADOWS ELEMENTARY SCHOOL
JENNA DR.
DARCY DRIVE
ABAGAIL ST.
ALEXANDRA PARK
CENTENNIAL PARK
STRATHMERE LODGE
ALBERT ST.
METCALFE ST. E.
COUNTY RD. No. 39
COUNTY RD. No. 9
H.O. TRANS. 16KV.-4800V NO.340
RED PIN - SWITCH OPEN
GREEN PIN - SWITCH CLOSED
LEGEND
H.O. HYDRO ONE
O.R. OPERATOR RESTRICTED
PRIVATE SUBSTATION
UNDERGROUND FEED
LIVE LINE LOOPS
STREET LIGHT
27.6 / 16KV SYSTEM
JULY 17, 2003
updated April 15, 2015
File: M.P.D.C. d/drawings/base/27.6kv.dwg.
Cad no. D:
ADCADD
P
9346010
276-16KV




# Thamesville

AUGUST 2015


TOWNSHIP OF
TILBURY NORTH
COUNTY OF ESSEX
TOWNSHIP OF
TILBURY EAST
COUNTY OF KENT
TOWNSHIP OF
TILBURY NORTH
COUNTY OF ESSEX
TDS F1 MANUAL BLOCKING
TDS F2 REMOTE BLOCKING
CANADIAN PACIFIC RAILWAY
F2 FEEDER
F1 FEEDER
ROAD BETWEEN CONCESSIONS 2 & 3
CLOUTHIER STREET
ROGERS STREET
TOWN LINE
INDUSTRIAL PARK ROAD
THE KING'S HIGHWAY 401
THE KING'S HIGHWAY 2
FIFTH CONCESSION ROAD
MICHIGAN CENTRAL RAILWAY
QUEEN STREET OR TOWN LINE
MIDDLE ROAD
KING'S HIGHWAY 98
FOSTER ROAD
SOLAR FARM
N
S
E
W
Tilbury
AUGUST 2015

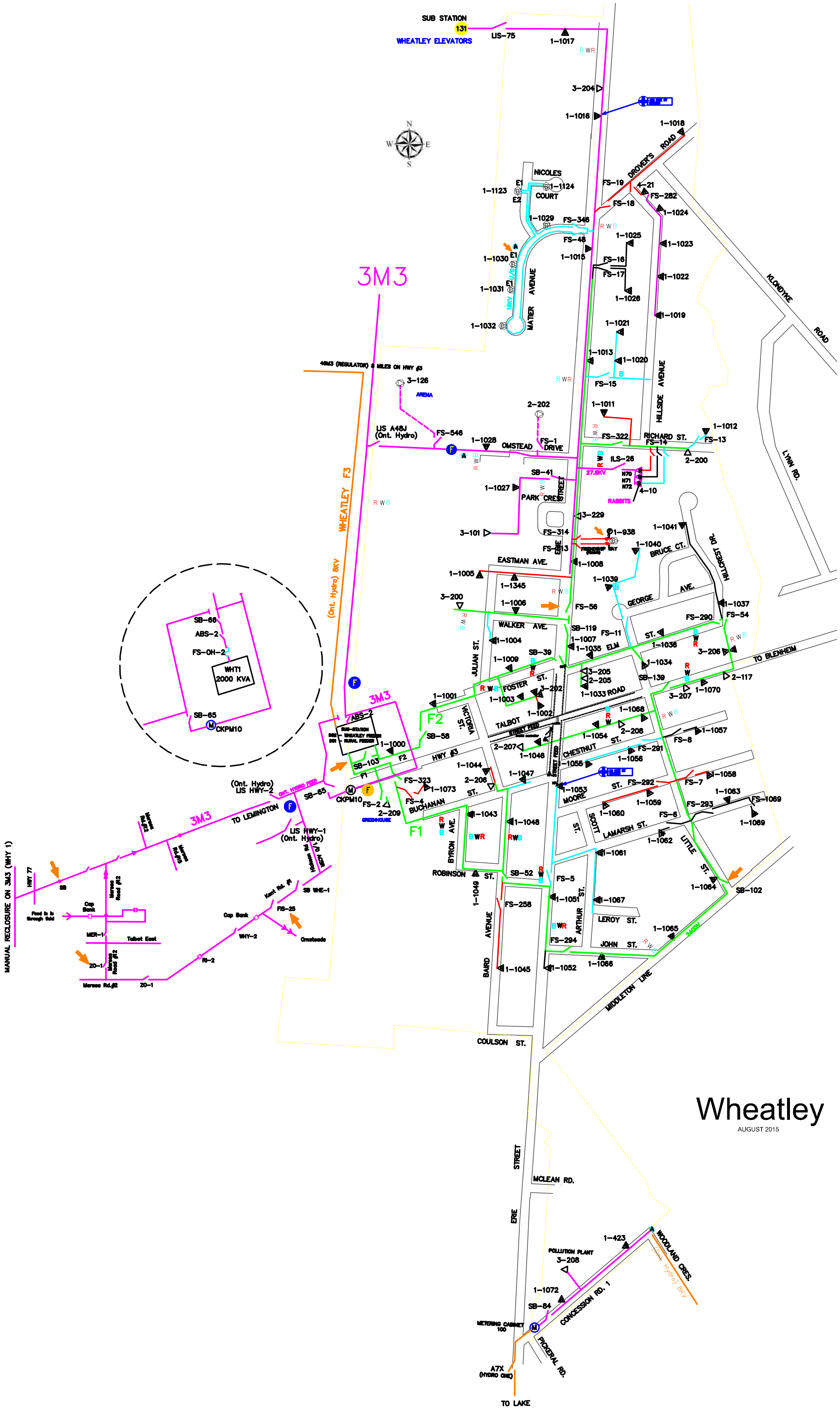



Wallaceburg

AUGUST 2015

## Storm Pumphouses - Wallaceburg

| Name | Location |
|---|---|
| Besoline | South side of Baseline at Beattie Street |
| Murray Street | Murray Street at Wallace Street (S/E corner of Murray Street Bridge) |
| Dora | South side of Margaret Avenue, at the end of Dora Drive, at Sydenham River |
| Alderwood | Northwest corner of Hilda Avenue and Larkwood |
| David Street | David Street at Sydenham River |
| Kerr Drain | Nelson Street, on Northwest side of Bridge on Running Creek |
| Mt. Pleasant | Sydenham Gardens Blvd. (South side) |
| Forhan Street | Forhan Street at Bridge on Running Creek |
| Westpark | Gordon Street - dead end of Linden Drive at Running Creek |
| Bruinsma | Andrew (at Railroad Bridge on Running Creek) |
| McDonald Tap Drain | West side of Elm Street by Kinsmen Park |
| Mason | North side of Mason Street, at Tracks by Wabco |
| Wellington Street | Creek Street Pump (downtown location) 3-449 |
| Gillard Street | Gillard Street, North of Baseline - D108 |



SUB STATION
131
WHEATLEY ELEVATORS
LIS-75
1-1017
3-204
1-1016
1-1018
DROVER'S ROAD
KLONDYKE ROAD
NICOLES COURT
1-1124
1-1123
1-1029
FS-346
FS-48
1-1015
1-1030
1-1031
1-1032
MATIER AVENUE
FS-19
4-21
FS-282
FS-18
1-1024
1-1025
1-1023
FS-16
FS-17
1-1022
1-1026
1-1019
1-1021
1-1013
1-1020
FS-15
HILLSIDE AVENUE
LYNN RD.
3M3
3-126
ARENA
2-202
1-1011
1-1012
FS-13
FS-546
LIS A48J (Ont. Hydro)
1-1028
OMSTEAD
FS-1 DRIVE
FS-322
RICHARD ST.
FS-14
2-200
ILS-26
27.6KV
N70
N71
N72
4-10
RABBITS
SB-41
1-1027
PARK CRES.
WHEATLEY F3
(Ont. Hydro) 8KV
3-229
3-101
FS-314
FS-313
1-938
1-1041
1-1040
BRUCE CT.
HILLCREST DR.
EASTMAN AVE.
1-1008
1-1005
1-1345
1-1039
3-200
1-1006
FS-56
GEORGE AVE.
1-1037
FS-290
FS-54
WALKER AVE.
SB-119
1-1007
FS-11
1-1035
ELM
ST.
1-1038
3-206
TO BLENHEIM
SB-66
ABS-2
FS-OH-2
WHT1 2000 KVA
SB-65
CKPM10
JULIAN ST.
1-1004
1-1009
SB-39
3-205
2-205
1-1033 ROAD
1-1034
SB-139
2-117
1-1070
3-207
FOSTER ST.
3-202
1-1001
1-1003
1-1002
3M3
F2
VICTORIA ST.
TALBOT
1-1068
ABS-2
1-1000
SB-58
2-208
1-1057
FS-8
1-1054
2-207
1-1046
CHESTNUT ST.
FS-291
1-1056
SB-103
F2
F1
HWY #3
1-1044
FS-323
1-1073
2-206
1-1047
1-1055
1-1058
FS-292
FS-7
1-1053
MOORE ST.
1-1063
FS-1069
(Ont. Hydro) LIS HWY-2
TO LEMINGTON
SB-65
CKPM10
FS-2
2-209
GREENHOUSE
FS-4
BUCHANAN ST.
1-1059
1-1060
FS-293
FS-6
SCOTT ST.
LAMARSH ST.
1-1062
1-1069
3M3
LIS HWY-1 (Ont. Hydro)
F1
1-1043
BYRON AVE.
1-1048
1-1061
LITTLE ST.
1-1064
SB-102
SB-52
ROBINSON ST.
1-1049
FS-5
1-1051
ARTHUR ST.
1-1067
FS-258
AVENUE
LEROY ST.
1-1065
FS-294
JOHN ST.
BAIRD
1-1045
1-1052
1-1066
MIDDLETON LINE
MANUAL RECLOSURE ON 3M3 (WHY 1)
HWY 77
SB
Cap Bank
MER-1
Talbot East
ZO-1
ZO-1
RI-2
WHY-2
FIS-25
SB WHE-1
Cap Bank
COULSON ST.
Wheatley
AUGUST 2015
ERIE STREET
MCLEAN RD.
1-423
WOODLAND CRES.
POLLUTION PLANT
3-208
1-1072
SB-84
CONCESSION RD. 1
METERING CABINET
PICKERAL RD.
A7X (HYDRO ONE)
TO LAKE

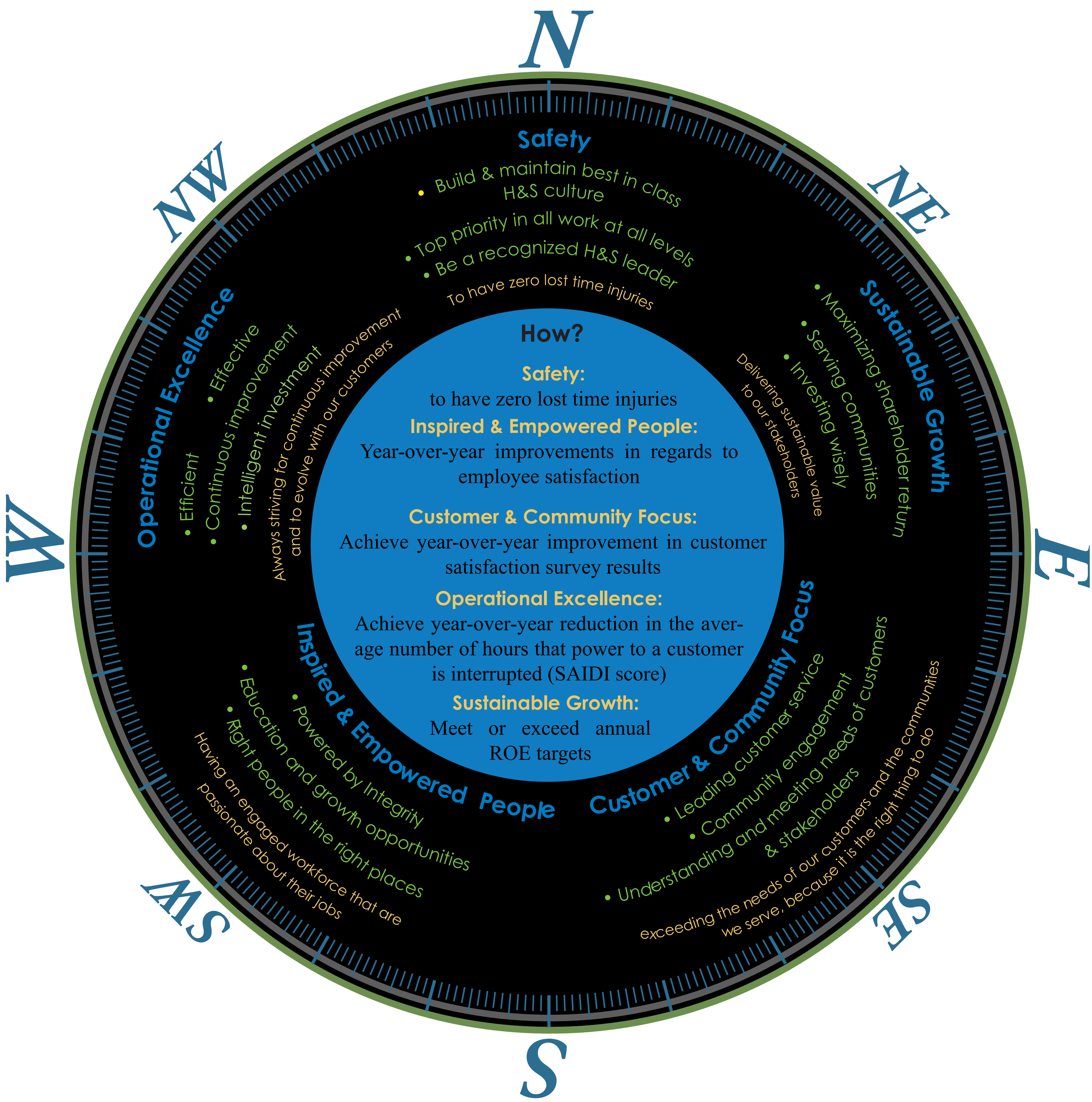
# ATTACHMENT 1-D

## The EPI Strategic Compass

ENTEGRUS®

# Vision

*To be an industry leader in all we do*




# Mission

*To provide safe, reliable delivery of electricity and related services, in an environmentally and fiscally responsible manner. To provide exceptional service to our customers, support to the communities we serve and rewarding growth opportunities for our employees.*

# ATTACHMENT 1-E

## The 2013 EPI Scorecard

# Scorecard - Entegrus Powerlines Inc.

9/24/2014

| Performance Outcomes | Performance Categories | Measures | 2009 | 2010 | 2011 | 2012 | 2013 | Trend | Target: Industry | Target: Distributor |
|---|---|---|---|---|---|---|---|---|---|---|
| **Customer Focus**<br>Services are provided in a manner that responds to identified customer preferences. | Service Quality | New Residential/Small Business Services Connected on Time | 97.80% | 97.60% | 93.80% | 92.00% | 97.00% | | 90.00% | |
| | | Scheduled Appointments Met On Time | 98.50% | 100.00% | 98.70% | 99.00% | 99.40% | | 90.00% | |
| | | Telephone Calls Answered On Time | 74.10% | 67.00% | 68.80% | 95.90% | 77.40% | | 65.00% | |
| | Customer Satisfaction | First Contact Resolution | | | | | | | | |
| | | Billing Accuracy | | | | | | | | |
| | | Customer Satisfaction Survey Results | | | | | | | | |
| **Operational Effectiveness**<br>Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives. | Safety | Public Safety [measure to be determined] | | | | | | | | |
| | System Reliability | Average Number of Hours that Power to a Customer is Interrupted | 0.70 | 1.33 | 0.88 | 1.18 | 1.23 | | | at least within 0.70 - 1.33 |
| | | Average Number of Times that Power to a Customer is Interrupted | 0.75 | 0.91 | 0.72 | 0.97 | 0.94 | | | at least within 0.72 - 0.97 |
| | Asset Management | Distribution System Plan Implementation Progress | | | | | | | | |
| | Cost Control | Efficiency Assessment | | | | 2 | 2 | | | |
| | | Total Cost per Customer [1] | $466 | $507 | $517 | $495 | $531 | | | |
| | | Total Cost per Km of Line [1] | $19,863 | $20,075 | $21,921 | $20,765 | $22,407 | | | |
| **Public Policy Responsiveness**<br>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 Annual Peak Demand Savings (Percent of target achieved) [2] | | | 13.00% | 11.00% | 11.30% | | | 12.12MW |
| | | Net Cumulative Energy Savings (Percent of target achieved) | | | 22.00% | 60.00% | 81.10% | | | 46.53GWh |
| | Connection of Renewable Generation | Renewable Generation Connection Impact Assessments Completed On Time | | | 60.00% | 60.00% | | | | |
| | | New Micro-embedded Generation Facilities Connected On Time | | | | | 100.00% | | 90.00% | |
| **Financial Performance**<br>Financial viability is maintained; and savings from operational effectiveness are sustainable. | Financial Ratios | Liquidity: Current Ratio (Current Assets/Current Liabilities) | 1.50 | 1.40 | 1.35 | 1.19 | 1.16 | | | |
| | | Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio | 0.80 | 1.31 | 1.27 | 1.28 | 1.22 | | | |
| | | Profitability: Regulatory Return on Equity — Deemed (included in rates) | | | | 9.85% | 9.85% | | | |
| | | Profitability: Regulatory Return on Equity — Achieved | | | | 7.61% | 7.61% | | | |

**Notes:**
1. These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor's annual reported information.
2. The Conservation & Demand Management net annual peak demand savings do not include any persisting peak demand savings from the previous years.

**Legend:**
- up
- down
- flat
- target met
- target not met

# Management Discussion and Analysis for Year 2013

**Service Quality**

Entegrus continues to meet and exceed all industry service quality targets. The 2013 telephone metric, although above historical averages, declined versus the prior year due to redeployment of resources for optimal benefit.

**Customer Satisfaction**

Customer satisfaction has always been an ongoing area of focus for Entegrus. In 2013 and 2014, Entegrus continued to pursue measures to enhance the customer experience, including: additional customer service training, a new phone system, a new website, a new customer billing information portal and the launch of social media. The 3 newly prescribed Customer Satisfaction methodologies shown on the scorecard were introduced by the regulator in 2014. Results for the latter half of 2014 will be reported in 2015.

**Safety**

Safety is a top priority for Entegrus. In 2013, Entegrus was awarded with the Infrastructure Health & Safety Association ("IHSA") ZeroQuest Sustainability Level. Entegrus is now seeking to be amongst the first Ontario electrical distributors to be recognized with the new IHSA Certificate of Recognition. Entegrus is a key sponsor of the local Safety Village and provides staffing to educate school children on public electrical safety. In addition, Entegrus is audited annually by the Electrical Safety Authority ("ESA"). These audits assess the safety of our electrical distribution system in relation to the public, and Entegrus has successfully passed each audit. This overall focus on safety resulted in Entegrus achieving a Lost Time Due to Injury rate of zero in 2013. The regulator has indicated that a new public safety measure for Ontario electrical distributors will be introduced in the latter half of 2014.

**System Reliability**

Entegrus continues to meet all regulated system reliability targets, and continues to apply a rigorous capital and maintenance program to sustain our distribution system and minimize outages.

**Asset Management**

The Entegrus engineering team will complete a formalized risk-based Asset Management Plan in 2014 in the format prescribed by the regulator. This Asset Management Plan will be part of a comprehensive Consolidated Distribution System Plan, which will include asset management and replacement, as well as grid modernization. The newly prescribed Consolidated Distribution System Plan is currently approximately 50% complete.

**Cost Control**

For 2013, Entegrus costs were 12.3% lower than the cost level predicted by the regulator's econometric model. Accordingly, Entegrus continues to be ranked in the second most efficient grouping of Ontario electrical distributors (there are five groups in total). Note that the Total Cost per Customer and Total Cost per Km of Line figures shown on the scorecard do not reflect Entegrus' actual costs. Rather, these figures represent econometric values derived by the regulator in order to rank Ontario electrical distributors on a comparative "same size" basis. Please refer to the footnote to the scorecard provided by the regulator further describing the benchmarking process. Entegrus' actual Total Operating, Maintenance & Administrative Expenses for 2013 were $237 per customer.

**Conservation & Demand Management**

The current conservation target period runs from January 1, 2011 to December 31, 2014. Net cumulative energy savings results carry over and are summed each year. Entegrus is on track to meet its net cumulative energy savings target by December 31, 2014. Net annual peak demand savings are measured at a point in time and are non-cumulative. In accordance with its conservation strategy, Entegrus is aggressively marketing peak demand conservation programming in 2014 in order to meet the net annual peak demand savings target.

**Connection of Renewable Generation**

In 2013, Entegrus exceeded the target for New Micro-embedded Generation Facilities Connected on Time. Entegrus did not receive any Renewable Generation Connection Impact Assessment application requests in 2013.

**Financial Ratios**

Entegrus remains liquid and its leverage is well within the regulated guidelines and provides sufficient capital to fund future distribution system needs.  This financial capacity is further supported by the recent Standard & Poor’s Rating Services rating of "A/Stable/--" for Entegrus Inc., the parent company of Entegrus Powerlines Inc.  Subsequent to the acquisitions of Middlesex Power, Dutton Hydro and Newbury Power, Entegrus has achieved a stable rate of return while providing customers with a period of distribution rate stability.

# ATTACHMENT 1-F

## The 2014 EPI Scorecard

(Draft)

# Scorecard - Entegrus Powerlines Inc.

8/7/2015

| Performance Outcomes | Performance Categories | Measures | | 2010 | 2011 | 2012 | 2013 | 2014 | Trend | Target: Industry | Target: Distributor |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Customer Focus**<br>Services are provided in a manner that responds to identified customer preferences. | Service Quality | New Residential/Small Business Services Connected on Time | | 97.60% | 93.80% | 92.00% | 97.00% | 98.80% | ↑ | 90.00% | |
| | | Scheduled Appointments Met On Time | | 100.00% | 98.70% | 99.00% | 99.40% | 98.00% | ↓ | 90.00% | |
| | | Telephone Calls Answered On Time | | 67.00% | 68.80% | 95.90% | 77.40% | 72.70% | ↑ | 65.00% | |
| | Customer Satisfaction | First Contact Resolution | | | | | | 76% | | | |
| | | Billing Accuracy | | | | | | 99.73% | → | 98.00% | |
| | | Customer Satisfaction Survey Results | | | | | | 92% | | | |
| **Operational Effectiveness**<br>Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives. | Safety | Level of Public awareness [measure to be determined] | | | | | | | | | |
| | | Level of Compliance with Ontario Regulation 22/04 | | NI | NI | C | C | C | ↑ | | 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 | | 1.33 | 0.88 | 1.18 | 1.23 | 1.31 | ↑ | | at least within 0.88 - 1.33 |
| | | Average Number of Times that Power to a Customer is Interrupted | | 0.91 | 0.72 | 0.97 | 0.94 | 0.84 | ↑ | | at least within 0.72 - 0.97 |
| | Asset Management | Distribution System Plan Implementation Progress | | | | | | 80% | | | |
| | Cost Control | Efficiency Assessment | | | | 2 | 2 | 2 | | | |
| | | Total Cost per Customer [1] | | $507 | $517 | $495 | $531 | $533 | | | |
| | | Total Cost per Km of Line [1] | | $20,075 | $21,921 | $20,765 | $22,407 | $22,585 | | | |
| **Public Policy Responsiveness**<br>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 Annual Peak Demand Savings (Percent of target achieved) | | | 13.00% | 11.00% | 11.30% | | | | 12.12MW |
| | | Net Cumulative Energy Savings (Percent of target achieved) | | | 22.00% | 60.00% | 81.10% | | | | 46.53GWh |
| | Connection of Renewable Generation | Renewable Generation Connection Impact Assessments Completed On Time | | | 60.00% | 60.00% | | 100.00% | | | |
| | | New Micro-embedded Generation Facilities Connected On Time | | | | | 100.00% | 100.00% | | 90.00% | |
| **Financial Performance**<br>Financial viability is maintained; and savings from operational effectiveness are sustainable. | Financial Ratios | Liquidity: Current Ratio (Current Assets/Current Liabilities) | | 1.40 | 1.35 | 1.19 | 1.16 | 1.61 | | | |
| | | Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio | | 1.31 | 1.27 | 1.28 | 1.22 | 1.44 | | | |
| | | Profitability: Regulatory Return on Equity | Deemed (included in rates) | | | 9.85% | 9.85% | 9.85% | | | |
| | | | Achieved | | | 7.61% | 7.61% | 9.63% | | | |

**Notes:**
1. These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor's annual reported information.

**Legend:** ↑ up ↓ down → flat
target met target not met

# ATTACHMENT 1-G

## Customer Engagement Activities

### Board Appendix 2-AC

| | |
|---|---|
| **File Number:** | EB-2015-0061 |
| **Exhibit:** | 1 |
| **Attachment:** | 1-G |
| **Page:** | 1 of 1 |
| **Date:** | 28-Aug-15 |

# Appendix 2-AC
## Customer Engagement Activities Summary

| **Provide a list of customer engagement activities** | **Provide a list of customer needs and preferences identified through each engagement activity** | **Actions taken to respond to identified needs and preferences. If no action was taken, explain why.** |
|---|---|---|
| Customer phone calls related to new accounts, bill inquiries, etc. (Ongoing) | 1 Reminded of the need to focus on affordable rates<br>2 Identified need to assist customers with billing and energy literacy information<br>3 Identified need for e-billing and self-service options | 1 Continued focus on monitoring of bill impacts and maintaining competitive distribution rates<br>2 Redesigned the EPI website in 2014 to provide additional customer information. Created explanatory customer videos to explain key concepts and assist with further engagement activities. Additional videos to launch in 2016.<br>3 Marketed e-billing service and launched "My Account" (self-service portal) in 2014 |
| Customer phone calls related to storms and outages, maintenance projects and vegetation management (Ongoing) | 1 Identified need for social media information source on storm outages<br>2 Identified need to provide customers with more on-line information with regard to outages, including visual depiction | 1 Launched social media channels (Twitter and Facebook) in 2014<br>2 Implementation of OMS with linkage to distribution system mapping in order to display the outage geographically on the EPI website for late 2015 |
| Bill inserts and semi-annual rate update brochures (Ongoing) | 1 Identified need for enhancements to brochures to increase their effectiveness and better assist with energy literacy. | 1 Added more explanatory content to rate brochures starting in 2013 and improved layout.<br>2 Added explanatory letters to complement the rate brochures for certain customers and rate classes. |
| Commercial and industrial account meetings (Ongoing) | 1 Identified need for additional focus on industrial power quality due to the susceptibility of modern machinery to minor fluctuations<br>2 Identified need for more immediate and additional access to consumption management information for the larger volume rate classes<br>3 Assistance with Global Adjustment Class A versus Class B considerations | 1 Implementation of a power quality program in 2016, including monitoring devices and engineering resources, to assess and mitigate these impacts.<br>2 Enhancements to "My Account" on-line consumption management tool for late 2015<br>3 Provided background information and assessment considerations re Global Adjustment |
| Commercial & Industrial Conservation Conferences (2013 & 2015) | 1 Identified the need and opportunity for additional site visits and program assistance by the conservation team<br>2 Identified need for additional focus on industrial power quality due to the susceptibility of modern machinery to minor fluctuations | 1 Additional site visits and program assistance provided by conservation team.<br>2 Implementation of a power quality program in 2016, including monitoring devices and engineering resources, to assess and mitigate these impacts. |
| Community Conservation Events (Ongoing) | 1 Identified need to assist customers with billing and energy literacy information<br>2. Identified need for additional information on save-on-energy programs | 1 Redesigned the EPI website in 2014 to provide additional customer information. Created explanatory customer videos to explain key concepts and assist with further engagement activities.<br>2 Provide bill inserts regarding save-on-energy programs and include conservation content in rate brochures. Add additional website content on conservation. |
| Children's Safety Village (Ongoing) | 1 Identified that there is a high degree of appetite to educate on electrical safety at the grade school level | 1 Continue with Safety Village and in school teaching opportunities to reinforce electrical safety at a young age |
| Website & Social Media (Ongoing) | 1 Identified need to assistance community with energy literacy<br>2. Identified need to provide more on-line information with regard to outages, including mapping enhancements to display the outage geographically | 1 Created and launched website videos explaining vital energy literacy concepts<br>2 Implementation of OMS with linkage to distribution system mapping on website planned for launch in late 2015 |
| St. Clair College Powerline Maintainer Program (Ongoing) | 1 Identified the need for the community to train and retain skilled people available to enter the workforce<br>2 This corresponds with EPI's need to have ready access to trained and locally-situated skilled labour | 1 Support the program with senior management board and instructor participation<br>2 Support the program with scrap material and out-of-date tools for teaching purposes<br>3 Hire EPI's lines co-ops from the program |
| Holiday Meal Preparation for Citizens in Need (Ongoing each Nov/Dec) | 1 Reminded that some EPI customers are in challenging personal and financial circumstances | 1 Continued employee empathy and sensitivity to community interaction and account collection activities<br>2 Continued focus on monitoring of bill impacts and maintaining competitive distribution rates |
| Customer Surveys by Convergys - Customer Satisfaction & First Call Resolution (2014-2015) | 1 Identified coaching opportunities for customer service reps<br>2 Identified need to continue to focus on power quality and reliability for industrial customers<br>3 Identified need to market and generate more awareness of existing self service options<br>4 Identified need to provide more billing and energy literacy information to customers | 1 Work with a consultant to provide Customer Service Reps with access to an on-line portal that compares their ongoing individual survey results against aggregate departmental results<br>2 Implementation of a power quality program in 2016, including monitoring devices and engineering resources, to assess and mitigate these impacts.<br>3 Additional marketing in 2015 to drive awareness of customer opportunities to use existing on-line consumption management tools.<br>4 Redesigned the EPI website in 2014 to provide additional customer information. Created explanatory customer videos to explain key concepts and assist with further engagement activities. Additional videos to launch in 2016. |
| Customer Surveys & Focus Groups by Innovative Research - Rates Application & Other Measures (2015) | 1 Identified need to provide more billing and energy literacy information to customers<br>2 Identified need to provide customers with more on-line information with regard to outages, including visual depiction<br>3 Identified need to focus on affordable rates<br>4 Identified need to focus on improving reliability, including replacement aging assets, modernization of the distribution system and focus on power quality and reliability for industrial customers | 1 Continued focus on monitoring of bill impacts and maintaining competitive distribution rates<br>2 Redesigned the EPI website in 2014 to provide additional customer information. Created explanatory customer videos in 2015 to explain key concepts and assist with further engagement activities. Additional videos to launch in 2016.<br>3 Continued focus on monitoring of bill impacts and maintaining competitive distribution rates.<br>4 The risk-based EPI DSP addresses reliability, replacement of aging assets, modernization of the distribution system and power quality. Specific to power quality, a program will be implemented in 2016, including monitoring devices and engineering resources, to assess and mitigate these impacts. |
| | | |
| | | |

**Note: Use "ALT-ENTER" to go to the next line within a cell**

# ATTACHMENT 1-H

## Convergys Top-Down Survey

# Entegrus Top-Down Survey

Convergys Analytics

*January, 2015*

# Top Down Survey Overview & Methodology

## Objective

- Gather Customer Satisfaction metrics to be used for OEB and scorecard reporting.
- Canvas Customer Satisfaction in the following areas: Power Quality and Reliability, Price, Billing/Payments, Communication, and Customer Service Experience

## Timing

- Surveying conducted October 21 – November 7, 2014

## Methodology

- Telephone survey conducted by a Convergys live agent

## Sampling

- Random sample of Entegrus customer base
- 600 completed surveys – 500 Residential completes and 100 Business completes

## Question Scales & Reporting

- Satisfaction asked on a 5 (Very Satisfied) to 1 (Not at all Satisfied) scale
- Top 3-Box (3, 4 and 5 ratings) reporting used for reporting of survey attributes





CONVERGYS

## Agenda

*Today's topics for discussion.*

1. Overview & Key Findings
2. Ontario Energy Board Metrics
3. Customer Satisfaction & Key Drivers
4. Customer Touch Points & Feedback
5. Recommendations

# Our objective as a business partner is to help Entegrus increase Customer Satisfaction.

## Increase customer satisfaction

How we do this…

- Outline what factors have the largest impact on satisfaction
- Identify differences in Business and Residential customer segments
- Identify underperforming areas to target for improvement
- Mine customer comments to determine what common themes reflect opportunities for improvement

## Improve customer interactions

How we do this…

- Working smarter to serve customers better by identifying and optimizing self-service opportunities
- Provide recommendations to improve the customer's experience when they do need to contact customer service

# Key Findings

- Overall Satisfaction (92%), but there are opportunities to improve the Customer Experience
- Some differences exist between Business and Residential Customers
  - Unique drivers of Satisfaction for Business and Residential
    - Top Satisfaction driver for Businesses is Overall Quality of Customer Service
    - Top Satisfaction driver for Residential is Value of Service
  - Slightly higher Overall Satisfaction for Residential Customers
  - Business Customers have a higher preference for email communication than Residential Customers
- Primary Opportunities for Improvement Include:
  - **Providing Tools to Manage Consumption** – Customers want to better understand how to manage their costs
  - **Billing** – Accuracy of billing is important to customers. The transactional study will provide additional insight into customer concerns and solutions
  - **Affordability** – Continued education of rates, fees and ways to reduce expenses will help improve Customer perception of pricing
  - **Self-Service** – To reduce contacts, enhance online and self-service Billing & Payment capabilities

# Ontario Energy Board Metrics

# Ontario Energy Board (OEB) Requirements

*Effectiveness and improvement in customer focus.*

The following measures will serve as the baseline for Entegrus' performance relative to Customer Satisfaction.

| | |
|---|---|
| Overall Satisfaction | 92% |
| Quality and Reliability of Power Service | 97% |
| Communication Satisfaction | 93% |
| Customer Service Experience | 93% |
| Price | 71% |
| Billing Satisfaction | 92% |
| First Contact Resolution* | 75% |

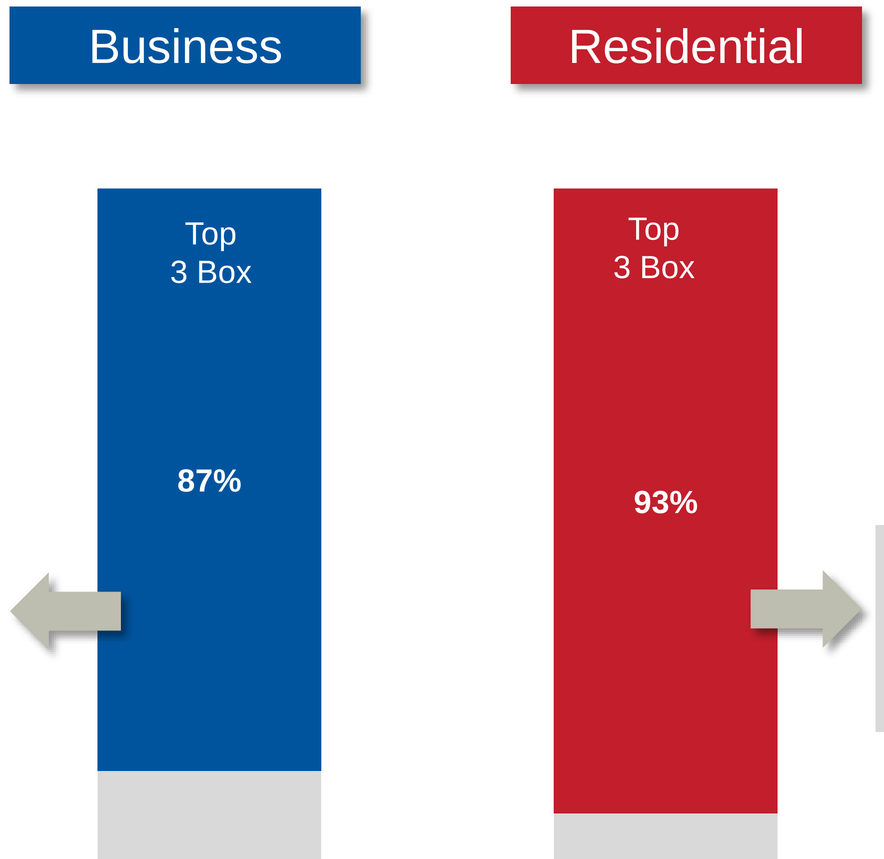
*First Contact Resolution (FCR) is measured by Transactional surveys that occur after a customer interaction (data from Oct-Dec 2014). All other measures are from the "Top-Down" survey which measures the entire customer experience.

Composite measures: Billing Satisfaction – Billing accuracy, ease of understanding, ease of access; Communication Satisfaction – Easy to understand, timeliness, accuracy, ease of access
Ratings represent top 3 box on a 5-point scale

# Customer Satisfaction & Key Drivers

# Customer Satisfaction

*Overall satisfaction is high, but opportunities for improvement exist, more so for Business Customers.*




**Reasons for Rating** (Business)

No Issues – 61%
Pricing too High – 27%
Billing Issues – 11%

**Reasons for Rating** (Residential)

No Issues – 53%
Pricing too High – 35%
Not Perfect/Don't give top ratings – 9%

Overall satisfaction for Residential Customers is significantly higher than Business Customers. Reasons for Rating based on customer comments.

## Key Drivers Introduction

*Key Drivers help us to understand what is most important to Customers and where to focus efforts to have the greatest impact on Overall Satisfaction.*

Pre-Step: Pare down the 15 attributes included in the survey into 7 more simplified groups, which represent all aspects of Customer touch points

1. What are the attribute groups' relationship to Satisfaction?

   *Action: Calculate each attribute groups' correlation to Satisfaction*

2. If all attribute groups have a moderate to strong relationship to Satisfaction, how can attribute groups be prioritized?

   *Action: Calculate the Relative Importance*

3. Once a Relative Importance model is developed, how much does it explain Satisfaction?

   *Action: Calculate the proportion of variance that explains Satisfaction*

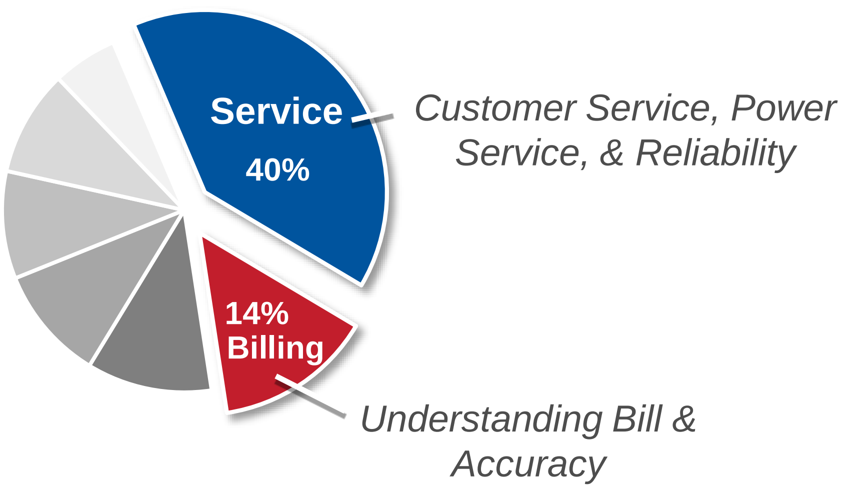
# Key Drivers

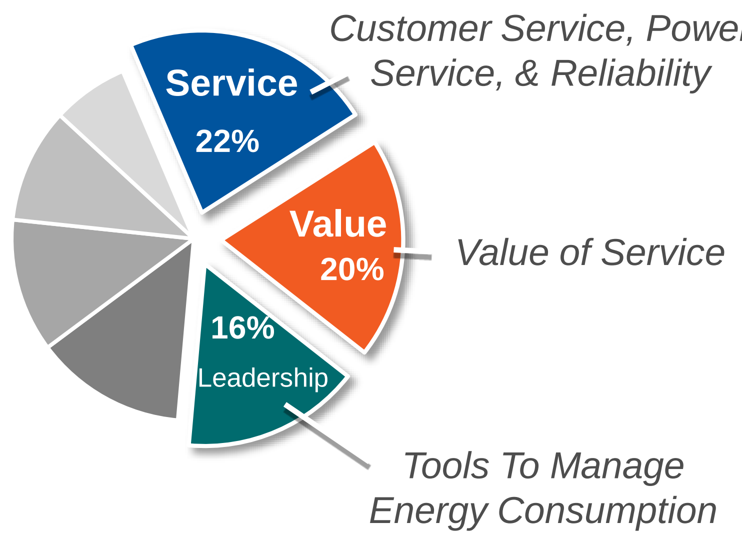
*The drivers of Overall Satisfaction differ somewhat between Business and Residential Customers.*



% Variance explained: 56%

% Variance explained: 48%







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# Customer Touch Points & Feedback

# Customer Contact

*Business customers are more likely to have contacted Entegrus than Residential customers.*

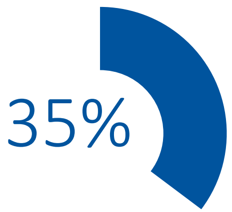
Customers who made a contact are less satisfied with ***Quality of Power Service***, ***Reliability***, and ***Ease of Understanding Your Bill*** than customers who did not contact in the past 6 months.

**Contact in Past 6 Months?**
*(% Yes)*

**Expectations Met?**
*(% Yes)*

**Top Contact Methods***
(By Volume)

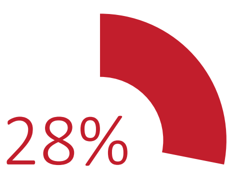
*Business*





Telephone: 100%
Email: 6%

*Residential*





Telephone: 94%
Email: 5%

** Note: Multi-select; responses may add to more than 100%*

*Differences in Business & Residential ratings are not statistically significant.*



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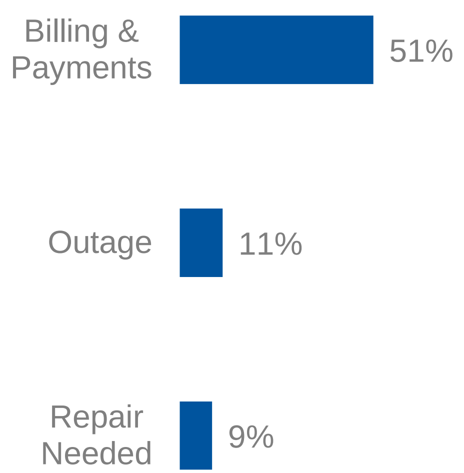
# Contact Reasons

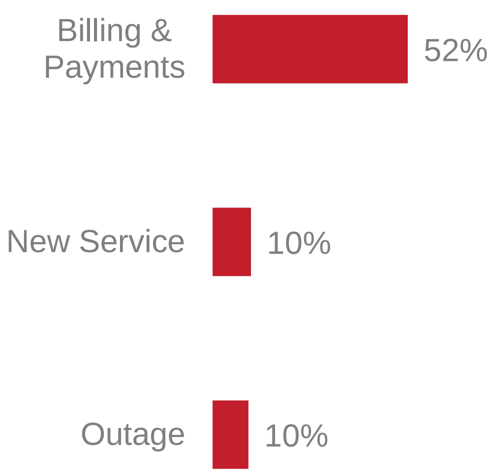
*Billing & Payments are the primary reason that Customers contacted Entegrus.*

Transactional surveys will provide more insight into the reasons that Customers contact Entegrus and opportunities to improve Satisfaction.

## *Business*




## *Residential*



# Contact Handling Findings & Opportunities

| # | Finding | Opportunity | Customer Feedback |
|---|---|---|---|
| 1 | **1 in 3 Business Customers contacted and 29% did not have expectations met.** | Focus on meeting Business Customer expectations. | *"The rates keep going up and the hydro keeps going off, which costs us money."* |
| 2 | **Half of Business and Residential contacts were for billing and payments.** | Increase awareness and enhance online self-service options to reduce the need for contacts. | *"I needed some billing information when I misplaced my bill."* <br> *"To get information on and pay my hydro bill."* |





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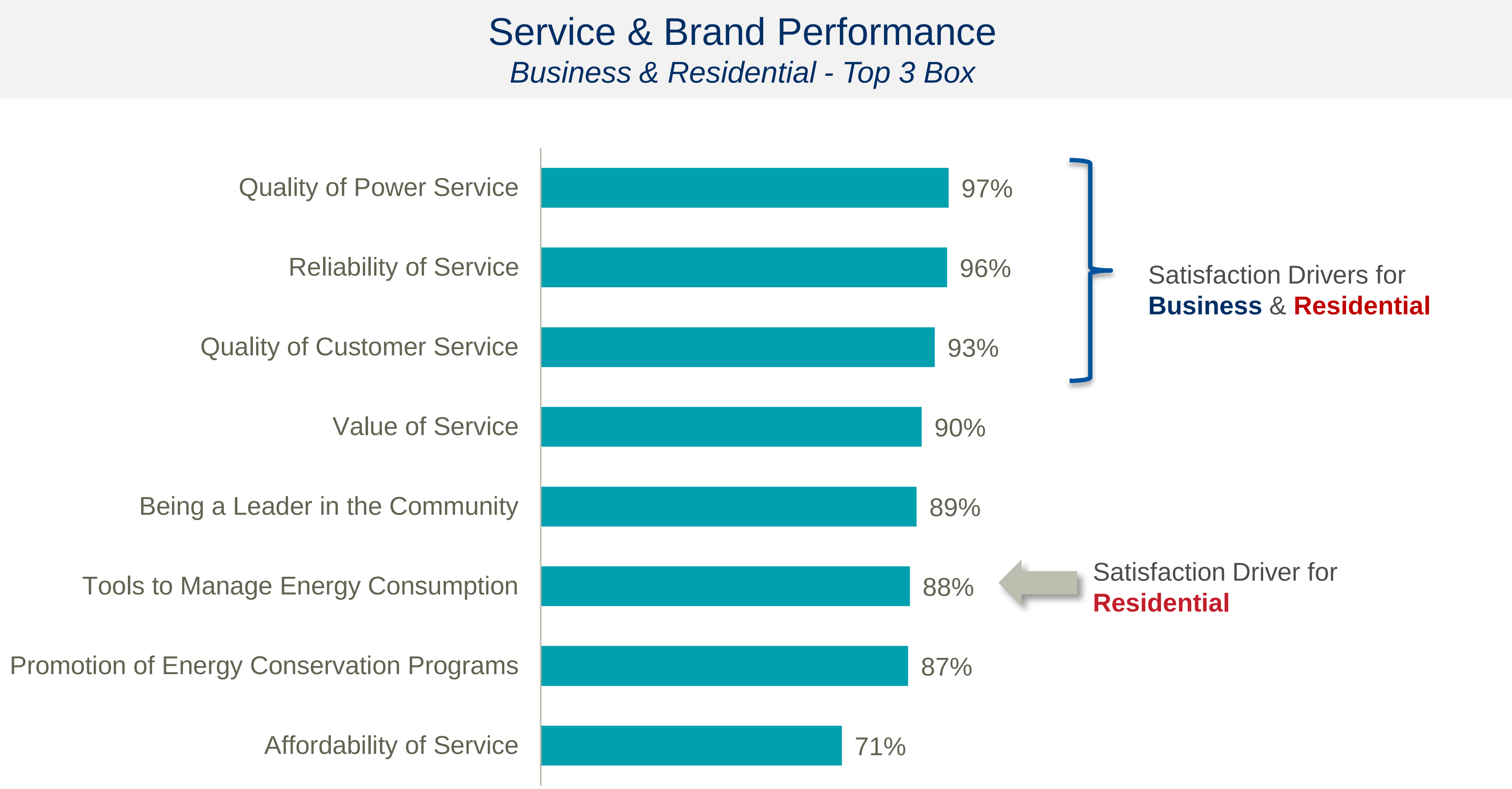
# Service & Brand Satisfaction

*Considering key drivers for both Business and Residential customers, their Satisfaction with Service and Brand performance is largely on par with one another.*



# Service and Brand Findings & Opportunities

| | *Finding* | *Opportunity* | *Customer Feedback* |
|---|---|---|---|
| 1 | ***Quality of Power Service* & *Reliability* are highly important to both Business and Residential Customers.** | Reduce recurring issues with loss of service. | *“We're getting little power flicks, such as one-second interruptions in the power. Sometimes it goes down and sometimes it doesn't, but it's more now than it used to be.”*<br>*“My power will flicker off for a moment or two and come back on, it happens relatively often.”*<br>*“They shut off the hydro for longer than they said they would for repairs. Now the lights flicker and they are always telling us how to save power, but the bulbs recommended don't last as long due to the power surging.”* |
| 2 | **Satisfaction with *Customer Service* is high and important to both Business & Residential Customers.** | Continue to focus on providing high quality customer service. | *“Every time I need assistance they are there to help, which makes me very satisfied.”* |





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# Service and Brand Findings & Opportunities

*Continued*

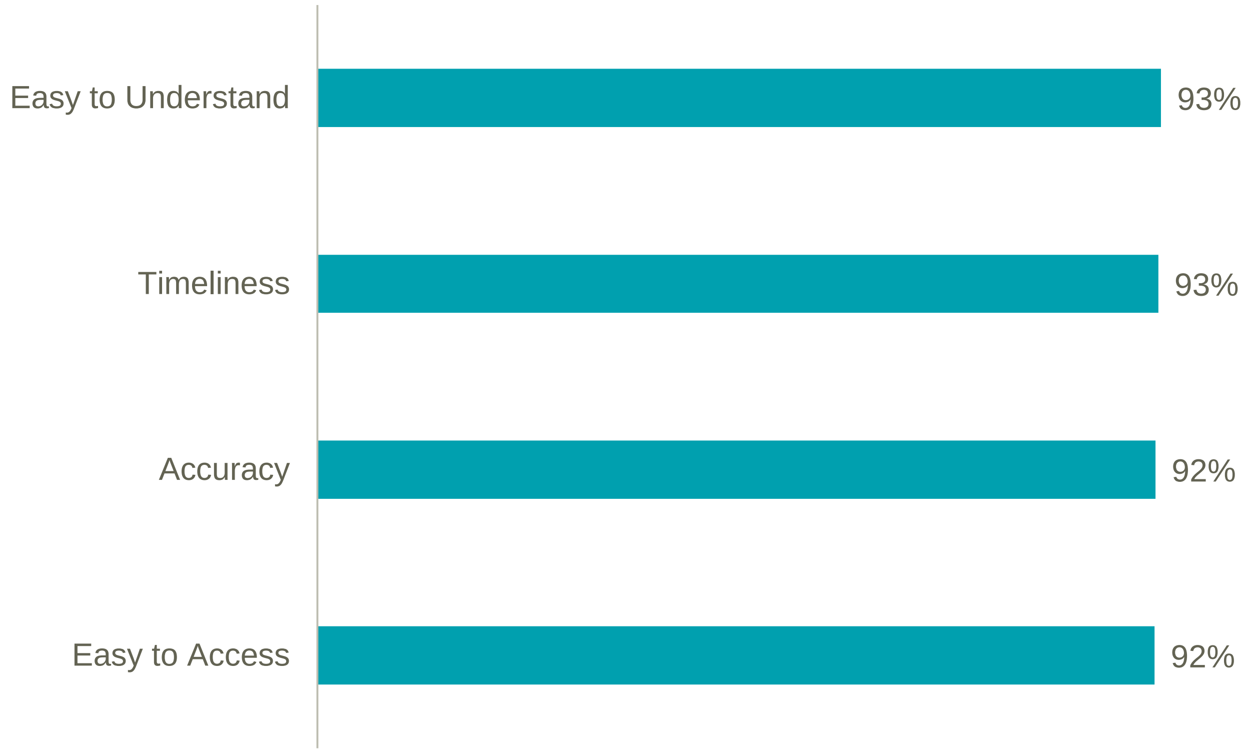
| | Finding | Opportunity | Customer Feedback |
|---|---|---|---|
| 3 | ***Tools to Manage Energy Consumption*** **is a driver of Satisfaction for Residential Customers, but lagged other service and brand measures in satisfaction.** | Help Customers better understand how to manage their energy consumption. | *"It is very expensive. We are very conscious of 'lights off' and not using power during high energy times and we still don't see a difference in the bill. It is pretty discouraging."* |
| 4 | **Pricing was frequently mentioned as a concern and only 71% are Satisfied with the *Affordability of Service*.** | Educate Customers on rates and on fees charged. | *"Hydro is always expensive and I'm never happy to see my bill with the rates going up all the time."* |

# Communication

*There is an opportunity to improve the accessibility of communication.*

## Communication Performance

*Business & Residential - Top 3 Box*



## Communication Preference

*Businesses have a stronger preference for email communication than Residential Customers.*

### Communication Preference
*Business vs. Residential*

| | Business | Residential |
|---|---|---|
| Letter in the Mail | 44% | 54% |
| Email Message | 35% | 24% |
| Telephone Call | 19% | 20% |

# Communication Findings & Opportunities

| | Finding | Opportunity | Customer Feedback |
|---|---|---|---|
| 1 | **Communication could be *Easier to Access*.** | Ensure Customers can easily access communication and their accounts via the website. | *“I would like an easier way to access information on my bill on the website.”* |
| 2 | **Business Customers are more likely to prefer email communication than Residential Customers.** | Important communication should be sent via both traditional mail and email. | *“I was having trouble accessing e-bill.”* |

# Billing

*Improved billing clarity can help improve perceptions of billing accuracy.*

## Billing Performance

*Business & Residential - Top 3 Box*


## % Contacted in Past 6 Months

| Billing Attribute | Not Satisfied (*Bottom 2 Box*) | Satisfied (*Top 3 Box*) | Reduction in Contacts when Moving from Not Satisfied to Satisfied |
|---|---|---|---|
| Billing accuracy | 42% | 29% | -13% |
| Ease of access | 37% | 29% | -8% |
| Ease of understanding | 37% | 28% | -11% |

# Billing Findings & Opportunities

| | *Finding* | *Opportunity* | *Customer Feedback* |
|---|---|---|---|
| 1 | **Improving billing clarity can reduce the need for customers to contact Entegrus.** | Ensure billing is understandable and accurate; provide proper notification of additional balances. | *“I called to ask about a 30 dollar fee for something like a transferring fee. I understand I’m a new customer. It would’ve been nice to get a heads up.”* |
| 2 | **Some Customers mention concerns about Smart Meters.** | Increase communication efforts around the implementation of Smart Meters. | *“When I go away for a few weeks and turn the heat down to low and unplug everything, the bill never goes down. With a smart meter, should it not go down?”* |

# Recommendations

# Recommendations

*Outside of maintaining and improving the Service fundamentals, focusing on communicating Tools to Manage Consumption will positively impact Residential Customer satisfaction.*

| Category | Recommendation |
|---|---|
| 1 **Communicating Tools to Manage Consumption**<br><br>**(Driver of Satisfaction for Residential)** | Help Customers learn and better understand how to manage their energy consumption by:<br>• **Enhance the website**. Add visibility and accessibility to "Save Energy" on the home page, and augment the graphics.<br>• **Send information**. Send monthly email marketing messages to consenting customers containing tips or postcards that can direct them to more information; also, Customer Service Reps can ask customers if they are interested in learning about managing energy consumption and send them information via email/mailing.<br>• **Leverage the social media space**. Post information or "how-to" videos online, or create a blog for customers to subscribe to, to learn about managing energy consumption.<br>• **Interact with the community**. Continue to issue press releases and work with local media (e.g., radio, news, etc.) to share information on managing energy consumption. Host events/seminars at Entegrus so people can come in and learn more or have booths/tables at community events with information on available tools. |

# Recommendations

*A focus on communicating Billing will positively impact both Business and Residential Customer satisfaction.*

| Category | Recommendation |
|---|---|
| 2<br>**Communicating Billing**<br><br>**(Driver of Satisfaction for Business)** | Customers who are able to understand their bill are more likely to feel that their bill is accurate, which can have a positive impact on pricing perceptions:<br>• **Utilize the website to explain billing details**. Upload a sample bill, and ensure that it is easily accessible. Add content details and explanations to each area of the bill to properly manage customer expectations about the amount of control that Entegrus has on pricing.<br>• **Create a billing video**. Consider creating an online video that walks customers through how to read a bill.<br>Leverage the transactional program results to get specific details on how to best impact Billing and Payment Issues. |





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# Recommendations

*Improvements in these areas will positively impact both Business and Residential Customers.*

| | Category | Recommendation |
|---|---|---|
| 3 | **Self-Service** | Ensure that customers are taking advantage of existing Self-Service tools by sponsoring promotions to increase Self-Service usage, making Self-Service tools more prominent on the website, and featuring Self-Service options in bill inserts and in monthly email newsletters. |
| 4 | **Power Quality and Reliability** | Continue taking strides to decrease outages and improve the overall reliability of service. |
| 5 | **Business vs. Residential Customer Differentiation** | Further differentiate content on Entegrus.com to provide messaging that is targeted to Business and Residential Customers based on their unique drivers of Satisfaction. |
| 6 | **Survey Attributes** | The key driver analysis indicates that not all survey measures are strong predictors of Overall Satisfaction. Recommended survey streamlining includes: <br>• Reducing Communication attributes to one measure – Overall quality of Communication provided by Entegrus |

# ATTACHMENT 1-I

## Convergys Transactional Customer Survey

# Entegrus Transactional Survey

*January, 2015*

# Transactional Survey Overview & Methodology

## Objective

- Canvas Customer Satisfaction related to a specific transaction.
- Measure First Contact Resolution (FCR) for OEB and scorecard reporting.

## Timing

- Surveying conducted October 1 – December 15, 2014

## Methodology

- Telephone survey conducted by a Convergys live agent

## Sampling

- 150 completed surveys

## Question Scales & Reporting

- Quality asked on a 5 (Excellent) to 1 (Poor) scale
- Top 3-Box (3, 4 and 5 ratings) reporting used for reporting of survey attributes

# Table of Contents

# Critical to measure general population & transactions

## Comprehensive

* TOP-DOWN SATISFACTION *


- Measures enterprise-wide satisfaction
- Influenced by multiple factors
- Harder for service ops to control

## Process-Oriented

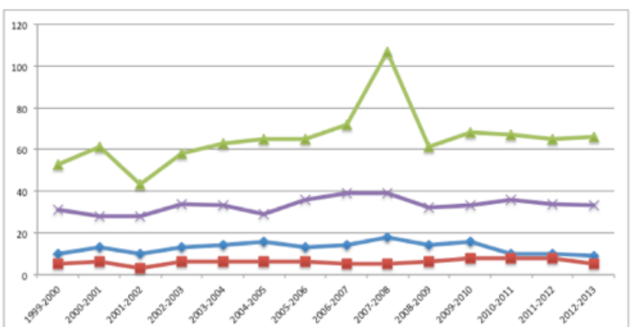
* TRANSACTIONAL SATISFACTION *


- Granular view of frontline performance
- Deep cross-channel insight
- Controllable by service ops

## … and an understanding of where service 'fits'

# Improving interactions drives Satisfaction

### Satisfaction KPI
NPS, Overall CSAT




up to

**45%**

### Touchpoint KPI
Customer Effort


* A leading indicator

of satisfaction variance can be accounted for by call center experience ratings





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# Why track performance?

Infuse the voice of your customers into service & operations through the survey instrument

**CAPTURE**
feedback across channels

**TRUST**
resulting intelligence

**APPLY**
and act on insights

**IMPROVE**
the end-to-end experience

multi-channel flexibility • centralized platform • seamless integration • ongoing support

# VOC is more than collecting customer feedback

## 8 Tenets of Successful Programs

Cross-Channel

Customer Lifecycle

Frontline Insight

Service Recovery

Online Portal

Linkage Analysis

Root Cause

Take Action

# Findings & Key Metrics

# Key Findings

**Overall Measures:** Overall Satisfaction and Call Satisfaction are 90% and 95% (Top 3 Box), respectively.

**Key Drivers:** Both the Rep's ability to demonstrate knowledge and resolution have the largest impact on overall Call Satisfaction.

- Demonstrating other hard skills in conjunction with courtesy is also key during all interactions.

**Contact Reasons:** *Billing Inquiries* and *Making Payments* account for roughly two-thirds of customer contacts.

- Customers may find it faster, easier and more convenient to address their billing and payment needs through self-service channels.

**Rep Performance:** Customers were very satisfied (97%) with the overall quality of service they receive from Reps when they called.

**Resolution:** Most customers (85%) had their issue resolved on the call, but First Contact Resolution (75%) has some room for improvement.

- FCR = Issue was resolved on the call and no previous contacts were made to attempt to resolve the issue (derived from survey questions).

Results are reported with a margin of error of +/- 8% at a 95% confidence level.

# Key Metrics

The following measures provide an overview of how Satisfied customers are when they call Entegrus and how often their issue is resolved when they call.

Overall Satisfaction 90%

Call Satisfaction 95%

Rep Satisfaction 97%

Resolution 85%

First Contact Resolution 75%



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# Call Satisfaction & Key Drivers

## Key Drivers Introduction

*Key Drivers help us to understand what is most important to Customers and where to focus efforts to have the greatest impact on Call Satisfaction.*

1. What are the attributes' relationship to Call Satisfaction?

   *Action: Calculate each attributes' correlation to Call Satisfaction*

2. If several attributes have a moderate to strong relationship to Satisfaction, how can attributes be prioritized?

   *Action: Calculate the Relative Importance*

3. Once a Relative Importance model is developed, how much does it explain Satisfaction?

   *Action: Calculate the proportion of variance that explains Satisfaction*



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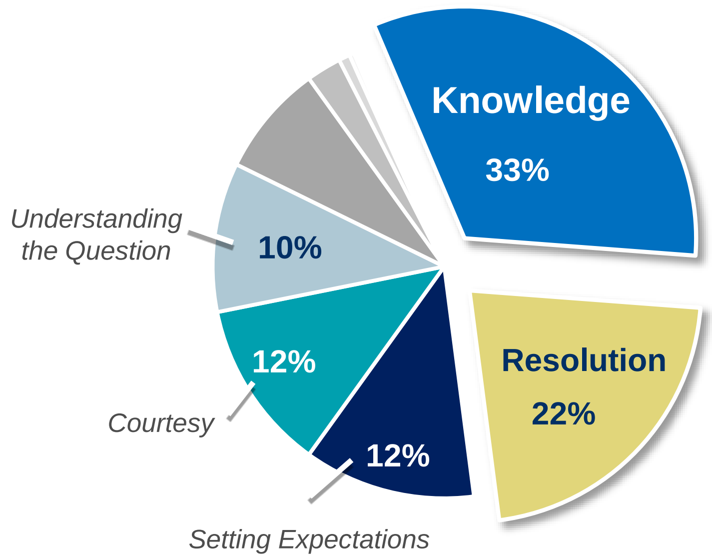
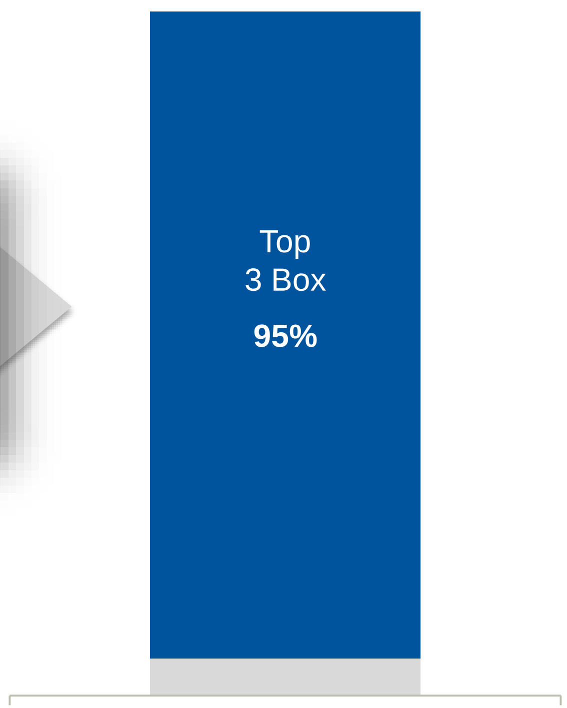
# Key Drivers

*Improving Satisfaction with key drivers will improve Call Satisfaction.*

The Rep's hard skills are the primary drivers of Call Satisfaction.




Call Satisfaction




% Variance explained: 37%

Percentages represent the relative impact of each attribute on Call Satisfaction.





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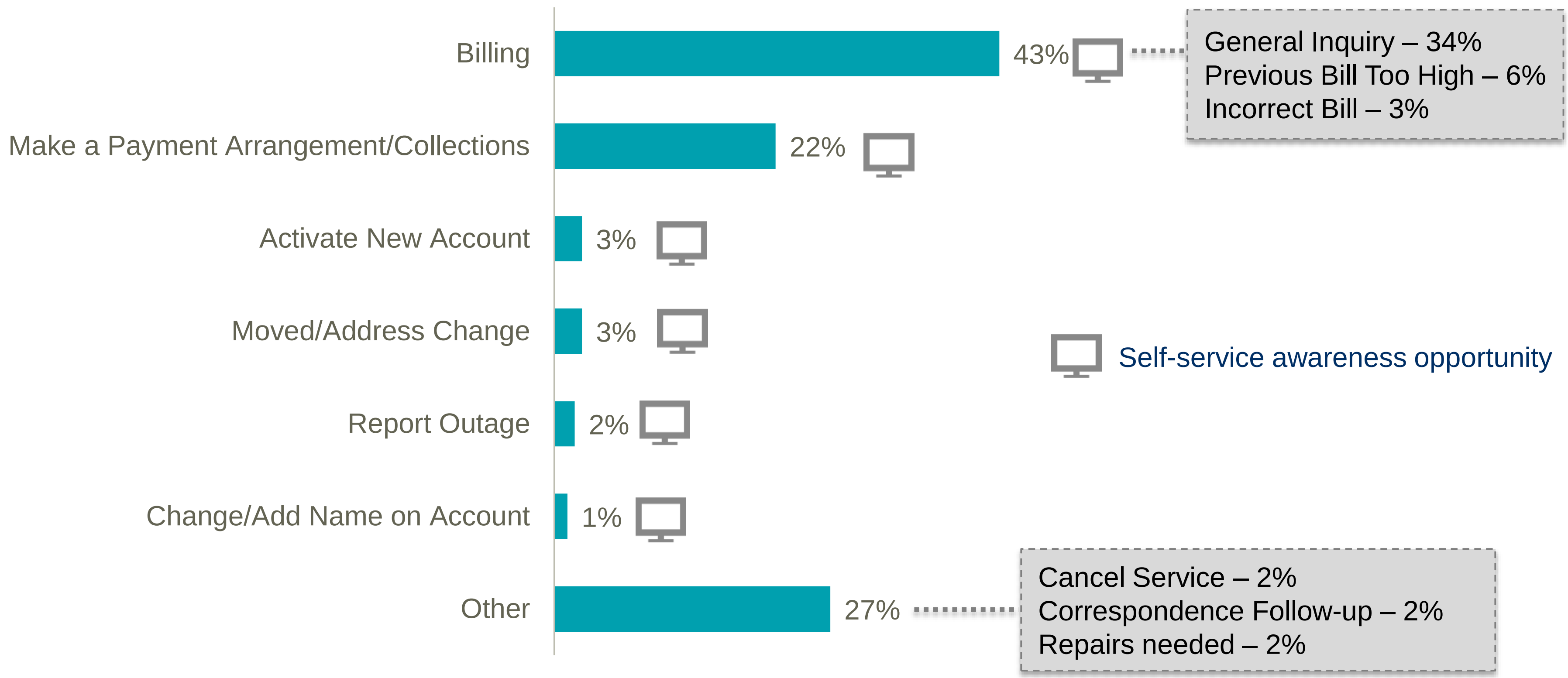
# Contact Reasons and Call Handling

# Reason for Contact

*Some contacts may be able to be handled via self-service channels.*

## Contact Reasons





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# Rep Evaluation – Excellent Service

*The majority of customers felt that the Overall Quality of Service provided was Excellent.*

Reps earn an Excellent rating when they demonstrate that they are helpful, courteous, and knowledgeable, throughout the entire call, and are able to answer the Customer's question.

"They were very courteous and knowledgeable. They were very congenial in regards to my being a customer."

"Because the rep was more than willing to assist me with me with my call. They worked with me very well for my payment arrangements. The rep was also friendly."


"They solved my problem in a very timely fashion."

"They listened to my questions. I just wanted to know what was going on, and they answered my questions and explained everything to me."

The bigger the word, the more frequently it is used in verbatims.
Among customers who rated the Rep a 5 Overall (Excellent).





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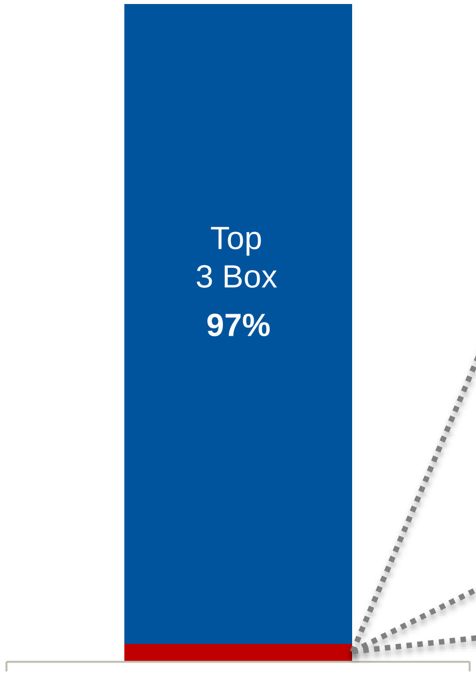
# Rep Evaluation – Poor Service

*Most customers who indicated that their service was poor felt that the Rep lacked knowledge or resolution.*

Less than 3% of customers rated the Overall Quality of Service that was provided by the Rep a “1 – Poor” or “2”.

## Overall Quality of Service
(Rep Satisfaction)




Use DataLink to monitor Rep performance and follow-up with Dissatisfied Customers

“I don't think the rep had enough **knowledge**. They steered me in the wrong direction. I don't think they know enough about what is going on and who does what.”

“Because the rep stated they would call me back on Monday, but didn't. I **still haven't gotten a callback**.”

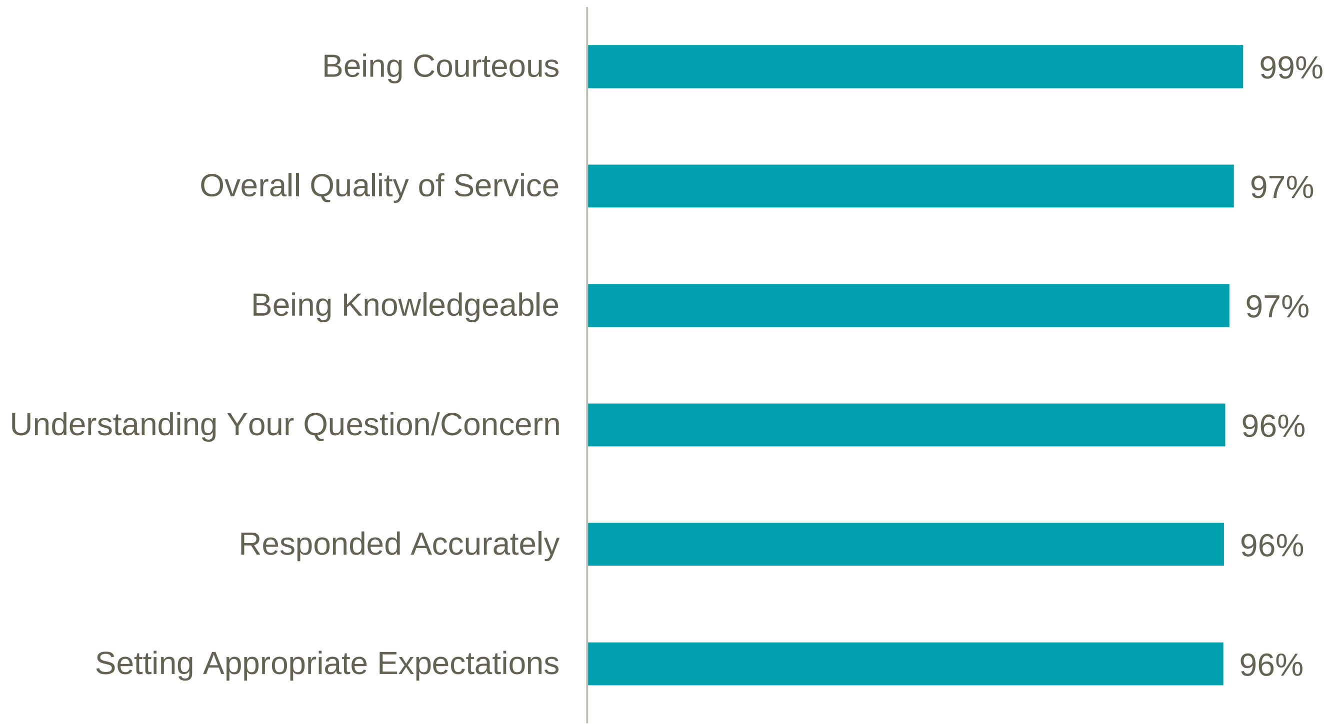
“There was **no comment from the rep** about why the information did not show up on the page I was looking at.”

## Rep Evaluation

*Reps received high ratings for the service that they provided to customers who called.*

### Rep Performance

*Top 3 Box*





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# How To Improve Rep Scores

*Focus on positive language to help convey a sense a of confidence and knowledge.*

Going from ***negative*** language to ***positive*** language will help drive rep improvement.

| **From negative language…** | → | **…to positive language** |
|---|---|---|
| *"We **don't** know when service will be restored."* | → | *"**We are** aware of the outage and are working to restore service."* |
| *"We **can't** send you your information until…"* | → | *"**We can** send you the information you requested on…"* |
| *"You'll **have to** talk with another department for that."* | → | *"The **best way** for me to handle this is..."* |
| *"Your account information **won't** be available until…"* | → | *"Your account information **will be** available on…"* |
| *"You'll **need to** call Ontario One Call for that issue."* | → | *"Ontario One Call **can** help you with that. Let me give you their number."* |

Information shown from 'The Effortless Experience'; *Conquering the New Battleground for Customer Loyalty* - 2013





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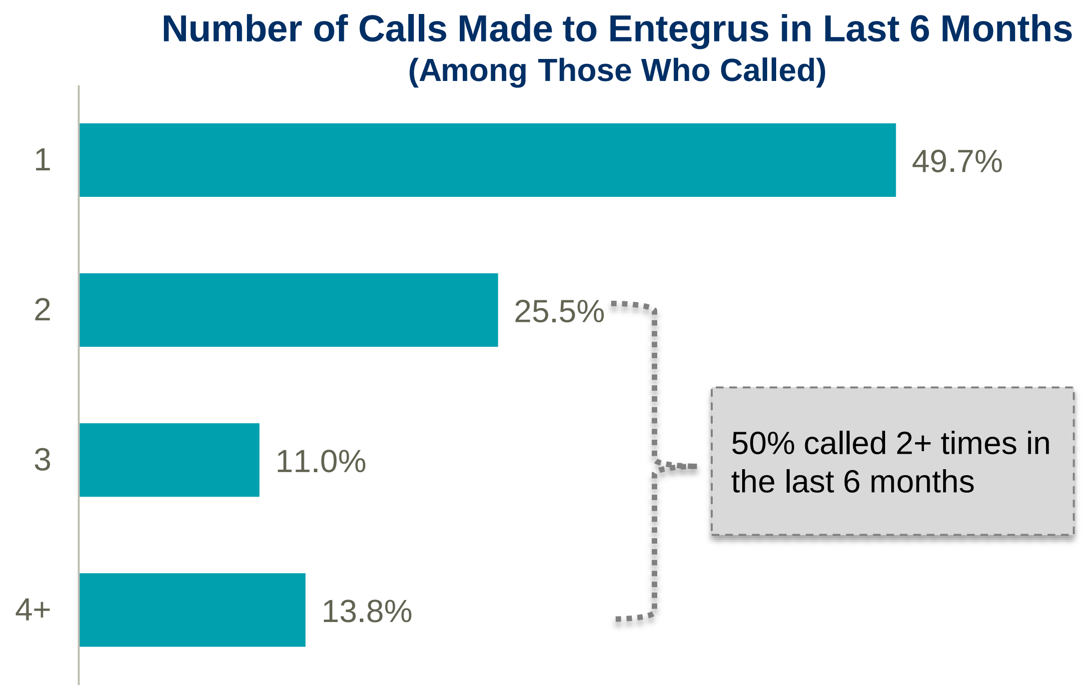
# Contacts

*About half of Customers who called Entegrus made multiple calls.*





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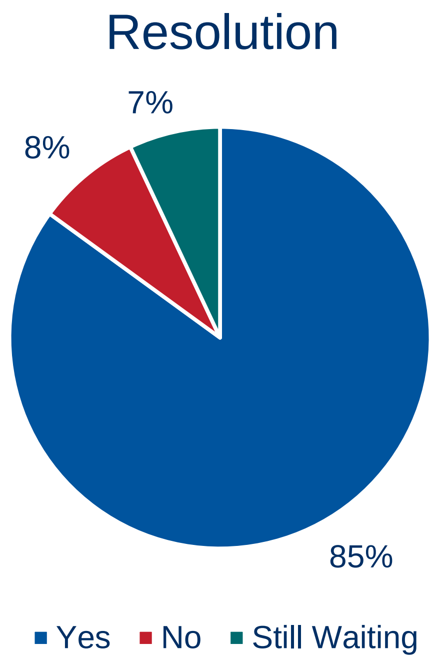
## Resolution

*Most customers indicated that their issue was resolved when they called.*

Opportunities to improve First Contact Resolution are focusing on the hard skills which can reduce follow-up calls, such as active listening and probing, providing sufficient detail, and clear explanation of next steps.




### Prior Contact Methods

Website – 3%
Email – 1%
Toll-free number – 1%
Other – 3%

### First Contact Resolution

75%

FCR = Issue was resolved on the call and no previous contacts were made to attempt to resolve the issue (derived from survey questions).

# How Can Reps Improve FCR?

*Making the interaction easy is key to resolving issues.*

## Engage the Customer

- Demonstrate a professional, confident, and engaging demeanor throughout the call
- Match the customer's tone and pace and allow his/her personality to dictate the tone of the call

## Identify Needs of the Customer

- Actively listen and probe where required to understand what the customer needs
- Encourage reps to take the time required to make sure the customer needs are clear

## Offer Relevant Options

- Explain to the customer how he/she can reach resolution
- Help the customer assess the different options and then provide a recommendation

## Inform/Educate the Customer

- Provide sufficient detail and share knowledge that the customer would not likely be exposed to otherwise
- Play the role of expert – help the customer make an informed decision

## Show Commitment

- Communicate the actions being taken and assure the customer
- Explain the next steps clearly to the customer

Source: 'The Effortless Experience'; Conquering the New Battleground for Customer Loyalty - 2013

# Key Rep Behaviors to Reinforce

*Making the call experience as 'effortless' as possible will help improve scores.*

## Engage the Customer

- Have a warm, engaged, interested, and outgoing demeanor
- Convey information with authority and insight
- Make the conversation interactive
- Demonstrate a personal understanding of the customer perspective

## Identify Needs

- Identify spoken and unspoken needs of the customer
- Ask well-timed and appropriate questions – qualify the customer needs
- Confirm needs have been met by asking close-ended questions

## Offer Relevant Options

- Provide relevant recommendations for both spoken and unspoken customer needs
- Guide the customer through options that are available and provide clear explanations on how/why solutions would alleviate their concerns
- Cross-sell if appropriate

## Inform/Educate

- Provide a comprehensive explanation of what FCR of the issue will be
- If appropriate, provide additional details or benefits of products/services
- Use value statements to explain why the customer would benefit from additional information
- Attempt to educate the customer on something new

## Show Commitment

- Take responsibility for the customer's needs
- Go above-and-beyond what is necessary to directly address the request
- Take extra actions that are not directly requested to add convenience/ease for the customer


**Suggestion:**
Print this slide, laminate it and give to each rep. Hanging a copy in their personal workspace will serve as a great reminder of what will drive success!

Source: 'The Effortless Experience'; Conquering the New Battleground for Customer Loyalty - 2013

# Recommendations

# Recommendations

*Overall, transactional satisfaction is very high, but some opportunities for improvement exist.*

- **Focus on Key Drivers of Satisfaction**
  - Coach Reps on hard skills, especially providing the customer with easy explanations and next steps, which will demonstrate knowledge and enhance perceptions of resolution within the first call.
  - Use positive language to influence the customer's perception of the interaction.

- **First Contact Resolution**
  - Identify the type of issues and calls that require multiple contacts to resolve in order to improve processes and rep training.

- **Self-Service Opportunities**
  - Educate consumers on self-service options for payments and account changes. Use customer bills, email marketing and Entegrus' website to inform customers of self-options.

- **Survey Modification**
  - Modify wording of Q10 (What other contact methods did you use, if any, to attempt to resolve your issue BEFORE you called on (date))?
  - Specify prior contact with Entegrus in order best measure FCR.

# Looking Ahead

# Future Analysis Possibilities

- **Business vs. Residential**
  - Determine if call handling differences exist between business and residential customers.
    - Most Customers called regarding their Residence (95%).

- **Call Reason Analysis**
  - Measure which call types are handled most effectively and which have room for improvement.

- **Impact of Holds and Transfers**
  - Evaluate whether placing customers on hold or transferring them has an impact on Satisfaction.
    - About 1 in 5 Customers were placed on hold (22%) or transferred (17%) during their call.

- **Customer Effort**
  - Develop a customer effort index in order to measure and trend effort.

# What is Customer Effort?

*How hard Customers have to work to get their issues resolved or questions answered*

## What We Know…

- Effort has a direct impact on Overall Satisfaction
- High Effort interactions can drive more Dissatisfied customers
- Reps can help mitigate High Effort situations
- Assessment of Effort must go beyond the center to the overall business
- Managing Effort is a win-win – increasing Satisfaction and driving down operational costs

## What Is Typically Included?

| | | |
|---|---|---|
| Attempted Alternate Channel *(Web, IVR, Etc.)* | Transferred | Issue Resolved |
| | Placed on Hold | Number of Contacts |
| *Pre-Call Effort* | *On-Call Effort* | |

# ATTACHMENT 1-J

Innovative Customer Consultation Report

Innovative Research Group, Inc.

Toronto • Vancouver

# Customer Consultation Report

## 2016 Distribution System Investment Plan Review

August 2015

Prepared for:

**Entegrus**
320 Queen St,
Chatham, Ontario
N7M 5K2

# Customer Consultation Report

# 2016 Distribution System Investment Plan Review

August 2015

This report has been prepared by Innovative Research Group Inc. ("INNOVATIVE") for Entegrus Inc. ("Entegrus").

The conclusions drawn and opinions expressed are those of the authors.

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# Introduction

## About this Consultation

Innovative Research Group Inc. (INNOVATIVE) was commissioned by Entegrus to help the utility design, collect feedback and document its customer engagement and consultation process as part of the development of Entegrus' 2016 Distribution System Investment Plan, which incorporates both capital infrastructure and operational plans.

Entegrus'2016 Distribution System Investment Plan is a key element of its next distribution rate application. The outcome of this application will determine Entegrus' electricity distribution rates for next year and will help set the pace of spending over the next 5 years.

The Ontario Energy Board's new "consumer-centric" approach to rate applications contained in the *Renewed Regulatory Framework for Electricity (RRFE)* requires Local Distribution Companies (LDCs) to demonstrate services are provided in a manner that responds to identified customer needs and preferences[1]. Distributors are required to provide an overview of customer engagement activities that they have undertaken with respect to its plans and how customer needs and preferences have been reflected in the distributor's application. This initiative sought to bring customers directly into the process of finding the right balance between cost and reliability in Entegrus' 2016 Distribution System Investment Plan.

This process of identifying and reacting to customer needs and preferences towards Entegrus' system plan development and execution, as it relates to rate applications, is new to all of Ontario's LDCs. There are no established practices and there are a number of options available to engage with customers. The following section explains how we approached this engagement.

### *Approach to Meaningful Customer Engagement*

It is our experience at INNOVATIVE that engaging customers in meaningful consultation can be a challenge. The reality of most consultation processes is that they start out aiming to collect the views of the average person, but end up collecting the views of organized advocacy groups.

Many customers feel they don't know enough to contribute to a public consultation. Others fear the combative nature of some public processes or prefer not to risk offending friends and neighbours by taking positions on issues that are sometimes controversial. Moreover, many customers simply do not pay attention and remain unaware of particular consultations that they would participate in if they had have been aware.

Running a consultation on the Entegrus' 2016 Distribution System Investment Plan has an additional challenge – customers' lack of familiarity with the distribution system; including how it is funded, regulated and the nature of its challenges. This is well documented in Ontario Energy Board research and in INNOVATIVE's own experience.

[1] OEB Renewed Regulatory Framework for Electricity Sections 2.4.2, 5.0, and 5.0.4.

Considering both the challenge of engaging a representative group of customers and the challenge of lack of knowledge, we developed a process built on five key principles:

1. Ensure all Entegrus customers have an opportunity to be heard.
2. Use random-sampling research elements to ensure a representative sample of customers are engaged.
3. Create open voluntary processes that allow anyone who wants to be heard an opportunity to express themselves.
4. Focus on fundamental value choices. Look for questions that ask people to choose between key outcomes rather than focus on the technical questions of how to reach those outcomes.
5. Create an opportunity for the public to learn the basics of the distribution system so they can provide a more informed point of view.

Since this was the first time Entegrus so explicitly engaged customers in the development of their distribution system planning, a specific effort was made to collect participant comments on the process itself.

# Customer Consultation Overview

Based on the principles outline above, INNOVATIVE worked with Entegrus staff to design a multifaceted customer engagement program which included a combination of qualitative and quantitative research elements. This consultation was designed to engage various rate classes and collect feedback on preferences and priorities as they relate Entegrus' 2016 Distribution System Investment Plan.

The consultation encompassed five core elements of customer engagement.

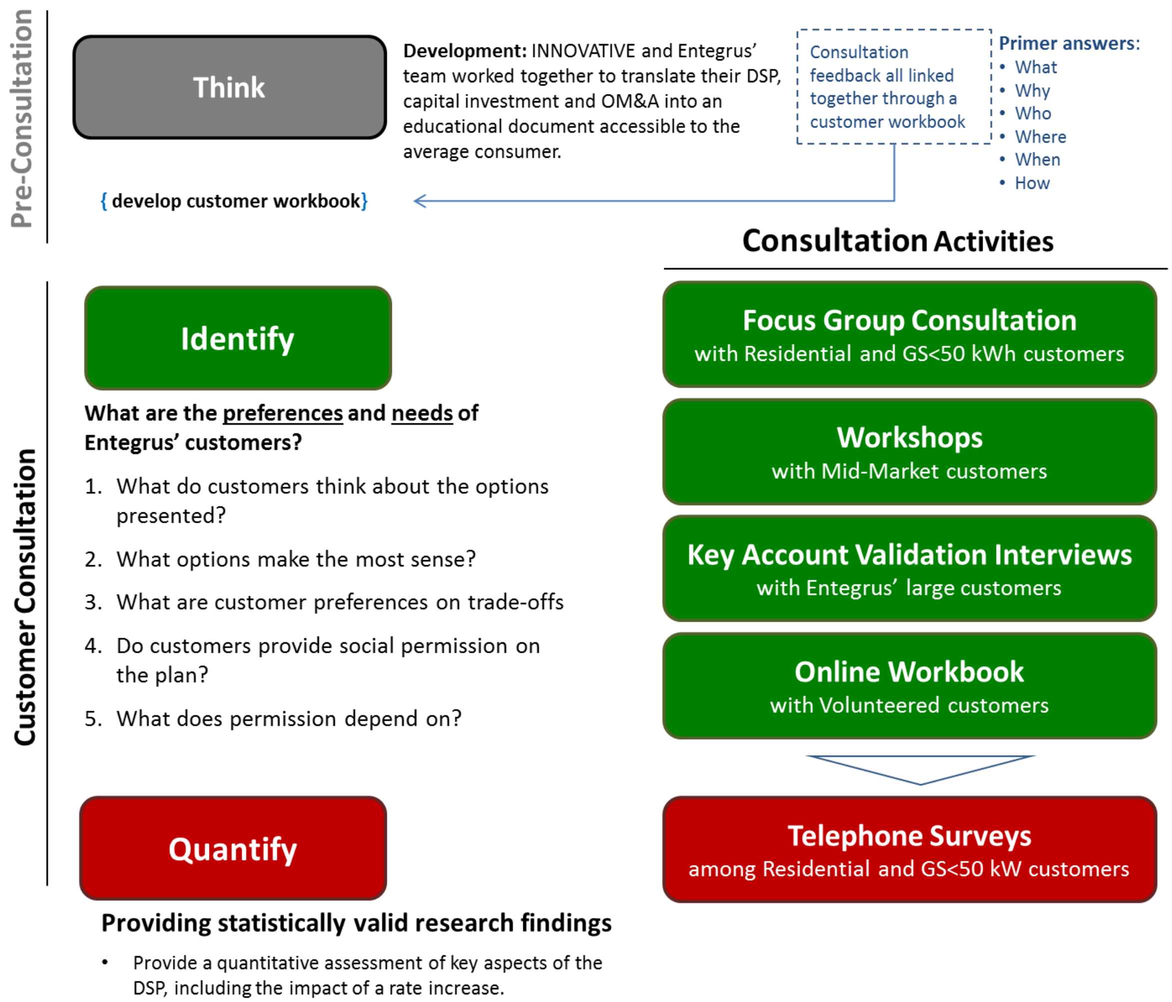
1. **General Service and Residential Consultation Groups:** This qualitative phase of the consultation was designed to educate customers, assess their preferences and priorities, gauge reaction to proposed rate changes, and ultimately inform the quantitative phases of the consultation. The groups were randomly recruited and held in Strathroy and Chatham. A workbook was used to provide the participants with core information about both the provincial and local electricity system, Entegrus' proposed capital investment and operating spend to maintain system reliability, as well as the rate impact for each respective rate class. Participants were provided incentives in recognition of their time commitment.
2. **Mid-Market Workshops**: General Service customers (GS > 50 kW and intermediate customer) were engaged through a randomly recruited workshop. This workshop included a presentation delivered by Entegrus regulatory and engineering staff on the utility's DSP and rate implication for this rate class, a Q&A session with Entegrus staff, and "breakout style" discussion groups lead by INNOVATIVE staff.

3. **Key Account Validation Interviews**: Key Accounts were consulted on the proposed 5-Year plan by Entegrus staff. INNOVATIVE followed-up by telephone with these customers after their consultation session to validate the process and to verify that Entegrus provided them with the information they needed to provide informed feedback on the proposed plan.
4. **Online Workbook**: The online workbook was promoted through print and online advertising with local media outlets, social media, inserts in customer bills and e-bills, as well as Entegrus' website. This phase of the consultation was available to any Entegrus customer who wanted to participate.
5. **Random Telephone Surveys**: INNOVATIVE conducted telephone surveys with residential and general service (GS < 50kW) customers to provide a quantitative assessment of key aspects of the system plan. Customer lists for both respondent groups were provided by Entegrus and the sample was randomly selected by INNOVATIVE.

There were three stages in developing and implementing Entegrus' customer consultation:

- **Think**: The first stage was to develop the core background material and key questions for the workbook. INNOVATIVE and Entegrus worked together to review the utility's system plan, capital investments and OM&A spending. Potential questions were identified that would enable customers to share their needs and preferences. Then a workbook was developed that would provide the information needed to enable customers with varying levels of knowledge to find answers to those questions.
- **Identify**: The second step was to determine the range of views held by the public regarding the system plan through the more qualitative elements of the process. This included holding two customer discussion groups using randomly recruited samples of residential and general service customers.
- **Quantify**: The third step was quantitative – a randomly recruited telephone survey of residential and general service customers. Randomly recruited surveys allow for generalizable conclusions that can be applied to the broader population of Entegrus customers. The surveys were developed based on the feedback from the qualitative research.

***Customer Engagement Stages***




## Workbook Development

As we noted earlier, a key challenge in obtaining customer feedback on Entegrus' rate application is the lack of knowledge customers have regarding Ontario's electricity system and Entegrus' role as the local distributor within the system. Entegrus' proposed distribution system plan, capital investment plan and OM&A budget are all very detailed and extensive documents that use technical language. Our challenge was to briefly cover these key issues and frame meaningful questions about customer needs and preferences.

Development of the consultation workbook began in early 2015. INNOVATIVE provided a framework for the workbook, which contained background information on the rate application process and the provincial electricity system. All content specific to Entegrus was provided by the utility.

The final consultation workbook had five distinct chapters:

1. **What is this Consultation About?** The purpose of the discussion, where the discussion fits in the context of electricity planning in Ontario.
2. **Electricity 101**: How the overall system works and the players involved in operating and regulating the system as it relates to Entegrus' customers.
3. **Entegrus' Distribution System Today**: A discussion of the structure and key elements of Entegrus' distribution system.
4. **Cost Pressures**: A discussion of the various challenges facing Entegrus' distribution system and an overview of recent and current initiatives to manage the challenges. This section provided an overview on forecasted capital and operating spending for 2016.
5. **What the Plan Means for You**: A section covering the expected impact on rates and overall reaction to the investment plan.

Although customer experience and familiarity with the energy sector varied, the same basic workbook was used in all qualitative customer engagements. The references to bill impact were varied to reflect the details of that specific rate class (either residential or GS less than 50 kW). As the customers went through the consultation workbook they were prompted with questions relating to system reliability, system challenges, and preferences on the direction of Entegrus' proposed system plan, capital investment and operating spend.

Another key element of the workbook was the questions. In developing the questions, we looked for those that could also work on the telephone, without requiring all of the information in the workbook.

**The *needs* questions were the easiest**. We started with a basic satisfaction question and then asked an open-ended question about how Entegrus could improve its services. We let customers discuss whatever topics they wanted to with no boundaries. Later in the workbook we probed satisfaction with the number and duration of outages and probed the impacts of those outages.

***Preferences* took a bit more thinking**. We were looking for value choices rather than technical issues. Key topics for preferences included:

- What should the balance be between system reliability and rate impact?
- What should Entegrus' priority be when planning its level of investment in replacing aging infrastructure?
- Should Entegrus adopt a run-to-failure policy to help contain costs?
- How important is grid modernization to customers?
- Should Entegrus invest in buildings, equipment and IT systems?
- Is rate harmonization fair; and if so do customers accept Entegrus' plan?

**The final substantive question asked about the cost of the plan and the outcomes it planned to achieve**. Sometimes this question is asked with a simple support or opposes response scale, but we found that this type of scale does not effectively capture customer responses. Instead, we gave customers three options as well as a "don't know" option:

- The rate increase is reasonable and I support it
- I don't like it, but I think the rate increase is necessary
- The rate increase is unreasonable and I oppose it
- Don't know

The workbook concluded with a final set of five questions to assess the workbook and process itself.

The workbooks for residential and general service customers can be found in the **Appendix** of this report.

# Executive Summary

The following section provides the detailed findings on the needs and the preferences of Entegrus' general service and residential customer base. In this section, we provide a high level overview of Entegrus customers' needs and preferences.

The overview includes feedback from customers who participated in the *qualitative stage* of the consultation where we explored the range of issues related to Entegrus' rate application, as well as feedback from another 620 customers who responded to the quantitative stage where we documented the incidence of *needs* and *preferences* across the customer population.

## Customer Needs & Preference

### Continued delivery of high quality services

Almost all Entegrus customers are satisfied with the job the utility is doing at running the electricity distribution system. This pattern was consistent across all rate classes in all phases of the customer consultation.

**Overall Satisfaction across Consultation Activities**

Q. Generally speaking, how satisfied are you with the job Entegrus is doing running your electricity distribution system?

| Response | Directional (Focus Groups) | | Directional (Workshop) | Directional (Online) | | Generalizable (Telephone Surveys) | |
|---|---|---|---|---|---|---|---|
| | Small GS | Residential | Mid-market & Large GS | Small GS | Residential | Small GS | Residential |
| Very satisfied | n=7 | n=2 | n=7 | n=16 | 46% | 30% | 36% |
| Somewhat satisfied | n=8 | n=13 | n=4 | n=7 | 44% | 55% | 52% |
| Somewhat dissatisfied | n=1 | n=0 | n=0 | n=2 | 6% | 6% | 5% |
| Very dissatisfied | n=0 | n=0 | n=0 | n=2 | 3% | 4% | 3% |
| Don't know / Refused | n=1 | n=1 | n=1 | n=0 | 1% | 5% | 4% |
| **TOTAL** | n=17 | n=16 | n=12 | n=27 | n=604 | n=111 | n=509 |

When we asked what Entegrus can do better to improve services, a most customers were either satisfied and had nothing to suggest or simply didn't know who the utility could improve services. However, among those who did have suggestions, comments focused on two areas:

- Lowering rates; and
- Improve power quality and reliability.

This paradox of *lower rates* while seeking *improvements in power quality and reliability* is the key dilemma the consultation sought to explore and better understand.

## Reliability of Service

The consultation focused deeper on the question of power service interruptions. In both the qualitative and quantitative phases of the consultation, information about the system's current average level of reliability was provided to customer. The consultation collected feedback on satisfaction with the current level of reliability, Entegrus' efforts to address reliability and impact of power outages.

The qualitative consultation phases explored the impacts of outages on customers, acceptable frequencies, and durations of outages. Those findings are detailed in the following section, in the qualitative phases of the customer consultation.

The telephone surveys built on the qualitative feedback and asked questions about customer preferences on the trade-off between cost and reliability.

Most residential (83%) and general service (86%) customers had experienced at least one outage in the 12 months leading up to the survey, with most outages lasting less than an hour. Asking respondents to think back to their most recent power outage:

- Half (52%) of residential respondents said the outage caused a *minor inconvenience*, while 28% said it caused *no inconvenience at all*. The most recent power outage was a *major inconvenience* for 11% of residential customers.
- This question was posed differently to general service customers. Almost one quarter (23%) reported the most recent outage to have had a *minor cost* to their business, while 38% said it had *barely any cost, just a bit of inconvenience.* The outage had a *major cost* to 22% of businesses.

When it comes to addressing power outages, a majority of residential and general service customers want to see spending focused on maintaining the current number and duration of outages that are experienced.

Regarding the number of power outages:

- One-in-five (22%) residential customers think Entegrus should spend what is needed to <u>reduce</u> the number of power outages, while almost half (45%) think they should spend what is needed to <u>maintain</u> the current level. Only 13% state that Entegrus should accept more power outages in order to keep customer costs from rising.
- General Service customers respond similarly on how to address the number of outages: 21% think that Entegrus should spend what is needed to <u>reduce</u> the number of power outages and 37% say they should spend what is needed to <u>maintain</u> the current level. Again, only a small minority (13%) believe that Entegrus should accept more power outages in order to keep customer costs from rising. Three-in-ten (29%) *don't know* how they feel.

Regarding the length of power outages:

- Almost seven-in-ten (68%) of residential customers think Entegrus should spend what is needed to either reduce (23%) or maintain (45%) the length of power outages. Only 16% think that Entegrus should accept longer power outages to help minimize customer costs from rising.

- Slightly different proportions of general service customers think that Entegrus should spend what is needed to reduce (27%) or maintain (36%) the length of power outages. 17% think that Entegrus should accept longer power outages to help minimize customer costs from rising.

Survey respondents were informed of Entegrus' proposed capital investment required to maintain system reliability and then asked to think about reliability in terms of bill impact.

- Two-thirds (66%) of residential customers and 58% general service customers believe that Entegrus should invest in aging infrastructure to maintain system reliability, even if it means their bills may increase.
- In regard to replacing the aging infrastructure both residential (70%) and general service (74%) or more in favour of replacing non-critical equipment before it breaks down, as opposed to waiting until it breaks down in order to get the full value from each piece.
- 62% of residential customers and 55% of general service customers feel that, while Entegrus should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably.
- Approximately four-in-five customers in both groups (82% RS; 82% GS) think the benefits of new technology are important enough to be a priority for Entegrus.

Power quality also came up as a key issue among Entegrus' larger business customers in the qualitative workshop consultations. While there was some concession among customer that no system is perfect and that there will always be the occasional outages, it was power quality that appeared to be the bigger concern among this group of customers. Particularly among organizations that rely heavily on automated machinery, these blips can be just as costly as long outages.

The need for stable and uniform power quality is becoming increasingly important as the technology used to run automated systems becomes more refined. Newer systems are much more precise and therefore have a much smaller window for variation. Even with the protection of a UPS, variation that would have previously gone unnoticed can cause a system to trip resulting in severe losses in product and productivity. The slightest variation in power quality can have an incredible cost in a matter of seconds.

Larger business customers very much expressed a need for Entegrus to invest in grid modernization technologies to help alleviate issues with power quality.

## Affordable electricity costs

It is true that many customers are feeling a "financial pinch" when it comes to their electricity bills. However, more customers feel they are obligated to invest in the system to maintain reliability for future generations.

When it comes to the impact on household finances and the bottom line, a number of customers indicate that their electricity bill has a significant impact:

- 69% of residential customers agree that "*The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities*";

- While 78% of GS customers agree that "*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.*"

Both residential and general service customers feel that it is important to contribute to the system in order to maintain reliability for years to come.

- 87% of residential and 80% of GS customers agree that "*Nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local electrical system for future generations.*"

## Customer Reaction to Proposed Rate Increase

Asking customer whether they support or oppose a rate increase puts many participants in a difficult spot. It is clear that many customers have an issue with the idea of "supporting" a rate increase. While they do not want or like a rate increase, they are often not opposed to a rate increase. In fact, many feel a rate increase is needed. As such, we created a response for these customers: "I don't like it, but I think the rate increase is necessary".

Other participants had no problem in expressing outright support for a rate increase. The statement we provided for them is "The rate increase is reasonable and I support it".

When we refer to the combination of these two groups – I don't like it but it's necessary and I support the rate increase – we refer to the level of "**social acceptance**".

Referring to the generalizable results from the telephone surveys, 74% of residential customers accept Entegrus' proposed rate increase, while 75% of general service customers accept the proposed rate increase.

***Q: Considering the cost of Entegrus' proposed plan, would you say …***

| Response | Directional (Focus Groups) | | Directional (Workshop) | Directional (Online) | | Generalizable (Telephone Surveys) | |
|---|---|---|---|---|---|---|---|
| | Small GS | Residential | Mid-market & Large GS | Small GS | Residential | Small GS | Residential |
| The rate increase is reasonable and I support it | n=2 | n=2 | n=4 | n=3 | 16% | 39% | 32% |
| I don't like it, but I think the rate increase is necessary | n=8 | n=10 | n=7 | n=15 | 50% | 36% | 42% |
| The rate increase is unreasonable and I oppose it | n=4 | n=4 | n=1 | n=9 | 28% | 22% | 24% |
| Don't know / Refused | n=3 | n=0 | n=0 | n=0 | 6% | 3% | 2% |
| **TOTAL** | **n=17** | **n=16** | **n=12** | **n=27** | **n=604** | **n=111** | **n=509** |

As seen throughout Entegrus' customer consultation, there is no simple answer to electricity utility spending and investing from the customer's perspective. Rate increases are undesirable, but lower reliability (and in some cases, power quality) is clearly unacceptable and a proactive and consistent approach to system maintenance appears to be understood and accepted by customers. As a result, Entegrus' customers accept the proposed spending and investment plan and its accompanying rate increase as an unfortunate necessity of maintain system reliability.

## Rate Harmonization

Customers were also asked to give their opinion on Entegrus' proposed rate harmonization.

The survey results show a strong majority of both residential (72%) and general service customers (69%) agree with the concept of rate harmonization. That is, Entegrus customers should pay the same rates for the same level of service, regardless of where they reside or businesses are located.

***Q: How strongly do you agree or disagree with the following statement: Entegrus customers should pay the same rates for the same level of service, regardless of where they live or operate a business.***

| Response | Generalizable (Telephone Surveys) | |
|---|---|---|
| | General Service | Residential |
| Strongly agree | **42%** | **46%** |
| Somewhat agree | **27%** | **27%** |
| Neither agree nor disagree | **3%** | **1%** |
| Somewhat disagree | **8%** | **9%** |
| Strongly disagree | **9%** | **8%** |
| Don't know/Refused | **10%** | **9%** |
| **TOTAL** | **n=111** | **n=509** |

Small General Service customers were asked an additional "acceptance" question in the telephone survey on the topic of rate harmonization, as this is the customer group who would be primarily affected by the proposed plan. The survey shows that more than three-in-five general services customers (61%) say they accept the proposed rate harmonization plan, while one quarter (25%) think it is unfair and oppose it.

Although only directional, larger GS customers also indicated that they generally support the idea of the proposed rate harmonization. When asked in the mid-market workshop, 'Which of the following best describes how you feel about rate harmonization?' a majority indicated that they thought rate harmonization made sense and that they support it.

# Focus Group Consultation

**Focus Group Consultation**
with Residential and
General Service customers

**PURPOSE:** To gain qualitative input on Entegrus' plan from residential and GS < 50 kW customers and to help inform the design of the subsequent telephone surveys.

## Summary

***General Satisfaction:***

Overall, participants are very satisfied with the service they receive from Entegrus. Those few that were dissatisfied tended to cite cost of electricity as the most pertinent factor. While some participants acknowledged that Entegrus is just a small part of the system as a whole, and therefore that some perceived short-comings are beyond its control, many were surprised to learn just how little control Entegrus has over issues of general concern.

***System Reliability:***

Participants in Strathroy experience outages more frequently than those from Chatham. In spite of this, almost every participant in both groups found the number of outages they experienced in the year prior to be at least somewhat acceptable. Small businesses are more negatively impacted by outages than residential consumers. The severity of the impact varies greatly, depending on how reliant on electricity the operations are. Participants found that Entegrus' response to outages is generally quick and efficient.

***Areas for Improvement:***

For General Service participants, the most important area of improvement is centred around conservation. Many feel that despite their best efforts, reducing their electricity costs is an ongoing struggle. There was some concern that Entegrus could be doing more to work with small businesses to help find efficiencies, in addition to the sentiment that cost-reduction programs currently in place are falling short of their objective.

Residential participants are for the most part quite satisfied with the service Entegrus is providing. Those who did have concerns over their service suggested improvements focus on cost and time-of-use pricing. Most participants were unaware that time-of-use is outside of Entegrus' domain. Additionally, several participants from the residential groups mentioned the treatment of seniors as a potential area of improvement.

***Concerns with Proposed Plan:***

The majority of participants feel that the proposed plan is going in the right direction - only two participants disagreed. Most participants feel that Entegrus should invest what is necessary to maintain the level of service they are providing. They also agree on the importance of Entegrus staff having the buildings and equipment they need. This sentiment carried the caveat that if they are going to support such investments, they want to know that their money is being spent efficiently.

### *Growth of Entegrus:*

One concern that did arise was in regard to Entegrus' growth. In light of the utility's history of acquisitions, some participants expressed concern that Entegrus would become too large. They feel that it should remain local, and if it continues to grow, operations will be forced to move elsewhere resulting in what they consider "good" jobs being lost.

### *Social Acceptance of Plan:*

Social acceptance of the plan is high. While the majority of participants don't like to see any kind of cost increase, they understand the necessity.

***Q: Considering what you know about the local distribution system, which of the following best represents your point of view?***

| Response | Strathroy | | Chatham | | COMBINED |
|---|---|---|---|---|---|
| | GS | RS | GS | RS | |
| The rate increase is reasonable and I support it | 2 | 0 | 0 | 2 | 4 |
| I don't like it, but I think the rate increase is necessary | 4 | 4 | 4 | 6 | 18 |
| The rate increase is unseasonable and I oppose it | 3 | 4 | 1 | 0 | 8 |
| Don't know | 1 | 0 | 1 | 0 | 2 |
| Missing value | 0 | 0 | 1 | 0 | 1 |
| **TOTAL** | 10 | 8 | 7 | 8 | 33 |

# Methodology

## About the General Service and Residential Customer Consultation

INNOVATIVE was engaged by Entegrus to conduct General Service and Residential customer consultation sessions designed to identify the needs and preferences of consumers as they relate to the utility's proposed spending on the distribution system.

The consultation sessions were held in Strathroy on May $26^{th}$, 2015 and in Chatham on May $27^{th}$, 2015. A total of 33 General Service and Residential customers participated in these consultation sessions.

| | |
|---|---|
| General Service under 50 kW Rate Class | 17 participants |
| Residential Rate Class | 16 participants |

## Recruiting Consultation Participants

General Service customers in the under 50 kW rate class were randomly selected from customer lists and then screened by telephone for appropriateness as session participants. These customers qualified for the consultation if they manage or oversee their business' electricity bill. This was to ensure that they were at least somewhat knowledgeable of their electricity costs and could have an informed discussion on the impact of the proposed rate increase.

Residential customers were screened to ensure they are the person in the household who has primary or shared responsibility for paying the electricity bill.

Entegrus provided INNOVATIVE with their entire lists of Residential and General Service <50 kW customers. These lists were used to randomly recruit qualified participants.

An incentive of $100 was provided to all General Service and $80 to all Residential customers who participated in the consultation sessions.

All consultation sessions were video recorded to verify participant feedback and verbatim quotes.

## Consultation Session Structure

The consultation sessions were structured around the themes contained in the workbook that was developed by INNOVATIVE and Entegrus staff.

The workbook themes included the following:

1. What is this Consultation About?
2. Electricity 101
3. Entegrus' Grid Today
4. Cost Pressures
5. What the Plan Means for You

At the start of each session, the facilitator gave an overview explaining the purpose of the consultation and why Entegrus is seeking feedback from General Service and Residential customers.

After explaining the purpose of the consultation, hardcopy workbooks were distributed to act as a session guide and for participants to record their answers to the questions contained within.

The facilitator then led the participants through the workbook section by section to ensure they understood the information and to answer any questions about the content.

When it came to the questions within the workbook, participants were asked to fill in their answers independently. The facilitator then led a group discussion on the answers participants provided and what the various issues meant for them or their businesses.

Hardcopy workbooks were collected from the participants at the conclusion of each consultation session.

Each consultation session ran for approximately 2 hours.

## Informing the Consultation Process

In addition to identifying customer needs and preferences as they relate to the proposed system plan, feedback collected from this phase of the consultation was used to inform the design of the telephone survey consultation phase of Entegrus' customer engagement program.

**NOTE:** Results contained within this report are based on a limited sample and should be interpreted as directional only.

# Participant Feedback

The following sections highlight the general feedback from each consultation group.

## General Service under 50 kW Rate Class

To begin the consultation, participants were introduced to the format and purpose of the consultation. The facilitator explained what the consultation is about, why Entegrus is holding such a consultation and why consumer feedback is important. Additionally, a central focus of this section was to familiarize participants with the electricity system itself. They were presented with a breakdown of the different components of the system and their functions. They were also shown how their electricity bill is broken down and what portion of it is allocated to Entegrus.

During this introduction period participants were encouraged to ask any questions that might arise. At the end of this discussion they were asked how well they felt they understood the parts of the electricity system, how they work together and which services Entegrus is responsible for. All participants but one felt they understood this at least *somewhat well* (*very well*: 3; *somewhat well*: 12; *not very well*: 1).

### General Satisfaction

Overall, participants from both Strathroy and Chatham are quite satisfied with the service they receive from Entegrus. Almost half of the participants in both groups indicated in the workbook that they were *very satisfied* (Strathroy: 4; Chatham: 3). The remaining participants are *somewhat satisfied*, excluding one who presented a general dissatisfaction in several domains.

> *It's not that I'm just somewhat dissatisfied with Hydro. I'm dissatisfied with the local government, provincial government, gas companies.*

Focus group consultations allow participants a platform from which to air grievances. As such, while every participant indicated in the workbook that they were ultimately satisfied with the service they receive, some anecdotal concerns did arise. The dissatisfaction that was reported centred around the cost of electricity, and illustrates some business owners' frustration with the system as a whole. Some recognized that Entegrus is just one part of the system, while others lamented Smart Meters.

> *Well somewhat dissatisfied, it's like you're dealing with a government agency when you call them.*

> *My opinion would be that residential fees are considerably less than business fees and businesses are filling [in for] the residential [fees], so why should we get penalized. We're a small user but still our delivery charges are a lot more and our rates are a lot more, for what? So we can try to survive the business and cut our costs and save everything we can?*

> *I think I'm angrier about the whole system and the way they waste our money and everything. Entegrus is a small part of it. Smart Meters don't belong in business. Nobody seems to be concerned about businesses. That isn't an attack on Entegrus but it just seems like the whole thing.*

> *Entegrus, I don't seem to have too often problems with them, other than that one page where it's saying we're going up $20 a month. My hydro bill has almost tripled because of Smart Meters. And now you're adding another thing. I'm not saying let's be unfair and us get better prices than somebody else. I don't for one minute believe that ours is going to go up and theirs will go down. I just don't ever think you will ever see anything go down.*

## System Reliability

System reliability varies across the groups. Participants from Strathroy experienced a higher volume of outages in the year prior. The number of outages ranged from one to more than four; experiencing two outages was the most common. Furthermore, almost all participants found the number of outages to be acceptable. They recognize that over the course of a year some outages are to be expected.

> *I can't reasonably expect that during the year I won't lose power.*

> *I don't think I have any reason to launch a great complaint. We had two outages in the past year that I can remember. That's not too bad for 365 days.*

Participants from Chatham experienced fewer outages overall, with only one participant experiencing more than two. The majority found the number of outages they experienced to be very acceptable (*very acceptable:* 4; *somewhat acceptable*: 2; *not acceptable at all*: 1). There was also mention of the speed at which power is returned in the event of an outage.

> *We've had a lot of work done downtown over the last couple years. I haven't really noticed a change, good or bad. You turn on the lights and they come on.*

> *I think within a couple hours they were back. They're relatively quick.*

While participants from both groups had varying ideas of what is a reasonable duration for a power outage, the majority felt that one hour or less is ideal. There was also question of how long the power has to be interrupted to be considered an outage, which elicited discussion of power flickering.

> *Every time there's a wind storm or a light rain or whatever the power goes off.*

> *I notice that when I'm welding sometimes in the morning. I set the welder to a certain temperature and when the ladies turn the ovens on – the power, you can notice it. It's irritating because it's a fluctuation especially if you're doing production welding because everything's set to a certain – it affects the quality of the product.*

## Impact of Outages

Businesses vary greatly in their daily operations and therefore experience outages differently. The cost of an outage depends how dependant their daily operations are on electricity. For some the impact is very minimal.

> *It really doesn't [affect my business], because in construction everything's off-grid and on a battery.*

Business that rely heavily on computers and tech systems are most inconvenienced. Several cite having to restart systems, which can be costly in terms of the time it takes to return to full productivity. In the event of longer outages, some businesses have to make the decision of whether or not to end the day early.

> *We've probably had more [than four outages], and when the system goes down, we don't work until it's back up. When the hydro goes out our computers take longer to come back on. It's just the way they were designed; it could take 45 minutes for them to reboot.*
>
> *There is no business because the cash register shuts down. The cooler starts causing me all kinds of problems. I close the doors.*
>
> *I can't order any parts because it's all done on the computer. If I have a car in the hoist in the safety-lock position, I can't do anything.*
>
> *I'm affected by both [short and long term outages]. If it goes out for a short time, I have to reset systems. If it goes out long, the guys don't know where the product is because it's all bin locations.*
>
> *I think the last time I told them to close the store and go home.*

The highest cost is to businesses that deal in perishable items that require refrigeration. The loss of product can have very severe consequences for small business that need to be run as efficiently as possible to remain successful.

> *If it was long term then it would be a huge cost. Fridges and freezers are good for a little while and then you start losing product. If it's stormy out and you have a sump pump in your basement, then you have that issue too.*
>
> *I also run a food bank in the same place as I run a thrift store. For me that could be a big loss in terms of the food bank. If it's out for very long I've lost a lot of product. And I can't make up for that. In most cases it's all donated, but it's still lost whether it's donated or not.*
>
> *If the power is off for too long, I start to lose product. It means no sales and lost product and you can't do anything because the store is dark. You have to sit with a candle and hope the staff doesn't burn the place down. Then I've created havoc with my computers.*

## Improving Service of the Local Distribution System

For the most part, participants are satisfied with the service they receive from Entegrus and do not have any suggestions as to how it could be improved. Those who did have an opinion on the matter were primarily concerned with conservation. Some expressed concerns that Entegrus could be doing more to help businesses save, and frustration with the administrative burdens involved with current programs.

*I got a $1,000 grant for my small business. They put all new lighting in.*

*These retro-fit programs, they're pretty good but it's tedious.*

*It's like dealing with a political agency. Even changing to the LED program. You've got to spend 12K to get 3K back. And then all you're doing is maintaining the cost of your bill. So it's a wash. The bureaucracy and the paperwork they make you do is unbelievable.*

*There are a lot of costs involved in upgrading to make those savings. They do offer money back through the Ontario government and all these programs, but still, you've got to lay out all this money to get money back.*

Furthermore, some felt that some programs currently in place were falling short of their objectives, and not offering the savings participants had hoped for.

*I never noticed anything from those lights all being changed. I never noticed any difference. That was just a waste of money.*

*You look at your bill and it's only a percent [the amount affected by energy efficiency], everything else is fixed costs. So you can only knock down half that [part of the] bill to start.*

Some found that impactful savings were made more difficult to come by due to time-of-use.

*It really is discouraging to operate normal business hours.*

*They keep saying you need to conserve energy. When you operate in the time-frame of 8[am] to 6[pm] every day they say you have to come up with a way to conserve energy – well, that's when you need your hydro at its peak. The rest of the time it's shut off. So how can they change that around to help you out during that time?*

*At home I do everything after 9 at night, I do laundry at 7. I can't start my business at 7 or 9 at night and say come and shop with me now because I can't afford the hydro to be open during the day.*

That said, most participants were unaware that Entegrus has no control of time-of-use billing.

*I have complaints about the time-of-use billing. I don't know how much of that is in the hands of Entegrus but it seems like when the Smart Meters came out – things like that – that it was a more local mandated thing.*

Finally, one participant mentioned wanting water and electricity bills separated to facilitate easier comprehension.

*I would like to see the water bill and the electricity bill on two separate bills. You tend to gloss over the bill, and at the end of the day you're blaming Hydro for the $200, when it's really just $110.*

## Customer Experience and Expectation

The majority of interactions participants have had with Entegrus have been quite positive. They noted Entegrus' fast response time and customer care in the event of a planned outage. One participant occasionally has to work with Entegrus, and commented on the ease of those interactions.

*I had a transformer blow across the way. They were right on the ball.*

*Two were scheduled – it was good because they call you, then they call you again.*

*If a customer's service went down then it affects my business where I've got to call it in and schedule it with Entegrus – an inspection – and Entegrus, I have to say, is excellent to deal with in that respect.*

## Capital Investment and Operational Budget

The majority of participants from both groups feel that Entegrus should invest what is necessary to replace the system's aging infrastructure in order to maintain system reliability, even if that results in an increase to their monthly bills. Only two participants in each group were in favour of lowering investments.

*As a society we have high expectations of service and as long as we continue to have that high expectation we may as well get down to the fact that it's going to cost more, because we want everything perfect.*

*Okay, so you want to have no power outages, you're going to pay way more money because we have to upgrade the power systems, that's basically what the question is.*

Regarding the operational budget, participants from Strathroy and Chatham were divided. All participants were asked to identify their position regarding spending on buildings, equipment and IT systems. Those from Strathroy were more inclined to feel that it is important for Entegrus staff to have the tools they need, and therefore Entegrus should be wise with its spending. On the other hand, the majority of participants in Chatham felt that Entegrus should make do with the buildings and equipment it already has.

## Cost Drivers

After reviewing the material presented in the workbook, all participants felt they understood the cost drivers faced by Entegrus at least *somewhat well*. Furthermore they were very confident in Entegrus' ability to manage these cost drivers while meeting their expectations; only one participant across both groups felt that Entegrus was not doing well. In regards to finding efficiencies and cost savings, the majority of participants are satisfied with the effort Entegrus has made.

*As far as price drivers, one in particular that stuck out – I mean, it all makes sense, things get old, you have to replace them, things become obsolete.*

## Rate Harmonization

Participants were asked to choose a statement that best describes how they feel about rate harmonization. To the majority of participants in each group, rate harmonization makes sense and they support it.

*I think it's odd that I'm consuming the same thing and an hour and half down the road the rates are different. I think fundamentally the rates should be the same. I'm buying the same product from the same shelf. I think it should be the same price. It just makes sense to me.*

*In our area it seems we're already paying more than other people, so we won't be as affected by the rate harmonization by a great percent.*

Among the few who do not support rate harmonization, there was concern that rates were only going to increase, instead of meeting somewhere in the middle. Additionally, some questioned why it is going to cost Entegrus more to maintain systems that were operating for less before they were acquired. It should be noted that the $20 increase referenced in the following quotations was an estimation of the increase that was offered by one participant and then adopted by the others.

> *If we're going up they got to go down. Where is that extra money going to? Is Entegrus going to be making extra? That's not harmonizing if you are raising us up to their level. Are they getting a reduction?*
>
> *If Entegrus owning these [new acquisitions] costs $20 more a month, are they doing something to mitigate that?*
>
> *You've got Strathroy, Mt Brydges, Park Hill that small commercial customers are going to see an increase of $20, and these are carry-overs from smaller distribution companies that have been acquired by Entegrus. The argument that our bills would be higher had Entegrus not acquired these seems to be counterintuitive to the fact that the smaller distribution companies were doing it cheaper.*

The facilitator was required to explain the mechanics and purpose of rate harmonization to these participants. They were unaware that the smaller companies had much worse reliability and a lot of investments have been made in those areas to bring the service up to a more acceptable standard. This explanation was echoed by one participant.

> *It doesn't say they are going to get lower. I still think that if you call the Chatham people after we get a $20 increase, they don't get a $20 decrease. Yeah they [Entegrus] can justify it. They're saying that it's anticipated we're going up and it's anticipated they're staying the same. That's what it says.*

## Proposed Plan and Rate Impact

After learning more about the cost drivers and the electricity distribution system as a whole, participants were asked if they felt the proposed budget was reasonable. The majority of them did; only three participants (from Strathroy) in total did not.

> *They must be doing something well because they keep buying up other hydro systems.*

Furthermore, when asked if the plan is going in the right direction the majority of participants felt that it was.

> *It's probably the right direction, I mean we have a very efficient system. The only thing I would like to see is a break or something special for non-profit groups.*

There was some discussion regarding the acquisition of surrounding distributors. Participants felt strongly that Entegrus should remain local. Some worried that should Entegrus become too large, jobs would be taken out of an already depressed area and moved elsewhere.

> *It's my understanding that the government only wants to deal with ten companies across the province. We may have to end up buying Windsor or Essex to stay large enough.*
>
> *You take the office out, you take the buildings out and there's going to be job loss to our area.*
>
> *I want to see Entegrus remain local, and I would hate to see that lost if they were to buy up Windsor [for example]. It seems totally absurd to me to run the electricity of Windsor out of Chatham. The idea of acquiring in order to be successful – that seems way too far.*

In regards to the rate increase, small businesses expressed some hesitation. While the majority understand the necessity and value the importance of continued reliability, small businesses feel the strain of any additional cost.

> *As a consumer and a business owner in Strathroy, am I going to be happy about this increase? No. As an entrepreneur selling energy efficient lighting and products, hey it's all good.*
>
> *We can't pay more money and stay in business.*
>
> *You have to look at it – okay, yeah we have some power outages, I don't want them. But at the same token, I don't want them to spend billions of dollars to make it so there's none and jump my rates up again. We can't pay more. Costs are getting out of control. It's getting more difficult to stay in business.*

### How Could the Consultation Process be Improved?

The majority of participants found the consultation to be informative with a good amount of information given the time frame. Some indicated that there could have been more discussion had they been given the information beforehand. One participant felt there could have been more information on the budget from previous years. Others would like to have seen a more detailed breakdown of the costs.

> *I would have liked to have seen a more clear-cut comparison from this year's proposed budget to years previous. There's a few graphs that show what's going into 2016 but I have very little context to say what was 2015's let alone when Chatham-Kent first acquired.*

While participants acknowledged that this consultation is a standard part of the rate application process there was some sentiment that the information presented carried an inherent bias.

> *This process is not new, it's how they've gotten their rate increases. Two years ago, they went through the same process. They determined what they feel they need to cover their administrative and distribution costs. It's a public process, people can go and argue against it. And then the board decides if it's reasonable.*
>
> *They're basically trying to sell us, ok we're going to raise the rates here. They have a monopoly and they can do what they want.*
>
> *I think all of these pages it's all worded in a way to say to convince you to say, "Yes please, increase my prices and fix everything up".*

## Residential Rate Class

The Residential rate class session began the same way as the General Service session. That is, participants were introduced to the format and purpose of the consultation. The facilitator explained what the consultation is about, why Entegrus is holding such a consultation and why consumer feedback is important. Discussion initially focused on the provincial electrical system and then narrowed down to a discussion about Entegrus' role within that system.

Initially, none of the participants were aware that only 20% of their bill is allocated to Entegrus. However, following the introduction, Residential participants felt that they understood the parts of the electricity system, how they work together and which services Entegrus is responsible for (*very well*: 3; *somewhat well*: 12; *not very well*: 1). Furthermore, after reviewing in more detail Entegrus' role as the distributor, participants were slightly more confident in their understanding (*very well*: 4; *somewhat well*: 11; *not very well*: 1).

*It's surprising at first but then you see the breakdown here and it makes sense*.

### General Satisfaction

Overall, Residential participants are quite satisfied with the service they receive. No participant from either group indicated dissatisfaction (*very satisfied*: 2; *somewhat satisfied:* 13; *don't know*: 1). Respondents found outages to be rare, and when they do happen, they are resolved quickly and efficiently.

> *The service is fine. My hydro doesn't go out very often and if it does it's usually a car accident or something.*
>
> *I could say I'm satisfied with the service. I don't really ever have power outages and when there is one it's back up and running pretty quick.*

The one point of contention was that even though the service is acceptable, some participants feel the cost is too high. After being familiarized with the material however, they realized that Entegrus is small part of the system as a whole, and that there are many other factors influencing the cost of electricity.

> *The service is fine, it's the cost. I lived in Northern Ontario and I paid a third of the cost. When I moved here I was stunned.*
>
> *The service to me is okay, it's the cost. Reading this I know that Entegrus can't change that, unfortunately for us.*

### System Reliability

Similar to General Service participants, Residential participants in Strathroy indicated that they experienced one to four or more outages in the year prior. A majority found the number of outages they experienced to be acceptable (*very acceptable*: 2; *somewhat acceptable*: 4; *not very acceptable*: 1; *not acceptable at all*: 1).

In Chatham, the distribution is different (*none*: 1; *one*: 3; *three*: 3; *don't know*: 1) and all participants found the number of outages they experienced to be at least somewhat acceptable.

Participants realize that outages are a natural and unavoidable occurrence, and given how quickly service is often restored, the inconvenience is minimal.

> *It [experiencing outages] is to be expected. Ever since in 2004 when all of Ontario went black – you kind of expect it in the summer time when everybody's using their air conditioners and running their pools.*
>
> *We had an outage for about an hour last summer. It happened to be just a really hot week. It wasn't terrible because we had candles handy and we read instead of watching Netflix.*
>
> *I think there was only one and that was only a half an hour. The other two were really nothing.*
>
> *Couple of them [outages], most about an hour. You just have to rearrange what you're doing.*
>
> *I can't really recall any if we did have them. I guess they were a short enough time span that I wasn't terribly inconvenienced.*

Several participants made note of instances of power flickering, and the impact these brief power interruptions can have.

> *I used to work at Meridian[2] and it would kill the machines. It would take an hour to get everything back up, even a flicker.*

> *I had a friend out in the Cedar Springs[3] area that was experiencing damage to the compressors in a refrigerator because of not complete outages, but 'flickers'.*

> (From workbook) *I find locally we get a number of energy hiccups. These are brief, i.e. lasting less than 1 min loss of power. This plays hell with my electronics. I'm wondering if there are ways to smooth these out to avoid them.*

Participants found outages to be acceptable except during specific times.

> *As long as it doesn't happen during the hockey game.*

## Improving Service of the Local Distribution System

There were a number of suggestions to improve service, the majority of which were centered around cost. Time-of-use was one topic that elicited differing views. Participants varied in their ability to work around peak-times. Furthermore, most were unaware that Entegrus is not responsible for determining peak-times.

> *I'm a shift worker; when I do laundry is when I can do it. I can't wait. I work at 6am in the morning. I can't wait. I have to swallow that charge because they've done that.*

> *The non-peak times need to be readjusted for people that work all day. When I come home from working until 6pm. Take into consideration that between 7-9pm is the most important time. Entegrus needs to reconsider how they determine peak time.*

> *I can't say that they can [improve service]. I'm a happy camper. I take my off-peak times very seriously, to the point where I don't even use my dryer but once a month. If you really are diligent you can save a lot of money. I've had my bill down below $50.*

There was also some anecdotal concern about the treatment of seniors.

> *They treat our seniors very crappy. My mother's a senior and gets her money at a certain time. The bills come out before, so what happens is they pay a late fee every time. This is an ongoing discussion at the seniors' home.*

> (From workbook) *As a senior living on a fixed income, increasing costs, especially the fixed extra charges and the loss of the 10% Ontario Clean Energy Benefit are an increasingly serious issue. Cost control is paramount.*

One participant made note of difficulty connecting to customer service.

> *Better communication in general with Strathroy, you don't want to talk to someone in Chatham. It's like calling Bell or whatever. We're all tired of that. We want to talk to someone, not a phone bank.*

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[2] Meridian is one of Entegrus' Key Account customers and participated in the Key Account Validation Interviews as seen in a subsequent section of this report.

[3] Cedar Springs is outside of Entegrus' services territory.

## Customer Experience and Expectation

Participants discussed working together with Entegrus to conserve energy and find savings. There were several points of view.

> *I think they should invest more in education. If the public's not aware of different things to save their appliances – just a spark protector will cost you five bucks.*
>
> *If they sent you a questionnaire with twenty questions that you could fill out and then gave you a profile of your consumption I would really look at that.*
>
> *It's not Entegrus' responsibility to save us money. It's our responsibility.*
>
> *I was actually quite impressed with what they have been doing. Numerous times I've received coupons for getting LED light bulbs. Pamphlets come with the bills and I think it's a matter of are people reading it.*

## Capital Investment

The majority of participants in both groups (Strathroy: 4; Chatham: 6) feel that Entegrus should invest what it takes to replace the aging infrastructure. Once familiarized with the system, there was support for Entegrus receiving and investing the funds it needs.

> *It's realistic to expect that as systems are aging they're going to have to cover the cost.*
>
> *I've had four [outages] and I've only been here a year and a half. It was awful out in the country, and now it seems they fixed it. Then I moved into the city and this is a repeat. What is the problem? Now that I understand this better, maybe Entegrus isn't getting enough money from Hydro One to maintain. From looking at this Entegrus is the little guy, let's give them some more money if it's going to help the town of Strathroy because that's who's servicing us – I don't need Hydro One getting more money.*

Participants feel similarly in regards to funding buildings and equipment for Entegrus staff. Almost every participant in both groups felt that it is important for Entegrus staff to have what they need to manage the system efficiently.

## Cost Drivers

After reviewing the material on cost drivers, nearly every participant felt they understood at least *somewhat well*; only three felt they understood these drivers *not very well*. Furthermore, the majority in both groups (Strathroy: 5; Chatham: 6) feel that Entegrus is doing a good job of managing these drivers while meeting their expectations. In regards to how well Entegrus is finding savings and efficiencies, once again the majority of participants in both groups (Strathroy: 7; Chatham: 7) feel that Entegrus is doing at least *somewhat well*. Furthermore, the majority in each group (Strathroy: 6; Chatham: 7) feel that the proposed budget is reasonable.

> *I think it's reasonable for what they're doing and just comparing them to the other big companies nearby – the other people that I talk to that deal with Hydro One - Entegrus just sounds so much better in how they look after things and I think they're a lot more responsible with their cost management and stuff like that. I'm pretty happy with it.*

## Rate Harmonization

None of the participants oppose rate harmonization, and the majority in both groups (5 in each location) feel that it makes sense and they support it. In spite of this, there was some concern that participants didn't have enough information to make that judgment, and that they might be unfairly charged.

> *You need to have the numbers before you can have an opinion.*

> *Amalgamations don't work. We have to carry the burden of someone who hasn't taken care of the system for years and so we end up paying the bill.*

## Proposed Plan and Rate Impact

Overall, participants are very confident in Entegrus' approach to the future. They found the information in the workbook informative, and the plan outlined therein to be satisfactory. All but one feel that Entegrus is planning at least *somewhat well* for the future, and the majority in each group (7 in each location) feel that the plan is heading in the right direction. There was also a general sense of appreciation, and confidence gained by the process of the consultation itself.

> *I think that it's a good idea that we're in the know. The more knowledge that we can accumulate the better. If they're willing to let us see what is going on I think that to me that gives me a lot of confidence in them because they're not being secretive, they're being really open, and they're willing to let us learn more about what they're planning on doing and how they're planning on doing it.*

Regarding the proposed increase, social permission is very high. Two participants feel the rate increase is reasonable and support it outright.

> *It's very fair. If you look at the cost increase, it's minimal.*

> *I think that I've learned a lot tonight and I appreciate their openness. It is what it is; it's the cost of living in this country. I think overall we're still in very good shape even if we see an increase. I think it's inevitable and we have to realize that has to happen for the service to remain at the high level it has been held at until now.*

The majority do not like to see increases of any cost, but they acknowledge that an increase is necessary for Entegrus to continue providing the level of service that participants expect.

> *I think overall my impression is that it's a necessary evil. Nobody likes paying high bill costs, but it looks like it's being managed well, all things considered.*

> *I don't exactly like my bills going up, but I understand why they have to.*

Finally, there was some acknowledgement that Entegrus is just a small part of the system as a whole. Most participants were not aware of this, and after the consultation had a better appreciation for Entegrus' role and limitations within the larger system.

> *Before I came into this I felt like they charged way too much, but I really didn't realize how little control they really have.*

## How Could the Consultation Process be Improved?

The overall impression of the workbook was very positive. Participants found the information to be pertinent and informative, with most feeling like it was just the right amount given the allotted time.

> *I thought this was very well done for a guy who didn't know a lot. I thought the book gave a very good orientation. I believe that these guys are committed to improvement.*

Most participants did not have any suggestions for improving future consultations. Some thought it should be kept the same while a few others felt that surveys, or an online workbook would be more cost effective.

# Questionnaire Results (Workbook)

The following tables are the tabulations of participant feedback to questions in the workbooks, which were returned at the end of each consultation session.

**Note**: "GS" = general service less than 50 kW customers, while "RS" = residential customers.

**1. Given what you know and what you have read so far, how well do you feel you understand the parts of the electricity system, how they work together and which services Entegrus is responsible for?**

| RESPONSE | Strathroy | | Chatham | | TOTAL |
|---|---|---|---|---|---|
| | GS | RS | GS | RS | |
| Very well | 4 | 3 | 3 | 0 | 10 |
| Somewhat well | 6 | 5 | 4 | 7 | 22 |
| Not very well | 0 | 0 | 0 | 1 | 1 |
| I don't understand at all | 0 | 0 | 0 | 0 | 0 |
| **TOTAL** | 10 | 8 | 7 | 8 | 33 |

**2. Generally, how satisfied are you with the service you receive from Entegrus?**

| RESPONSE | Strathroy | | Chatham | | TOTAL |
|---|---|---|---|---|---|
| | GS | RS | GS | RS | |
| Very Satisfied | 4 | 1 | 3 | 1 | 9 |
| Somewhat satisfied | 5 | 7 | 3 | 6 | 21 |
| Somewhat dissatisfied | 1 | 0 | 0 | 0 | 1 |
| Very dissatisfied | 0 | 0 | 0 | 0 | 0 |
| Don't know | 0 | 0 | 0 | 1 | 1 |
| Missing Value | 0 | 0 | 1 | 0 | 1 |
| **TOTAL** | 10 | 8 | 7 | 8 | 33 |

**4. How well do you feel you understand the important parts of the electricity system, how they work together, and which services Entegrus is responsible for?**

| RESPONSE | Strathroy | | Chatham | | TOTAL |
|---|---|---|---|---|---|
| | GS | RS | GS | RS | |
| Very well | 3 | 2 | 2 | 2 | 9 |
| Somewhat well | 7 | 5 | 5 | 6 | 23 |
| Not very well | 0 | 1 | 0 | 0 | 1 |
| I don't understand at all | 0 | 0 | 0 | 0 | 0 |
| **TOTAL** | 10 | 8 | 7 | 8 | 33 |

**5. The average Entegrus customer experiences one power outage per year. Do you recall how many outages your company experienced in the past year?**

| RESPONSE | Strathroy | | Chatham | | TOTAL |
|---|---|---|---|---|---|
| | GS | RS | GS | RS | |
| None | 0 | 0 | 1 | 1 | 2 |
| One | 1 | 2 | 3 | 3 | 9 |
| Two | 3 | 2 | 1 | 0 | 6 |
| Three | 1 | 1 | 0 | 3 | 5 |
| Four | 1 | 2 | 0 | 0 | 3 |
| More than four | 2 | 1 | 1 | 0 | 4 |
| Don't know | 2 | 0 | 1 | 1 | 4 |
| **TOTAL** | 10 | 8 | 7 | 8 | 33 |

**6. How acceptable were the number of power outages you experienced over the last 12 months?**

| RESPONSE | Strathroy | | Chatham | | TOTAL |
|---|---|---|---|---|---|
| | GS | RS | GS | RS | |
| Very acceptable | 3 | 2 | 4 | 4 | 13 |
| Somewhat acceptable | 6 | 4 | 2 | 4 | 16 |
| Not very acceptable | 0 | 1 | 0 | 0 | 1 |
| Not acceptable at all | 1 | 1 | 1 | 0 | 3 |
| Don't know | 0 | 0 | 0 | 0 | 0 |
| **TOTAL** | 10 | 8 | 7 | 8 | 33 |

**7. How acceptable were the number of power outages your company experienced over the last 12 months?**

| RESPONSE | Strathroy | | Chatham | | TOTAL |
|---|---|---|---|---|---|
| | GS | RS | GS | RS | |
| No outage is acceptable | 2 | 0 | 3 | 2 | 7 |
| One | 3 | 3 | 0 | 1 | 7 |
| Two | 3 | 2 | 2 | 4 | 11 |
| Three | 1 | 1 | 0 | 0 | 2 |
| Four | 0 | 0 | 0 | 0 | 0 |
| More than four | 0 | 0 | 1 | 0 | 1 |
| Don't know | 1 | 2 | 1 | 1 | 5 |
| **TOTAL** | 10 | 8 | 7 | 8 | 33 |

**8. What do you feel is a reasonable duration for a power outage?**

| RESPONSE | Strathroy | | Chatham | | TOTAL |
|---|---|---|---|---|---|
| | GS | RS | GS | RS | |
| No outage is acceptable | 2 | 0 | 1 | 0 | 3 |
| 30 minutes | 3 | 2 | 1 | 1 | 7 |
| 1 hour | 3 | 4 | 2 | 3 | 12 |
| 2 hours | 1 | 2 | 0 | 2 | 5 |
| 3 hours | 1 | 0 | 2 | 2 | 5 |
| 4 hours or more | 0 | 0 | 0 | 0 | 0 |
| Don't know | 0 | 0 | 1 | 0 | 1 |
| **TOTAL** | 10 | 8 | 7 | 8 | 33 |

**9. With regards to projects focused on replacing aging equipment in poor conditions, which of the following statements best represents your point of view?**

| RESPONSE | Strathroy | | Chatham | | TOTAL |
|---|---|---|---|---|---|
| | GS | RS | GS | RS | |
| Entegrus should invest what it takes to replace the system's aging infrastructure to maintain system reliability, even if that increases my monthly electricity bill by a few dollars over the next few years. | 6 | 4 | 5 | 6 | 21 |
| Entegrus should lower its investment in renewing the system's aging infrastructure to lessen the impact of any bill increase, even if that means more or longer power outages. | 2 | 2 | 2 | 1 | 7 |
| Don't know | 0 | 2 | 0 | 1 | 3 |
| Missing Value | 2 | 0 | 0 | 0 | 2 |
| **TOTAL** | 10 | 8 | 7 | 8 | 33 |

**10. As a company, Entegrus needs building to house its staff, vehicles, and tools to service the power lines and IT systems to manage the distribution system and customer information. Which of the following statements best represents you point of view?**

| RESPONSE | Strathroy | | Chatham | | TOTAL |
|---|---|---|---|---|---|
| | GS | RS | GS | RS | |
| Entegrus should find ways to make do with the buildings, equipment and IT systems it already has. | 3 | 1 | 5 | 0 | 9 |
| While Entegrus should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably. | 7 | 7 | 2 | 7 | 23 |
| Don't know | 0 | 0 | 0 | 1 | 1 |
| **TOTAL** | 10 | 8 | 7 | 8 | 33 |

**11. How well do you feel you understand the cost drivers that Entegrus is responding to?**

| RESPONSE | Strathroy | | Chatham | | TOTAL |
|---|---|---|---|---|---|
| | GS | RS | GS | RS | |
| Very well | 2 | 2 | 3 | 1 | 8 |
| Somewhat well | 8 | 5 | 4 | 5 | 22 |
| Not very well | 0 | 1 | 0 | 2 | 3 |
| Not at all | 0 | 0 | 0 | 0 | 0 |
| Don't know | 0 | 0 | 0 | 0 | 0 |
| **TOTAL** | 10 | 8 | 7 | 8 | 33 |

**12. How well do you think Entegrus is managing these cost drivers while meeting customer expectations?**

| RESPONSE | Strathroy | | Chatham | | TOTAL |
|---|---|---|---|---|---|
| | GS | RS | GS | RS | |
| Very well | 1 | 0 | 1 | 1 | 3 |
| Somewhat well | 7 | 6 | 5 | 6 | 24 |
| Not very well | 1 | 1 | 0 | 1 | 3 |
| Not at all | 0 | 0 | 0 | 0 | 0 |
| Don't know | 1 | 1 | 1 | 0 | 3 |
| **TOTAL** | 10 | 8 | 7 | 8 | 33 |

**13. How satisfied are you with the efforts Entegrus has made to find efficiencies and cost savings in the distribution system?**

| RESPONSE | Strathroy | | Chatham | | TOTAL |
|---|---|---|---|---|---|
| | GS | RS | GS | RS | |
| Very satisfied | 1 | 0 | 0 | 2 | 3 |
| Somewhat satisfied | 6 | 7 | 4 | 5 | 22 |
| Not very satisfied | 3 | 0 | 0 | 1 | 4 |
| Not at all satisfied | 0 | 0 | 0 | 0 | 0 |
| Don't know | 0 | 0 | 3 | 0 | 3 |
| Missing Value | 0 | 1 | 0 | 0 | 1 |
| **TOTAL** | 10 | 8 | 7 | 8 | 33 |

**14. Which of the following best describes how you feel about rate harmonization?**

| RESPONSE | Strathroy | | Chatham | | TOTAL |
|---|---|---|---|---|---|
| | GS | RS | GS | RS | |
| It makes sense and I support it | 3 | 5 | 3 | 5 | 16 |
| I don't support it, but it is probably inevitable | 1 | 2 | 2 | 0 | 5 |
| I am opposed to it | 2 | 0 | 0 | 0 | 2 |
| Don't know | 0 | 0 | 1 | 2 | 3 |
| Missing Value | 4 | 1 | 1 | 1 | 7 |
| **TOTAL** | 10 | 8 | 7 | 8 | 33 |

**15. Do you think the Ontario Energy Board should support Entegrus in harmonizing its rates?**

| RESPONSE | Strathroy | | Chatham | | TOTAL |
|---|---|---|---|---|---|
| | GS | RS | GS | RS | |
| Yes | 4 | 6 | 4 | 5 | 19 |
| No | 3 | 0 | 1 | 0 | 4 |
| Don't know | 0 | 1 | 1 | 2 | 4 |
| Missing Value | 3 | 1 | 1 | 1 | 6 |
| **TOTAL** | 10 | 8 | 7 | 8 | 33 |

**16. Now that you have a better sense of the operations of Entegrus, including the cost drivers, do you feel the proposed budget is reasonable?**

| RESPONSE | Strathroy | | Chatham | | TOTAL |
|---|---|---|---|---|---|
| | GS | RS | GS | RS | |
| Yes | 7 | 6 | 5 | 7 | 25 |
| No | 2 | 1 | 0 | 0 | 3 |
| Don't know | 1 | 1 | 2 | 1 | 5 |
| **TOTAL** | 10 | 8 | 7 | 8 | 33 |

**17. From what you have read here and what you may have heard elsewhere, does Entegrus' investment plan seem like it is going in the right direction or the wrong direction?**

| RESPONSE | Strathroy | | Chatham | | TOTAL |
|---|---|---|---|---|---|
| | GS | RS | GS | RS | |
| Right direction | 7 | 7 | 5 | 7 | 26 |
| Wrong direction | 1 | 0 | 0 | 1 | 2 |
| Don't know | 2 | 1 | 2 | 0 | 5 |
| **TOTAL** | 10 | 8 | 7 | 8 | 33 |

**18. How well did Entegrus' plan cover the topics you expected?**

| RESPONSE | Strathroy | | Chatham | | TOTAL |
|---|---|---|---|---|---|
| | GS | RS | GS | RS | |
| Very well | 1 | 3 | 3 | 2 | 9 |
| Somewhat well | 7 | 5 | 3 | 6 | 21 |
| Not very well | 2 | 0 | 1 | 0 | 3 |
| Not at all | 0 | 0 | 0 | 0 | 0 |
| Don't know | 0 | 0 | 0 | 0 | 0 |
| **TOTAL** | 10 | 8 | 7 | 8 | 33 |

**19. How well do you think Entegrus is planning for the future?**

| RESPONSE | Strathroy | | Chatham | | TOTAL |
|---|---|---|---|---|---|
| | GS | RS | GS | RS | |
| Very well | 2 | 3 | 3 | 4 | 12 |
| Somewhat well | 5 | 5 | 4 | 3 | 17 |
| Not very well | 1 | 0 | 0 | 1 | 2 |
| Not at all | 0 | 0 | 0 | 0 | 0 |
| Don't know | 2 | 0 | 0 | 0 | 2 |
| **TOTAL** | 10 | 8 | 7 | 8 | 33 |

**20. Considering what you know about the local distribution system, which of the following best represents your point of view?**

| RESPONSE | Strathroy | | Chatham | | TOTAL |
|---|---|---|---|---|---|
| | GS | RS | GS | RS | |
| The rate increase is reasonable and I support it | 2 | 0 | 0 | 2 | 4 |
| I don't like it but I think the rate increase is necessary | 4 | 4 | 4 | 6 | 18 |
| The rate increase is unreasonable and I oppose it | 3 | 4 | 1 | 0 | 8 |
| Don't know | 1 | 0 | 1 | 0 | 2 |
| Missing Value | 0 | 0 | 1 | 0 | 1 |
| **TOTAL** | 10 | 8 | 7 | 8 | 33 |

# Mid-Market Consultation

**Mid-Market Workshop**
with General Service customers

**PURPOSE:** To gain qualitative input on Entegrus' plan from GS > 50 kW customers and to obtain feedback on the proposed options.

The following summary highlights key findings from the mid-market consultation held in Chatham on Wednesday, May 27th, 2015.

## Summary

### *General Satisfaction*

Overall, mid-market consumers express high levels of satisfaction with the service they receive from Entegrus. Those who have worked with Entegrus report positive interactions. The majority of the issues that were presented by mid-market consumers were focused on other parts of the system. Unlike other consumers who are less knowledgeable, mid-market consumers acknowledge that Entegrus is just one part of the system and are satisfied with the job Entegrus is doing.

### *Impact of Outages*

Much of the discussion in the breakout groups was focused on the impact outages have within participants' organizations. Mid-market consumers are affected by outages to a great degree of variation. For certain consumers, an outage can be extremely costly; causing food spoilage, lost wages and productivity; while others experience only a minor inconvenience.

### *Power Quality*

There was some concession that no system is perfect and there will occasionally be outages. However, very brief outages, or 'blips', are seen to occur much too frequently and are felt to be very unacceptable. Particularly in organizations that rely heavily on automated machinery, these blips can be just as costly as longer outages.

The need for stable and uniform power quality is becoming increasingly important as the technology used to run automated systems becomes more refined. Newer systems are much more precise and therefore have a much smaller window for variation. Even with the protection of a UPS, variation that would have previously gone unnoticed can cause a system to trip resulting in severe losses in product and productivity. The slightest variation in power quality can have an incredible cost in a matter of seconds.

### *Communication During Outages*

For many consumers, the most important improvement that Entegrus can make is with regard to communication during outages. Receiving information regarding estimated outage recovery times is an important factor influencing the decisions that need to be made in the event of an outage.

### *Rate Harmonization*

Participants generally support rate harmonization; they feel that given the local situation it makes sense. Additionally, half are in agreement that Entegrus should be supported in the proposed service territory rate harmonization.

### *Entegrus' Proposed Rate Impact*

Participants are overall quite optimistic regarding Entegrus' approach to the future. The majority feel that the plan is going in the right direction and almost all support the rate increase – albeit somewhat reluctantly. For most participants it's important for Entegrus to invest what it takes to maintain the service they are providing, and they feel that it is important for staff to have the equipment they need. While the cost of electricity is often a significant line item in their operating budgets, Entegrus' proposed rate increase is largely seen as immaterial by most participants in the large commercial and intermediate rate classes. What's more important to these consumers is a partnership with Entegrus; an active relationship focused maintaining and improving their competitive edge.

***Q: Considering what you know about the local distribution system, which of the following best represents your point of view?***

| Response | Total |
|---|---|
| The rate increase is reasonable and I support it | 4 |
| I don't like it, but I think the rate increase is necessary | 7 |
| The rate increase is unseasonable and I oppose it | 1 |
| **TOTAL** | 12 |

# Methodology

## About the Mid-Market Consultation

In this phase of the consumer consultation research program for Entegrus, INNOVATIVE conducted a workshop with mid-market consumers. These consumers fall into two distinct groups: i) GS > 50 kW; and ii) Intermediate (monthly demand of at least 1,000 kW). The purpose of this workshop was to provide consumers with some education about their local distribution system, and then to gather their feedback on Entegrus' proposed investment and spending plan for 2016-2020.

The workshop session was held in Chatham on May 27th, 2015. A total of 12 mid-market consumers participated in this workshop session.

### *Recruiting Consultation Participants*

Entegrus recruited their mid-market consumers to take part in the workshop as part of a planned day-long event that also included the presentation of case studies, a discussion about conservation programs, and a panel Q&A session. All commercial and industrial consumers who received an invitation to this event were invited to register for the rate consultation workshop.

All consultation breakout sessions were video recorded to verify participant feedback and verbatim quotes.

### *Consultation Session Structure*

The workshop session began with a presentation from senior Entegrus staff, explaining the challenges facing the system, the proposed investment plan, and the consumer impacts. This presentation lasted approximately one hour, and included a brief Q&A period with consumers in the audience.

Following the Entegrus presentation and Q&A, consumers were separated into groups depending on their energy consumption levels (Intermediate and GS > 50 kW), and were taken to breakout rooms to begin the next step of the consultation, a small, moderator-led group discussion.

As a primary tool for the consumer consultations, INNOVATIVE and Entegrus developed an informational workbook to provide research participants with an overview of the electricity system, Entegrus' role within it and their challenges, efficiencies, investment plans and impact on distribution rates. These break-out focus group sessions were structured around the themes contained in this workbook.

The workbook themes included the following:

1. What is this Consultation About?
2. Electricity 101
3. Entegrus' Grid Today
4. Cost Pressures
5. What the Plan Means for You

Because consumers had already heard a presentation from Entegrus, the breakout focus group sessions were quickly able to focus on the topics explored in the workbook.

The facilitator distributed the workbooks and they were used as a guide for the remainder of the session. The workbooks contained questions to gather feedback from consumers on specific aspects of the system, Entegrus' investment plan, and resulting impact on rates.

The facilitator then led participants through the workbook section by section to ensure they understood the information and to answer any questions they had about the content.

Participants were asked to independently respond to the questions within the workbook. The facilitator then led a group discussion on the answers participants provided and what the various issues meant for their organization.

The hardcopy workbooks were collected from the participants at the conclusion of each consultation session.

Each breakout session ran for approximately 1.5 hours.

**NOTE:** Results contained within this report are based on a limited sample and should be interpreted as directional only.

# Participant Feedback

The following participant feedback was gathered from the consultations on May 27th, 2015 with mid-market consumers.

## Mid-Market (GS > 50 kW & Intermediate) Rate Class

### *General Satisfaction*

The consultations began with participants introducing themselves and talking briefly about the organization they were representing. Before looking to the workbook, they were asked to discuss any issues they were currently facing with Entegrus. The resounding response was that participants are generally very satisfied with Entegrus.

> *We don't have any issues at this point.*
>
> *We don't really have an issue with the LDCs, we have more of an issue with the Global Adjustment but that's a different matter.*
>
> *I feel very satisfied. Anytime you need their assistance they're always very willing to help us and with the rebates and everything.*

The issues that were mentioned were understood by the participants to be outside Entegrus' domain. One participant, whose concern is in regards to cost, feels that Entegrus does an excellent job in supporting them and helping them to find efficiencies. Another was more concerned with the system as a whole.

> *From the energy side of things, it's not any issue with Entegrus. I'm looking at the integrity of the system and what systems they have in place from a better maintenance standpoint, and what they can do from an infrastructure standpoint to support us and our operations in Strathroy.*

One suggestion for improving service was to make detailed usage information more readily available. This would help large consumers maintain awareness of their usage behaviours and allow for cost mitigation strategies to be designed and implemented.

> *One thing I wish they could possibly give us is more online access to what our demand and consumption information is – customer service kind of thing. I know it is available but it's at a cost. It's quite expensive just to see what we use. Especially after what we watched [in the presentation] today it would really help us understand where our usage is and where we peak without getting in the really insanely expensive. Just give some high level information. Customer service wise though, everyone is fantastic.*

### *Staying Competitive in Partnership with Entegrus*

For many participants, who have made substantial investments in their operations in addition to commitments to the community, having to move out of the area is a worst-case scenario. A number of participants expressed that they saw Entegrus as partner that they need to work with to remain competitive in today's increasingly global economy.

> *It's obviously a big cost for us. Everything that we do runs off electricity. Going back to the comment, investing would that make us move somewhere else, probably not. But it makes us less competitive.*

*We're not always competing with external sources. We're also competing with our own because there are multiple locations within our business. We're competing to have our business in Chatham versus sending it to Auburn hills or somewhere else.*

*It's our perception with our parent company that is in the States. They have rates that are a third of what we are paying. We're also looked at as a negativity. There's not much we can do. Entegrus helps us a lot to understand all these things and what we can do to offset electricity usage. But our challenge is just to explain to our corporate entity the reasons why electricity is so expensive in Ontario, which is very difficult.*

*The challenges we have is with the cost of electricity, not with Entegrus. Entegrus definitely supports us very well.*

### Impact of Outages

Participants are affected differently depending on their daily operations, and how reliant they are on electricity to function. While outages can have a great impact on productivity, some participants recognize that no system is perfect and the occasional outage is reasonable.

*Three outages over a year isn't bad. It's getting progressively better, but of course it's going to create a lot of issues in our plant also. We also have the automated machines that have to be reset, furnaces have to be relit. It creates a lot of havoc. But it seems to be an unavoidable occurrence. It's just something you deal with, so I think three outages is reasonable.*

*As far as customer service they have been great. We would have power fluctuations as well. When we actually have a total outage that's a problem because we have to restart all our tests. I don't know about when it goes to the voltage, if the tests are ruined. I don't know that part of it. Of course they can't control the weather and all that good stuff but things that they potentially can control would help us. Again, it's a big cost having to restart tests.*

Others are less complacent. For almost half of the participants, zero outages a year are acceptable. For these participants communication during outages is paramount.

*Our biggest problem is we have voiceover IT phone systems and if hydro goes down we're down. To every person in this municipality, including police, fire and ambulance, it's a major problem. Zero [outages a year] are acceptable. If you're responsible in emergency situations zero is acceptable.*

*It will generally take us a few months to track everything down with the machine. The one that we're doing, it does [132,000 units] an hour. So 10 minutes in there is quite a shipment for us to be shutting down.*

### Power Quality

While some participants recognize that an occasional outage is to be expected, what almost all found to be unacceptable was the frequency of short power interruptions many of the participants referred to as 'blips'. Almost every participant had an anecdote to share when it came to blips. Blips can be just as costly, if not more costly given the frequency of them, as outages of longer durations. Many systems need to be rebooted in the event of a blip, and sometimes this results in lost product.

*Some of them are really small, but they do occur. If you're working with highly sensitive equipment whether it be a full blown outage [or not] you can still have disruptions.*

*My company is highly automated so even the slightest blip involves recovering say, 80 robots. So it doesn't matter how many maintenance guys you have, recovering every machine for five minutes multiplied by several machines, several robots, [power outages are] very costly.*

*We've got backup generators so that's not really a problem. It's the blips. Sometimes you got a blip and you'll have three or four in a row. One time we had to run upstairs and shut the power off because we can't work anymore when it keeps on going on and off. For us it's not acceptable, even though we have a backup generator.*

*I'm an operating guy, an outage is scrap to me. I've got 500 pieces on the line and then 200 to 300 of them are scrapped automatically every time a "blip" happens. Plus the other thing where we're down for half an hour to an hour across the whole plant while they relight numerous furnaces.*

### *Communication During Outages*

During an outage, communication is the most important factor. When dealing with large organizations with many moving parts it's important to have accurate, readily available information in order to make decisions. In the event of planned outages and system maintenance, having this information ahead of time would be a definite advantage.

*We [have operations] all over the municipality. We need to know what areas are going to be affected and for how long.*

*They're [outages] not good however we do have generators that support vital systems, like the cooling systems. It's always a risk if the generator doesn't turn on right away. The response sometimes when we do have outages is vague about timing. That could be improved. Businesses need to know what's going on to make a decision.*

Further touching on the idea of partnership, participants highlighted information *sharing* as a key concern. In addition to communication of outages before they are schedule to happen, they seek a platform of open discussion with Entegrus. They are looking for Entegrus to "sit at the table" with them and develop a means of consistent communication in regards to strategy and planning.

*Proactive information sharing. So switch changes, any proactive thing they're doing on their side that affect our utility service and create power outages. Any kind of post-outage activity about what caused it so we can provide feedback from our end.*

*I think it's not acceptable [the frequency of outages/blips] but to build on that – it's the information sharing portion of it. What's the cause of these outages? How are they being measured? I think some of it stems from proactive maintenance measures. They're doing maintenance, whether it be upstream in Hydro One or in Entegrus' distribution system but ultimately it affects us and its lack of communication that can cause issues. If we can plan for it more proactively it might reduce some of the downtime costs associated from a manufacturing standpoint.*

When asked how participants would like this information made available to them, the majority felt that up to the minute information would be most readily accessible online.

*Radio, somebody's always got a radio somewhere.*

*Maybe an automated information system, whether it's on their website [or somewhere else].*

*Online is good. Trying to dial into the LDCs, the phones often busy – or the information's not there.*

*Hydro One's good at that [online communication]. They've got it on their website immediately.*

### *Rate Harmonization*

Participants were asked whether or not they support rate harmonization. While the majority do think it *makes sense and they support it*, some remain unsure. Four of the twelve participants either didn't respond, or responded *don't know*.

*It makes sense to me. I think they have some synergy with the four distributors they have acquired.*

Furthermore half of the participants felt the Ontario Energy Board should support Entegrus in harmonizing its rates while four again were unsure (*don't know*: 2; *missing value*: 2).

### *Proposed Rate Impact*

Almost every participant feels that Entegrus is going in the right direction with the plan it has proposed. Investing in infrastructure in order to improve reliability is very important. Power quality and reducing blips is paramount; it's an issue that may lead to some businesses having to move out of the area

*You have to have infrastructure that's going to last us and be reliable. If we don't have reliable power the company will move out of town. If we keep complaining and nothing can be done, then it'll be time to pick up and go.*

*We know with machines going down for a period of time, it costs us; we have to deliver the [product] tomorrow. So from the company standpoint if we're going to spend money to prevent it, if there's a way to prevent it we spend the money. It's an investment and if we need parts, if we need UPS to do this and this to prevent something they go and do it.*

Other participants disagree and feel that Entegrus should have planned better for the future.

*I can't pass capital investments on to my customers so I think they should work within their means.*

One thing that was widely agreed upon was that the run-to-failure approach is not the best. The detriments and inconsistencies in power quality that would result are felt to outweigh the potential savings.

*In general no, it's not a good philosophy.*

*Predictive and proactive maintenance is where you want to be. You never want to be doing reactive maintenance.*

Finally, social permission for the rate increase is very high. Only one participant felt that the increase was unreasonable, and therefore doesn't support it. Several support the increase outright, however the majority indicate that while they don't like the increase, they recognize its necessity.

# Questionnaire Results (Workbook)

**1. Given what you know and what you have read so far, how well do you feel you understand the parts of the electricity system, how they work together and which services Entegrus is responsible for?**

| RESPONSE | TOTAL |
|---|---|
| Very well | 6 |
| Somewhat well | 6 |
| Not very well | 0 |
| I don't understand at all | 0 |
| **TOTAL** | 12 |

**2. Generally, how satisfied are you with the service you receive from Entegrus?**

| RESPONSE | TOTAL |
|---|---|
| Very Satisfied | 7 |
| Somewhat satisfied | 4 |
| Somewhat dissatisfied | 0 |
| Very dissatisfied | 0 |
| Don't know | 1 |
| **TOTAL** | 12 |

**4. How well do you feel you understand the important parts of the electricity system, how they work together, and which services Entegrus is responsible for?**

| RESPONSE | TOTAL |
|---|---|
| Very well | 5 |
| Somewhat well | 7 |
| Not very well | 0 |
| I don't understand at all | 0 |
| **TOTAL** | 12 |

**5. The average Entegrus customer experiences one power outage per year. Do you recall how many outages your company experienced in the past year?**

| RESPONSE | TOTAL |
|---|---|
| None | 0 |
| One | 0 |
| Two | 2 |
| Three | 4 |
| Four | 3 |
| More than four | 3 |
| Don't know | 0 |
| **TOTAL** | 12 |

**6. How acceptable were the number of power outages you experienced over the last 12 months?**

| RESPONSE | TOTAL |
|---|---|
| Very acceptable | 1 |
| Somewhat acceptable | 4 |
| Not very acceptable | 5 |
| Not acceptable at all | 1 |
| Don't know | 0 |
| Missing value | 1 |
| **TOTAL** | 12 |

**7. How acceptable were the number of power outages your company experienced over the last 12 months?**

| RESPONSE | TOTAL |
|---|---|
| No outage is acceptable | 5 |
| One | 3 |
| Two | 2 |
| Three | 0 |
| Four | 0 |
| More than four | 0 |
| Don't know | 0 |
| Missing value | 2 |
| **TOTAL** | 12 |

**8. What do you feel is a reasonable duration for a power outage?**

| RESPONSE | TOTAL |
|---|---|
| No outage is acceptable | 4 |
| 30 minutes | 3 |
| 1 hour | 2 |
| 2 hours | 1 |
| 3 hours | 0 |
| 4 hours or more | 0 |
| Don’t know | 1 |
| Missing value | 1 |
| **TOTAL** | 12 |

**9. With regards to projects focused on replacing aging equipment in poor conditions, which of the following statements best represents your point of view?**

| RESPONSE | TOTAL |
|---|---|
| Entegrus should invest what it takes to replace the system’s aging infrastructure to maintain system reliability, even if that increases my monthly electricity bill by a few dollars over the next few years. | 9 |
| Entegrus should lower its investment in renewing the system’s aging infrastructure to lessen the impact of any bill increase, even if that means more or longer power outages. | 2 |
| Don’t know | 1 |
| **TOTAL** | 12 |

**10. As a company, Entegrus needs building to house its staff, vehicles, and tools to service the power lines and IT systems to manage the distribution system and customer information. Which of the following statements best represents you point of view?**

| RESPONSE | TOTAL |
|---|---|
| Entegrus should find ways to make do with the buildings, equipment and IT systems it already has. | 3 |
| While Entegrus should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably. | 9 |
| Don't know | 0 |
| **TOTAL** | 12 |

**11. How well do you feel you understand the cost drivers that Entegrus is responding to?**

| RESPONSE | TOTAL |
|---|---|
| Very well | 1 |
| Somewhat well | 11 |
| Not very well | 0 |
| Not at all | 0 |
| Don't know | 0 |
| **TOTAL** | 12 |

**12. How well do you think Entegrus is managing these cost drivers while meeting customer expectations?**

| RESPONSE | TOTAL |
|---|---|
| Very well | 1 |
| Somewhat well | 9 |
| Not very well | 0 |
| Not at all | 0 |
| Don't know | 2 |
| **TOTAL** | 12 |

**13. How satisfied are you with the efforts Entegrus has made to find efficiencies and cost savings in the distribution system?**

| RESPONSE | TOTAL |
|---|---|
| Very satisfied | 1 |
| Somewhat satisfied | 9 |
| Not very satisfied | 1 |
| Not at all satisfied | 0 |
| Don't know | 0 |
| Missing Value | 1 |
| **TOTAL** | 12 |

**14. Which of the following best describes how you feel about rate harmonization?**

| RESPONSE | TOTAL |
|---|---|
| It makes sense and I support it | 7 |
| I don't support it, but it is probably inevitable | 0 |
| I am opposed to it | 1 |
| Don't know | 2 |
| Missing Value | 2 |
| **TOTAL** | 12 |

**15. Do you think the Ontario Energy Board should support Entegrus in harmonizing its rates?**

| RESPONSE | TOTAL |
|---|---|
| Yes | 6 |
| No | 2 |
| Don't know | 2 |
| Missing Value | 2 |
| **TOTAL** | 12 |

**16. Now that you have a better sense of the operations of Entegrus, including the cost drivers, do you feel the proposed budget is reasonable?**

| RESPONSE | TOTAL |
|---|---|
| Yes | 10 |
| No | 0 |
| Don't know | 2 |
| **TOTAL** | 12 |

**17. From what you have read here and what you may have heard elsewhere, does Entegrus' investment plan seem like it is going in the right direction or the wrong direction?**

| RESPONSE | TOTAL |
|---|---|
| Right direction | 11 |
| Wrong direction | 0 |
| Don't know | 1 |
| **TOTAL** | 12 |

**18. How well did Entegrus' plan cover the topics you expected?**

| RESPONSE | TOTAL |
|---|---|
| Very well | 3 |
| Somewhat well | 9 |
| Not very well | 0 |
| Not at all | 0 |
| Don't know | 0 |
| **TOTAL** | 12 |

**19. How well do you think Entegrus is planning for the future?**

| RESPONSE | TOTAL |
|---|---|
| Very well | 5 |
| Somewhat well | 7 |
| Not very well | 0 |
| Not at all | 0 |
| Don't know | 0 |
| **TOTAL** | 12 |

**20. Considering what you know about the local distribution system, which of the following best represents your point of view?**

| RESPONSE | TOTAL |
|---|---|
| The rate increase is reasonable and I support it | 4 |
| I don't like it but I think the rate increase is necessary | 7 |
| The rate increase is unreasonable and I oppose it | 1 |
| Don't know | 0 |
| **TOTAL** | 12 |

# Key Account Validation Interviews

**Key Account Interviews**
with Volunteered customers

**PURPOSE:** To validate the consultation process and verify that Entegrus provided Key Account customers with the information they needed to form an informed opinion on the proposed plan.

## Methodology

Innovative Research Group (INNOVATIVE) conducted two validation phone calls with key account customers. After key account customers were briefed on the proposed five year Distribution System Plan by Entegrus staff, INNOVATIVE followed-up by telephone in order to validate the process and to verify that Entegrus had provided these customers with the information they needed to provide informed feedback on the proposed plan.

The initial Entegrus consultations were held in July, 2015. INNOVATIVE followed up with both Greenfield and Meridian, Entegrus key account customers. Each validation interview was conducted over the telephone and lasted approximately five to ten minutes.

**NOTE:** Results contained within this report are based on a very limited sample and should be interpreted as directional only.

### *Recruiting Key Account Participants*

The key account participants were selected from a client-provided list. The key account customers represented the highest-consumption customers in the Entegrus service area. This consultation was in conjunction with regular engagement practices between Entegrus and their key accounts.

The following key account customers were selected for validation follow-up interviews.

| Key Account Group | Interview Date |
|---|---|
| Greenfield | August 11, 2015 |
| Meridian | August 17, 2015 |

### *Key Account Consultation Process*

INNOVATIVE assisted Entegrus in developing the framework used to consult with the key account rate class and to collect feedback on how the five year Distribution System Plan will affect them.

The basic concept of the key account discussion was to cover the same issues as the broader consultation (which follows the consultation workbook). However, as expected, key accounts had a much stronger initial knowledge base and a much more specific understanding of their needs. That meant there was a higher demand for more detailed information about specific circuits, performance on those circuits and initiatives to enhance the reliability and security of those circuits.

With only two key accounts, Entegrus customized their consultation sessions for each customer, focusing on the issues that were most relevant to that customer.

### *Key Account Interview Structure*

| | |
|---|---|
| **Introduction** | Ensure the customer understands the scope and purpose of this consultation |
| **Knowledge** | Ensure the customer has the core background information to participate in the rest of the discussion |
| **Challenges** | Provide the customer with background as to the challenges Entegrus must manage in providing service |
| **Rate Impacts** | Inform the customer about the impact on their rates of the proposed plan and collect their comments and concerns related to proposed plan |
| **Rate Harmonization** | Were the details of rate harmonization clearly explained and do you support the current proposed rate harmonization? |

# Participant Feedback

The following section highlights the general feedback from the key account rate class group.

### *Overall Take-Away*

While both customer representatives who participating in the validation interviews accept the proposed plan and it rate impact on their business, there was an overall sense that they would have benefited from more information prior to entering their DSP review meeting with Entegrus representatives as well as more time to digest the impact of the plan on their business.

### *Customer Experience and Expectations*

One key account customer felt that Entegrus did not spend enough time addressing the unique challenges their business was facing in terms of their distribution assets. That said, this particular customer admittedly had a very good understanding of these issues, yet would have liked more time to review materials prior to their consultation meeting with Entegrus representatives.

### *Coverage of Distribution System Topics*

While one customer felt the consultation meeting with Entegrus representatives was good and answered all of their question, the other customer felt it was difficult to say whether the DSP covered the expected areas, again because they would have liked to have been a bit more prepared for the consultation meeting.

### *System Renewal and Rate Impact*

In general, one key account customer felt that the rate application process is moving too quickly, without adequately involving customers like themselves. In order to gather the appropriate internal feedback, this customer believed that more time and additional consultations would be beneficial.

Ultimately, both customer representatives accept the need for the proposed rate increase and believe it is necessary.

### *Rate Harmonization*

One key account customer felt that the proposed rate harmonization plan was adequately explained, as were any related follow-up questions. However, this customer felt that given that the information was provided in the summer, a number of key managers are on vacation and have not yet been able to review the information provided in the consultation.

The other key account customer felt that the proposed rate harmonization plan was reasonable and supported the rate harmonization plan represented by Entegrus.

# Validation Interview Questionnaire Results

The following tables are the tabulations of key account user feedback to validation questions INNOVATIVE asked when following up on Entegrus' interviews with their key account rate class.

Reponses to *open-ended* questions are included in the body text of the previous sections.

Numbers in purple denote the total sum of customer responses to interview questions.

*Missing values* are recorded beneath each table to indicate the number of participants who left a particular question unanswered.

1. Can you please confirm that you recently met with representatives of Entegrus about their Distribution System Plan?

| Response | KA1 | KA2 | Count |
|---|---|---|---|
| Yes | 1 | 1 | 2 |
| No | 0 | 0 | 0 |
| **Total** | **1** | **1** | **2** |

2. Did you have an opportunity to express any concerns about how well Entegrus is meeting your needs?

| Response | KA1 | KA2 | Count |
|---|---|---|---|
| Yes | 0 | 1 | 1 |
| No | 1 | 0 | 1 |
| **Total** | **1** | **1** | **2** |

3. Did Entegrus do a good job explaining the challenges they are facing in maintaining the system?

| Response | KA1 | KA2 | Count |
|---|---|---|---|
| Yes | 0 | 1 | 1 |
| No | 1 | 0 | 1 |
| **Total** | **1** | **1** | **2** |

4. Did the Distribution System plan cover the key areas you expected?

| Response | KA1 | KA2 | Count |
|---|---|---|---|
| Yes | 0 | 1 | 1 |
| No | 1 | 0 | 1 |
| **Total** | **1** | **1** | **2** |

5. Do you feel Entegrus' proposed rate of system renewal is too fast, too slow or about right?

| Response | KA1 | KA2 | Count |
|---|---|---|---|
| Too fast | 1 | 0 | 1 |
| About right | 0 | 1 | 1 |
| Too slow | 0 | 0 | 0 |
| **Total** | **1** | **1** | **2** |

6. Considering what you know about the local distribution system, which of the following best represents your point of view:

| Response | KA1 | KA2 | Count |
|---|---|---|---|
| The proposed rate increase is reasonable and I support it | 0 | 0 | 0 |
| I don't like it, but I think the proposed rate increase in necessary | 1 | 1 | 2 |
| The proposed rate increase is unreasonable and I oppose it | 0 | 0 | 0 |
| **Total** | **1** | **1** | **2** |

7. Did Entegrus representatives adequately explain their proposed rate harmonization plan and how it may affect your business?

| Response | KA1 | KA2 | Count |
|---|---|---|---|
| Yes | 1 | 1 | 2 |
| No | 0 | 0 | 0 |
| **Total** | **1** | **1** | **2** |

IF YES, how do you feel about Entegrus' proposed rate harmonization?

| Response | KA1 | KA2 | Count |
|---|---|---|---|
| It seems fair and I support it | 0 | 1 | 1 |
| While it seems fair, I don't support it | 1 | 0 | 1 |
| It seems unfair and I oppose it | 0 | 0 | 0 |
| **Total** | **1** | **1** | **2** |

# Online Workbook

**Online Workbook**
with Volunteered customers

**PURPOSE:** To inform customers on the details of Entegrus' plan, obtain feedback on the proposed options, and collect input for subsequent telephone survey design.

As part of its 2016 Application Review, Entegrus, Inc. has commissioned Innovative Research Group (INNOVATIVE) to develop and implement an online workbook to inform and engage customers on its distribution system plan.

Securing social acceptance for rate changes and capital investment planning is paramount, both for the long-term viability of the electricity distribution industry as a whole and the protection of consumer interests. The workbook is a critical element of Entegrus' on-going dialogue with its customers and will provide valuable input for its 2016-2020 plan to be submitted to the Ontario Energy Board (OEB).

Over the course of four weeks, INNOVATIVE collected feedback from both residential and small business customers through a confidential and secure online portal. In this engagement exercise, customers were informed with text, graphics and embedded videos about various aspects of the distribution system, billing, regulation, specific challenges in the region, work done on maintaining the system and key aspects of Entegrus' five-year plan. As they progressed through the workbook, customers were asked questions on a number of topics including:

- Satisfaction and familiarity with Entegrus and the electricity system;
- System reliability and maintenance;
- Investment in infrastructure, planning for the future;
- Cost drivers;
- Rate harmonization;
- The proposed rate increase;
- And feedback on the consultation process.

The following report will highlight the main findings of the online workbook survey, addressing these topics with an eye towards the specific challenges Entegrus faces moving forward to 2020.

Results contained within this report are based on a non-representative, volunteer sample and are intended for exploratory research only.

Graphs and tables may not always total 100% due to rounding values rather than any error in data. In addition, sums are added before rounding numbers.

# Summary

All in all, Entegrus and the proposed changes receive a favourable response from residential customers.

***Self-reported knowledge and satisfaction is high among residential customers.***

- Nearly all (95%) of the residential respondents say they have a good understanding of the electricity system and Entegrus' role.
- Nine-in-10 (90%) residential customers feel satisfied with the service they receive from Entegrus.

***Cost and rates appear to be a concern for residential respondents.***

- Residential customers generally seem satisfied with current levels of system reliability: eight-in-ten (79%) say the number of outages they experience is "acceptable".
- When asked if there is anything Entegrus can do to improve service, nearly half (46%) mention a topic related to their electricity rates (28% "Affordable/reduced rates"; 10% "reduce Debt Retirement Charge/delivery fees"; 8% "Smart meter issues/Time of Use rates"). Just 6% mention "reliability/fewer outages" as a key way Entegrus can improve service.

***Reliability and satisfaction seem to go hand-in-hand.***

- Among the 55 residential customers dissatisfied with Entegrus service, nearly 7-in-10 (69%) had more than one outage in the past year. Just a third (32%) of those satisfied with their service had more than one.
- Net acceptance of the number of outages also varies widely between satisfied (+70%) and dissatisfied (-9%) residential customers.
- When asked what they felt is a "reasonable" amount of time for an outage, nearly 3-in-10 (29%) dissatisfied residential customers say "no amount of time" is acceptable compared to just 11% of satisfied residential customers.

***Majority of residential customers support investment in infrastructure and supporting assets despite potential costs to them personally.***

- More than half (56%) agree that Entegrus should invest whatever it takes to replace aging infrastructure, even if it means higher electricity bills.
- More than two-thirds (67%) agree that Entegrus should make sure the staff has the buildings, IT and equipment it needs to effectively manage the system.

***Most feel they understand the cost drivers facing Entegrus and think it is responding well to the challenges.***

- More than 8-in-10 (85%) residential customers think they have a good understanding of the cost drivers involved and over 2-in-3 (68%) feel Entegrus is managing its cost drivers well while meeting customers' needs.
- Over two-thirds (67%) of residential customers are satisfied with Entegrus' cost saving efforts.

### *A plurality support the idea of rate harmonization.*

- After an extensive explanation of rate harmonization in the online workbook, nearly half of residential customers support it (45%) with slightly less opposed ("don't support it, but inevitable": 36%; "opposed": 7%).
- A majority (52%) of residential customers think the OEB should support Entegrus on rate harmonization, but 3-in-10 (29%) don't know one way or the other.

### *Residential customers feel the Entegrus' proposed plan is headed in the right direction.*

- A majority (54%) of residential customers think the proposed budget is reasonable and that the investment plan is headed in the right direction (61%).
- More than 8-in-10 (83%) residential customers feel that Entegrus is planning well for the future.

### *2-in-3 (66%) residential customers accept proposed rate increase.*

- At the end of the survey, 2-in-3 (66%) residential customers are prepared to accept the proposed rate increase. Under 2-in-10 (16%) think it's reasonable and support it and half (50%) don't like it, but believe it necessary. Almost 3-in-10 (28%) oppose the rate increase and think it's unreasonable.
- In this sample of residential customers, homeowners (68% vs. 46% renters), those who are satisfied with Entegrus' service (72% vs. 15% dissatisfied), and those who think Entegrus is planning well for the future (77% vs. 8% "not well") are the most likely to accept the increase.

# Methodology

## A Background on the Online Workbook

The Entegrus online workbook was designed in consultation with INNOVATIVE to collect customer feedback and inform customers of the challenges facing the local distribution system. Over the course of 26 questions with links to informative videos, the workbook breaks down the key challenges facing Entegrus and the plan to address them over the next five years.

The first section “What is this Consultation About?” explains to customers the purpose of the consultation as well as the rate application process and the role of consumer feedback in long-term planning. Customers are given a clear explanation with visual aids on the breakdown of their electricity bills and the role of Entegrus in the distribution of electricity in Ontario.

In the second section “Electricity 101”, after a short description of regulation in Ontario, the workbook gages customers’ understanding of Entegrus’ role in the electricity system and satisfaction with their current service.

The third section, “Entegrus’ Grid Today”, provides a more in-depth description of the distribution system, including background on the company itself and its current electrical infrastructure. Again, customers are asked about their understanding of the system and Entegrus’ role to see how additional information may have helped them understand the issue better. The rest of the questions in this section focus on system reliability: the number and length of outages and customer perceptions of what is “reasonable”.

“Cost Pressures”, the fourth section, examines some of the challenges facing Entegrus today in its operating and capital budget and proposed investment in infrastructure and supporting assets to improve reliability. Customers are consulted on replacing aging equipment and spending on assets such as buildings, equipment and IT; whether they understand the cost drivers; how well they think Entegrus is managing these cost drivers; and how satisfied they are with Entegrus’ ability to find efficiencies in the system.

The final section “What Entegrus’ Plan Means for You” explains how these challenges affect the consumer in terms of their monthly bill. First, “rate harmonization” is explained to the consumer and they are asked to describe how they feel about it and whether or not the OEB should support Entegrus in harmonizing its rates. The last few questions of the survey gage customer support for the investment planning and rate increase: whether or not the proposed budget is reasonable; whether or not the investment plan is going in the right or wrong direction; how well the plan covers topics of interest to the consumer; how well Entegrus is planning for the future; and, finally, the social acceptance question: do they support the rate increase?

In an appendix, six additional open-ended questions were asked regarding how to improve these consultations moving forward. Topics included customers’ overall impression and additional feedback on the volume of information, content covered, outstanding questions, suggestions for future consultations and thoughts on the videos linked throughout the survey.

### *Field Dates:*

The workbook was accessible online for Entegrus customers from May 21st to June 19th, 2015.

### *Promoting the Online Workbook:*

Entegrus promoted the workbook through a number of methods:

- Advertised on the homepage of www.entegrus.com
- A press release issued on May 22nd, 2015, which received coverage in local media outlets (Chatham Daily News, Sydenham Current, Blackburnnews.com, 105.7 My FM News in Strathroy)
- Residential rate brochures sent to 41, 285 customers
- Smart Shopper Newspaper advertisement on May 21st, 2015
- Emails sent to the complete list of valid customer emails on file (6,640 customers)
- ¼ page ad in Chatham Daily News and Strathroy Age Dispatch, week of June 1st, 8th and 15th
- Online advertising (Chatham Daily News website banners, targeted Facebook advertising across service territory)

### *Publishing the Workbook Online*

INNOVATIVE hosted the workbook at the following URL: www.entegrusworkbook.com. This website prevented Entegrus customers from filling out questions more than once and saved progress as they went, allowing them to return to the workbook to finish at a time of their choosing.

The personal information of Entegrus customers was kept anonymous and confidential on INNOVATIVE's secure business servers. INNOVATIVE does not ever provide links to personal information submitted on Entegrus' website.

### *Validating Customer Responses:*

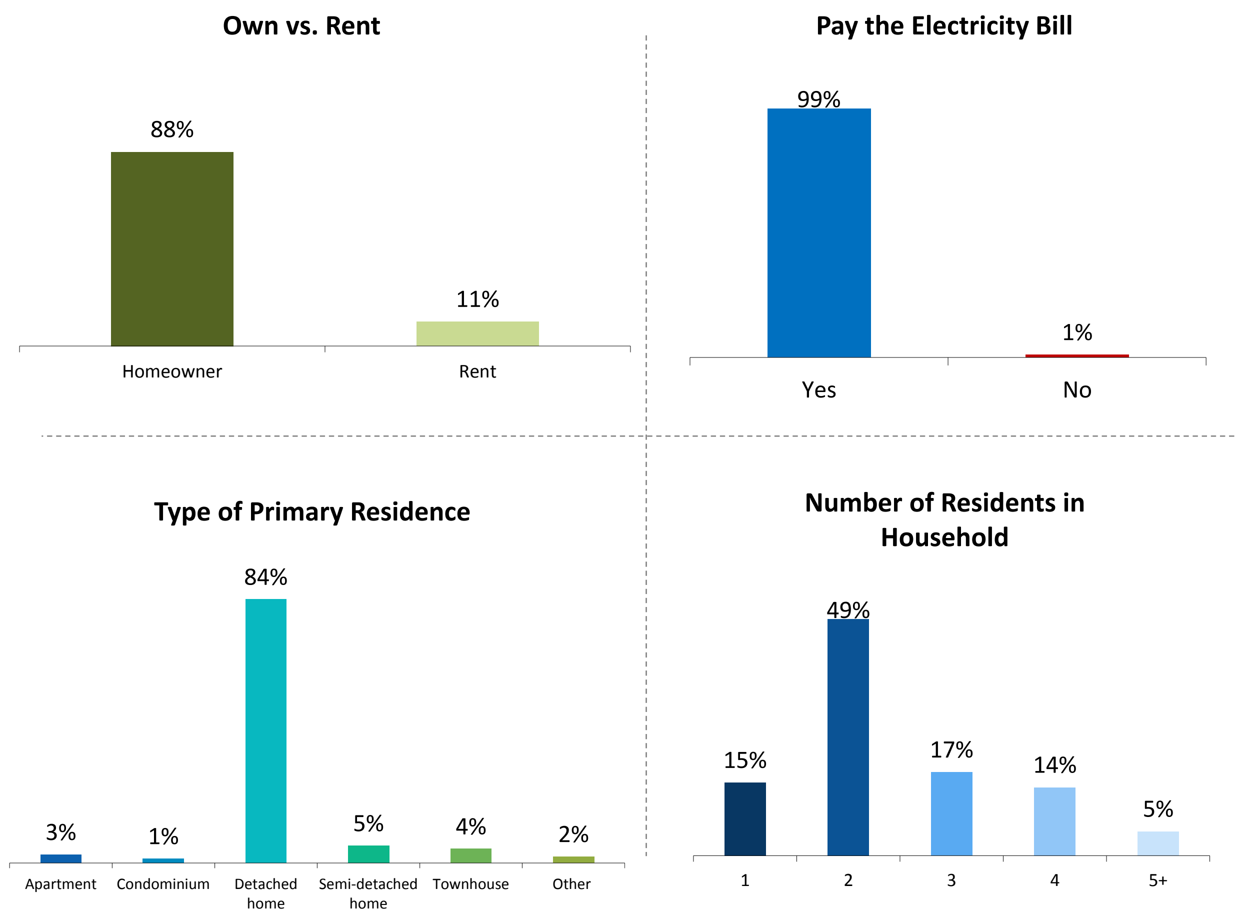
Anyone who answered a question in the workbook was tagged with an identification number based on both their postal code and their response as either an Entegrus residential or business customer. This was then validated against a file provided by Entegrus of all customer postal codes; those deemed invalid were removed from the final sample. In addition, IP addresses were tracked to ensure respondents were unique and human.

# Respondent Profile

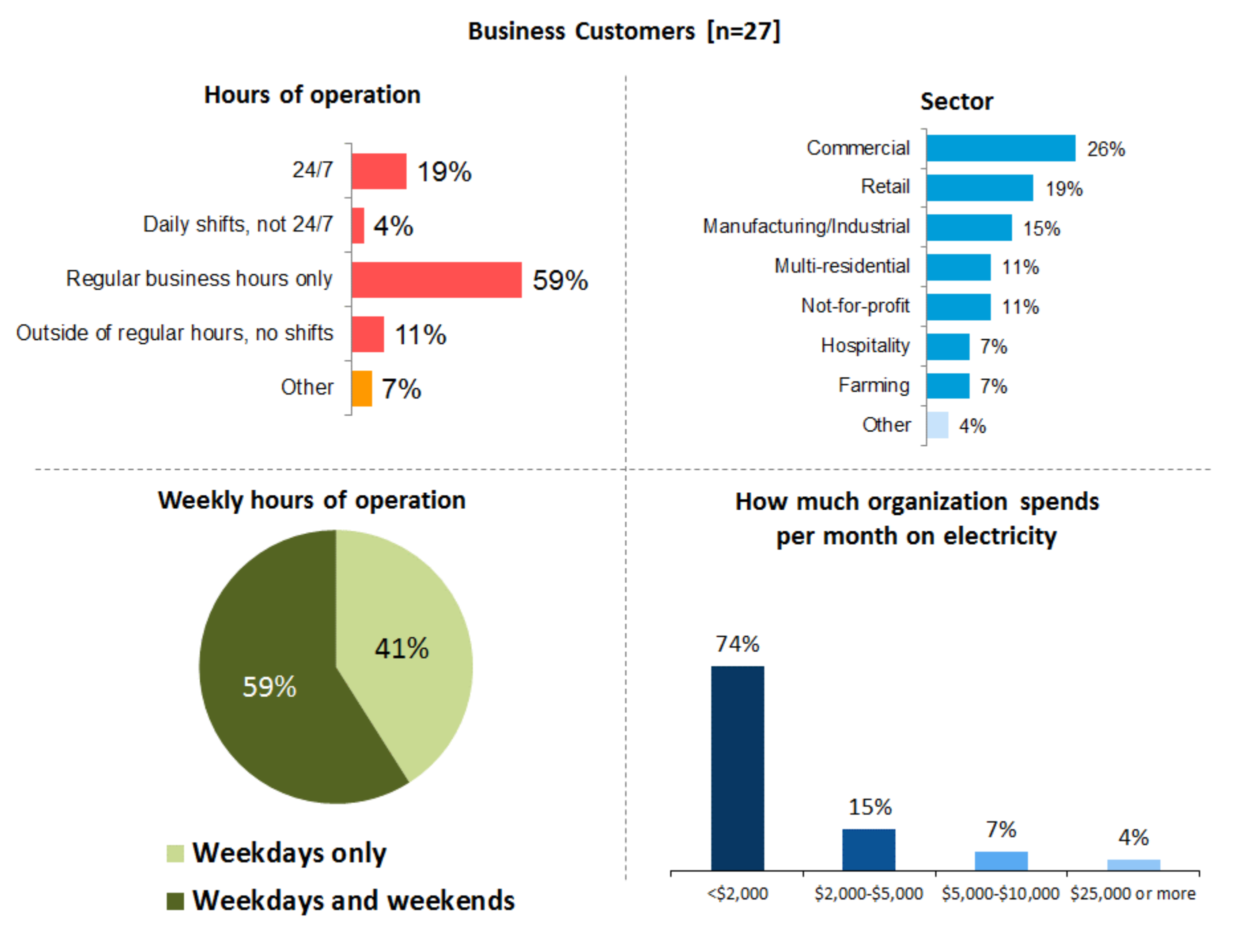
Overall, 604 residential and 27 business customers completed the workbook. (Note that open-ended response n-sizes may vary.)

The two charts below outline the demographic breakdown for residential customers (rent vs. own, responsibility for bill, residence type, number in household) and firmographics (work area, monthly spending) for business customers. Due to the small sample size (n=27) of business customers, the following analysis and supporting charts will focus largely on residential customers.

### Figure B1: Residential Customer Profile [n=604]



## Figure B2: Business Customer Profile [n=27]



# Respondent Feedback

The following sections will outline feedback provided by the 604 residential customers who completed the survey. (Note that since only 27 business customers completed the survey, their results are reported as n-sizes only in the bottom-left corner of each chart.)

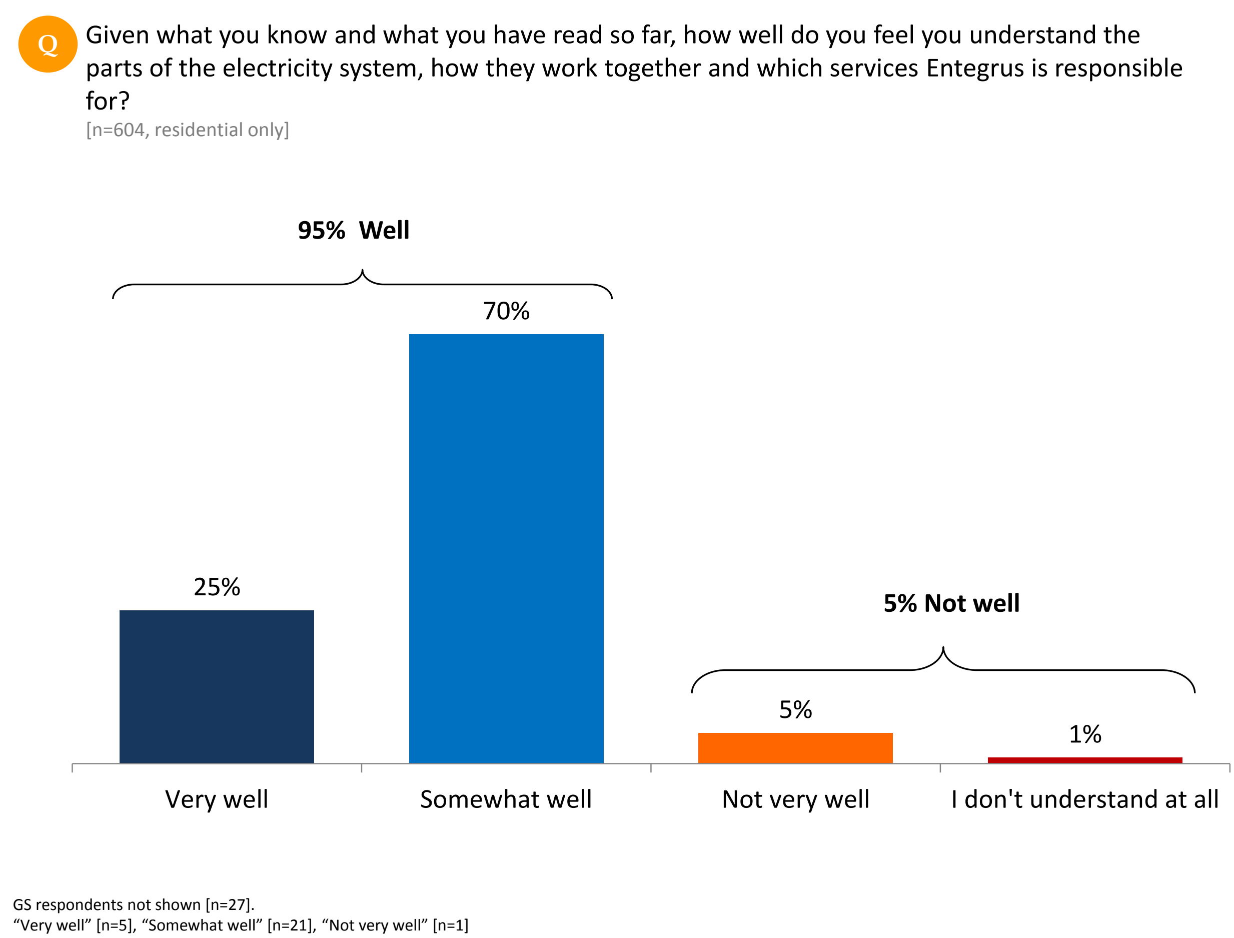
## Familiarity, Satisfaction and System Reliability

This first section examines how well residential customers understand Entegrus' role in the electricity system, their satisfaction with service and perceptions of system reliability.

### *Understanding of the System*

After reviewing the introductory materials, nearly all (95%) residential customers say they understand the various parts of the electricity system and Entegrus' role, with one quarter (25%) who say they understand it very well. Just 5% say they don't understand it very well or not at all.

**Figure 1: Understanding of Electricity System and Entegrus**



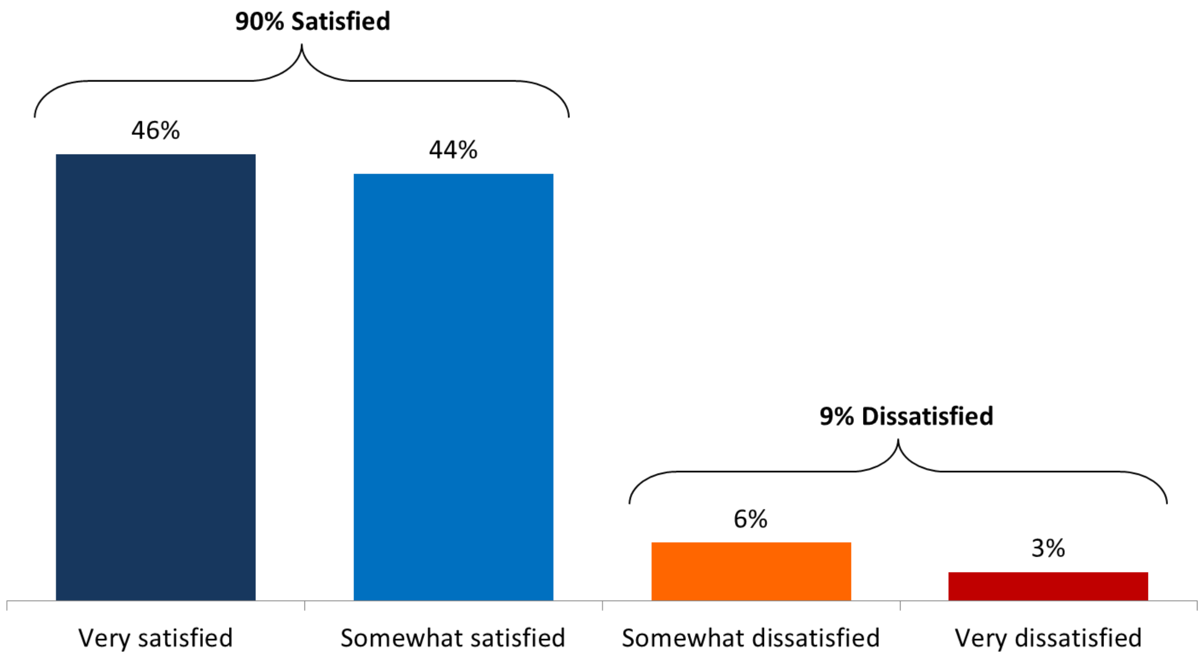
### *Satisfaction and System Reliability*

Overall satisfaction with Entegrus is quite high: nine-in-ten (90%) residential customers say they are satisfied, with nearly half (46%) saying they are "very satisfied". Less than one-in-ten (9%) say they are dissatisfied with the service they receive from Entegrus.

- Residential customers who own (91%) are slightly more satisfied with Entegrus' service than those who rent (81%).

## Figure 2: Satisfaction with Service

Q Generally, how satisfied are you with the service you receive from Entegrus?
[n=604, residential only]



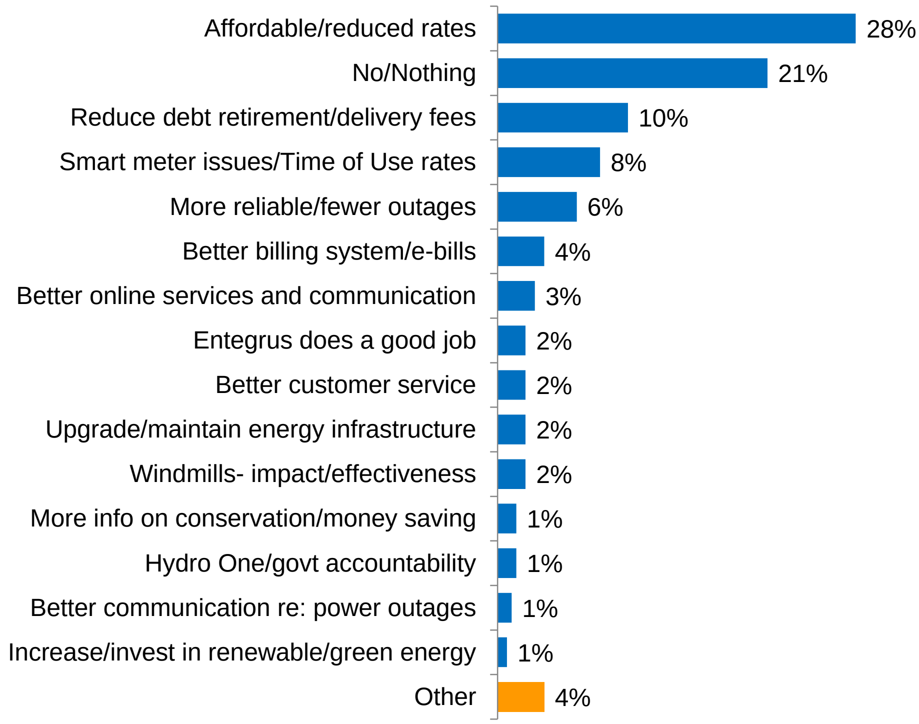

Note: "Don't know" (1%) not shown.
GS respondents not shown [n=27].
"Very satisfied" [n=16], "Somewhat satisfied" [n=7], "Somewhat dissatisfied" [n=2], "Very dissatisfied" [n=2]

In an open-ended question on how Entegrus could improve service, the top three issues for residential customers all involved rates: making service more affordable (28%), reducing or eliminating the Debt Retirement Charge and delivery fees (10%) and issues related to Smart Meters and Time-of-Use rates (8%). More than 2-in-10 (21%) said there was nothing in particular Entegrus could do to improve service. It is also worth noting that 330 of the 604 respondents did not provide an answer to this question, suggesting that they do not have any specific complaints about Entegrus service.

- Of those 48 residential customers who say they are not satisfied with the service, nearly half (48%) say Entegrus should improve service through "affordable/reduced rates".

## Figure 3: Improving Service

Q Is there anything in particular that Entegrus can do to improve its service to you?
[n=274, residential only, n=330 non-responders]



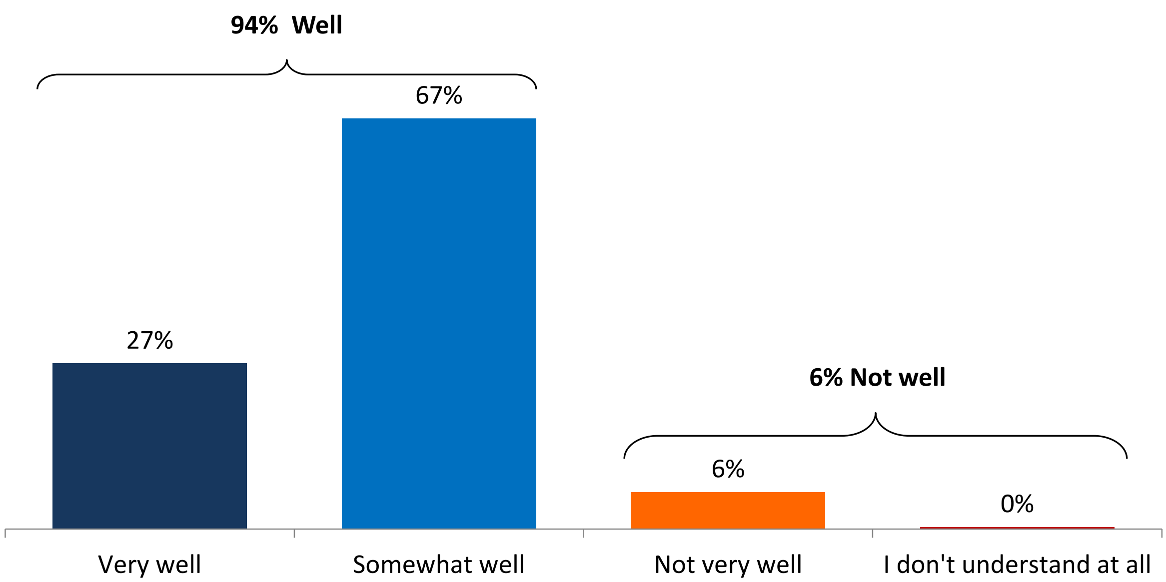

Note: "Don't know" (1%), "Refused/Bad Respondent" (2%) not shown.
GS respondents not shown [n=12].
Top mentions: "Affordable/reduced rates" [n=2], "Reduce debt reduction/delivery fees" [n=2], "No/Nothing" [n=2].

After customers were shown a series of text and graphics outlining the construction of Entegrus' distribution grid, they were asked again about how well they understand the system and Entegrus' role. Nearly all residential customers (94%) still stated they understood Entegrus' role in the electricity system well.

- Those who are satisfied with Entegrus' service (96%) are more likely to feel they understand the electricity system than those who are dissatisfied with their service (82%).

## Figure 4: Understanding of Electricity System and Entegrus, Revisited

Q How well do you feel you understand the important parts of the electricity system, how they work together, and which services Entegrus is responsible for?
[n=604, residential only]



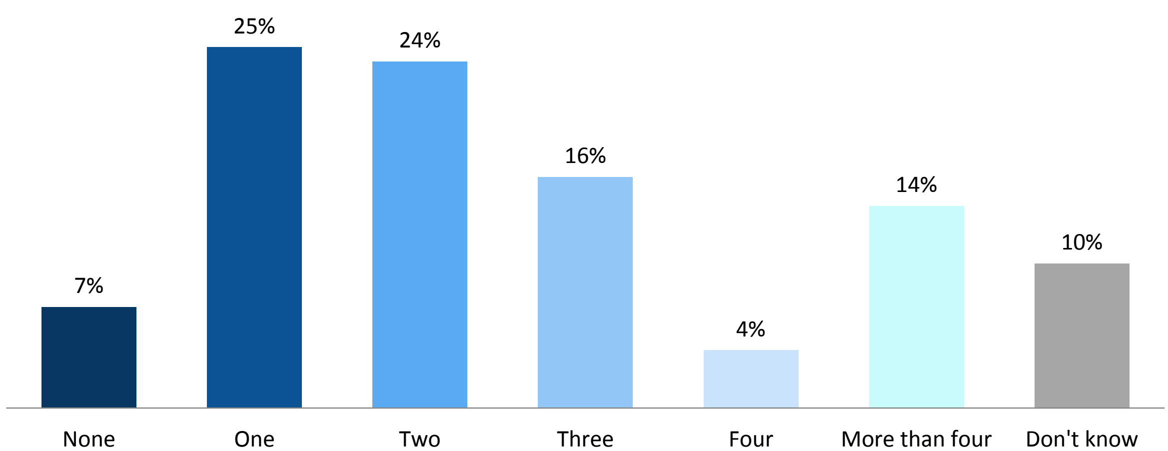

GS respondents not shown [n=27].
"Very well" [n=9], "Somewhat well" [n=18]

Nearly six-in-ten (58%) residential customers say they experienced more than one outage per year. One quarter (25%) say they experienced just one (the estimated average for Entegrus customers) and less than one-in-ten (7%) experienced no outages.

- Of those residential customers who are dissatisfied with their service, seven-in-ten (69%) report having more than one outage in the past year, compared to just 32% among those satisfied with their service.

## Figure 5: Number of Outages Reported

Q The average Entegrus customer experiences one power outage per year. Do you recall how many outages you experienced in the past year?
[n=604, residential only]



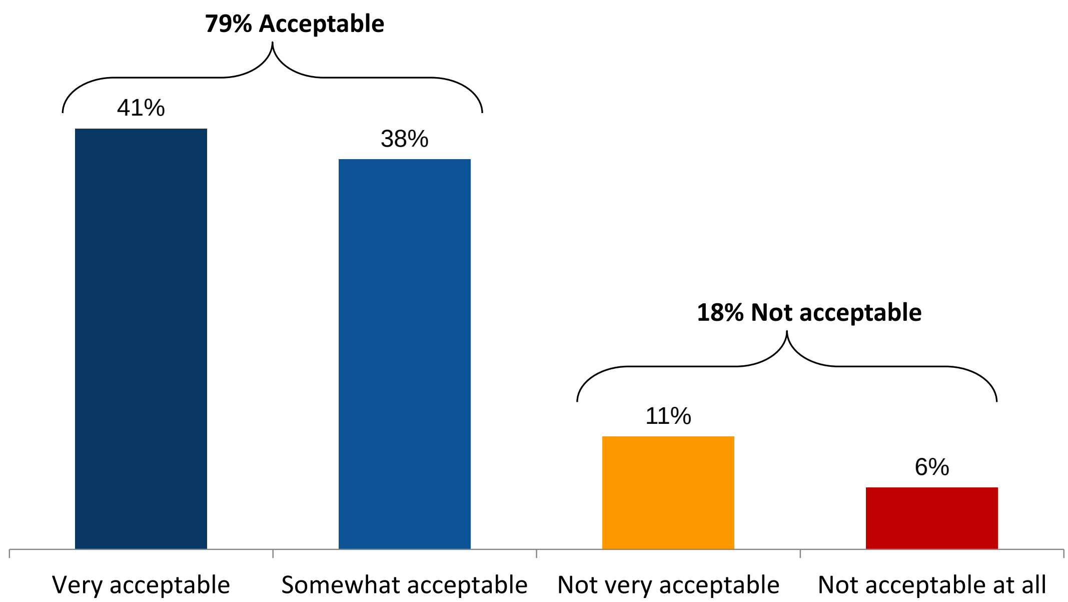

GS respondents not shown [n=27]
"None" [n=4], "One" [n=4], "Two" [n=5], "More than four" [n=8], "Don't know" [n=6]

A strong majority (79%) of residential customers say that the number of outages is acceptable with four-in-ten (41%) saying it is "very acceptable". Fewer than two-in-ten (18%) say the number of outages they've experienced over the last 12 months is "not acceptable".

- Acceptance of number of outages varies widely between satisfied (83%) and dissatisfied customers (44%).

## Figure 6: Number of Outages, Acceptability

Q No system delivers perfectly reliable electricity. There is a balancing act between reliability and the cost of running the system. Please answer the following questions: *How acceptable were the number of power outages you experienced over the last 12 months?*
[n=604, residential only]




Note: "Did not have any outages" (1%) "Don't know" (2%) not shown.

GS respondents not shown [n=27]
"Very acceptable" [n=12], "Somewhat acceptable" [n=10], Not very acceptable" [n=2], "Not acceptable at all" [n=1], "Don't know" {n=2]

Among residential customers, about a third (34%) think that one outage a year is reasonable and slightly fewer (30%) think that two outages a year is reasonable. Fewer than one-in-five (17%) say that any number of outages is unreasonable.

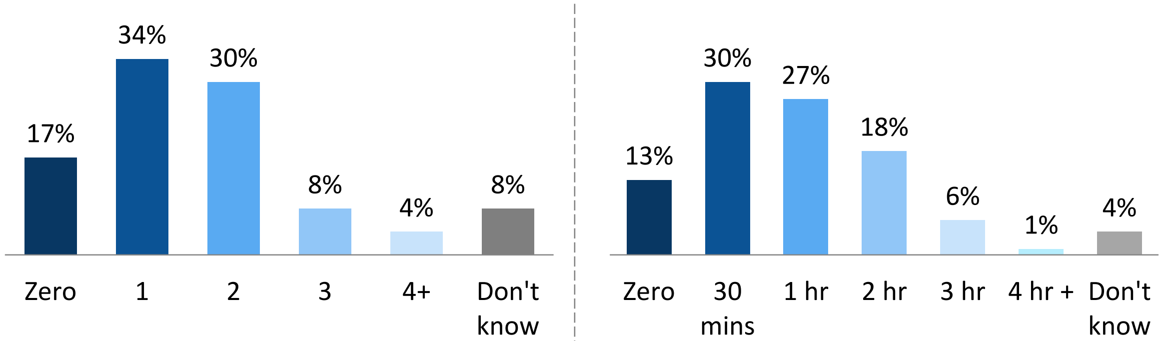
More than half (57%) think that outages of an hour or less are reasonable while more than one-in-ten (13%) say that no outage of any duration is acceptable.

- For 28% of dissatisfied residential customers, "no amount of time" is acceptable, compared to just 11% of satisfied residential customers.

### Figure 7: Acceptable Frequency and Duration of Outages

Q How many power outages do you feel are reasonable in a year?
[n=604, residential only]

Q What do you feel is a reasonable duration for a power outage?
[n=604, residential only]




GS respondents not shown [n=27]
"0" [n=8], "1" [n=5], "2" [n=7], "3" [n=1], "4" [n=1], "More than four" [n=2], "Don't Know" [n=3]

GS respondents not shown [n=27]
"0" [n=4], "30 mins" [n=9], "1 hr" [n=9], "2hr" [n=3], "3 hr" [n=2]

## Investment Solutions, Cost Drivers and Rate Harmonization

This next section examines residential customers' understanding of the cost pressures Entegrus faces, its capital investment needs, key cost drivers, perceptions of Entegrus' performance in finding capital efficiencies and views on rate harmonization.

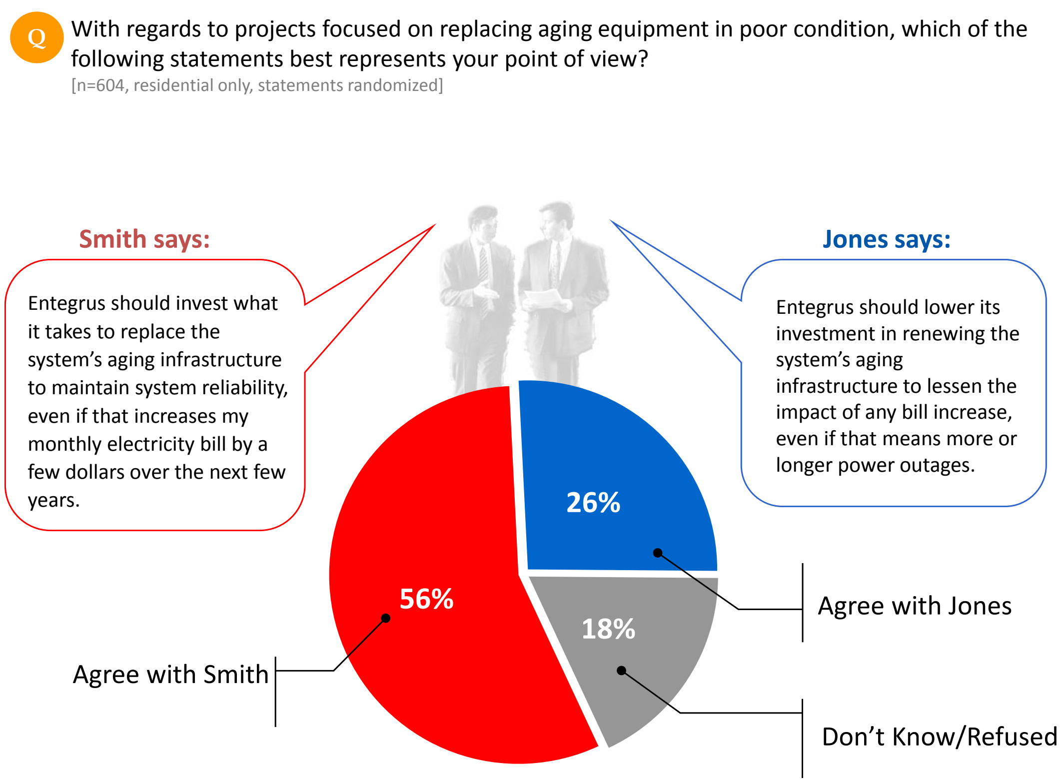
### *Investment in Infrastructure and Supporting Assets*

After reviewing an information-based section on capital investments in the workbook, respondents were asked to indicate their preferences in terms of investment vs. reliability. Should Entegrus increase capital expenditures to replace aging infrastructure even if it means higher rates for customers, or lower its investment despite potential outages to lessen impact on customer bills?

More than half (56%) of Entegrus customers feel that the company should invest what it takes to replace the aging infrastructure, even if it means a bill increase. In contract, about one quarter (26%) say that Entegrus should reduce investment in infrastructure to reduce the impact on customers' bills. Nearly one-in-five (18%) don't know how to respond.

- While 60% of satisfied residential customers feel Entegrus should invest in infrastructure, only 9% of dissatisfied customers feel the same.
- Residential customers that own their own home (58%) are more likely than renters (42%) to support additional investment in infrastructure.

### Figure 8: Investment in Aging Infrastructure



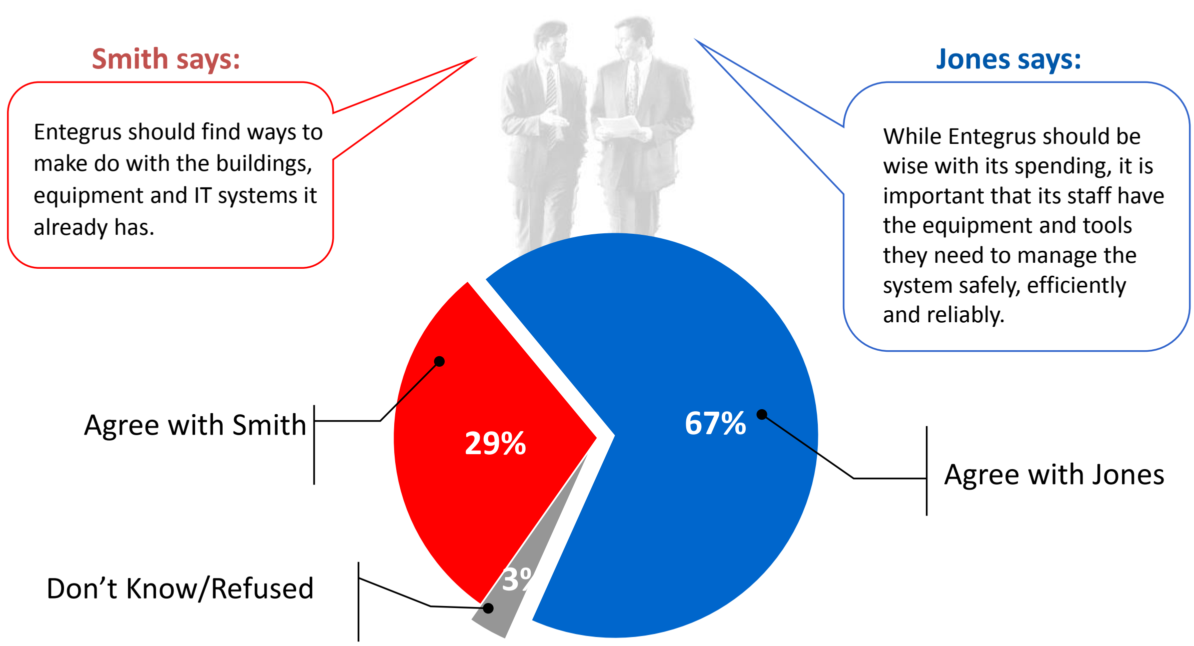

GS respondents not shown [n=27]
"Invest what it takes" [n=15], "Lower its investment" [n=9],"Don't know" [n=3]

About two-thirds (67%) of residential customers feel it is important that Entegrus has the supporting assets it needs to manage the system safely, while three-in-ten (29%) think Entegrus should make do with its current buildings, equipment and IT systems.

- Owners (69%) are a bit more likely than renters (57%) to agree that it is important staff have the supporting assets they need.
- Less than a third (31%) of dissatisfied residential customers agree that Entegrus should invest in buildings, equipment and IT systems, while more than seven-in-ten (71%) satisfied residential customers feel the same.

### Figure 9: Investment in Buildings, Equipment and IT Systems

Q As a company, Entegrus needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the system and customer information. Which of the following statements best represents your point of view?
[n=604, residential only, statements randomized]



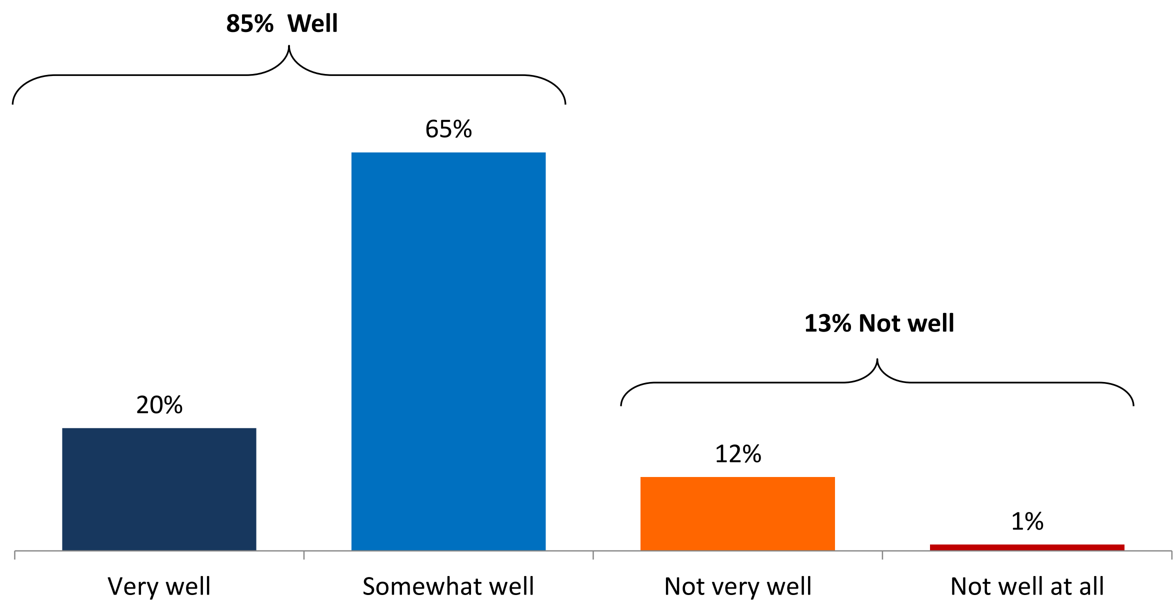

GS respondents not shown [n=27]
“Make do with what it has” [n=11], “Important that staff has equipment they need” [n=16]

### *Cost Drivers and Cost Savings*

A strong majority (85%) of residential customers feel they have a good understanding of the cost drivers impacting Entegrus.

## Figure 10: Understanding of Cost Drivers

Q How well do you feel you understand the cost drivers that Entegrus is responding to?
[n=604, residential only]



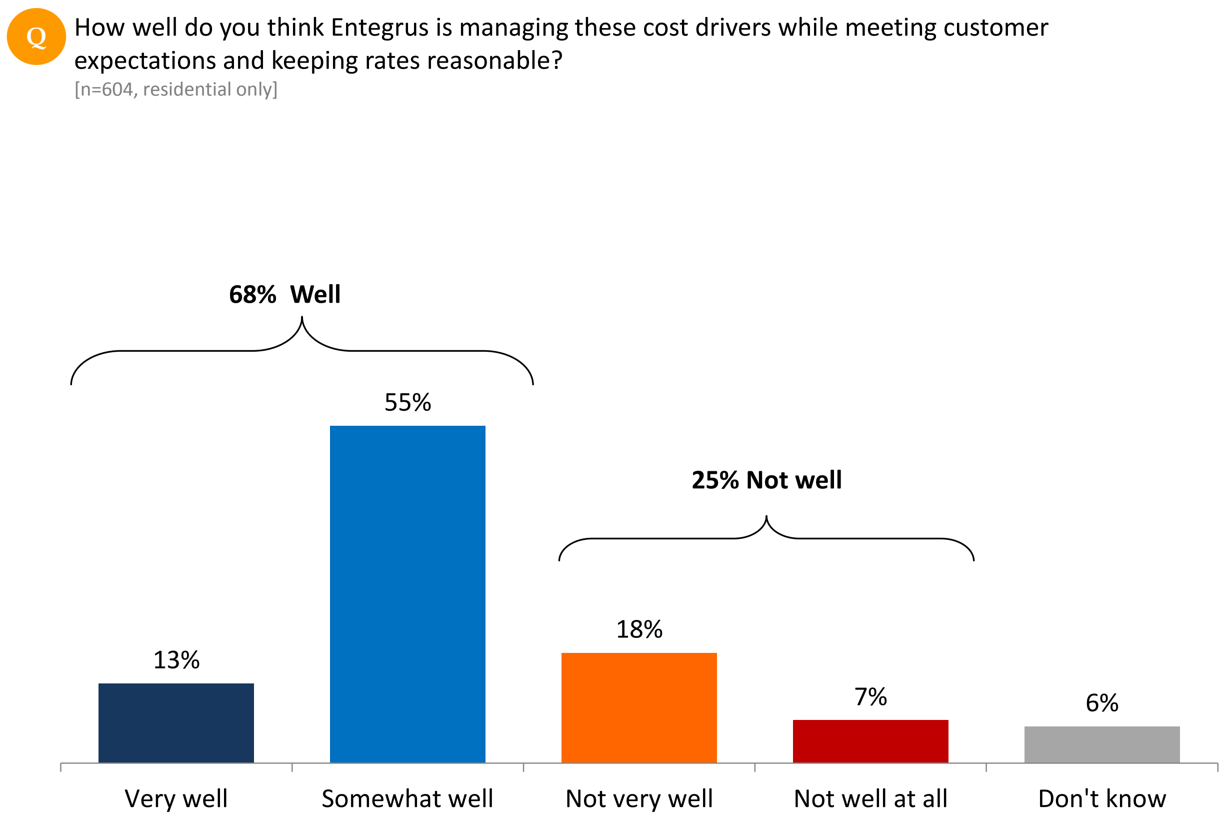

Note: “Don’t know” (2%) not shown.

GS respondents not shown [n=27].
“Very well” [n=7], “Somewhat well” [n=18], “Not very well” [n=1], “Not well at all” [n=1],

More than two-thirds (68%) of residential customers feel that Entegrus is managing its cost drivers well while meeting customers' needs and keeping rates reasonable. Just a quarter (25%) of residential respondents feel that Entegrus is currently not managing its cost drivers well.

- Owners (70%) are more likely than renters (58%) to think Entegrus is managing these cost drivers well.
- Residential customers who are satisfied with their service (74%) are much more likely than dissatisfied residential customers (11%) to feel that Entegrus is managing cost drivers well.

## Figure 11: Responding to Cost Drivers



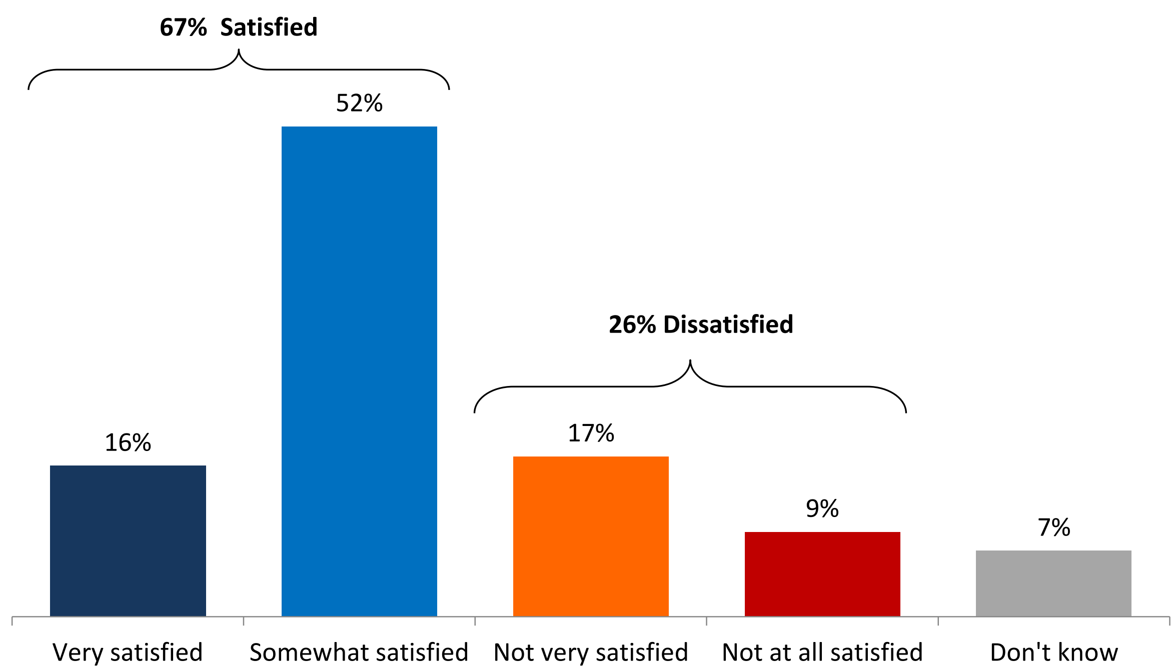

GS respondents not shown [n=27].
"Very well" [n=4], "Somewhat well" [n=12], "Not very well" [n=6], "Not well at all" [n=2], "Don't know" [n=3]

Two-thirds (67%) of residential respondents say they are satisfied with the efforts Entegrus has made to find cost efficiencies while a quarter (26%) say they are dissatisfied with the efforts.

- Again, homeowners (69%) are more likely than renters (54%) to feel satisfied with Entegrus' cost saving efforts so far.

## Figure 12: Satisfaction with Efficiencies and Cost Savings

Q How satisfied are you with the efforts Entegrus has made to find efficiencies and cost savings in the distribution system?
[n=604, residential only]




GS respondents not shown [n=27].
"Very satisfied" [n=5], "Somewhat satisfied" [n=14], "Not very satisfied" [n=4], "Not at all satisfied" [n=3], "Don't know" [n=1]

## Rate Harmonization

Before asking respondents for feedback on rate harmonization, the workbook provided the following context:

***What is Rate Harmonization?***
*Rate harmonization means bringing these four sets of distribution rates into one harmonized rate so that all Entegrus customers in the same rate class are paying the same for their electricity distribution. See the adjacent graphs.*
*This ensures customers pay the same cost for receiving the same level of service.*

***Why Harmonize Rates?***
- *Provide more rate stability because one set of distribution rates for all customers is less volatile and subject to swings than four separate sets of rates.*
- *Improved customer service through reduced confusion over rates.*
- *Reduced administrative costs.*
- *The Ontario Energy Board (OEB) is working with local distribution companies across the province to harmonize rates after acquisitions.*

***How Will It Impact Me?***
*By its nature, a rate harmonization usually means that some customers will pay a little more, while others pay a little less.*

*However, Entegrus plans to operate, maintain, and modernize its electricity distribution system without an overall distribution rate increase in 2016. In terms of Residential customers, this means that the process of harmonizing rates is not anticipated to create any distribution rate increases versus the current distribution rates in any of the above-noted four rate zones.*

***Why Now?***
*The OEB rules only allow rate harmonization to be done through a Cost of Service Application such as the one that is the focus of this consultation.*

When asked how they feel about rate harmonization, nearly half (45%) of residential customers say it makes sense to them and they support it. More than one third (36%) do not support it, but feel "it's inevitable" and less than one-in-ten (7%) are opposed to it.

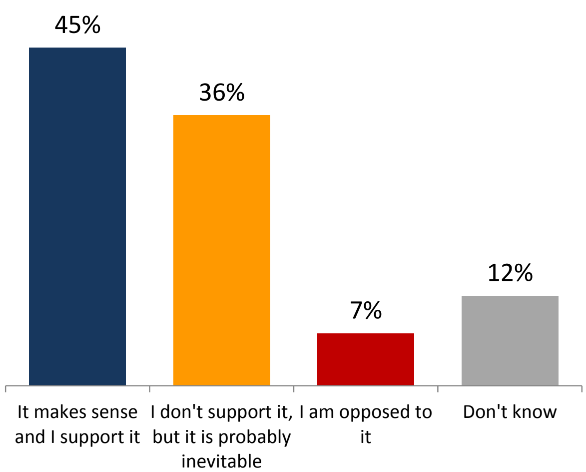
- Homeowners (47%) are more likely to say they support rate harmonization than renters (29%).
- Satisfied residential customers (48%) are more likely than dissatisfied customers (16%) to say rate harmonization makes sense and they support it.

A slim majority (52%) of residential customers feel that the OEB should support Entegrus in harmonizing its rates with only one-in-five (19%) who feel the opposite. On this complex issue there appears to be some confusion, with nearly three-in-ten (29%) who don't know how to answer.

- Owners (54% vs. 38% renters) and satisfied customers (56% vs. 20% dissatisfied) are the most likely to feel the OEB should support Entegrus in harmonizing its rates.

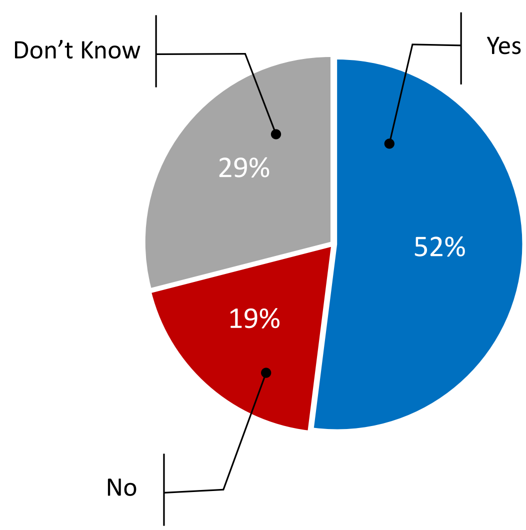
## Figure 13: Support for Rate Harmonization

Q The OEB rules only allow rate harmonization to be done through a Cost of Service Application such as the one that is the focus of this consultation. Which of the following best describes how you feel about rate harmonization?
[n=604, residential only]




GS respondents not shown [n=27]:
"Makes sense, support" [n=17]; "Don't support, inevitable" [n=6]; "Opposed to it" [n=3] "Don't Know" [n=1]

Q Do you think the Ontario Energy Board should support Entegrus in harmonizing its rates?
[n=604, residential only]




GS respondents not shown [n=27]:
"Yes" [n=17]; "No" [n=4]; "Don't know" [n=6]

## Budget, Planning and Rate Impact

This last section examines customer feedback on Entegrus' proposed budget, perceptions of the company's planning to date and, finally, social acceptance for the proposed rate increase.

### *Perceptions of Budget and Planning*

More than half (54%) of residential customers feel that the proposed budget is reasonable given what they now know. Less than one-in-four either don't find it reasonable (22%) or don't know enough to say (24%).

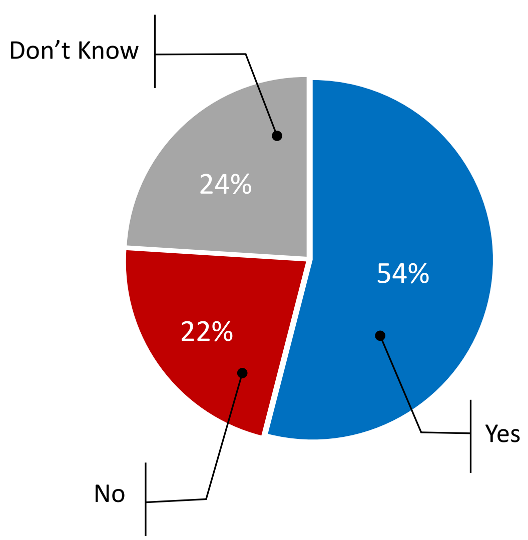
- Owners (56% vs. 20% renters) and residential customers satisfied with Entegrus' service (60% vs. 2% dissatisfied) are more likely to think the proposed budget is reasonable.

Roughly three-in-five (61%) think Entegrus' investment plan is going in the right direction. Only about one-in ten (13%) say the plan is going in the wrong direction and a quarter (26%) just don't know.

- Owners (64% vs. 42% renters) and satisfied residential customers (67% vs. 7% dissatisfied) are more likely to think the plan is headed in the right direction.

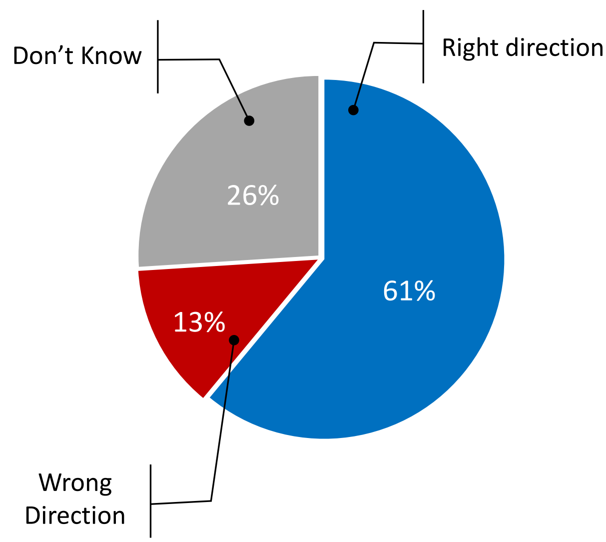
#### Figure 14: Budget and Investment Plan

Q Now that you have a better sense of the operations of Entegrus, including the cost drivers, do you feel the proposed budget is reasonable?
[n=604, residential only]




GS respondents not shown [n=27]:
"Yes" [n=14]; "No" [n=6]; "Don't know" [n=7]

Q From what you have read here and what you may have heard elsewhere, does Entegrus' investment plan seem like it is going in the right direction or the wrong direction?
[n=604, residential only]

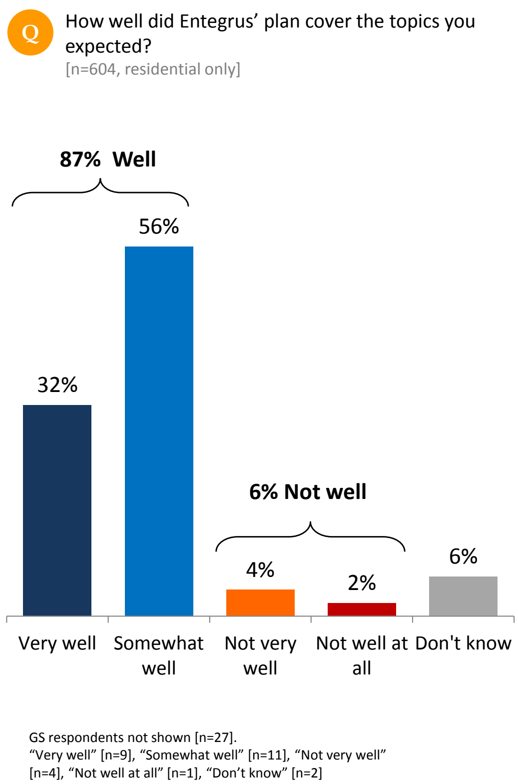


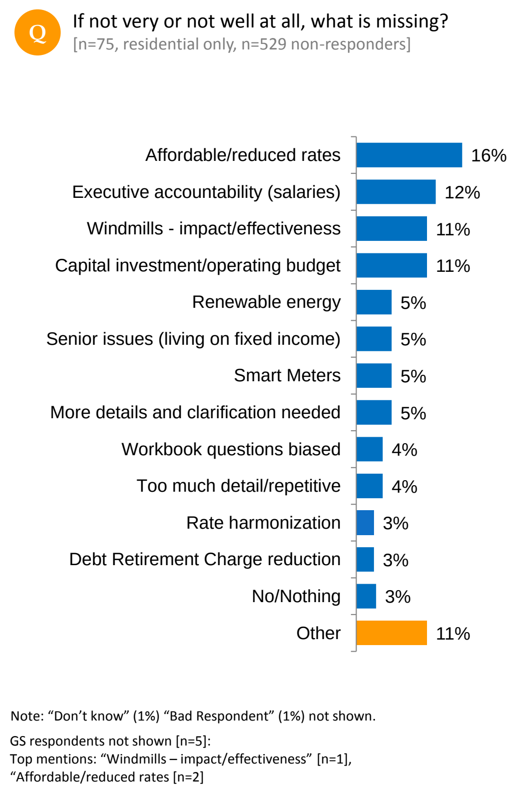

GS respondents not shown [n=27]:
"Right direction" [n=17]; "Wrong direction" [n=4]; "Don't know" [n=6]

Nearly nine-in-ten (87%) residential customers feel Entegrus' plan covered the topics they expected well.

Of the 75 residential customers who responded to the open-ended question asking what was missing, top mentions include "affordable/reduced rates" (16%), "executive accountability (salaries)" (12%), "windmill impact and effectiveness" (11%) and "capital investment and operating budget" (11%).

## Figure 15: Coverage of Key Topics

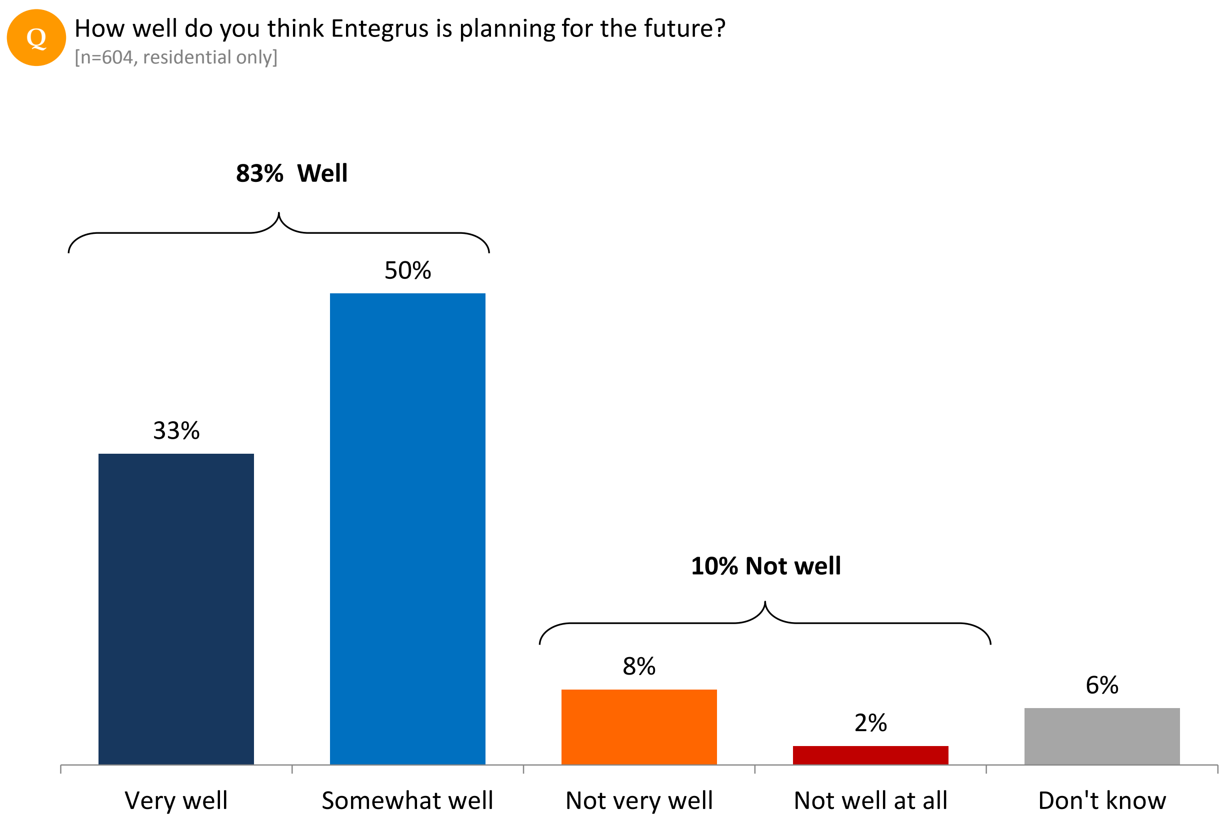


A strong majority (83%) of residential customers think Entegrus is planning well for the future with a third (33%) who say it is planning "very well".

- Those who own their own home (85% vs. 68% renters) and satisfied residential customers (88% vs. 45% dissatisfied) are the most likely to say Entegrus is planning well for the future.

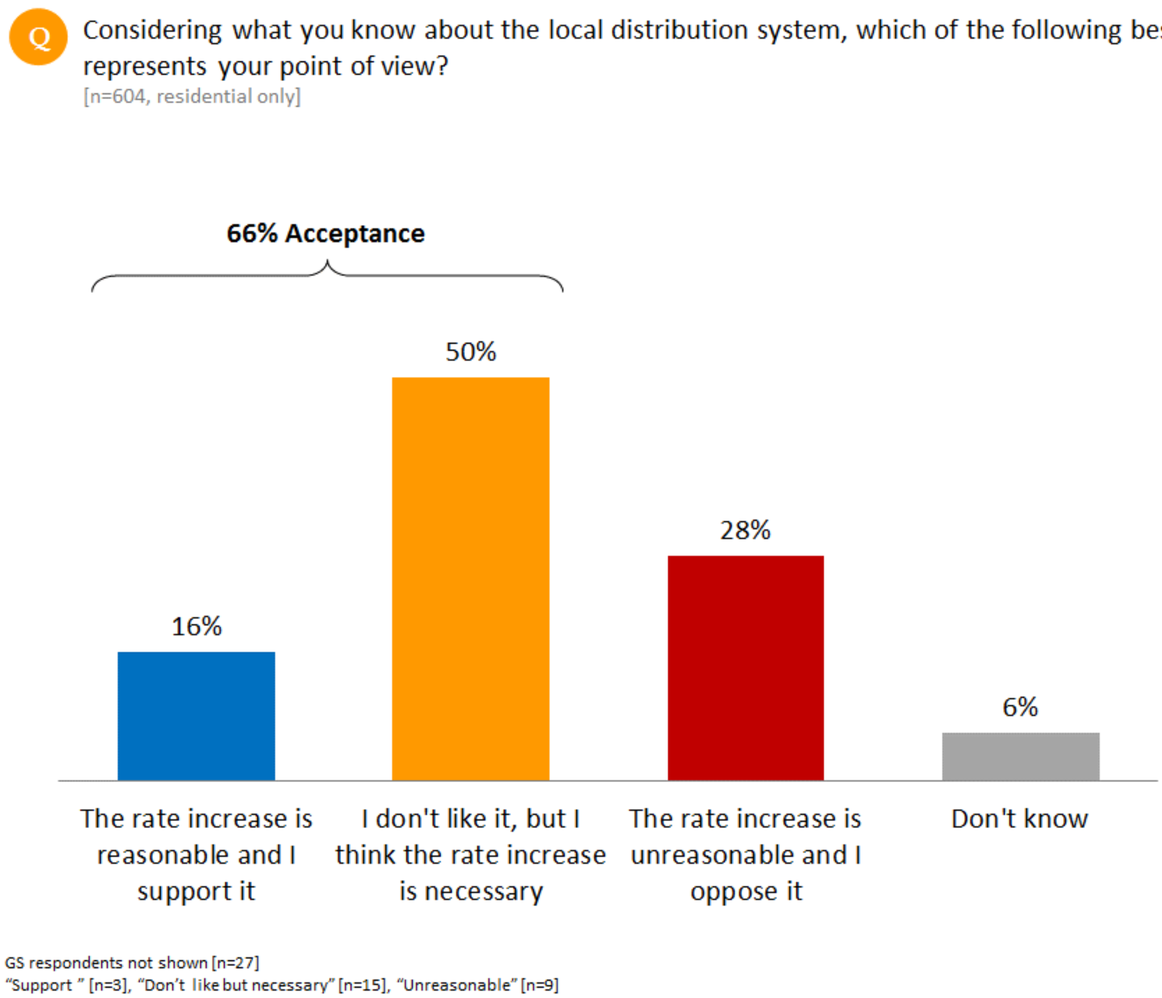
## Figure 16: Planning for Future




GS respondents not shown [n=27].
"Very well" [n=9], "Somewhat well" [n=15], "Not well at all" [n=2], "Don't know" [n=1]

By the end of the workbook, two-thirds (66%) of residential customers are prepared to accept the proposed rate increase. About one-in-six (16%) think it's reasonable and support it while half (50%) don't like it, but think it's necessary. Nearly three-in-ten (28%) think the proposed rate increase is unreasonable and oppose it.

## Figure 17: Social Acceptance for Rate Increase



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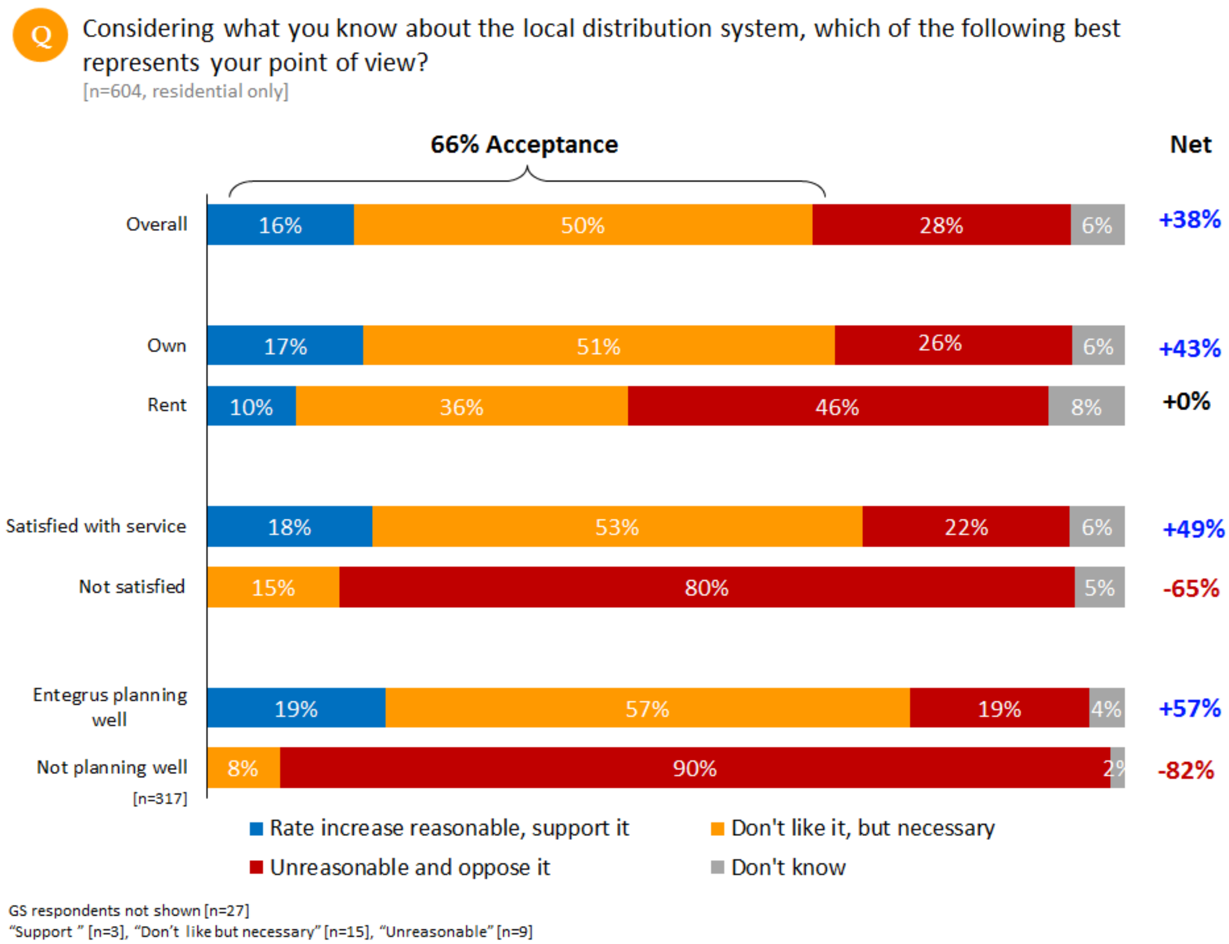
## Figure 18: Acceptance Breakdown by Group




In the breakdown of social acceptance, some striking differences emerge among residential customers:

- *Own vs. Rent:* Those who own their own home (68%) are more likely than renters (46%) to accept the rate increase.
- *Satisfaction with service:* 72% of those residents satisfied with service accept the rate increase. Just 15% of those who are not satisfied say the same.
- *Planning for future:* Over three-quarters (77%) of those who think Entegrus is planning well for the future accept the increase. Among those who don't think Entegrus is planning well for the future, only 8% are prepared to accept an increase – and only because they think it is necessary.

# Feedback on the Workbook Design

After the survey was complete, respondents were asked to fill out six additional (and optional, so n-sizes vary) feedback questions on the workbook itself. Topics included general impression of the workbook, volume of information, content covered, outstanding questions, suggestions for future consultations and the video content.

- Overall impression of the workbook among the 392 who provided feedback was quite positive: a quarter (26%) said it was "informative/educational" and 14% said it was "good/excellent".
- A large plurality (45%) of respondents who responded to the question (n=386) said the volume of information was “about right” while a quarter (25%) felt it was “too much/too long”.
- Nearly half (44%) of the 326 respondents who answered said they did not feel any content was missing.
    - "Alternative energy and conservation" (7%), "accountability (operating costs, salaries)" (5%) and "spending and budget" (5%) came up as topics residential respondents would have liked to seen included in the workbook.
- As for outstanding questions, about half (49%) of those 272 respondents who answered said they had none.
- For future consultations, a plurality (34%) of those who responded (n=266) mention the current method/online surveys as their preferred way to participate. About one-in-five 17% mentioned email and one-in-ten (9%) would prefer social media.
    - One-in-ten (9%) would not participate again if asked.
- Feedback on the videos (n=318) was also quite positive ("Good/excellent:” 27%; "Fine/OK": 17%: "Informative/educational": 10%; "Well-presented and organized”: 7%).
    - Roughly one-in-five (16%) reported that they didn't watch the videos
    - About 10% made negative comments about the videos

## Figure 19: General Impression of Workbook

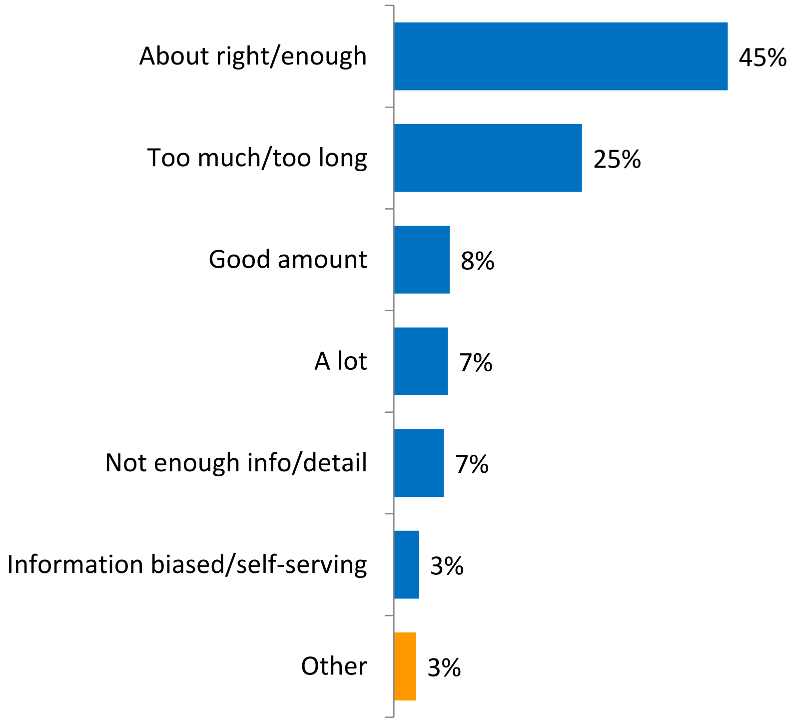

Note: "Don't know" (<1%) "Refused" (1%) not shown.

GS respondents not shown [n=16].
Top mentions: "Good/excellent" [n=3], "Interesting" [n=3], "Easy to read/understand" [n=2]

## Figure 20: Volume of Information

Q **Volume of Information:** Did Entegrus provide too much information, not enough, or just the right amount?

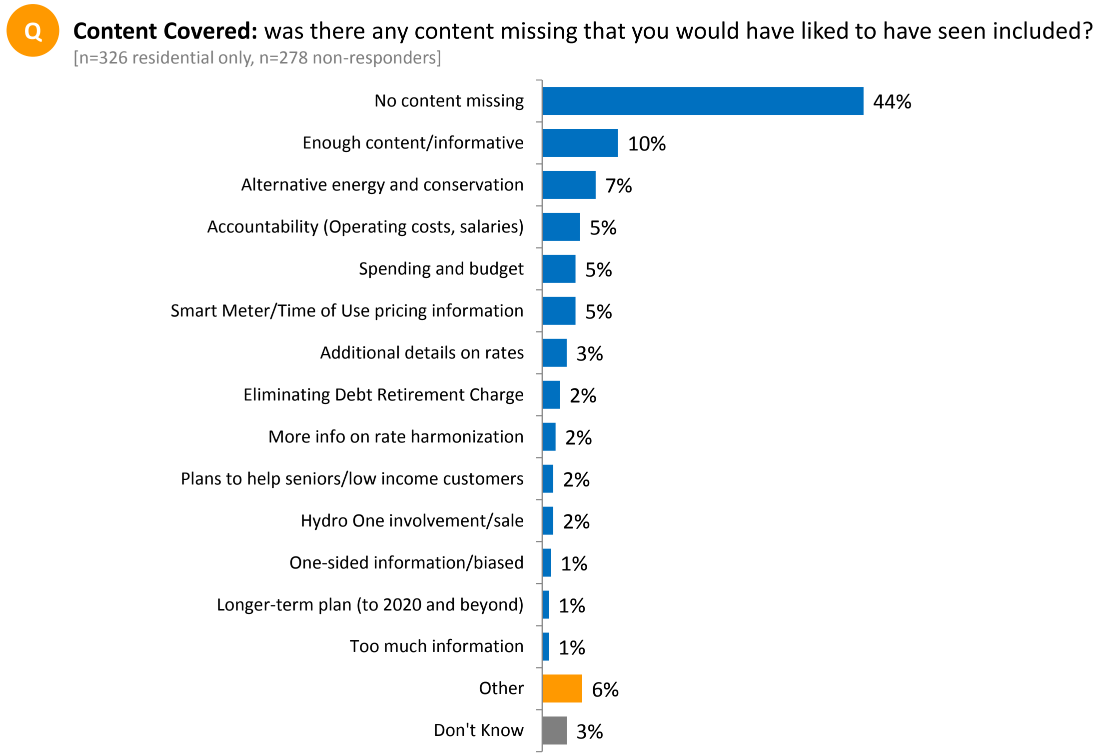
[n=386 residential only, n=218 non-responders]




Note: “Don’t know” (<1%) “Refused/Bad Respondent” (2%) not shown.

GS respondents not shown [n=16].
Top mentions: “About right/enough” [n=6], “Too much/too long” [n=7], “Not enough info/detail” [n=2]

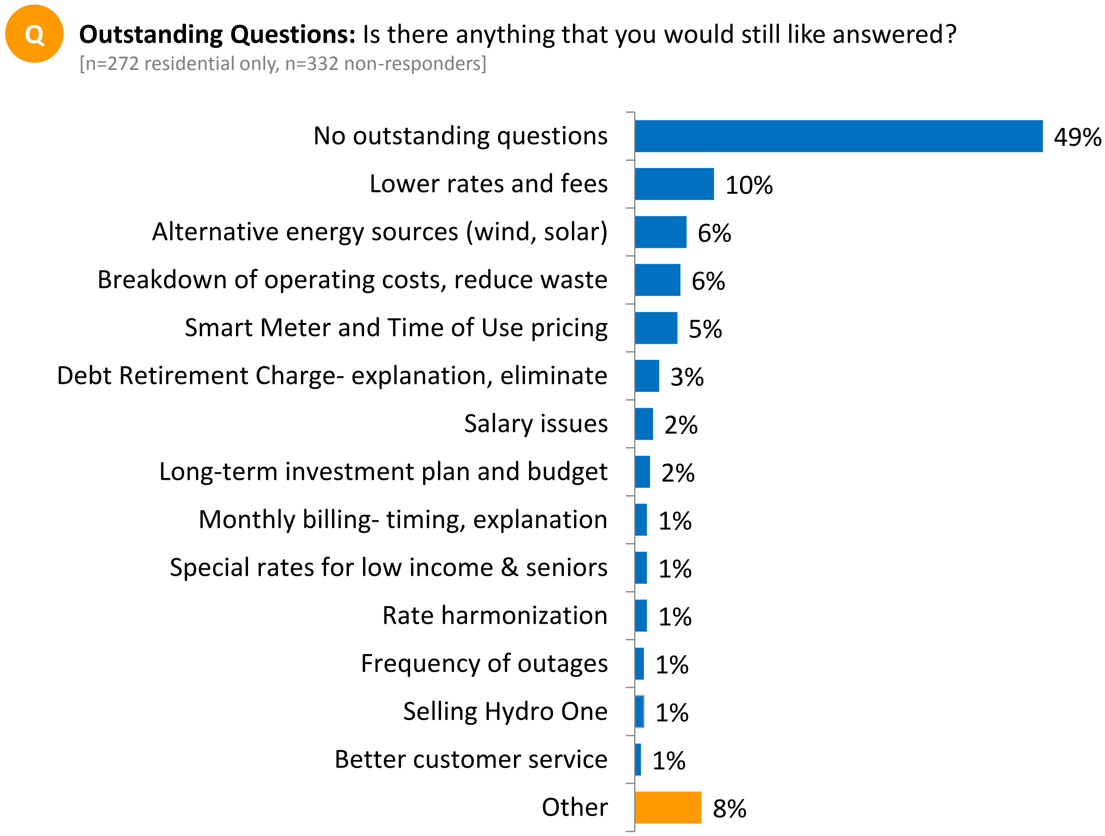
## Figure 21: Content Covered




Note: “Refused” (1%) not shown.

GS respondents not shown [n=14]
Top mentions: “No” [n=8], “Informative” [n=1], “Additional details on rates” [n=1]

## Figure 22: Outstanding Questions

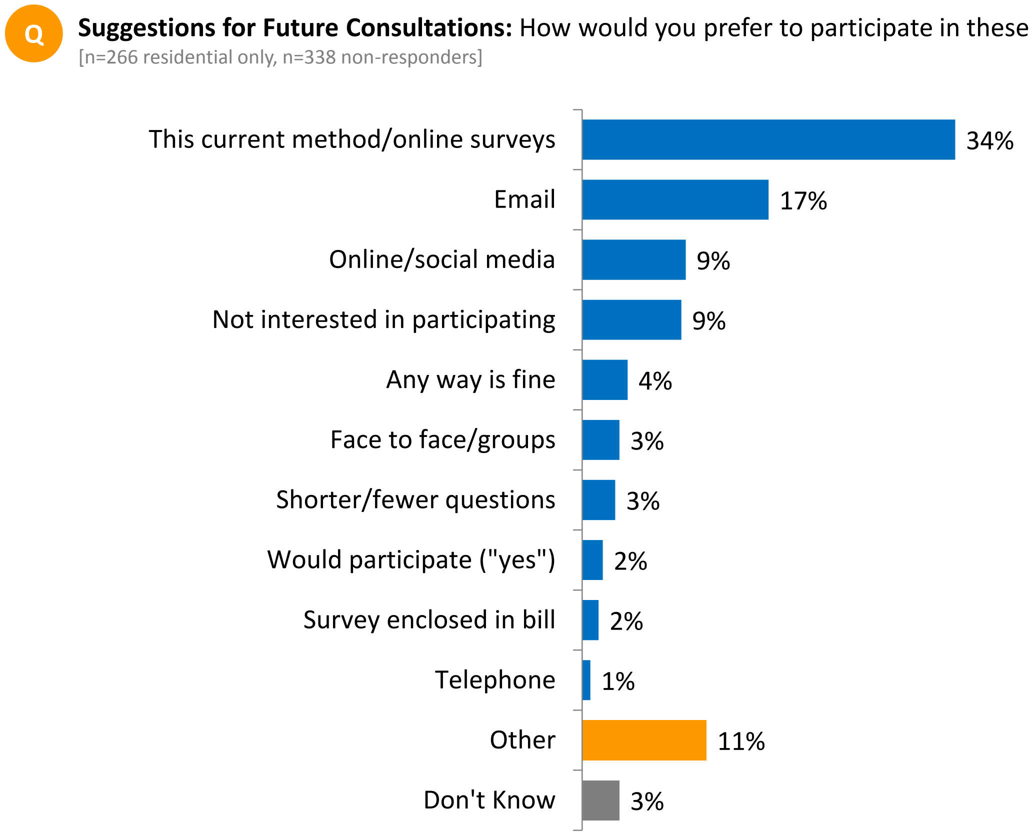



Note: “Don’t know” (1%) “Refused/Bad Respondent” (1%) not shown.

GS respondents not shown [n=12]
Top mentions: “Breakdown of operating costs/reduce waste” [n=2], “Smart meter and ToU pricing” [n=1] and “Lower rates and fees” [n=1]

### Figure 23: Future Consultations

**Suggestions for Future Consultations:** How would you prefer to participate in these consultations?
[n=266 residential only, n=338 non-responders]

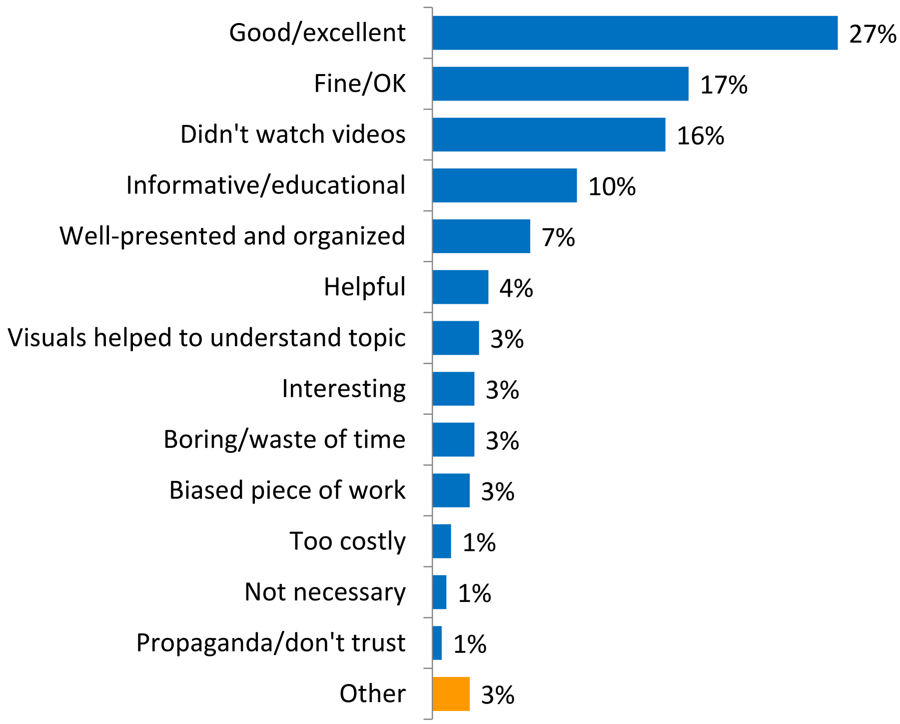



Note: “Refused/Bad Respondent” (2%) not shown.

GS respondents not shown [n=12]
Top mentions: “Current method/online surveys” [n=4], “Social media” [n=2], “Email” [n=2]

## Figure 24: Videos

**Videos:** What did you think about the videos that were included in this survey?
[n=318 residential only, n=286 non-responders]




Note: "Don't know" (1%) "Refused/Bad Respondent" (2%) not shown.

GS respondents not shown [n=11]
Top mentions: "Good/excellent" [n=5], "Well presented/organized" [n=3], "informative/educational" [n=1]

# Customer Telephone Surveys

**Telephone Surveys**
among Residential and GS customers

**PURPOSE:** To obtain statistically significant quantitative customer feedback on Entegrus' plan and assess reaction to customer opinions obtained from the previous research phases.

## Summary

This next section summarizes the telephone survey results of 509 residential (RS) and 111 general service (GS) <50 kW Entegrus customers.

### *Familiarity and Satisfaction*

- Approximately half of residential (52%) and general service (47%) customers are familiar with their local distribution system.
- Satisfaction with the job Entegrus is doing managing the system is high among both residential (88%) and general service (85%) customers.
- When asked how service could be improved, 31% of both residential and general service customers suggest a reduction in rates.
- About one quarter (26%) of residential customers and two-in-ten (22%) general service customers say there is nothing Entegrus could do to improve service.

### *Electricity Bill Knowledge*

- Only 38% of residential customers are familiar with how much of their monthly bill is allocated to Entegrus; the same is true for 34% of general service customers.

### *System Reliability*

- Residential customers most commonly experienced two outages in the year prior (20%). Of the 391 customers who experienced at least one outage, a plurality (32%) were without power for less than 15 minutes.
- General service customers also most commonly experienced two outages (23%), however the duration was more often longer. Three-in-ten (31%) of the 89 customers who experienced an outage were without power for between one and three hours.
- The majority (52%) of residential customers described the most recent power outage they experienced to be a *minor inconvenience*.
- Equal proportions of general service customers described their most recent outage as having a *significant* cost to their business (22%) as having only a *minor* cost to their business (23%).
- The plurality of residential (45%) and general service (37%) customers think investment in addressing outages should focus on *maintaining* the current number. This sentiment is parallel in regards to duration of outages (RS: 45% maintain; GS: 37% maintain).

### *System Challenges & Priorities*

- The majority of residential (66%) and general service (58%) customers think Entegrus should invest what it takes to replace the system's aging infrastructure to maintain system reliability.
- The run-to-failure approach is not supported by residential or generals service customers. Seven-in-ten (70%) of residential and three-quarters (74%) of general service customers feel aging equipment should be replaced *before* it breaks down.
- Four-in-five residential (82%) and general service (79%) customers acknowledge the importance of investing now in modernizing the grid, even though there are many other areas of the system that require investment.
- Most customers feel that while Entegrus should be wise with its spending, it's important for staff to have the tools and equipment they need to manage the system efficiently and reliably (RS: 62%; GS: 55%).

### *Overall Assessment of Plan*

***Residential Acceptance:*** 75%

| **Top 3 Reasons for Willing Acceptance** | |
|---|---|
| ***Q: And why do you say that? [Asked of residential respondents who had an opinion on Entegrus' proposed rate increase]*** | |
| Necessary/need to invest in infrastructure | 34% |
| Increase reasonable/affordable | 24% |
| Increases are inevitable/prices rise/inflation | 16% |

***General Service Acceptance:*** 75%

| **Top 3 Reasons for Willing Acceptance** | |
|---|---|
| ***Q: And why do you say that? [Asked of general service respondents who had an opinion on Entegrus' proposed rate increase]*** | |
| Increase acceptable/affordable | 40% |
| Necessary/need to invest in infrastructure | 31% |
| Increases are inevitable/prices rise/inflation | 9% |

### *Rate Harmonization*

- A strong majority of both residential (72%) and general service customers (69%) agree with the concept of rate harmonization. That is, that customers should pay the same rates for the same level of service.
- In the follow-up question for general service customers only, more than three-in-five (61%) say they accept rate harmonization with only one quarter (25%) who think it is unfair and oppose it.

# Methodology

INNOVATIVE conducted two customer surveys by telephone for Entegrus:

1. A residential customer survey conducted among **509 respondents** between June 23rd and June 27th, 2015.
2. A general service customer survey conducted among **111 respondents** between June 23rd and July 2nd, 2015.

Participants were randomly selected from customer lists provided by Entegrus (30,886 residential records and 3,448 general service records).

- A sample of 509 residential customers is considered accurate to within ±4.3 percentage points, 19 times out of 20.
- A sample of 111 general service customers is considered accurate to within ±9.3 percentage points, 19 times out of 20.

The margin of error in both surveys will be larger within each sub-grouping of the samples.

### *Questionnaire Design*

The questionnaires were designed to simulate the journey that respondents in the Workbook-led Consultation Sessions experienced. This included a combination of educating the customer, having customers reflect on their personal experience with their distribution system, and having them make value judgments on trade-offs between system reliability and bill impact.

As part of simulating the "*workbook journey*", the questionnaires were informed by and incorporated feedback from the previous phases of Entegrus' customer engagement. This included sharing both supportive and non-supportive feedback in the survey from previous phases of Entegrus' customer consultation as it related to Entegrus' proposed capital investment and the associated rate increase. Wording of questions differed slightly between the residential and General Service survey – for example, in the preambles the size of monthly bills differed between residential and general service customers – but otherwise remained consistent.

The average survey ran at approximately 10 minutes.

### *Fielding the Survey*

**Residential (RS) Customer Survey**:

For the purposes of executing the residential survey, Entegrus provided INNOVATIVE with a confidential list containing **30,886** of their residential customers' contact information.

The contact list included only residential customers with residential telephone contact information on file and who had been a customer of Entegrus since at least January 1, 2014. The information contained in the contact list included customer name, telephone number, home address, service area, and total annual usage between January 1 and December 31, 2014.

Only one customer per household was eligible to complete the residential survey. Survey respondents were screened to certify that only the resident with primary or shared responsibility for paying their Entegrus electricity bill was interviewed. This step was taken to ensure that survey respondents represented the most qualified person within a household to answer questions about their electricity bill and whether Entegrus' proposed rate increase would have a relative impact on their bill.

Before retiring any randomly selected telephone number from the contact list, eight attempts were made to reach a potential respondent for each unique telephone number, or until an interviewer received a hard refusal. Each night,new sample was released from the contact list to replace completed or retired numbers.

Entegrus' residential customers were contacted by telephone between 5pm and 8pm on weekdays; between 10am and 6:30pm on Saturdays; and between 3pm and 8pm on Sundays.

**General Service Customer Survey**:

The sample for the General Service survey consisted of **3,448** customers drawn from a confidential list provided to INNOVATIVE by Entegrus. General service respondents were screened to ensure they were in charge of managing the electricity bill at their organization.

General service customers were contacted on weekdays between 9am to 5pm.

All fieldwork was conducted using INNOVATIVE's computer-assisted telephone interviewing (CATI) system.

### *Sample Design*

The two surveys followed a stratified random sampling methodology. This is a method of sampling that involves the division of a population into smaller groups known as strata. In stratified random sampling, the strata are formed based on members' shared attributes or characteristics (in this case, customer service area or electricity usage). A random sample from each stratum is taken in a number proportional to the stratum's size when compared to the customer population. These subsets of the strata are then pooled to form a random sample.

In both surveys, residential and general service customers were divided into quartiles based on annual electricity usage to ensure the sample had a proportionate mix of customers from low, medium-low, medium-high, and high electricity usage households.

**Residential and General Service Sample Design:**

Entegrus customers were divided into quartiles based on annual electricity usage. The following table illustrates the segmentation of the residential and general service customer survey samples by usage quartile. Within each of the consumption quartiles indicated in the table below, the sample was stratified by region. In the residential survey, the distribution was 80% Chatham-Kent, 18% Strathroy, Parkhill and Mt. Brydges, and 2% Dutton and Newbury. Similarly, the target distribution for the General Service survey was 80% Chatham-Kent, 17% Strathroy, Parkhill and Mt. Brydges, and 3% Dutton and Newbury.

| Customer Type | | Total Sample | Low | Medium-Low | Medium-High | High |
|---|---|---|---|---|---|---|
| **Residential** | Target | 500 | 125 | 125 | 125 | 125 |
| | Actual | 509 | 125 | 125 | 130 | 129 |
| | Difference | +9 | 0 | 0 | +5 | +4 |
| **General Service** | Target | 200 | 50 | 50 | 50 | 50 |
| | Actual | 111 | 27 | 29 | 28 | 27 |
| | Difference | -89 | -23 | -21 | -22 | -23 |

### *Sample Weights*

Weights were applied to the residential data as the stratified random samples are accurate representations of Entegrus' actual residential customer distribution and type.

Slight weights were applied to the General Service data in order to align survey sample regional distribution with actual distribution.

### *Financial Flexibility*

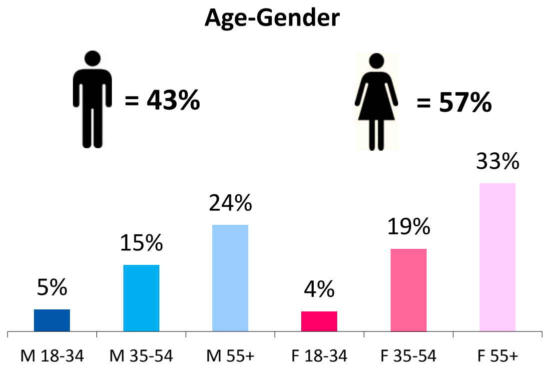
One measure noted throughout this report is "financial flexibility", also referred to as "financial strain". This information was captured with the reasoning that the degree of financial impact a respondent's electricity bill has on their monthly household/organization's finances may influence some of their preferences; that is, on some topics customers' answers may differ depending on their financial strain. Such differences have been noted throughout the report.

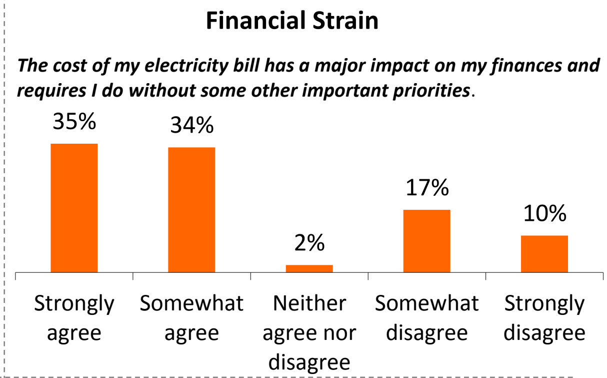
Financial strain was determined by agreement with a customer input statement which indicated that the cost of their electricity bill has a major impact and requires customers to do without – or put off – other investments or spending priorities. Customers who agreed with this statement (responded *strongly agree* or *somewhat agree*) were classified as financially strained. This measure was included in a cross-tabulation of the survey results.

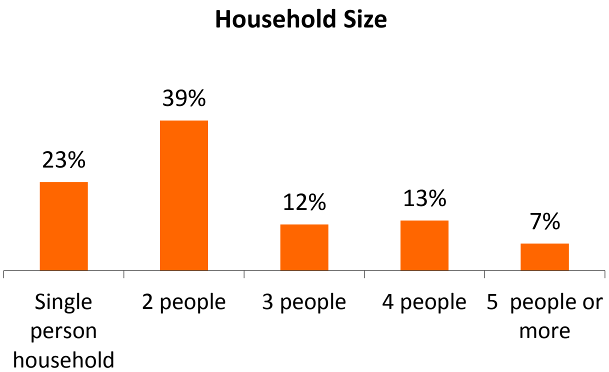
### *Demographic Profiles*

The following details the demographic characteristics of respondents who completed the Residential Ratepayer telephone survey [n=509].

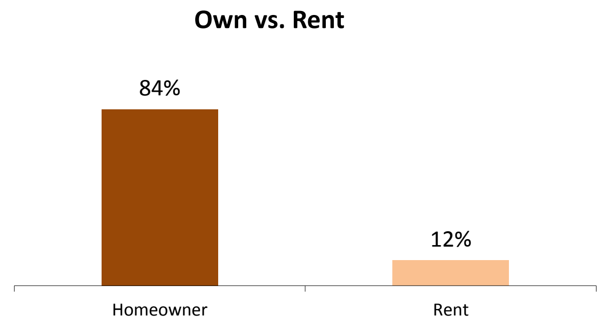
## Figure A: Residential Customer Profile




Note: Refused (5%) not shown

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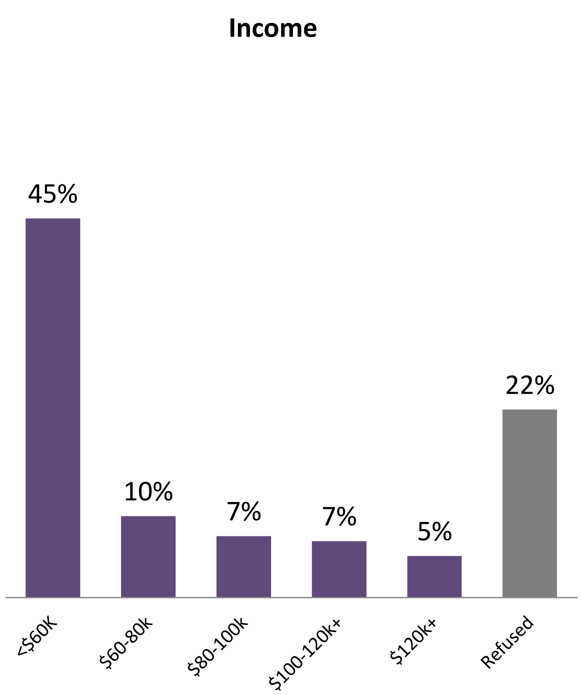
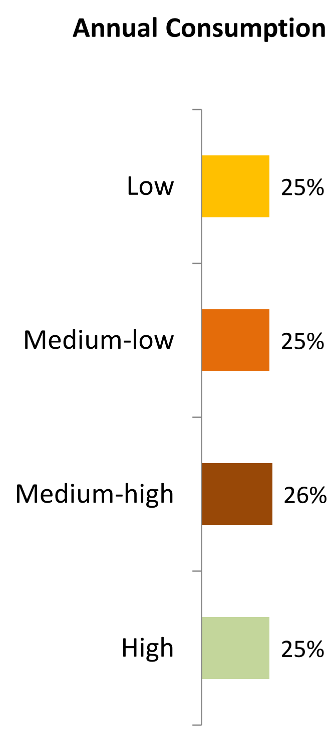
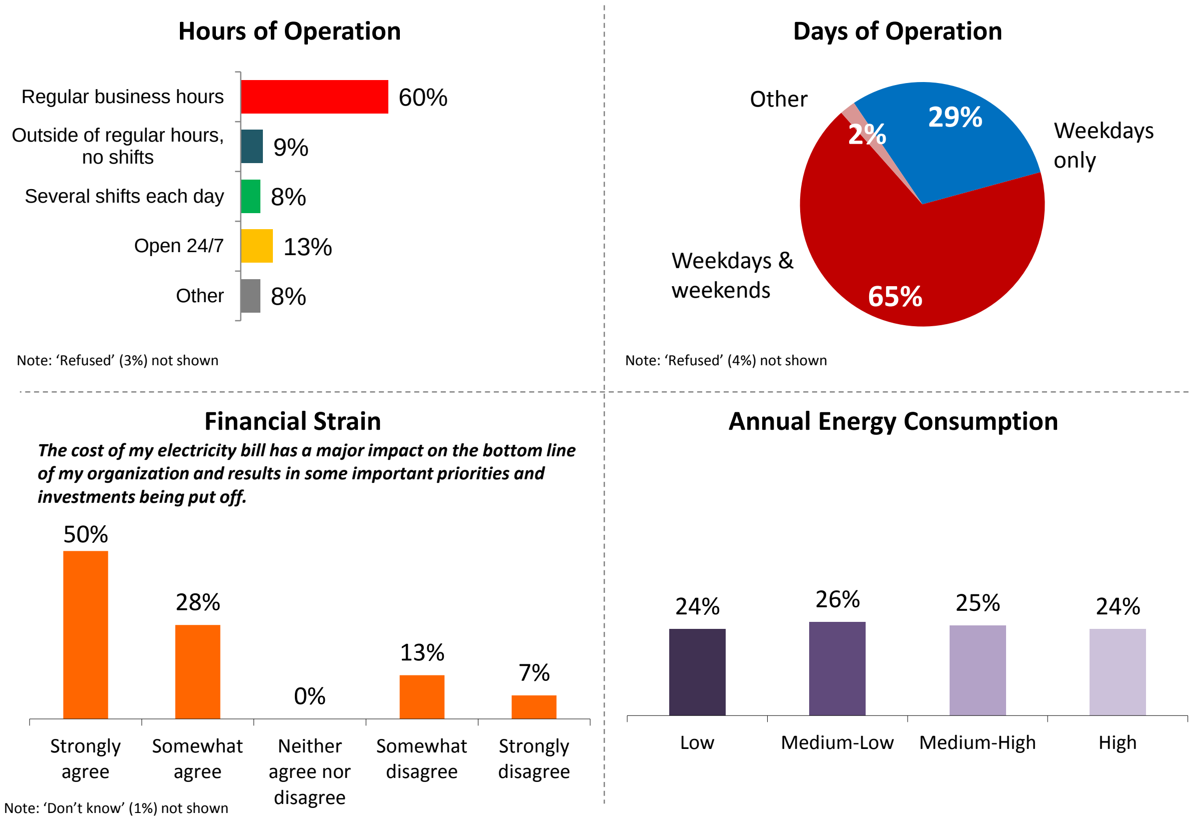


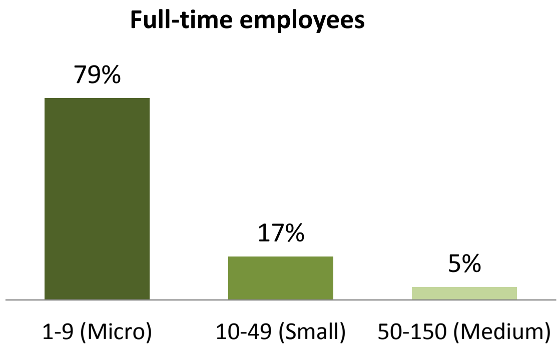



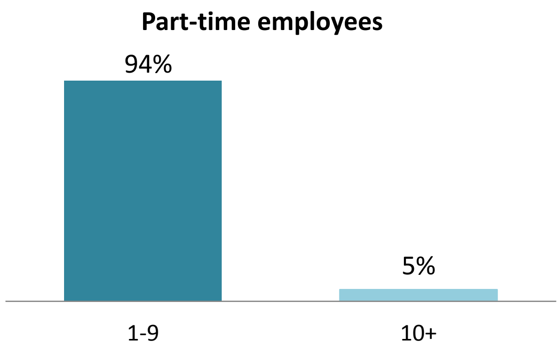
## Firmographic Profiles

Below are the firmographics of respondents who completed the General Service Ratepayer telephone survey [n=111].

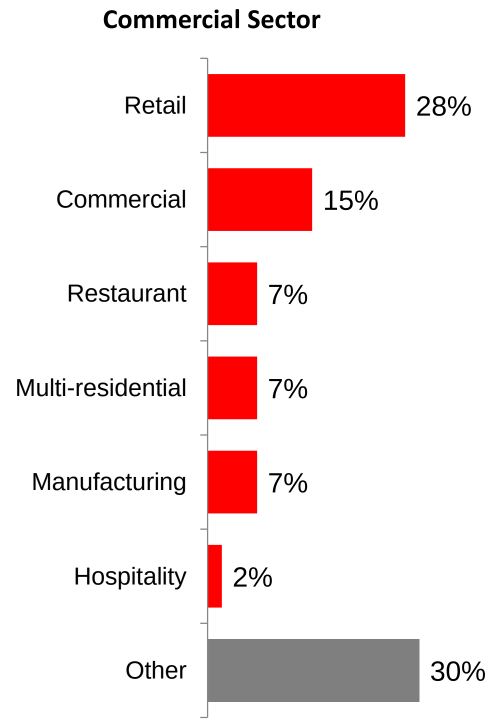
## Figure B: GS Customer Profile






Note: 'Refused' (2%) not shown




Note: 'Don't know/Refused' (3%) not shown

# Respondent Feedback

## Familiarity and Satisfaction

The first portion of the survey was dedicated to ascertaining customers' familiarity with their local distribution system and gauging their general satisfaction with how Entegrus is managing it. Customers were also given the opportunity to express how Entegrus could improve its service to them – in the form of an open-ended question. The results for residential customers are presented first, followed by general service customers (this pattern will continue for the remainder of this report).

### *Familiarity and Satisfaction Summary*

- Approximately half of residential (52%) and general service (47%) customers are familiar with their local distribution system.
- Satisfaction with the job Entegrus is doing managing the system is high among both residential (88%) and general service (85%) customers.
- When asked how service could be improved, 31% of both residential and general service customers suggest a reduction in rates.
- About one quarter (26%) of residential customers and two-in-ten (22%) general service customers say there is nothing Entegrus could do to improve service.

### *Preamble for Familiarity and Satisfaction Section*

Prior to answering the questions in the General Satisfaction Section, respondents were presented with the following preamble concerning key components of Ontario's electricity system:

*"To start, I'd like to ask you a few questions about the electricity system …*

*As you may know, Ontario's electricity system has three key components:* ***generation, transmission*** *and* ***distribution****.*

- ***Generating stations*** *convert various forms of energy into electric power;*
- ***Transmission lines*** *connect the power produced at generating stations to where it is needed across the province; and*
- ***Distribution lines*** *carry electricity to the homes and businesses in our communities.*

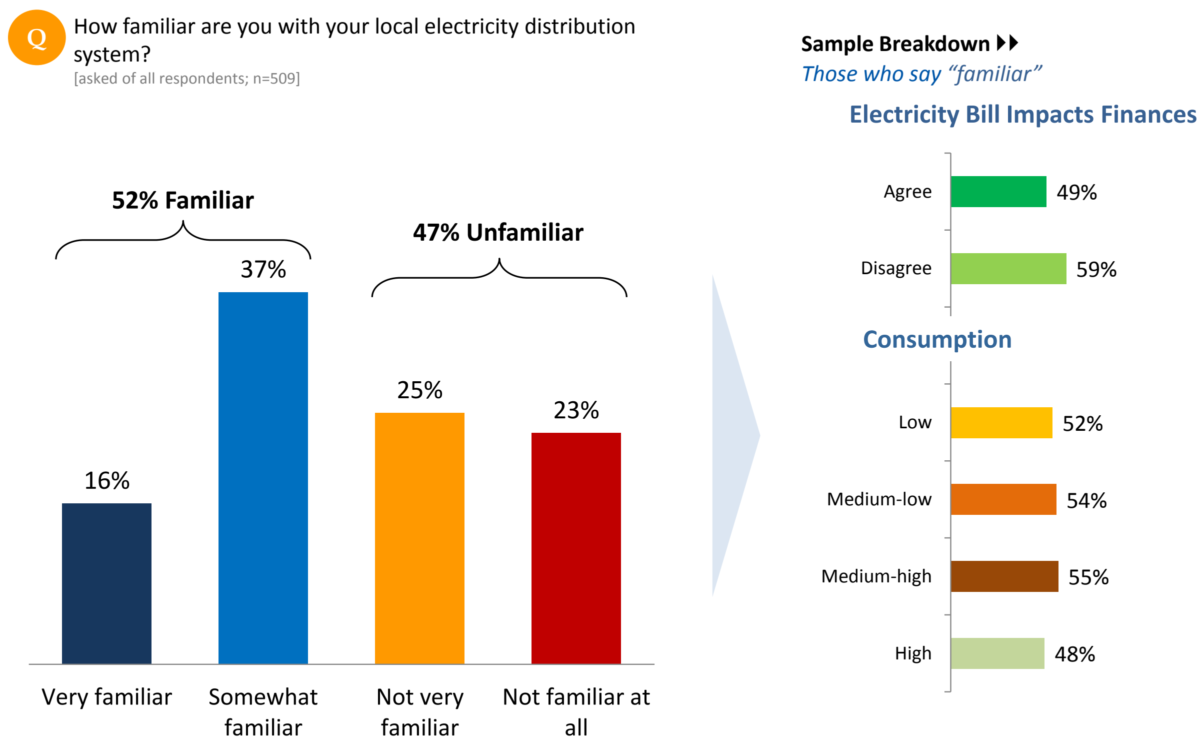
*Today we're going to talk about your* **local distribution system** *which is maintained and operated by* ***Entegrus****."*

### *Familiarity with Local Electricity Distribution System*

Residential customers are divided in their familiarity with their local electricity distribution system. Just over half (52%) say they are familiar, while just under half (47%) are not. Most of those who are familiar are only *somewhat familiar*, and 16% are *very familiar.* Of those that are unfamiliar, roughly equal proportions are *not very familiar* (25%) and *not familiar at all* (23%).

- Customers that agree that their electricity bill impacts their finances are less familiar (49%) than those who disagree (59%).
- High consumption level customers are the least familiar (48%) of the consumption level groups.

## Figure RS.1: Familiarity with the Local Distribution System

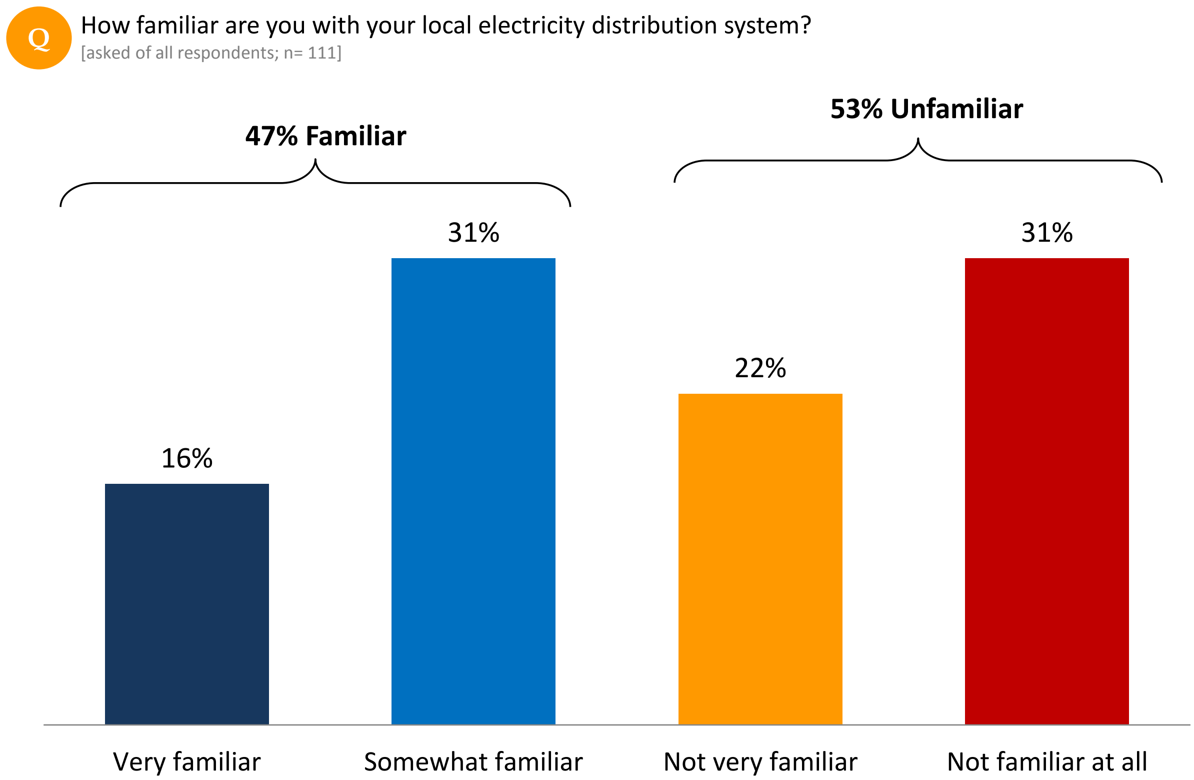



**Note:** 'Don't know/Refused' (<1%) not shown.

General service customers are slightly less familiar with their local electricity distribution system than residential customers; less than half (47%) say they are familiar. 16% are *very familiar*, while three-in-ten are *somewhat familiar.* Of the 53% who are unfamiliar, 22% are *not very familiar* and three-in-ten (31%) are *not familiar at all*.

- Customers whose organization's finances are impacted by their electricity bill report a lower level of familiarity (45%) than those who are not financially strained (53%).

## Figure GS.1: Familiarity with the Local Distribution System

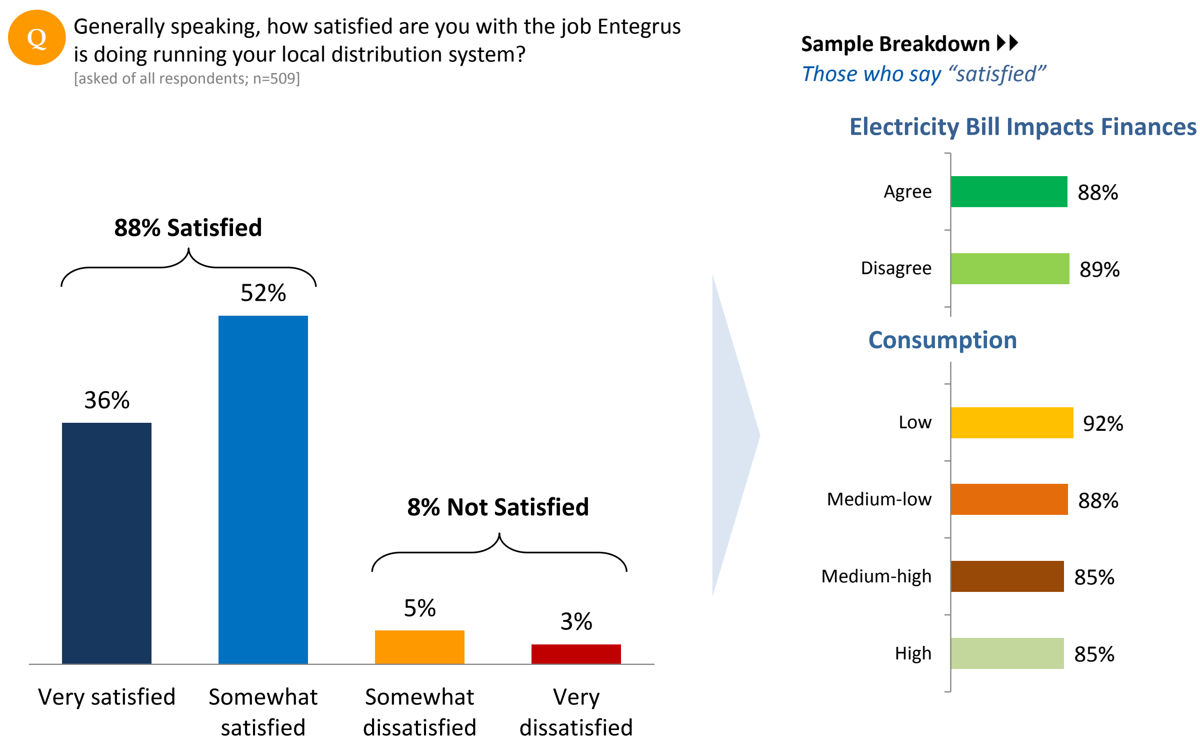


### *Satisfaction with Entegrus Running the Distribution System*

Almost nine-in-ten (88%) residential customers say they are satisfied with Entegrus' management of the local distribution system. Of those, over one third (36%) are *very satisfied* and just over half (52%) are *somewhat satisfied.*

- Financial impact does not seem to correlate with satisfaction as equal proportions of financially strained (88%) and unstrained (89%) say they are satisfied.
- Satisfaction decreases as consumption level increases; low consumption level customers say they are the most satisfied (92%), while medium-high and high consumption level customers report the least satisfaction (85%).

## Figure RS.2: Satisfaction with Entegrus



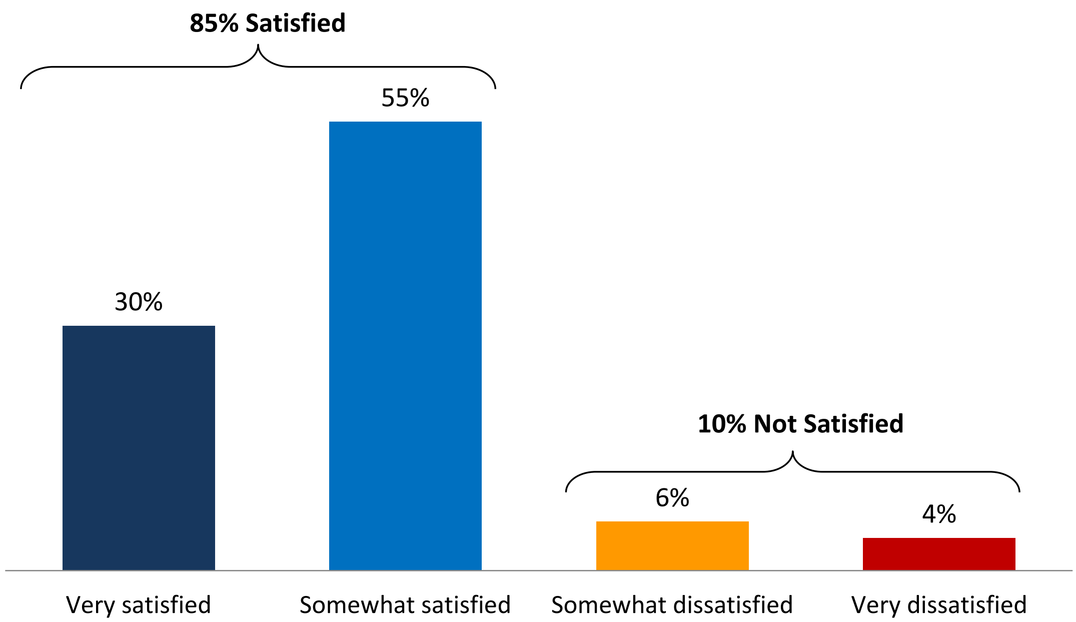

**Note:** 'Don't know' (4%) and 'Refused' (<1%) not shown

Level of satisfaction among general service customers is also high (85%). Three-in-ten (30%) say they are *very satisfied* and over half (55%) say that they are *somewhat satisfied*.

- Of general service customers under no financial strain, nine-in-ten (92%) report satisfaction with Entegrus. Satisfaction is slightly lower for those who are financially strained (83%).

### Figure GS.2: Satisfaction with Entegrus

Q Generally speaking, how satisfied are you with the job Entegrus is doing running your local distribution system?
[asked of all respondents; n= 111]




**Note:** 'Don't know' (5%) not shown.

### *How to Improve Service*

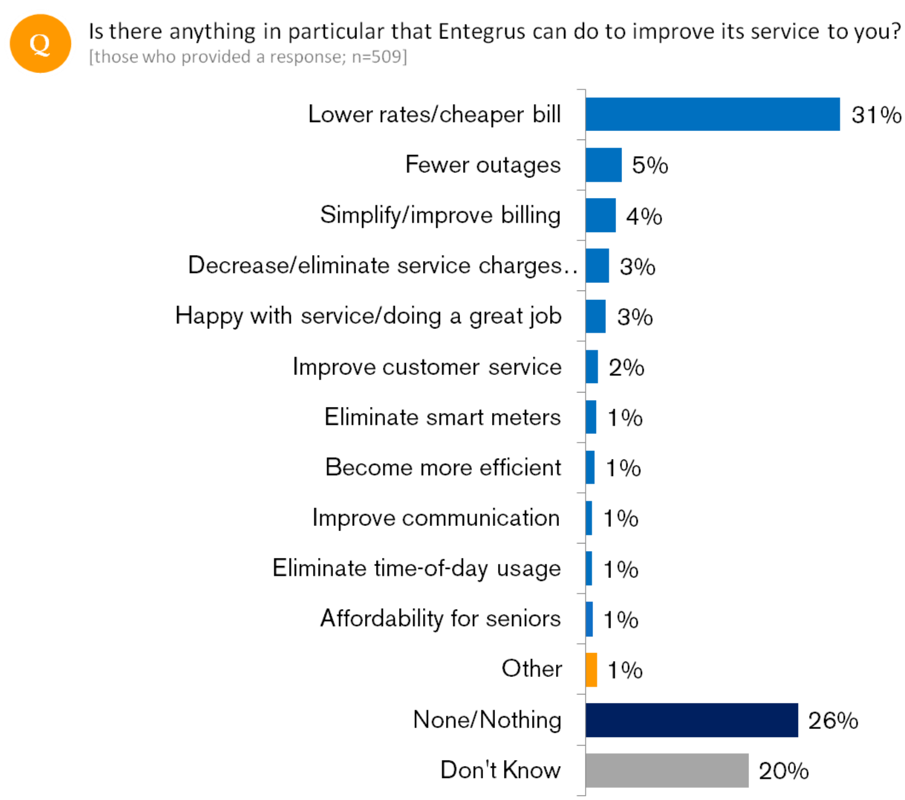
Customers were asked if there is anything in particular Entegrus can do to improve its service to them. This question was open-ended allowing for any and every response to be captured, including issues that are not under Entegrus' control.

One quarter (26%) of residential customers did not have anything to suggest – they are satisfied with the job Entegrus is doing. Furthermore, an additional 20% say that they *don't know*, which may also be interpreted as indicative of satisfaction.

For a plurality (31%) of residential customers "lower rates/cheaper bill" was the most widely agreed upon improvement. The prevalence of this response is almost twice as high among those who are financially strained (36% versus 19%).

Other suggestions are shared by five percent of customers at most. "Fewer outages" (5%) and "simplify/improve billing" (4%) are the other most frequently suggested improvements.

## Figure RS/GS.3: How to Improve Service



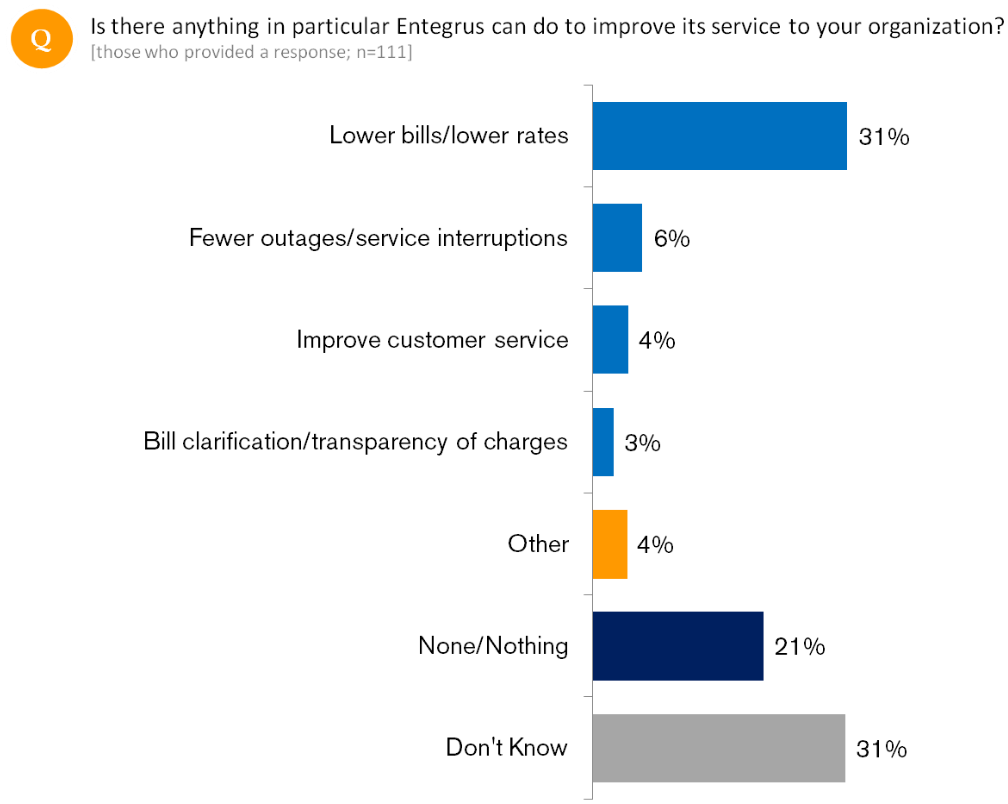

**Note:** 'Refused' (1%) not shown

General service customers had much the same improvements to suggest as residential customers, with very similar proportions. Three-in-ten (31%) would like to see “lower bills/lower rates.” This suggestion is more than twice as prevalent in organizations that are financially impacted by their electricity bill (36% versus 14%).

“Fewer outages/service interruptions” (6%) and “improve customer service” (4%) were also mentioned.

More than half of the customers did not have any improvements to suggest, whether they indicated “none/nothing” (21%) or that they “don’t know” (31%).

### Figure GS.3: How to Improve Service



## Electricity Bill Knowledge

In earlier phases of the customer consultations, it was clear that most customers are generally unaware of how much of their monthly bill is allocated to distribution. In order to generalize the prevalence of this in the general population, customers were read a preamble explaining the average amount remitted to Entegrus and then were asked how familiar they were with this breakdown of their bill.

### *Electricity Bill Knowledge Summary*

- 38% of residential customers are familiar with how much of their monthly bill is allocated to Entegrus; the same is true for 34% of general service customers.

### *Preamble for Bill Knowledge & Impact Section*

For this component of the survey, respondents were presented with a preamble concerning the breakdown of costs of an electricity bill. The two surveys provided different preambles based on targeted respondents.

Below is the preamble for **residential customers**:

*"I'd now like to talk with you about your electricity bill …*

*While some customers pay more and others pay less, the **average residential customer pays about $140 a month** for electricity of **which $29 to $36 or approximately 20% goes to Entegrus**. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies."*

The **General Service** preamble was worded slightly differently:

*"I'd now like to talk with you about your electricity bill …*

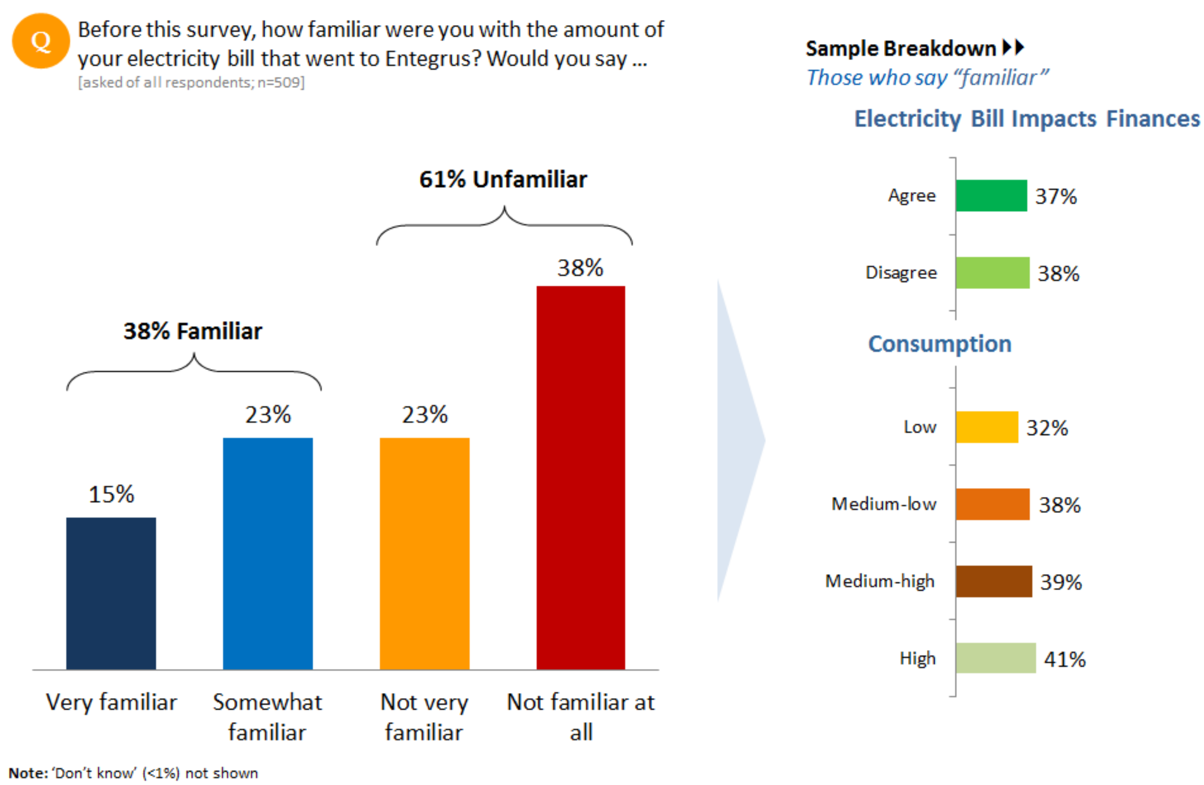
*While some customers pay more and others pay less, the **average small business or general service customer pays about $340 a month** for electricity of **which $45 to $78 or approximately 20% goes to Entegrus**. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies."*

### *Familiarity with Share of Bill Going to Entegrus*

Following the preamble less than two-in-five (38%) customers report being familiar with the breakdown of their bill. As many indicated that they were *not familiar at all* with this fact.

- Awareness of how much of their bill is allocated to Entegrus increases with consumption level (32% low; 38% medium-low; 39% medium-high; 41% high).

## Figure RS.4: Familiarity with Share of Bill Going to Entegrus

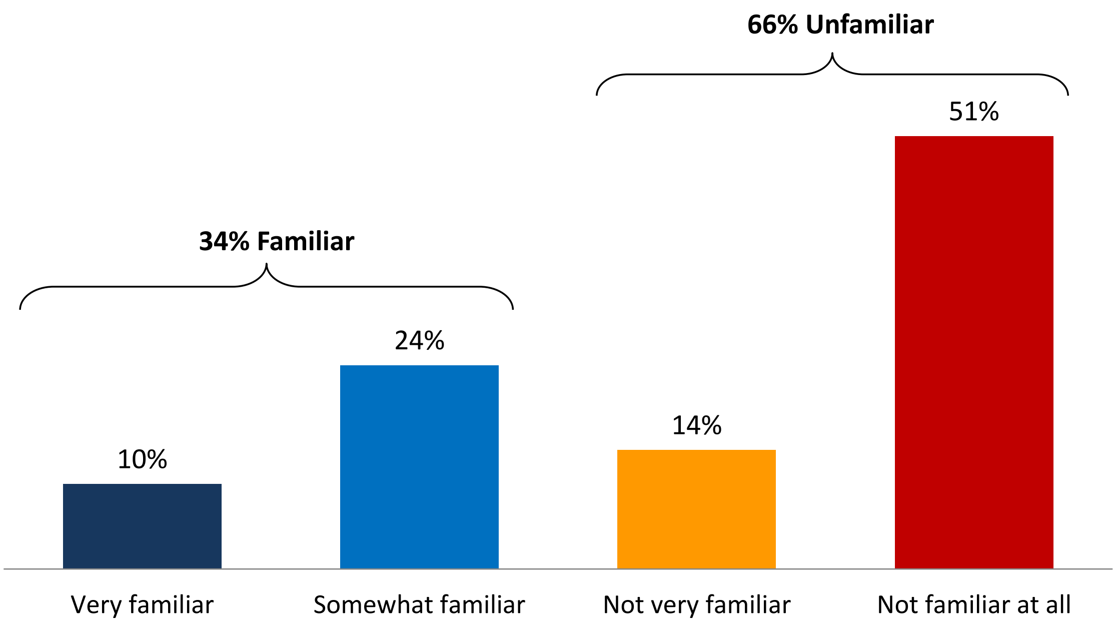


One-third (34%) of general service customers are familiar with the amount of their organization's electricity bill remitted to Entegrus, with one-in-ten (10%) *very familiar* and one quarter (24%) *somewhat familiar.* Two-thirds (66%) say they are unfamiliar, with the majority (51%) *not familiar at all.*

### Figure GS.4: Familiarity with Share of Bill Going to Entegrus

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

[asked of all respondents; n= 111]



## System Reliability

This section covers the feedback provided by respondents on power service interruptions occurring over the past year. They were asked to describe the frequency and duration of outages, in addition to the impact it has on them or their organization. This series of questions also investigates perceptions around spending, and reducing the number and length of power service interruptions.

### *System Reliability Summary*

- Residential customers most commonly experienced two outages in the year prior (20%). Of the 391 customers who experienced at least one outage, the plurality (32%) were without power for less than 15 minutes.
- General service customers also most commonly experienced two outages (23%), however the duration was more often longer. Three-in-ten (31%) of the 89 customers who experienced an outage were without power for between one and three hours.
- The majority (52%) of residential customers described the most recent power outage they experienced to be a *minor inconvenience*.
- Roughly equal proportions of general service customers described their most recent outage as having a *significant* cost to their business (22%) as having only a *minor* cost to their business (23%).
- The plurality of residential (45%) and general service (37%) think investment in addressing outages should focus on *maintaining* the current number. This sentiment is parallel in regards to duration of outages (RS: 45% maintain; GS: 37% maintain).

### *Preamble for Power Service Interruptions*

The following questions focused on how customers feel Entegrus should manage the frequency of unexpected power outages. A preamble concerning the average number of power interruptions was provided prior to the question.

This preamble read as follows :

*"Despite best efforts, no electrical distribution system can deliver perfectly reliable electricity. As a general rule, the more reliable the system, the more expensive the system is to build and maintain.*

*With that said, the average* ***Entegrus*** *customer experiences* ***one*** *unexpected power outage per year."*

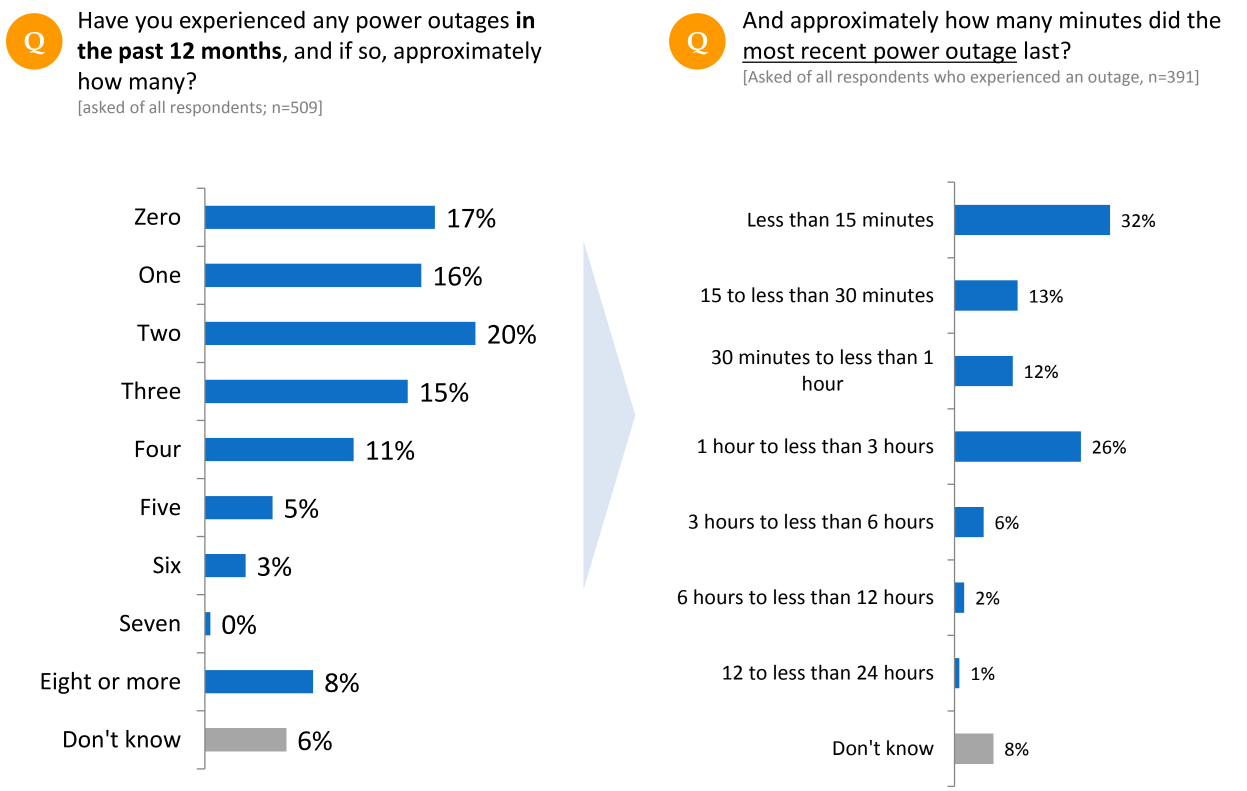
### *Number and Length of Outages*

Customers were first asked how many outages they had experienced in the past year. Those who did experience an outage were then asked how long they were without power.

It is most common for residential customers to have experience two outages (20%) in the past year. Approximately one-in-seven experienced one (16%) or none at all (17%). Less than one-in-ten experienced outages ranging from five to eight or more.

Of those customers who did experience an outage (n=391), the most recent outage most commonly lasted less than 15 minutes (32%). One quarter of the outages lasted between 15 minutes and an hour (15-30 minutes: 13%; 30 minutes – 1 hour: 12%), while another quarter (26%) lasted between one and three hours.

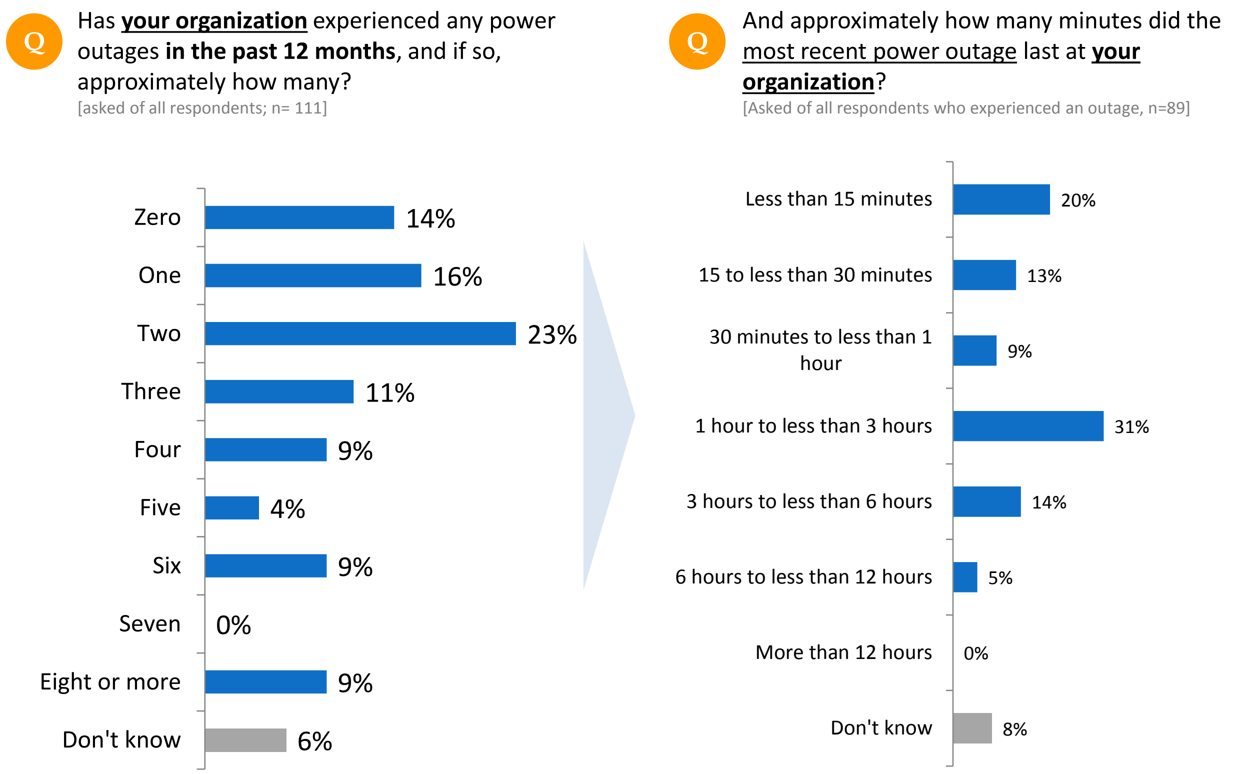
## Figure RS.5: Frequency and Duration of Outages



Like residential customers, two was the number of outages most frequently experienced by general service customers (23%), followed by one (16%), and then zero (14%). More general service than residential customers however experienced six (9%) and eight or more (9%).

Of those customers who experienced an outage at their organization, it was reported that they most commonly lasted between one and three hours (31%). Two-in-ten outages (20%) lasted less than 15 minutes.

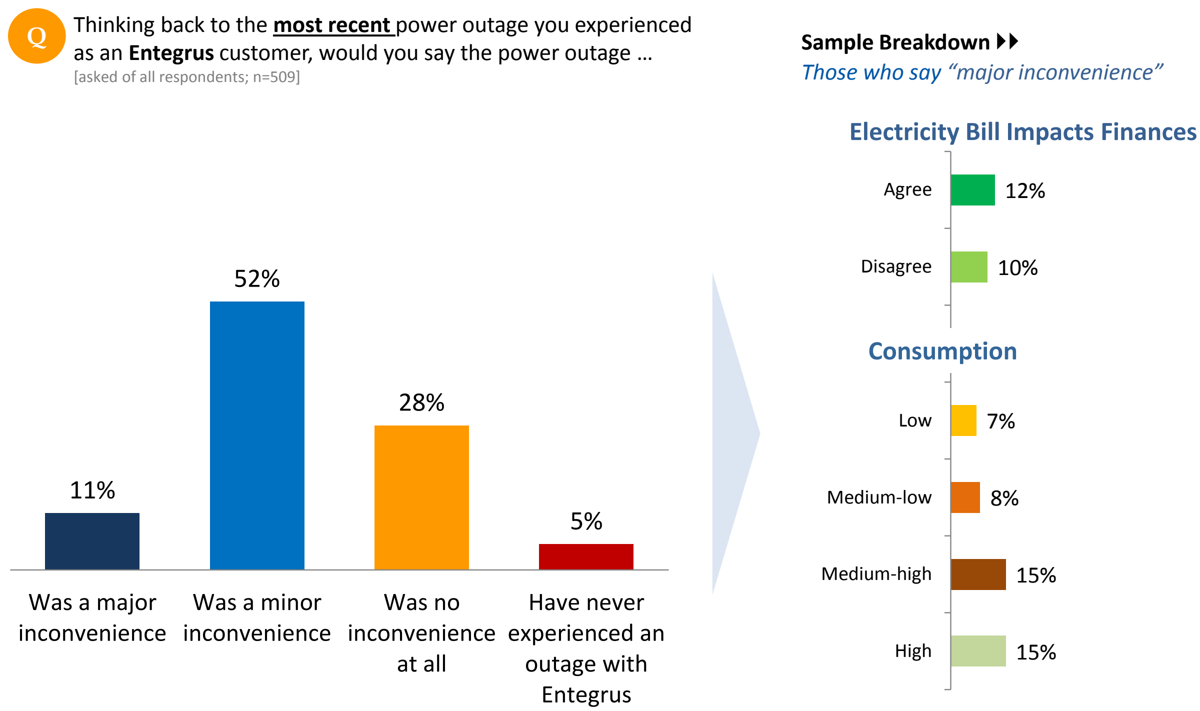
### Figure GS.5: Frequency and Duration of Outages



All customers were asked to evaluate the inconvenience caused by the most recent power outage they experienced. Just over half (52%) of residential customers report it being only a *minor inconvenience*. Three-in-ten (28%) say it was *no inconvenience at all*, while a further five percent *have never experienced an outage with Entegrus*.

One-in-ten (11%) residential customers found the outage to be a *major inconvenience*; the prevalence of this level of impact increases with consumption level (7% low; 8% medium-low; 15% medium-high; 15% high).

## Figure RS.6: Impact of Outages

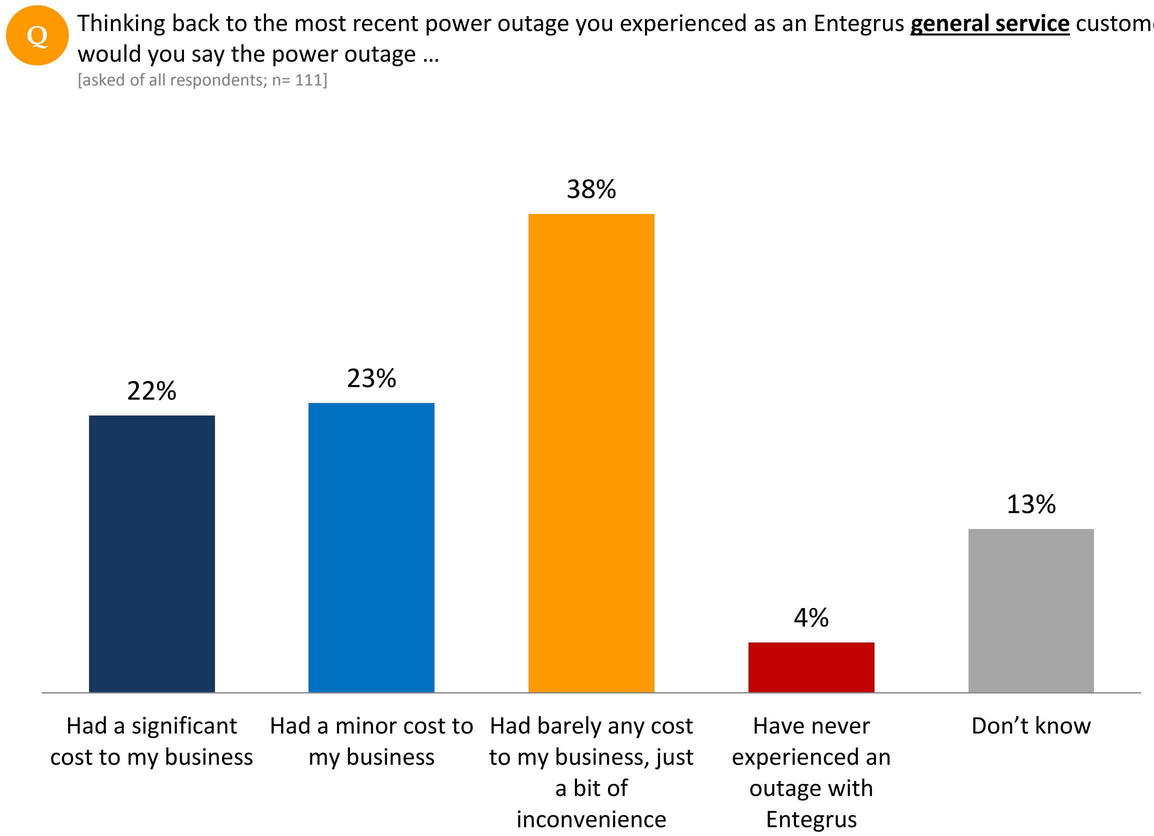



**Note:** 'Don't know' (3%) and 'Refused' (<1%) not shown

This question was posed slightly different to general service customer; rather than inconvenience, customers were asked if the most recent outage they experienced had a cost to their business. For a plurality (38%) of customers, there was *barely any cost, just a bit of inconvenience*. Similar proportions experienced a *significant cost* (22%) and a *minor cost* (23%).

- Organizations that are financially strained are more likely to have suffered a significant cost to their business as a result of their most recent power outage (25% versus 10% not strained).

## Figure GS.6: Impact of Outages

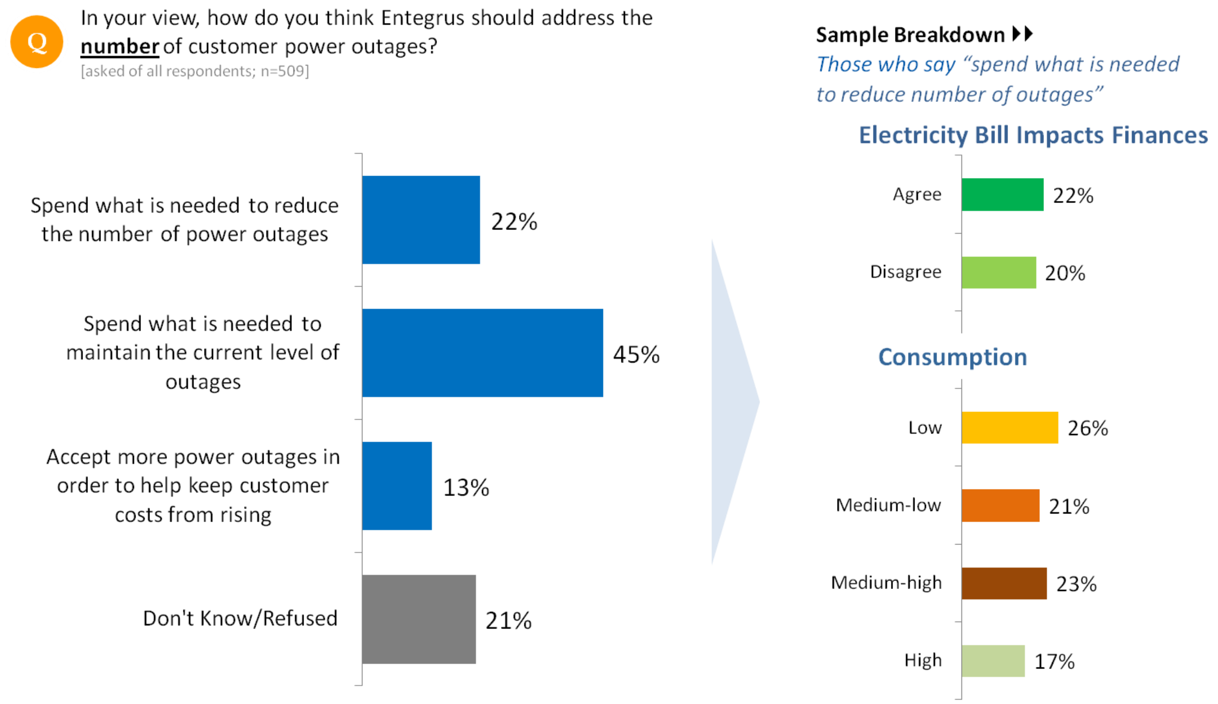


### *Addressing the Frequency of Power Outages*

In regards to how Entegrus should address the frequency of power outages, a plurality (45%) feel that spending should focus on *maintaining* the current level of outages, while two-in-ten (22%) would prefer Entegrus to spend what is needed to *reduce* the number of outages. Thirteen percent would accept more power outages in order to help customer costs from rising.

- Low consumption level customers are the most likely to support spending to *reduce* the number of outages (26%), while high consumption level customers are the least (17%).

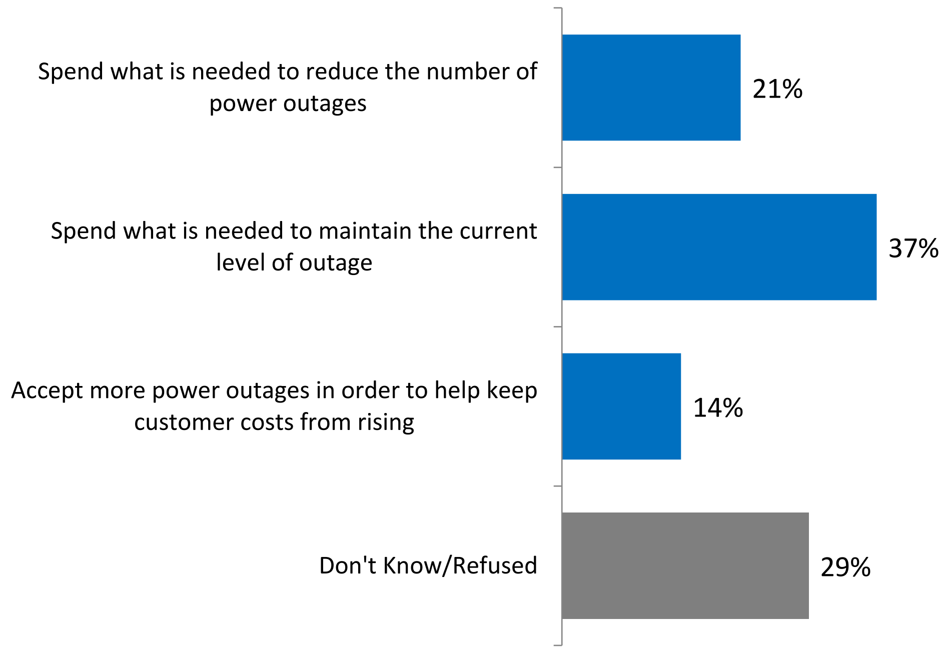
## Figure RS.7: Addressing the Frequency of Power Outages



Similarly, the plurality (37%) of general service customers feel that spending should focus on maintaining the current level of outages. Two-in-ten (21%) would see the number of outages reduced, while 14% would rather accept more outages in order to keep costs from rising.

### Figure GS.7: Addressing the Frequency of Power Outages

Q In your view, how do you think Entegrus should address the **number** of customer power outages?
[asked of all respondents; n= 111]

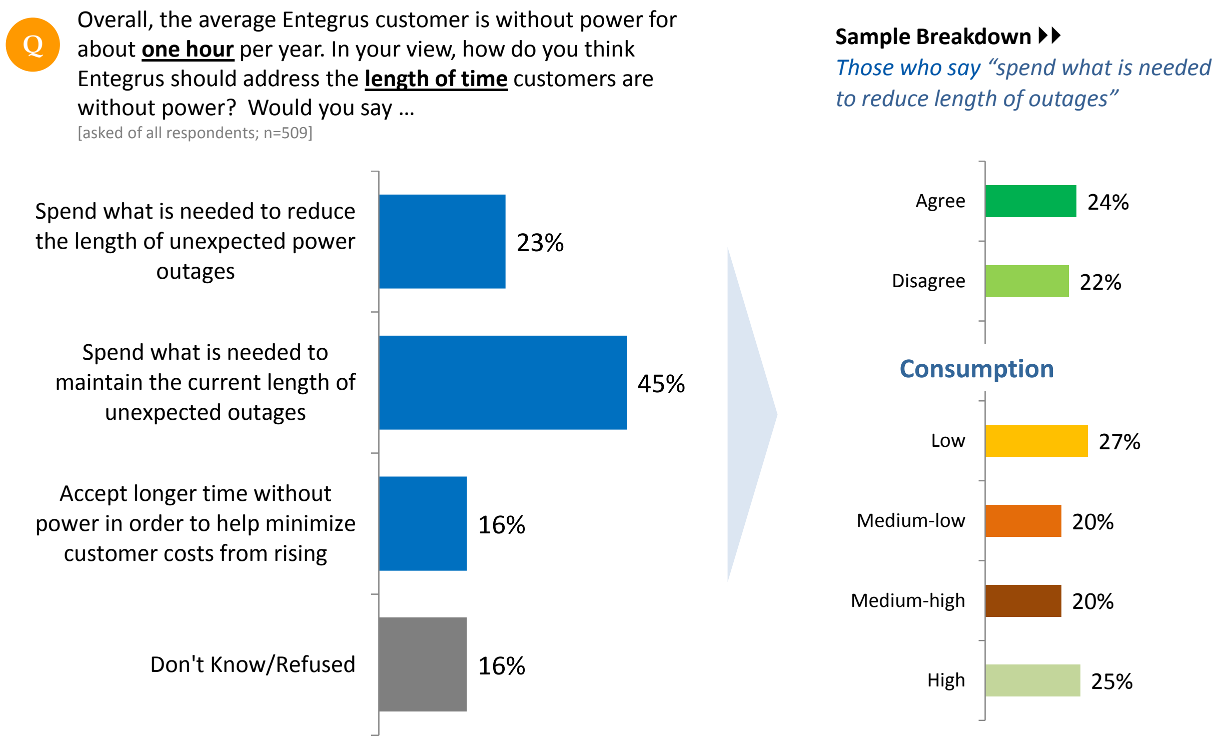


### *Addressing the Duration of Power Outages*

In regards to the duration of outages, customers were informed that the average Entegrus customer is without power for about one hour per year. With this in mind, the plurality of customers feel that Entegrus should spend what is need to *maintain* the current length of outages. Almost one quarter (23%) would prefer the length to be *reduced*, while 16% are willing to accept longer time without power in order to keep costs from rising.

- There is no significant variation among the different groups, in terms of financial flexibility and consumption level.

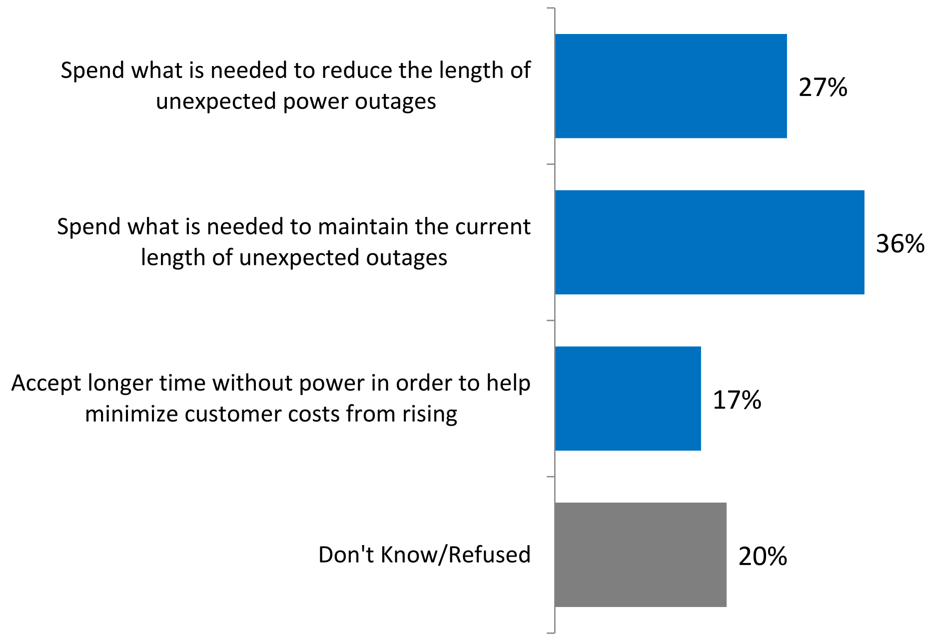
## Figure RS.8: Addressing the Duration of Outages



General service customers are in agreement with residential customers with regards to addressing the duration of outages. One third (36%) feel that spending should *maintain* the current length of unexpected outages; one quarter would like to see that length reduced; and 17% are willing to accept longer outages.

### Figure GS.8: Addressing the Duration of Outages

Q Overall, the average Entegrus customer is without power for about **one hour** per year. In your view, how do you think Entegrus should address the **length of time** customers are without power? Would you say …
[asked of all respondents; n= 111]



## System Challenges & Priorities

This section explores respondents' preferences on various aspects of Entegrus' capital investment and OM&A spending plans.

### *System Challenges & Priorities Summary*

**Investment in Aging Infrastructure**

The majority of residential (66%) and general service (58%) customers think Entegrus should invest what it takes to replace the system's aging infrastructure to maintain system reliability.

**Replacing Aging Infrastructure**

The run-to-failure approach is not supported by residential or generals service customers. Seven-in-ten (70%) residential and three-quarters (74%) of general service customers feel aging equipment should be replaced *before* it breaks down.

**Investment in New Technologies and Infrastructure**

Four-in-five residential (82%) and general service (79%) customers acknowledge the importance of investing now in modernizing the grid, even though there are many other areas of the system that require investment.

**Investment in Equipment and Tools**

Most customers feel that while Entegrus should be wise with its spending, it's important for staff to have the tools and equipment they need to manage the system efficiently and reliably (RS: 62%; GS: 55%).

### *Preamble for System Challenges & Priorities Section*

The following introduces the 'System Challenges and Priorities' section of the survey:

*"While **Entegrus** believes it has done its best to prolong the life of the assets that make up the distribution system, many of these assets are approaching the end of their useful life.*

*As part of its investment plan, **Entegrus** is proposing an infrastructure renewal program. The estimated cost of this system renewal program is **<u>$22 million</u>** between 2016 and 2020.*

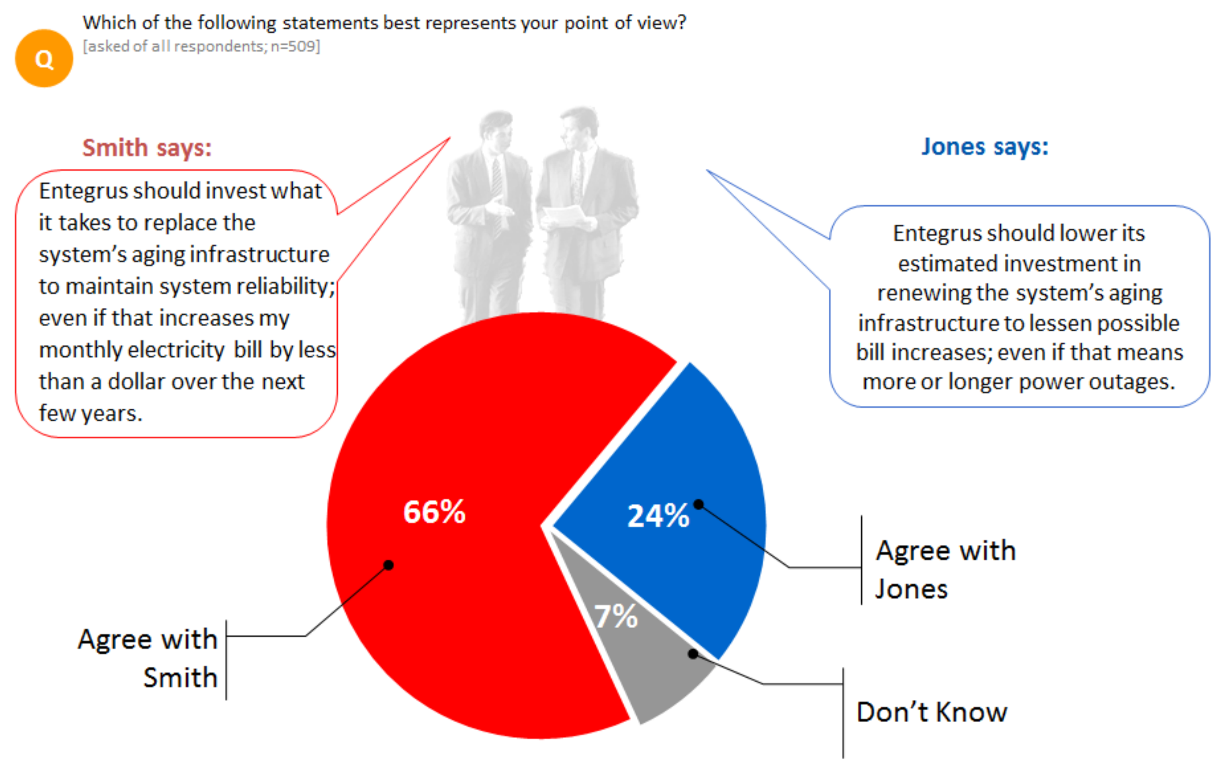
*Although this plan will allow **Entegrus** to make, what independent studies suggest are, the necessary investments needed to maintain system reliability, **<u>it may have an impact on customer bills</u>**."*

### *Investment in Aging Infrastructure*

Even if it means an increase to their monthly bill, two-thirds (66%) of residential customers feel that Entegrus should invest what it takes to replace the system's aging infrastructure. Conversely, one quarter (24%) feel that the estimated investment should be lower to lessen possible bill increases; even if that means more or longer power outages.

- Financially strained customers are significantly less likely to accept increases to their bills in order to maintain system reliability (60% versus 81% unstrained)
- High consumption level customers (58%) are least likely to support investing what it takes (70% low; 64% medium-low; 71% medium-high).

## Figure RS.9: Investment in Aging Infrastructure

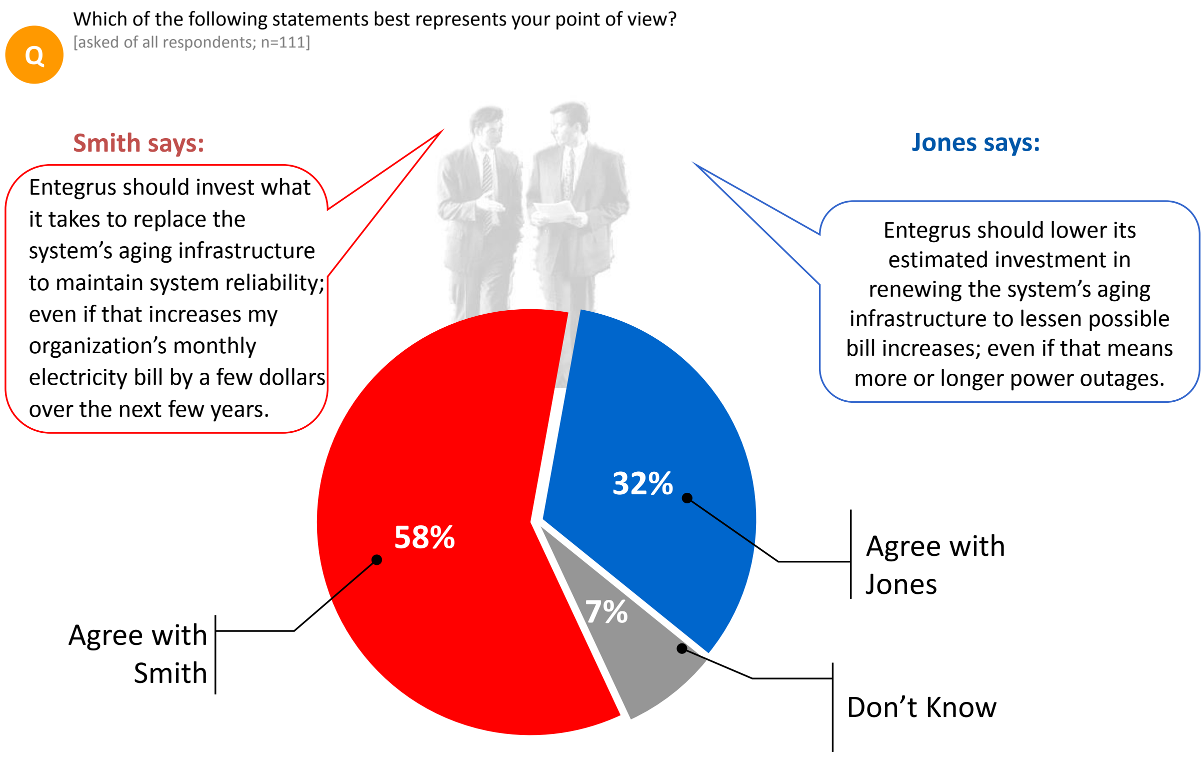



**Note:** Statements randomized. 'Refused' (4%) not shown.

The majority (58%) of general service customers also feel that Entegrus should invest what it takes to replace the system's aging infrastructure, while one third (32%) feel that the investment should be lowered.

- Less than half (43%) of low consumption level customers support investing to maintain reliability. This is a much smaller proportion than the other consumption level groups (63%medium-low; 57%medium high; 68% high).

### Figure GS.9: Investment in Aging Infrastructure




**Note:** Statements randomized. 'Refused' (3%) not shown.

### *Replacing Aging Infrastructure*

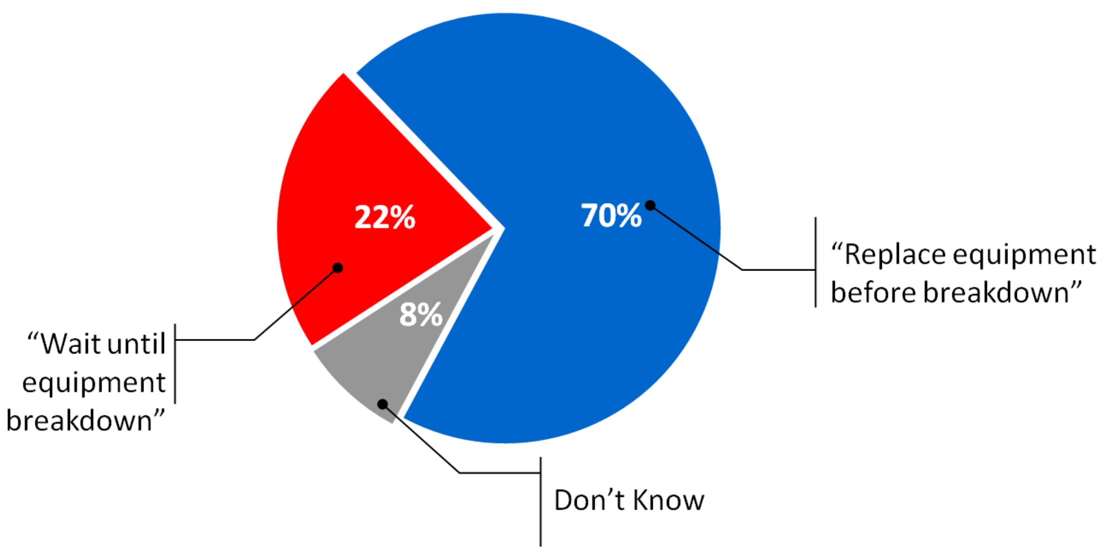
The next question addressed how Entegrus should manage its aging infrastructure, and introduced the run-to-failure approach. Customers were asked whether they would rather replace non-critical infrastructure before it breaks down, or wait until it does break down in order to get full value from each piece of equipment.

Seven-in-ten (70%) residential customers support the replacement of equipment before it breaks down. Financially strained customers are less likely to agree with this approach (66% versus 81% unstrained). Two-in-ten (22%) would rather wait until breakdown.

## Figure RS.10: Replacing Aging Infrastructure

Q Thinking about the aging equipment in Entegrus' distribution system, do you feel it's best to wait until non-critical infrastructure – that is, equipment that impacts a limited number of customers – breaks down to get full value from each piece of equipment, even if it means short power outages for some customers ...Or do you feel the best approach is to replace the equipment before it breaks down to avoid unscheduled power outages, even if it means not getting the "full" value from each piece of equipment?

[asked of all respondents; n=509]

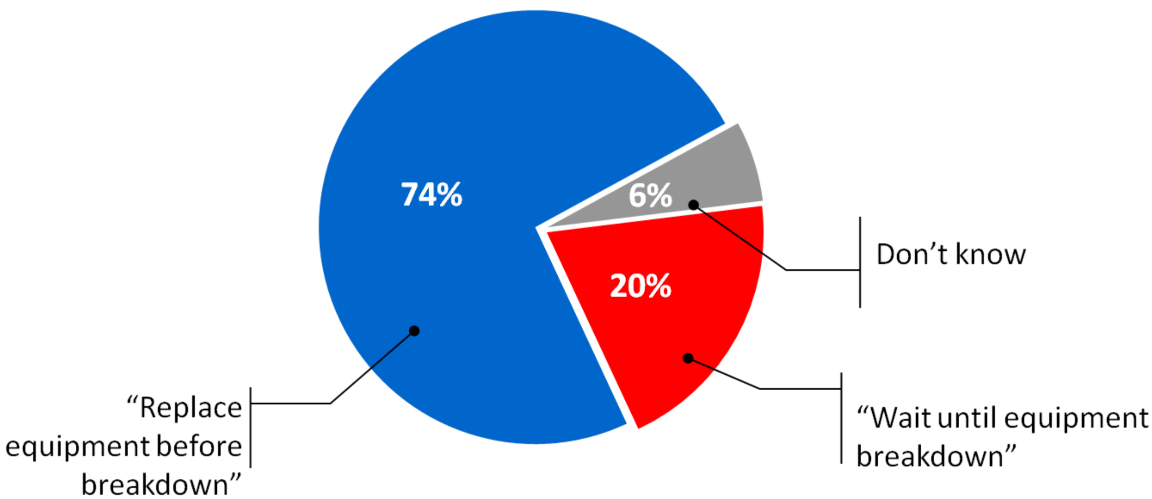


General service customers are slightly more in favour than residential customers of replacing infrastructure before it breaks down, with three-quarters (74%) in support of this approach. Like residential customers, organizations under financial strain are less likely to support this approach (71% versus 82% unstrained). One-in-five (20%) would prefer to wait until equipment breaks down.

## Figure GS.10: Replacing Aging Infrastructure

Q Thinking about the aging equipment in Entegrus' distribution system, do you feel it's best to wait until non-critical infrastructure – that is, equipment that impacts a limited number of customers – breaks down to get full value from each piece of equipment, even if it means short power outages for some customers ...Or do you feel the best approach is to replace the equipment before it breaks down to avoid unscheduled power outages, even if it means not getting the "full" value from each piece of equipment?

[asked of all respondents; n=111]



### *Investment in New Technologies and Infrastructure*

### *Preamble for Investment in New Technologies and Infrastructure*

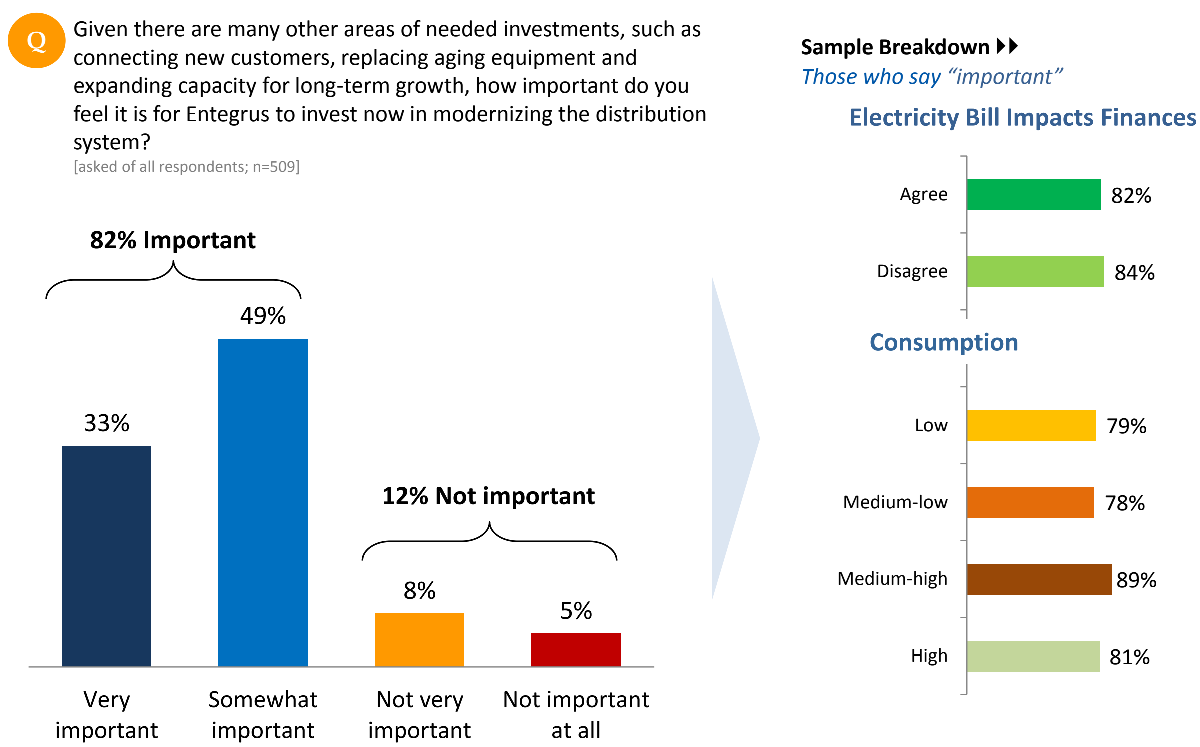
The following question included this brief preamble:

> *"Modernizing the distribution system can allow Entegrus to improve reliability. Investments, such as automated switches, may allow Entegrus to minimize the number of people impacted by outages and to restore electricity to many customers in a matter of seconds."*

Four-in-five (82%) residential customers feel that even though there are many other areas in need of investment, it is important to invest now in modernizing the grid. One third (33%) of customers feel that it is *very important* and half (49%) that it is *somewhat important*).

- There is no significant difference between any of the groups in terms of impact of electricity bill or consumption level.

## Figure RS.11: Investment in New Technologies and Infrastructure

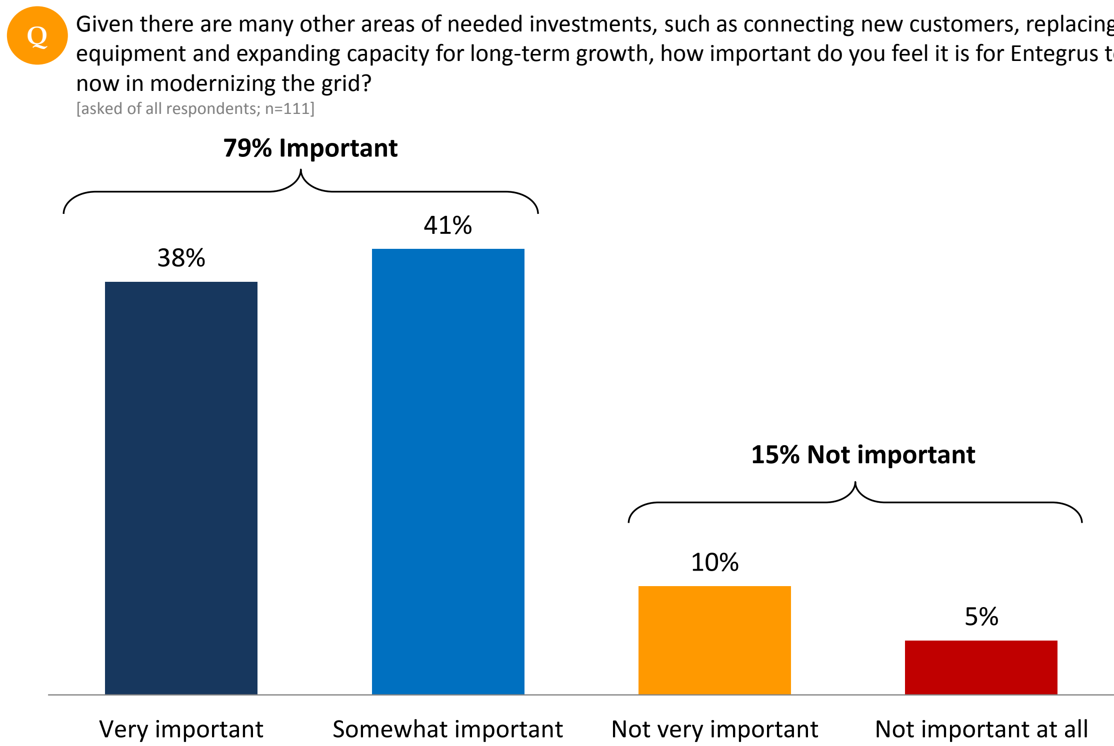



**Note:** 'Don't know' (5%) and 'Refused' (1%) not shown

General service customers also acknowledge the importance of investing now in modernizing the grid. Four-in-five (79%) feel as such, broken down into 38% who feel it is *very important* and two-in-five (41%) who feel it is *somewhat important*.

- Those whose organizations are financially impacted by their electricity bill are less likely to support this investment (76% versus 89% unstrained).

### Figure GS.11: Investment in New Technologies and Infrastructure




**Note:** 'Don't know' (5%) and 'Refused' (1%) not shown

### *Investment in Equipment and Tools*

### *Preamble for Investment in Equipment and Tools*

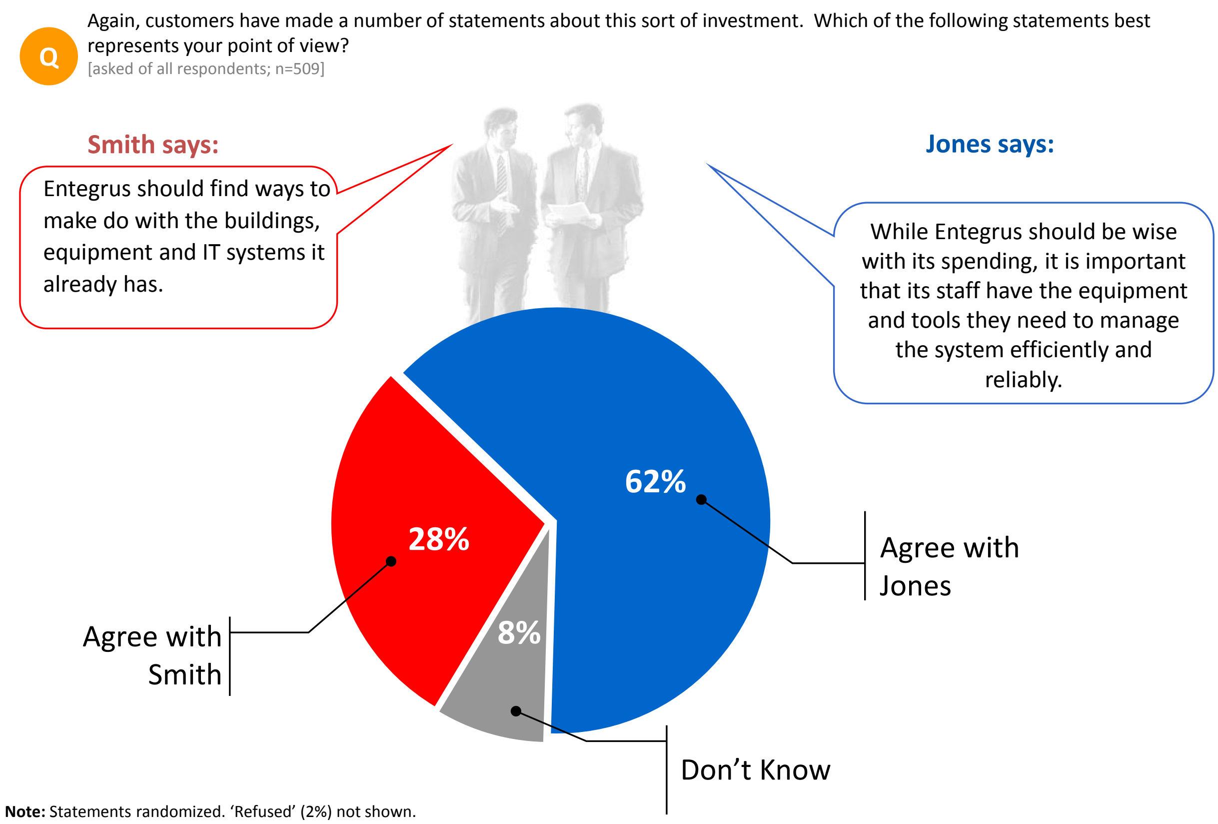
Before the survey question on investment in equipment and tools, this preamble was read:

| |
|---|
| *Entegrus is not just the local electricity distribution system itself, but a company that operates the system. As a company, Entegrus needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the electrical system and customer information.* |

The majority (62%) of residential customers feel that while Entegrus should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably. Conversely, three-in-ten (28%) feel that Entegrus should make do with the buildings, equipment and IT systems it already has.

- Residential customers who are financially strained are less likely to acknowledge the importance of Entegrus staff having the equipment and tools they need (58% versus 77% unstrained).

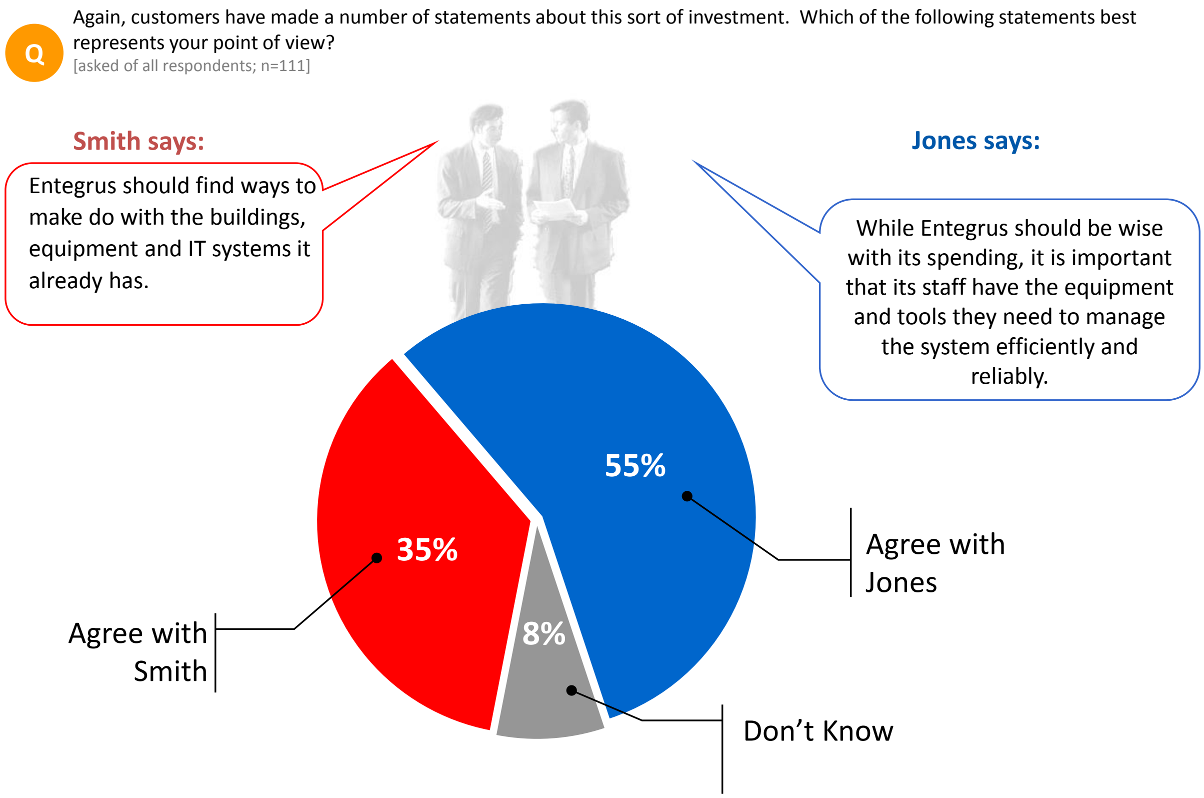
**Figure RS.12: Investment in Equipment and Tools**



While general service customers are in line with residential customers, a smaller majority (55%) feel that it's important to supply Entegrus staff with the equipment and tools they need to manage the system efficiently and reliably. Just over one third (35%) feel that Entegrus should make do with what it already has.

- Financially strained customers or more likely to feel Entegrus should make do with what it has (42% versus 11% unstrained).
- Low consumption level customers are much more likely to feel that Entegrus should make do with what it has (54% versus 30% medium-low; 22% medium-high; 36% high).

### Figure GS.12: Investment in Equipment and Tools




**Note:** Statements randomized. 'Refused' (2%) not shown.

## Reaction to Previous Customer Consultation Input

This section measures agreement with some of the key opinion statements provided by Entegrus customers in previous phases of the consultation. There were a total of nine customer statements in the survey.

### *Customer Reaction Statements*

Residential and general service customers held the same opinion in regards to the most and least agreed upon statements. The statement both groups are most likely to agree with was "Nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local electrical system for future generations" (RS:45% strongly agree, 42% somewhat agree; GS: 47% strongly agree, 33% somewhat agree).

The statement customers were least likely to agree with was "I'm/My organization is willing to pay a bit more for my electricity if it means better system reliability" (RS: 13% strongly agree, 32% somewhat agree; GS: 8% strongly agree, 37% somewhat agree).

### *Residential Customer Reaction*

Of the nine statements, three received more than 80% agreement.

- "Nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local electrical system for future generations" (45% strongly agree, 42% somewhat agree).
- "A few power outages are fine for me personally, but I worry about the impact this has on more vulnerable people, such as the elderly" (53% strongly agree, 32% somewhat agree).
- "I think Entegrus should do more to help customers find ways to reduce their electricity consumption and costs" (52% strongly agree, 32% somewhat agree).

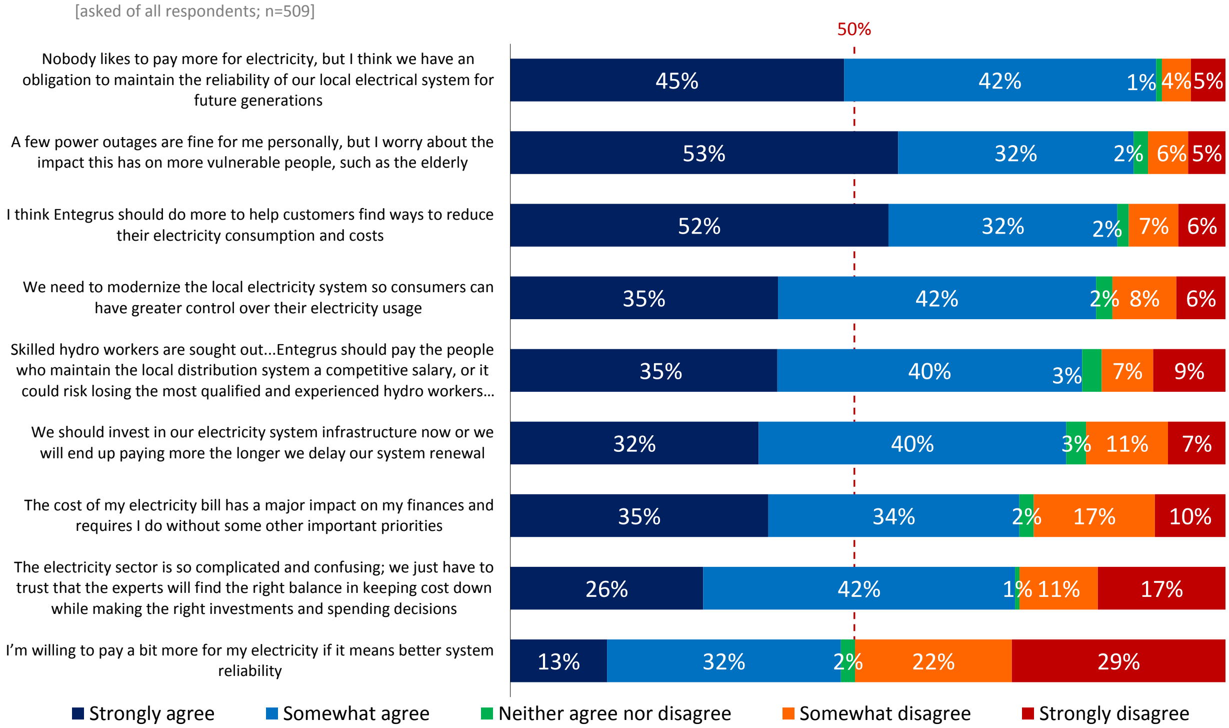
Only one statement received less than 50% agreement: "I'm willing to pay a bit more for my electricity if it means better system reliability" (13% strongly agree, 32%).

As noted in the Methodology section, this is the section that was used to determine financial flexibility by using the customer input statement "The cost of my electricity bill has a major impact on my finances and requires I do without some other priorities." In terms of agreement, the statement ranks seventh out of nine among residential customers, with 69% agreement (35% strongly agree, 34% somewhat agree).

## Figure RS.13: Reaction to Customer Input

Q The following statements have been made by customers throughout Entegrus' on-going rate application consultation process. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.

[asked of all respondents; n=509]



### *General Service Customer Reaction*

The most agreed upon statement has 80% agreement and reads "Nobody likes to pay more for electricity but I think we have an obligation to maintain the reliability of our local electricity system for future generations."

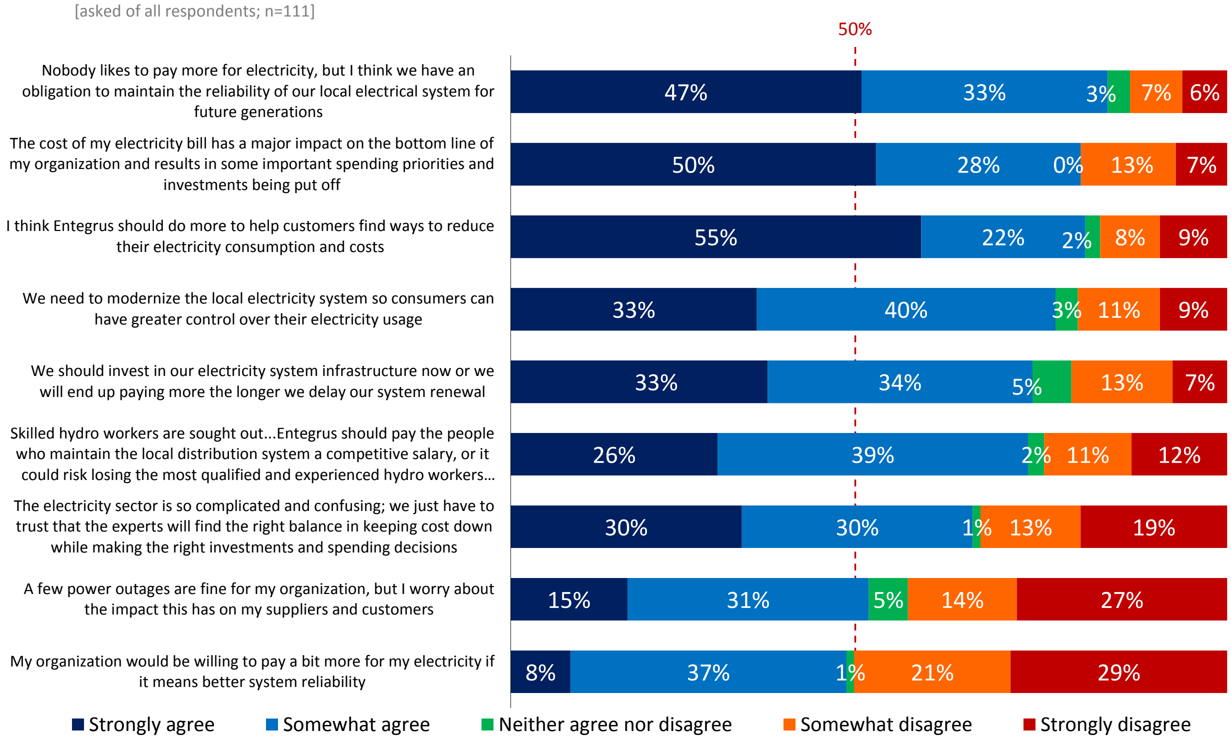
The statement that ranks second highest is also the statement used to determine financial flexibility and has 78% agreement: "The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off" (50% strongly agree, 28% somewhat agree).

Two of the input statements received less than 50% agreement.

- "A few power outages are fine for my organization, but I worry about the impact this has on my suppliers and customers" (15% strongly agree, 31% somewhat agree).
- "My organization would be willing to pay a bit more for my electricity if it means better system reliability" (8% strongly agree, 37% somewhat agree).

## Figure GS.13: Reaction to Customer Input

Q The following statements have been made by customers throughout Entegrus' on-going rate application consultation process. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked of all respondents; n=111]



## Assessment of Plan

In this next section, respondents were asked the extent to which they are prepared to accept the proposed estimated rate increase."Acceptance" refers to those who either think the rate impact is reasonable and support the increase, or who don't like the increase, but think it is necessary.

### *Acceptance of Rate Increase Summary*

Three-quarters of both residential (75%) and general service (74%) give social acceptance for the proposed rate increase.

- Support from residential customers is broken down into two-fifths (39%) who support the increase outright, and 36% who don't like it but acknowledge its necessity.
- General service customers show slightly less outright support (32%) and more reluctant support (42%).

### *Opinions on Proposed Rate Increase*

Residential customers most commonly cite the following reasons for holding each of the three opinions:

- *The rate increase is reasonable and I support it*: One third (34%) acknowledge that it is necessary to invest in the infrastructure.
- *I don't like it, but I think the rate increase is necessary:* 22% reluctantly acknowledge the necessity of investing in infrastructure.
- *The rate increase is unreasonable and I oppose it:* More than one quarter (28%) are opposed to the increase because they feel bills/rates are already too high.

The top mentions for general service customers are as follows:

- *The rate increase is reasonable and I support it*: Two-in-five (40%) feel that the rate increase is affordable and acceptable.
- *I don't like it, but I think the rate increase is necessary:* Almost one quarter (23%) acknowledge the necessity of investing in infrastructure.
- *The rate increase is unreasonable and I oppose it*: More than half (56%) feel that bills/rates are already too high.

### *Financial Flexibility and Level of Acceptance*

Those who are more financially impacted are less inclined to support the proposed increase.

- Seven-in-ten (70%) financially strained residential customers support the increase, compared to 88% of those unstrained.
- The vast majority of financially unstrained general service customers (87%) support the increase; while 71% of financially strained customers indicate support.

### *Preamble for Assessment of Plan Section*

Before the Assessment of Plan questions were asked, residential customers were presented with the following preamble:

*"**Entegrus** believes that proactive renewal and consistent maintenance is needed to maintain system performance, while keeping the impact on customer bills manageable over the long-term. Over its proposed 5 year plan, **Entegrus** will …*

- *spend an estimated **$48 million** on on-going maintenance and the operation of the distribution system; and*
- *invest an estimated **$39 million** in new equipment and infrastructure priorities that will help ensure system reliability.*

*To fund this proposed plan, the **average residential customer in Entegrus' service area will see their rates increase by approximately $0.52 per month** on the distribution portion of their bill over the next five years. So, by 2020, the average residential household will be paying an **estimated $2.58 more per month** on the distribution portion of its electricity bill, which is roughly the rate of inflation."*

*For GS customers, the previous paragraph was replaced with this one:*

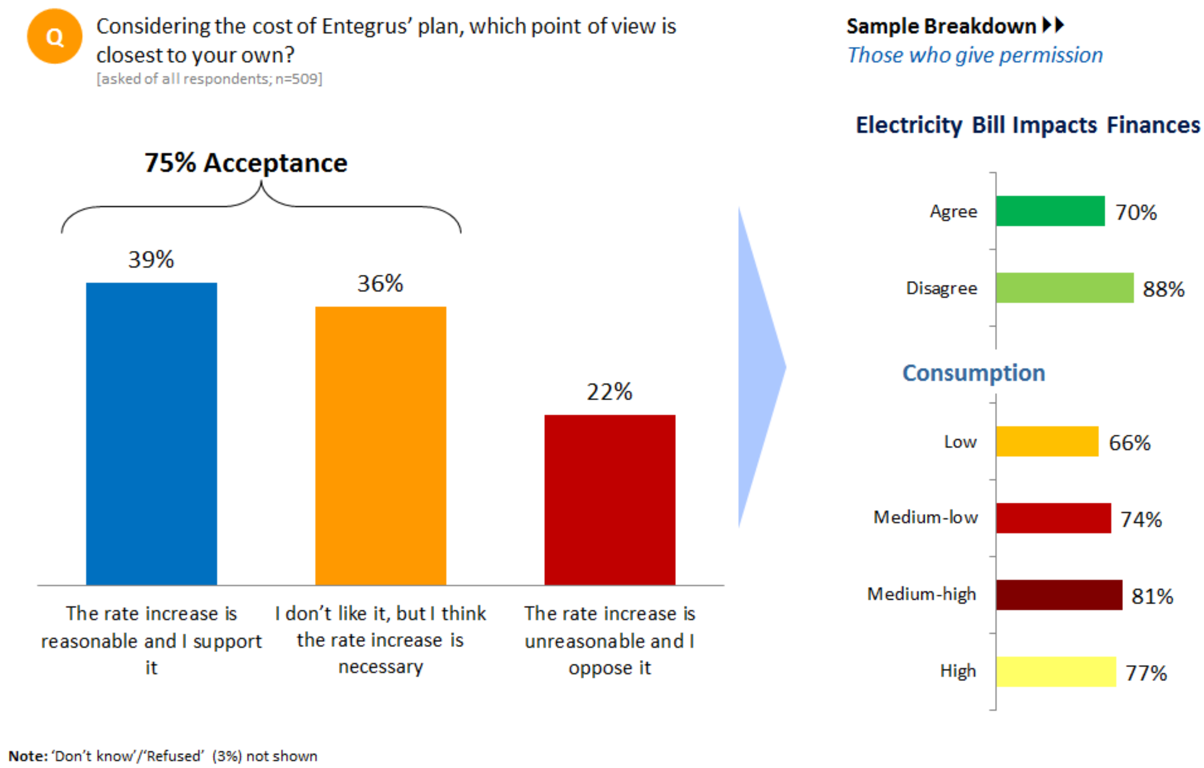
*"To fund this proposed plan, the **average small business customer in Entegrus' service area will see their rates increase by approximately $1.15 per month** on the distribution portion of their bill over the next five years. So, by 2020, the average small business customer will be paying an **estimated $5.76 more per month** on the distribution portion of their electricity bill, which is roughly the rate of inflation."*

### *Acceptance of Rate Increase*

With the above information in mind, three-quarters (75%) of residential customers are prepared to accept the estimated rate increase. Nearly two-in-five (39%) think it is a reasonable increase and slightly fewer (36%) "don't like it, but think it's necessary". Less than one quarter (22%) say the increase is unreasonable and oppose it.

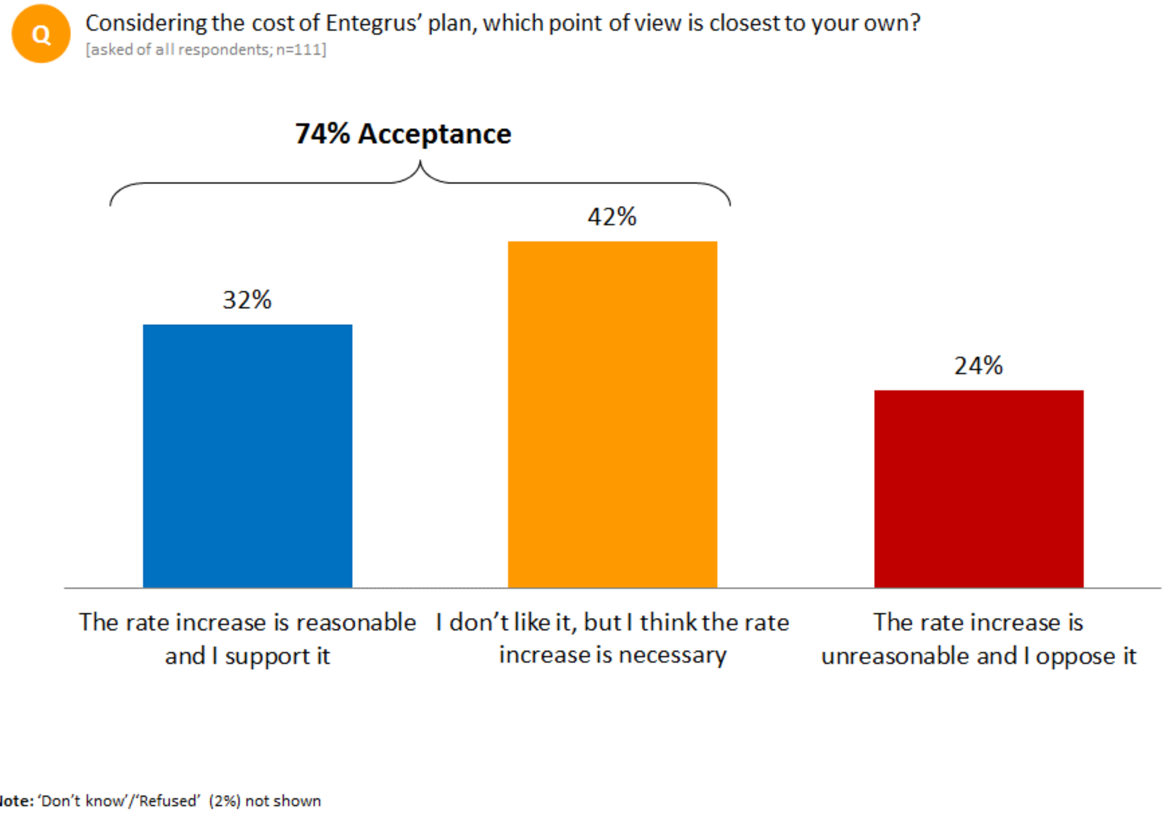
- Low consumption electricity users are the least likely to accept a rate increase (66% vs. 74%-81%).

## Figure RS.14 - Acceptance of Rate Increase



General service customers are equally likely to support the proposed increase (74%) with less than one quarter (24%) who would not accept a rate increase.

### Figure GS.14 - Acceptance of Rate Increase



### *Opinions on Proposed Rate Increase*

Residential customers who think the rate increase is reasonable mentioned the "need to invest in infrastructure" (34%), "increase is affordable" (24%) and "increases are inevitable" (16%) as the leading reasons for supporting the rate increase.

Almost one quarter (22%) of residential customers who don't like the increase, but think it's necessary cite the "need to invest in infrastructure" as their primary reason.

A plurality of residential customers who think the increase is unreasonable and oppose it do so because "their rates are already too high" (28%) and one-in-ten (11%) do so because it "always costs more than they say it will".

## Figure RS.15 – Opinion on Proposed Rate Increase

Q And why do you say that?

[asked of all respondents; n=509]

| PERMISSION: Reasonable, support it | % RS |
|---|---|
| Necessary/need to invest in infrastructure | 34% |
| Increase is reasonable/affordable | 24% |
| Increases are inevitable/prices rise/inflation | 16% |
| We need reliable/better service | 5% |
| Pay now to avoid high costs in future | 3% |
| Going to increase anyway/No choice | 3% |
| Other | 6% |
| None | 2% |
| Don't Know | 8% |
| **Sample Size** | **n=197** |

| NO PERMISSION: Unreasonable, oppose it | % RS |
|---|---|
| Bill/Rates already too high | 28% |
| Will cost more than they say/always more increases | 11% |
| Live on fixed/low income/can't afford | 9% |
| Due to financial mismanagement/should be more efficient | 9% |
| Should use profits/budget for upgrade | 6% |
| Don't trust/need more transparency | 5% |
| No one likes price increases | 4% |
| Going to increase anyway/No choice | 4% |
| Income does not increase | 4% |
| Customers shouldn't pay | 4% |
| Salaries/bonuses too high | 3% |
| Other | 5% |
| Don't Know | 9% |
| **Sample Size** | **n=114** |

| PERMISSION: Don't like, but necessary | % RS |
|---|---|
| Necessary/need to invest in infrastructure | 22% |
| No one likes price increases | 11% |
| Increases are inevitable/prices rise/inflation | 8% |
| Live on fixed/low income/can't afford | 7% |
| We need reliable/better service | 6% |
| Bill/Rates already too high | 5% |
| Income does not increase | 4% |
| Pay now to avoid high costs in future | 3% |
| Don't trust/need more transparency | 3% |
| Will cost more than they say/always more increases | 3% |
| Due to financial mismanagement/should be more efficient | 3% |
| Customers shouldn't pay | 2% |
| Should use profits/budget for upgrade | 2% |
| Other | 7% |
| None | 1% |
| Don't Know | 12% |
| **Sample Size** | **n=183** |

Of the 35 general service customers who think the rate increase is reasonable and support it, two-in-five (40%) do so because the increase is “affordable” and three-in-ten (31%) cite the “need to invest in infrastructure”.

Among the 47 General service customers who don’t like the increase, but think it’s necessary, about one quarter (23%) feel it’s “necessary to invest in infrastructure” or that “increases are inevitable” (23%).

And of the 27 business customers who feel the rate is unreasonable and don’t support it, more than half (56%) do so because they feel their “rates are already too high”.

## Figure GS.15 – Opinion on Proposed Rate Increase

Q **And why do you say that?**

[asked of all respondents; n=111]

| PERMISSION: Reasonable, support it | % RS |
|---|---|
| Increase is acceptable/affordable | 40% |
| Necessary/need to invest in infrastructure | 31% |
| Increases are inevitable/prices rise/inflation | 9% |
| Pay now to avoid high costs in future | 6% |
| Need more transparency/hidden charges | 6% |
| Other | 3% |
| Don't Know | 6% |
| **Sample Size** | **n=35** |

| NO PERMISSION: Unreasonable, oppose it | % RS |
|---|---|
| Bill/Rates already too high | 56% |
| Entegrus should manage their business better | 15% |
| No one likes price increases | 7% |
| Can't afford increase | 7% |
| Other | 11% |
| Don't Know | 4% |
| **Sample Size** | **n=27** |

| PERMISSION: Don’t like, but necessary | % RS |
|---|---|
| Necessary/need to invest in infrastructure | 23% |
| Increases are inevitable/prices rise/inflation | 23% |
| Entegrus should manage their business better | 13% |
| No one likes price increases | 11% |
| Bill/Rates already too high | 9% |
| Pay now to avoid high costs in future | 4% |
| Can't afford increase | 4% |
| Need more transparency/hidden charges? | 2% |
| Don't Know | 11% |
| **Sample Size** | **n=47** |

### *Financial Flexibility and Level of Acceptance*

It is expected that the proposed rate increase would have greater financial impact on some customers than others; specifically, the customers' level of acceptance for a rate increase could differ depending on their level of financial flexibility. Financial flexibility was captured in the customer input statements:

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

**General Service**: *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.*

Customers who agreed with the statement for their rate class were considered to be "financially strained."

Overall, acceptance is lower among residential customers from financially strained households than those who are not strained (70% versus 85%). Financially strained residential customers are almost three times more likely to oppose the rate increase than those who are not financially strained (27% versus 10%).

**Figure RS.16 - Financial Flexibility and Level of Acceptance**

| | Financially Strained Households | Not Financially Strained Households |
|---|---|---|
| The rate increase is reasonable and I support it | 29% | 65% |
| I don't like it, but I think the rate increase is necessary | 41% | 23% |
| The rate increase is unreasonable and I oppose it | 27% | 10% |
| **Overall Permission** | **70%** | **88%** |

**Note:** 'Don't know'/'Refused' not shown

With the understanding that these n-sizes are directional only, financially strained general service customers (n=86, 71%) were also less likely than more financially flexible customers (n=23, 87%) to accept the rate increase.

**Figure GS.16 - Financial Flexibility and Level of Acceptance**

| | Financially Strained Organizations | Not Financially Strained Organizations |
|---|---|---|
| The rate increase is reasonable and I support it | 28% | 45% |
| I don't like it, but I think the rate increase is necessary | 43% | 42% |
| The rate increase is unreasonable and I oppose it | 28% | 9% |
| Overall Permission | **71%** | **87%** |

**Note:** 'Don't know'/'Refused' not shown

## Rate Harmonization

In the final section, both residential and general service customers were asked to give their opinion on rate harmonization. General service customers were asked an additional "acceptance" question on the topic.

#### *Rate Harmonization Summary*

A strong majority of both residential (72%) and general service customers (69%) agree with the concept of rate harmonization. That is, that customers should pay the same rates for the same level of service.

In the follow-up question for general service customers only, more than three-in-five (61%) say they accept rate harmonization with one quarter (25%) who think it is unfair and oppose it.

### *Preamble for Rate Harmonization*

Before this last section of the survey instrument, the preamble below was read:

> *"As you may know, Entegrus is comprised of the former Chatham-Kent Hydro, Middlesex Power, Dutton Hydro and Newbury Power distribution systems. As a result, Entegrus currently has four sets of legacy distribution rates, which differ slightly between communities.*
>
> *Since the merger, Entegrus has invested millions of dollars in upgrades to standardize the entire system design to ensure greater efficiency and to ensure that all customers have similar levels of reliability. Entegrus now feels that all customers should pay the same rates for distribution services.*
>
> *While this rate harmonization is not expected to result in any increases to residential customer rates, it will effect some local businesses. Some businesses will see their rates come down slightly and others will see their rates go up slightly. This adjustment to rates will ensure all businesses are paying the same rate for the services they receive from Entegrus."*

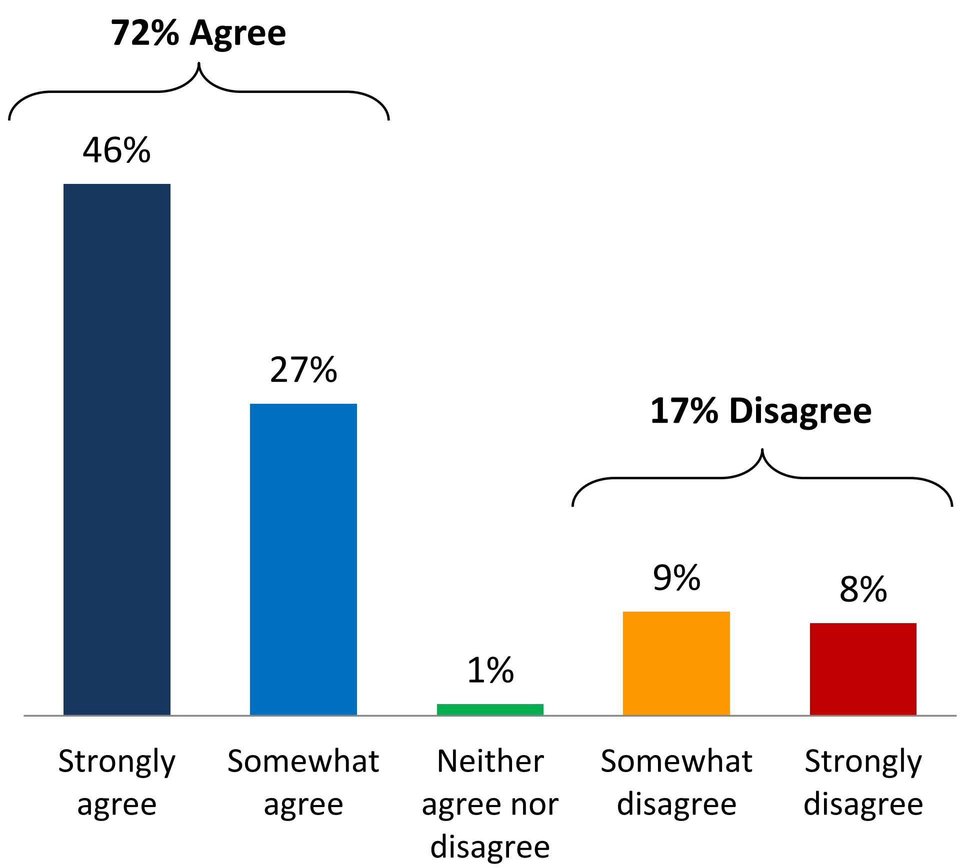
### *Acceptance of Rate Harmonization*

Nearly three-quarters (72%) of residential customers agree that all Entegrus customers should pay the same rates, regardless of geography or customer type. Just 17% of residential customers feel otherwise.

- Residential customers who think a rate increase is reasonable and support it (79%) are more likely to accept rate harmonization than those who oppose a rate increase (65%).

**Figure RS.17 – Opinions on Rate Harmonization**

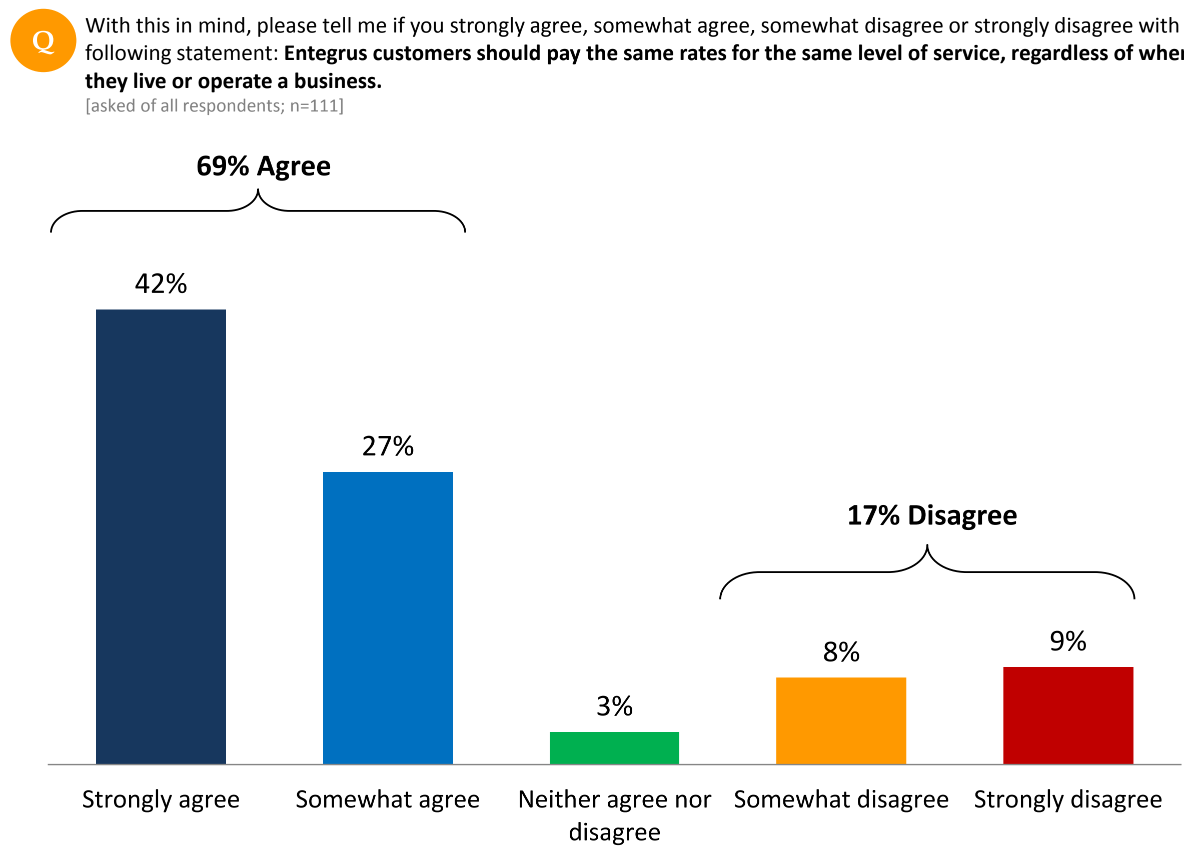
Q With this in mind, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree with the following statement: **Entegrus customers should pay the same rates for the same level of service, regardless of where they live or operate a business.**
[asked of all respondents; n=509]




**Note:** 'Don't know' (7%), 'Depends on whose rates are changed' (<1%) and 'Refused' (2%) not shown

Of the 111 general service respondents, almost seven-in-ten (69%) feel that all Entegrus customers should pay the same rate with less than two-in-ten (17%) who say the opposite.

### Figure GS.17 – Opinions on Rate Harmonization




**Note:** 'Don't know' (9%), 'Depends on whose rates are changed' (1%) and 'Refused' (1%) not shown

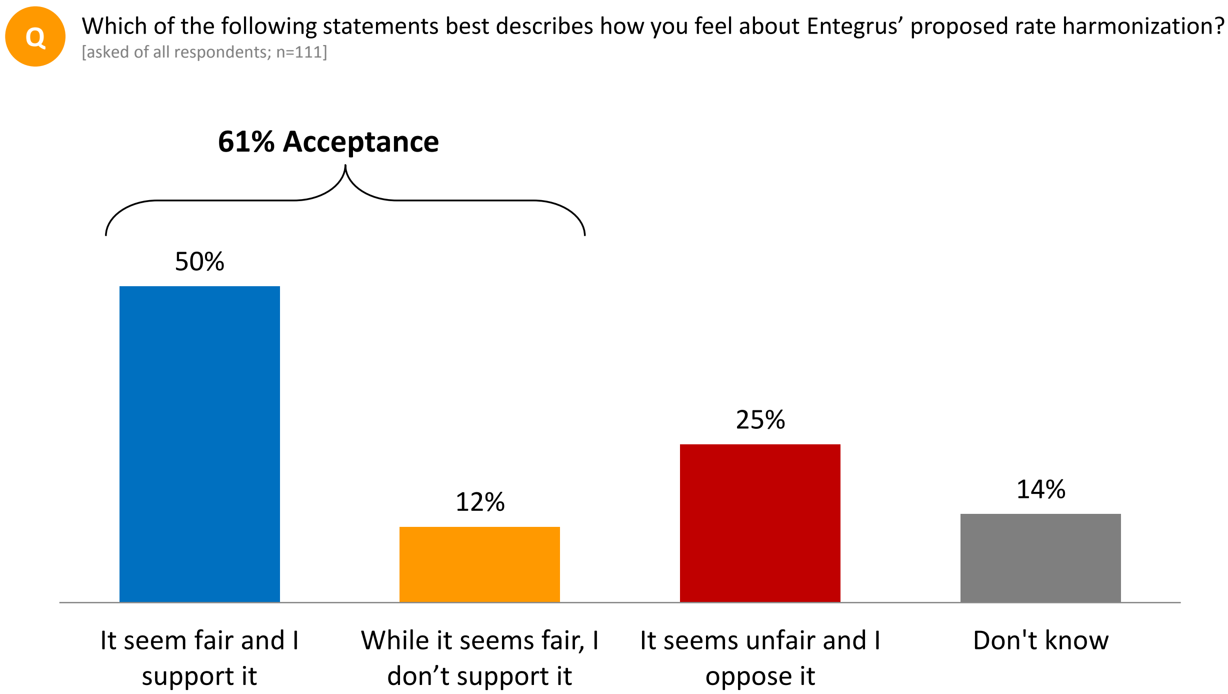
### *[GS Only] Permission for Rate Harmonization Preamble*

The final question, asked only of general service customers, includes this preamble:

> *If rate harmonization goes ahead, it is anticipated that the **average small business customer** in Chatham-Kent, Dutton and Newbury will see **no change** in their distribution rates, outside of the proposed rate application.*
>
> *However, it is anticipated that the **average small business customer** in Strathroy, Mount Brydges and Parkhill may see a one-time increase of approximately $20, on top of any increases related to Entegrus' rate application, as this group of customers currently pays a bit less than it costs to service them.*

A majority (61%) accept rate harmonization. One quarter (25%) think rate harmonization is unfair and oppose it and 14% don't know either way.

### *Figure GS.18 [GS Only] Permission for Rate Harmonization*



# Survey Instruments

## Residential Survey Instrument

## A. Introduction

Hello, my name is ______________ and I'm calling from **Innovative Research Group** on behalf of **Entegrus (pronounced: IN – TEG – RUS),** your electricity distributor.

Innovative Research Group is a national public opinion research firm. We have been commissioned by **Entegrus** to help them better understand the needs and preferences of customers who are responsible for paying their household's electricity bill.

**Entegrus** – which distributes electricity to homes and businesses in your community – is preparing to submit its 5-year investment plan to the Ontario Energy Board for regulatory review. Since this plan will impact your bill, Entegrus wants to hear from you, so your views can help shape its plan.

A1. Would you mind if I had **10 minutes** of your time to ask you some questions? All your responses will be kept strictly confidential.

| | | |
|---|---|---|
| Yes | 1 | **[continue]** |
| No – Not primary bill payer | 2 | **[go to TRANSFER-1]** |
| No – BAD TIME | 3 | **ARRANGE CALLBACK** |
| No – HARD REFUSAL | 4 | **[Terminate]** |

MONIT

This call may be monitored or audio taped for quality control and evaluation purposes.

PRESS TO CONTINUE 1

A2. Have I reached you at your home phone number?

| | | |
|---|---|---|
| Yes – SPEAKING, CONTINUE | 1 | [**continue to A3**] |
| No – AT OFFICE or WORKPLACE | 2 | [**continue to A3**] |
| No – on cellular or mobile phone | 3 | **[skip to CELL]** |
| Refused – LOG (Thank and Terminate) | 99 | **[Terminate]** |

**CELL.** Are you currently operating a car, truck or other motor vehicle?

| | | |
|---|---|---|
| YES (**INTERVIEWER: SCHEDULE CALLBACK**) | 1 | **ARRANGE CALLBACK** |
| NO | 2 | **[continue to A3]** |
| Refused – LOG (Thank and Terminate) | 99 | **[Terminate]** |

A3. Are you the person primarily responsible for paying the electricity bill in your household?

| | | |
|---|---|---|
| Yes – I pay the bill | 1 | [continue to A4] |
| Yes – shared responsibility | 2 | [continue to A4] |
| No | 3 | [go to TRANSFER-1] |
| Don't know (**DNR**) | 98 | **[Terminate]** |

**TRANSFER-1**

Can I speak with the person in your household who usually pays the electricity bill?

| | | |
|---|---|---|
| Yes | 1 | [**BACK TO** *INTRO* ] |
| No – NOT AVAILABLE/BAD TIME – (ARRANGE CALLBACK) | 2 | [ARRANGE CALLBACK] |
| No – HARD REFUSAL | 3 | [**Terminate**] |
| Don't know (**DNR**) | 98 | [**Terminate**] |

A4. And can you confirm that your household receives an electricity bill from Entegrus?

| | | |
|---|---|---|
| Yes | 1 | **[continue]** |
| No | 2 | **[Terminate]** |
| Don't know (**DNR**) | 98 | **[Terminate]** |

**GENDER** Note gender by observation:

| | |
|---|---|
| Male | 1 |
| Female | 2 |

# B. General Satisfaction

**These questions are designed to focus respondents thinking on the parts of the electricity system that Entegrus operates.**

B5. PREAMBLE-1

To start, I'd like to ask you a few questions about the electricity system …

As you may know, Ontario's electricity system has three key components: **generation, transmission and distribution.**

- **Generating stations** convert various forms of energy into electric power;
- **Transmission lines** connect the power produced at generating stations to where it is needed across the province; and
- **Distribution lines** carry electricity to the homes and businesses in our communities.

Today we're going to talk about your **local distribution system** which, in your community, is maintained and operated by **Entegrus.**

B6. How familiar are you with **the local electricity distribution system**? Would you say … [READ LIST]

| | |
|---|---|
| Very familiar | 1 |
| Somewhat familiar | 2 |
| Not very familiar | 3 |
| Not familiar at all | 4 |
| Don't know (**DNR**) | 98 |
| Refused (**DNR**) | 99 |

B7. Generally speaking, how satisfied are you with the job **Entegrus** is doing running your local distribution system? Would you say … [**READ LIST**]

| | |
|---|---|
| Very satisfied | 1 |
| Somewhat satisfied | 2 |
| Somewhat dissatisfied | 3 |
| Very dissatisfied | 4 |
| Don't know (**DNR**) | 98 |
| Refused (**DNR**) | 99 |

B8. Is there anything in particular **Entegrus** can do to improve its service to you? [**OPEN**]

| | |
|---|---|
| Don't know (**DNR**) | 98 |
| Refused (**DNR**) | 99 |

## C. Bill Knowledge & Impact

I'd now like to talk with you about your electricity bill …

C9. While some customers pay more and others pay less, the **average residential customer pays about $140 a month** for electricity of **which $29 to $36 or approximately 20% goes to Entegrus**. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

Before this survey, how familiar were you with the amount of your electricity bill that went to **Entegrus**? Would you say … [READ LIST]

| | |
|---|---|
| Very familiar | 1 |
| Somewhat familiar | 2 |
| Not very familiar | 3 |
| Not familiar | 4 |
| Don't know (**DNR**) | 98 |
| Refused (**DNR**) | 99 |

## D. System Reliability

**These questions are designed to get the respondent to think about their experience with system reliability.**

**READ PREAMABLE**: Despite best efforts, no electrical distribution system can deliver perfectly reliable electricity. As a general rule, the more reliable the system, the more expensive the system is to build and maintain.

With that said, the average **Entegrus** customer experiences **one** unexpected power outage per year.

D10. Have you experienced any power outages **in the past 12 months**, and if so, approximately how many? [DO NOT READ LIST]

| | | |
|---|---|---|
| No outages | 0 | [SKIP to D15] |
| 1 outage | 1 | [CONTINUE] |
| 2 outages | 2 | [CONTINUE] |
| 3 outages | 3 | [CONTINUE] |
| 4 outages | 4 | [CONTINUE] |
| 5 outages | 5 | [CONTINUE] |
| 6 outages | 6 | [CONTINUE] |
| 7 outages | 7 | [CONTINUE] |
| 8 or more outages | 8 | [CONTINUE] |
| Don't know (**DNR**) | 98 | [SKIP to D15] |
| Refused (**DNR**) | 99 | [SKIP to D15] |

**READ ONLY IF D10 = 1 thru 8**

D11. And approximately how many minutes did the most recent power outage last? [DO NOT READ LIST; select category accordingly]

| | |
|---|---|
| Less than 15 minutes | 1 |
| 15 to less than 30 minutes | 2 [specify "if less than 15 minutes", if respondent states "less than 30 minutes"] |
| 30 minutes to less than 1 hour | 3 |
| 1 hour to less than 3 hours | 4 |
| 3 hours to less than 6 hours | 5 |
| 6 hours to less than 12 hours | 6 |
| 12 to less than 24 hours | 7 |
| More than 24 hours | 8 |
| Don't know (**DNR**) | 98 |
| Refused (**DNR**) | 99 |

D12. Thinking back to the **most recent** power outage you experienced as a **Entegrus** customer, would you say the power outage ...
**[READ LIST; ROTATE 1 and 3]**

| | |
|---|---|
| Was a major inconvenience | 1 |
| Was a minor inconvenience | 2 |
| Was no inconvenience at all | 3 |
| Have never experienced an outage with Entegrus (**DNR**) | 97 |
| Don't know (**DNR**) | 98 |
| Refused (**DNR**) | 99 |

D13. In your view, how do you think **Entegrus** should address the **number** of customer power outages? Would you say ... **[READ LIST]**

**[Rotate response codes 1 and 3]**

| | |
|---|---|
| Spend what is needed to **reduce** the number of unexpected power outages | 1 |
| Spend what is needed to **maintain** the current level of unexpected power outages | 2 |
| Accept **more** power outages in order to help keep customer costs from rising | 3 |
| Don't Know (**DNR**) | 98 |
| Refused (**DNR**) | 99 |

D14. Overall, the average **Entegrus** customer is without power for about **one hour per year**.

In your view, how do you think **Entegrus** should address the **length of time** customers are without power? Would you say ... **[READ LIST]**

**[Rotate response codes 1 and 3]**

| | |
|---|---|
| Spend what is needed to reduce the length of unexpected power outages | 1 |
| Spend what is needed to maintain the current length of unexpected outages | 2 |
| Accept longer time without power in order to help minimize customer costs from rising | 3 |
| Don't Know (**DNR**) | 98 |
| Refused (**DNR**) | 99 |

# E. System Challenges & Priorities

## System Renewal Question

E15. [PREAMBLE to E16] While **Entegrus** believes it has done its best to prolong the life of the assets that make up the distribution system, many of these assets are approaching the end of their useful life.

As part of its investment plan, **Entegrus** is proposing an infrastructure renewal program. The estimated cost of this system renewal program is **$22 million** between 2016 and 2020.

Although this plan will allow **Entegrus** to make, what independent studies suggest are, the necessary investments needed to maintain system reliability, **it *may* have an impact on customer bills.**

E16. Which of the following statements best represents your point of view?
**[Read and Rotate statements 1 and 2]**
Some customers have said …

Entegrus should invest what it takes to replace the system's aging infrastructure to maintain system reliability; even if that increases my monthly electricity bill by less than a dollar over the next few years. 1

Others have said …

Entegrus should lower its estimated investment in renewing the system's aging infrastructure to lessen possible bill increases; even if that means more or longer power outages. 2

Don't know (**DNR**) 98

Refused (**DNR**) 99

## Run-to-Failure Question

E17. Thinking about the aging equipment in Entegrus' distribution system, do you feel it's best to wait until non-critical infrastructure – that is, equipment that impacts a limited number of customers – breaks down to get full value from each piece of equipment, even if it means short power outages for some customers …

… Or do you feel the best approach is to replace the equipment before it breaks down to avoid unscheduled power outages, even if it means not getting the "full" value from each piece of equipment?
[DO NOT READ LIST; unless respondents needs prompt]

| | |
|---|---|
| Wait until equipment breakdown | 1 |
| Replace equipment before breakdown | 2 |
| Don't know (**DNR**) | 98 |
| Refused (**DNR**) | 99 |

## System Service Questions

[PREAMBLE FOR E18] Modernizing the distribution system can allow Entegrus to improve reliability. Investments, such as automated switches, may allow Entegrus to minimize the number of people impacted by outages and to restore electricity to many customers in a matter of seconds.

E18. Given there are many other areas of needed investments, such as connecting new customers, replacing aging equipment and expanding capacity for long-term growth, how important do you feel it is for Entegrus to invest now in modernizing the distribution system?

| | |
|---|---|
| Very important | 1 |
| Somewhat important | 2 |
| Not very important | 3 |
| Not important at all | 4 |
| Don't know (**DNR**) | 98 |
| Refused (**DNR**) | 99 |

## General Plant Questions

E19. Entegrus is not just the local electricity distribution system itself, but a company that operates the system. As a company, Entegrus needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the electrical system and customer information.

Again, customers have made a number of statements about this sort of investment. Which of the following statements best represents your point of view?
**[Read and Rotate statements 1 and 2]**

Some customers have said ...

Entegrus should find ways to make do with the buildings, equipment and IT systems it already has. 1

Others have said ...

While Entegrus should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably. 2

| | |
|---|---|
| Don't know (**DNR**) | 98 |
| Refused (**DNR**) | 99 |

# F. Reaction to Customer Input

**Below are the common themes that have arisen in qualitative customer consultations.**

The following statements have been made by customers throughout **Entegrus'** on-going rate application consultation process.

For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.

| | |
|---|---|
| Strongly agree | 1 |
| Somewhat agree | 2 |
| Neither agree nor disagree (**DNR**) | 3 |
| Somewhat disagree | 4 |
| Strongly disagree | 5 |
| Don't Know (**DNR**) | 98 |
| Refused (**DNR**) | 99 |

**RANDOMIZE QUESTIONS**

## Willingness / Ability to Pay

F20. The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.

F21. I'm willing to pay a bit more for my electricity if it means better system reliability.

## Pay Now or Later

F22. We should invest in our electricity system infrastructure **now** or we will end up paying more the longer we delay our system renewal.

## Deferring to the Experts

F23. The electricity sector is so complicated and confusing; we just have to trust that the experts will find the right balance in keeping cost down while making the right investments and spending decisions.

## CDM

F24. I think **Entegrus** should do more to help customers find ways to reduce their electricity consumption and costs.

## Legacy

F25. Nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local electrical system for future generations.

## Modernizing the Grid

F26. We need to modernize the local electricity system so consumers can have greater control over their electricity usage.

## System Reliability

F27. A few power outages are fine for me personally, but I worry about the impact this has on more vulnerable people, such as the elderly.

## Labour Costs

F28. Skilled hydro workers are sought out across North America and Ontario. **Entegrus** should pay the people who maintain the local distribution system a competitive salary, or it could risk losing the most qualified and experienced hydro workers to other utilities.

## G. Assessment of Plan

G29. PREAMBLE

**Entegrus** believes that proactive renewal and consistent maintenance is needed to maintain system performance, while keeping the impact on customer bills manageable over the long-term. Over its proposed 5 year plan, **Entegrus** will …

- spend an estimated **$48 million** on on-going maintenance and the operation of the distribution system; and
- invest an estimated **$39 million** in new equipment and infrastructure priorities that will help ensure system reliability.

To fund this proposed plan, the **average residential customer in Entegrus' service area will see their rates increase by approximately $0.52 per month** on the distribution portion of their bill over the next five years. So, by 2020, the average residential household will be paying an estimated **$2.58 more per month** on the distribution portion of its electricity bill, which is roughly the rate of inflation.

G30. Considering the cost of Entegrus' plan, would you say [READ LIST] …
**Rotate response codes "1 "and "3"**

| | |
|---|---|
| The rate increase is reasonable and I support it | 1 |
| I don't like it, but I think the rate increase is necessary | 2 |
| The rate increase is unreasonable and I oppose it | 3 |
| Don't know (**DNR**) | 98 |
| Refused (**DNR**) | 99 |

**Ask only if G30 = 1, 2 or 3**

G31. And why do you say that? [OPEN]

| | |
|---|---|
| Don't know (**DNR**) | 98 |
| Refused (**DNR**) | 99 |

## Rate Harmonization

G32. [PREAMBLE TO G33] As you may know, Entegrus is comprised of the former Chatham-Kent ("Cha-Tum-Kent") Hydro, Middlesex Power, Dutton Hydro and Newbury Power distribution systems. As a result, Entegrus currently has four sets of legacy distribution rates, which differ slightly between communities.

Since the merger, Entegrus has invested millions of dollars in upgrades to standardize the entire system design to ensure greater efficiency and to ensure that all customers have similar levels of reliability. Entegrus now feels that all customers should pay the same rates for distribution services.

While this rate harmonization is not expected to result in any increases to residential customer rates, it will effect some local businesses. Some businesses will see their rates come down slightly and others will see their rates go up slightly. This adjustment to rates will ensure all businesses are paying the same rate for the services they receive from Entegrus.

G33. With this in mind, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree with the following statement:
***Entegrus customers should pay the same rates for the same level of service, regardless of where they live or operate a business.***

| | |
|---|---|
| Strongly agree | 1 |
| Somewhat agree | 2 |
| Neither agree nor disagree (**DNR**) | 3 |
| Somewhat disagree | 4 |
| Strongly disagree | 5 |
| Depends on whose rates are change (**DNR**) | 97 |
| Don't know (**DNR**) | 98 |
| Refused (**DNR**) | 99 |

# H. Segmentation

These last few questions are for statistical purposes only and we remind you again that all of your responses are completely confidential.

H34. In which year were you born? **[Enter YEAR]**

**INTERVIEWER NOTE: if REFUSE; ask "AGE".**

**AGE**: Can you tell me what age category do you fall into? [**READ LIST**]

| | |
|---|---|
| Younger than 34 | 1 |
| 35 to 54 | 2 |
| 55 years or older | 3 |
| Refused (**DNR**) | 99 |

H35. Do you own or rent your home? **[Do not read list]**

Own 1

Rent 2

Refused (**DNR**) 99

H36. Counting yourself, how many people live in your household? **[Do not read list]**

1 person 1

Enter number of people 2---7

8 or more 8

Refused (**DNR**) 99

**Q15IN**. Is your total annual HOUSEHOLD INCOME, before tax, under or over $60,000?

| | | |
|---|---|---|
| UNDER $60,000 | 1 | **(CONTINUE)** |
| OVER $60,000 | 2 | => Q15B |
| REFUSE **(DO NOT OFFER)** | 9 | => skip END |

READ LIST

**Q15A.** And would that be...?

| | | |
|---|---|---|
| Under $20,000 | 01 | => skip to END |
| $20,000 to under $40,000 | 02 | => skip to END |
| $40,000 to under $60,000 | 03 | => skip to END |
| UNDER $60,000 UNSPECIFIED (**DO NOT READ**) | 04 | => skip to END |
| REFUSE (**DO NOT READ**) | 99 | => skip to END |

**Q15B**. And would that be...?

| | |
|---|---|
| $60,000 to under $80,000 | 05 |
| $80,000 to under $100,000 | 06 |
| $100,000 to under $120,000 | 07 |
| $120,000 to under $140,000 | 08 |
| $140,000 or more | 09 |
| OVER $60,000 UNSPECIFIED (**DO NOT READ**) | 10 |
| REFUSE **(DO NOT READ)** | 999 |

## THANK and END SURVEY

Thank you very much for taking the time to complete this survey.

## General Service Survey Instrument

# Introduction

Hello, my name is ______________ and I'm calling from **Innovative Research Group** on behalf of **Entegrus**, your local electricity distributor.

Innovative Research Group is a national public opinion research firm. We have been commissioned by **Entegrus** to help them better understand the needs and preferences of its customers.

Can I please speak to the person who is in-charge of managing the electricity bill at your organization?

1) Yes, speaking **<contact on the line>** **[skip to A1]**

2) Yes **<transferred to contact>** **[skip to A1]**

3) No **<not the right contact person>** **[GO to "NEW"]**

4) No **<busy>** "When is a good time to callback?" **[record callback time ]**

5) Maybe **<may I ask who is calling**?> **[skip to GATE]**

**NEW**. And … can I have their …

First Name ___________

Last Name ___________

Title/Position _________

Phone Number _________

**ASK to be transferred …**

**if transferred → go to A1**

**if not transferred → Thank & Add to Callback List**

---

**GATE.** My name is _________ and I'm calling on behalf of your local electricity distributor, **Entegrus**. **INTERVIEWER NOTE: If gatekeeper asks the purpose of call** → I'd like to ask the person in-charge of managing the electricity bill at your organization a few questions concerning a **Entegrus** customer consultation.

1) Yes <**transferred to contact**> **[skip to A1]**

2) No <**not available**> "When is a good time to callback? **[record callback time and GO to "NEW"]**

3) No **<not interested in talking>** **[Thank & Terminate]**

**A1 QUAL PREAMBLE:**

**Read preamable again, if transferred to new person:**

Hello, my name is _________ and I'm calling from **Innovative Research Group**, a national public opinion research firm. We have been hired by **Entegrus** to help them better understand the needs and preferences of their customers.

IF INTRO = 1, read:

**Entegrus** – which distributes electricity to residential and business customers in your community – is preparing to submit its investment and spending plan to the Ontario Energy Board for regulatory review. Since this plan will impact your bill, **Entegrus** wants to hear from you, so your views can help shape its plan.

A1. Would you mind if I had ten minutes of your time to ask you some questions? All your responses will be kept strictly confidential.

| | | |
|---|---|---|
| Yes | 1 | **[continue]** |
| No – Not primary bill payer | 2 | **[go to TRANSFER-1]** |
| No – BAD TIME | 3 | **ARRANGE CALLBACK** |
| No – HARD REFUSAL | 4 | **[Terminate]** |

MONIT: This call may be monitored or audio taped for quality control and evaluation purposes.

PRESS TO CONTINUE 1

A2. Just to confirm, does your organization receive an electricity bill from Entegrus?

| | | | |
|---|---|---|---|
| 01 | YES | 1 | **[continue]** |
| 02 | NO | 2 | **[Terminate]** |
| 98 | DK (DO NOT READ) | 98 | **[Terminate]** |

A3. As part of your job, are you in-charge of managing or overseeing your organization's electricity bill?

| | | |
|---|---|---|
| Yes | 1 | [**Continue to B4**] |
| No | 2 | CAN I SPEAK TO THE PERSON WHO MANAGES YOUR ORGANIZATION'S ELECTRICITY BILL? [**Return to NEW]** |
| DK | 3 | CAN I SPEAK TO THE PERSON WHO MANAGES YOUR ORGANIZATION'S ELECTRICITY BILL? [**Return to NEW**] |

A4. **READ STATEMENT TO RESPONDENT:** While you may be an Entegrus residential customer, for the following questions I'd like you to answer from the perspective of the business or organization that you represent. While we are currently surveying residential customers, you have been randomly selected from a limited sample of small business and non-residential customers and it's important we understand the unique needs and preferences of this group of customers. **So again, please answer the following questions from the perspective of your business or organization's needs and preferences**.

# B. General Satisfaction

B5. PREAMBLE-1

To start, I'd like to ask you a few questions about the electricity system …

As you may know, Ontario's electricity system has three key components: **generation, transmission** and **distribution.**

- **Generating stations** convert various forms of energy into electric power;
- **Transmission lines** connect the power produced at generating stations to where it is needed across the province; and
- **Distribution lines** carry electricity to the homes and businesses in our communities.

Today we're going to talk about your **local distribution system** which, in your community, is maintained and operated by **Entegrus**.

B6. How familiar are you with the **local electricity distribution system**?
Would you say … [READ LIST]

| | |
|---|---|
| Very familiar | 1 |
| Somewhat familiar | 2 |
| Not very familiar | 3 |
| Not familiar at all | 4 |
| Don't know **(DNR)** | 98 |
| Refused **(DNR)** | 99 |

B7. Generally speaking, how satisfied are you with the job Entegrus is doing running your local distribution system? Would you say … [READ LIST]

| | |
|---|---|
| Very satisfied | 1 |
| Somewhat satisfied | 2 |
| Somewhat dissatisfied | 3 |
| Very dissatisfied | 4 |
| Don't know (**DNR**) | 98 |
| Refused (**DNR**) | 99 |

B8. Is there anything in particular Entegrus can do to improve its service to **your organization**?
[OPEN]

| | |
|---|---|
| Don't know (**DNR**) | 98 |
| Refused (**DNR**) | 99 |

# C. Bill Knowledge & Impact

I'd now like to talk with you about your electricity bill …

C9. While some customers pay more and others pay less, the **average small business or general service customer pays about $340 a month** for electricity of **which $45 to $78 or approximately 20% goes to Entegrus.** The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

Before this survey, how familiar were you with the amount of your electricity bill that went to **Entegrus**? Would you say … [READ LIST]

| | |
|---|---|
| Very familiar | 1 |
| Somewhat familiar | 2 |
| Not very familiar | 3 |
| Not familiar | 4 |
| Don't know (**DNR**) | 98 |
| Refused (**DNR**) | 99 |

# D. System Reliability

READ PREAMABLE: Despite best efforts, no electrical distribution system can deliver *perfectly reliable* electricity. As a general rule, the more reliable the system, the more expensive the system is to build and maintain.

With that said, the average **Entegrus** customer experiences **one** unexpected power outage per year.

D10. Has **your organization** experienced any power outages in the past 12 months, and if so, approximately how many? [**DO NOT READ LIST**]

| | | |
|---|---|---|
| No outages | 0 | [**SKIP to D15**] |
| 1 outage | 1 | [CONTINUE] |
| 2 outages | 2 | [CONTINUE] |
| 3 outages | 3 | [CONTINUE] |
| 4 outages | 4 | [CONTINUE] |
| 5 outages | 5 | [CONTINUE] |
| 6 outages | 6 | [CONTINUE] |
| 7 outages | 7 | [CONTINUE] |
| 8 or more outages | 8 | [CONTINUE] |
| Don't know (**DNR**) | 98 | [**SKIP to D15**] |
| Refused (**DNR**) | 99 | [**SKIP to D15**] |

**READ ONLY IF D10 = 1 thru 8**

D11. And approximately how many minutes did the most recent power outage last at **your organization**? [DO NOT READ LIST; select category accordingly]

Less than 15 minutes 1
15 to less than 30 minutes 2 [specify "if less than 15 minutes", if respondent states "less than 30 minutes"]
30 minutes to less than 1 hour 3
1 hour to less than 3 hours 4
3 hours to less than 6 hours 5
6 hours to less than 12 hours 6
12 to less than 24 hours 7
More than 24 hours 8
Don't know (**DNR**) 98
Refused (**DNR**) 99

D12. Thinking back to the **most recent** power outage you experienced as an Entegrus **general service** customer, would you say the power outage …
**[READ LIST; ROTATE 1 and 3]**

Had a significant cost to my business 1
Had a minor cost to my business 2
Had barely any cost to my business, just a bit of inconvenience 3
Have never experienced an outage with Entegrus (DNR) 97
Don't know (**DNR**) 98
Refused (**DNR**) 99

D13. In your view, how do you think **Entegrus** should address the **number** of customer power outages? Would you say … **[READ LIST]**

**[Rotate response codes 1 and 3]**

Spend what is needed to **reduce** the number of unexpected power outages 1
Spend what is needed to **maintain** the current level of unexpected power outages 2
Accept **more** power outages in order to help keep customer costs from rising 3
Don't Know (**DNR**) 98
Refused (**DNR**) 99

D14. Overall, the average **Entegrus** customer is without power for about **one hour per year**. In your view, how do you think **Entegrus** should address the **length of time** customers are without power? Would you say … **[READ LIST]**

**[Rotate response codes 1 and 3]**

Spend what is needed to **reduce** the length of unexpected power outages 1
Spend what is needed to **maintain** the current length of unexpected outages 2
Accept **longer** time without power in order to help minimize customer costs from rising 3
Don't Know (**DNR**) 98
Refused (**DNR**) 99

# E. System Challenges & Priorities

## System Renewal Question

E15. [PREAMBLE to E16] While **Entegrus** believes it has done its best to prolong the life of the assets that make up the distribution system, many of these assets are approaching the end of their useful life.

As part of its investment plan, **Entegrus** is proposing an infrastructure renewal program. The estimated cost of this system renewal program is **$22 million** between 2016 and 2020.

Although this plan will allow **Entegrus** to make, what independent studies suggest are, the necessary investments needed to maintain system reliability, ***it may* have an impact on customer bills.**

E16. Which of the following statements best represents your point of view?
**[Read and Rotate statements 1 and 2]**
Some customers have said …

Entegrus should invest what it takes to replace the system's aging infrastructure to maintain system reliability; even if that increases my organization's monthly electricity bill by a few dollars over the next few years. 1

Others have said …

Entegrus should lower its estimated investment in renewing the system's aging infrastructure to lessen possible bill increases; even if that means more or longer power outages. 2

Don't know (**DNR**) 98

Refused (**DNR**) 99

## Run-to-Failure Question

E17. Thinking about the aging equipment in Entegrus' distribution system, do you feel it's best to wait until non-critical infrastructure – that is, equipment that impacts a limited number of customers – breaks down to get full value from each piece of equipment, even if it means short power outages for some customers …

… Or do you feel the best approach is to replace the equipment before it breaks down to avoid unscheduled power outages, even if it means not getting the "full" value from each piece of equipment?
[DO NOT READ LIST; unless respondents needs prompt]

Wait until equipment breakdown 1

Replace equipment before breakdown 2

Don't know 98

## System Service Questions

**[PREAMBLE FOR E18]** Modernizing the distribution system can allow Entegrus to improve reliability. Investments, such as automated switches, may allow Entegrus to minimize the number of people impacted by outages and to restore electricity to many customers in a matter of seconds.

E18. Given there are many other areas of needed investments, such as connecting new customers, replacing aging equipment and expanding capacity for long-term growth, how important do you feel it is for Entegrus to invest now in modernizing the grid?

Very important 1

Somewhat important 2

Not very important 3

Not important at all 4

Don't know (**DNR**) 98

Refused (**DNR**) 99

## General Plant Questions

E19. Entegrus is not just the local electricity distribution system itself, but a company that operates the system. As a company, Entegrus needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the electrical system and customer information.

Again, customers have made a number of statements about this sort of investment. Which of the following statements best represents your point of view?
**[Read and Rotate statements 1 and 2]**

Some customers have said ...

Entegrus should find ways to make do with the buildings, equipment and IT systems it already has. 1

Others have said ...

While Entegrus should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably. 2

Don't know (DNR) 98

Refused (DNR) 99

# F. Reaction to Customer Input

**Below are the common themes that have arisen in qualitative customer consultations.**

The following statements have been made by customers throughout **Entegrus'** on-going rate application consultation process.

For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.

Strongly agree 1

Somewhat agree 2

Neither agree nor disagree (**DNR**) 3

Somewhat disagree 4

Strongly disagree 5

Don't Know (**DNR**) 98

Refused (**DNR**) 99

**RANDOMIZE QUESTIONS**

## Willingness / Ability to Pay

F20. 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.

F21. My organization would be willing to pay a bit more for my electricity if it means better system reliability.

## Pay Now or Later

F22. We should invest in our electricity system infrastructure **now** or we will end up paying more the longer we delay our system renewal.

## Deferring to the Experts

F23. The electricity sector is so complicated and confusing; we just have to trust that the experts will find the right balance in keeping cost down while making the right investments and spending decisions.

## CDM

F24. I think **Entegrus** should do more to help customers find ways to reduce their electricity consumption and costs.

## Legacy

F25. Nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local electrical system for future generations.

## Modernizing the Grid

F26. We need to modernize the local electricity system so consumers can have greater control over their electricity usage.

## System Reliability

F27. A few power outages are fine for my organization, but I worry about the impact this has on my suppliers and customers.

## Labour Costs

F28. Skilled hydro workers are sought out across North America and Ontario. **Entegrus** should pay the people who maintain the local distribution system a competitive salary, or it could risk losing the most qualified and experienced hydro workers to other utilities.

# G. Assessment of Plan

G29. PREAMBLE **Entegrus** believes that proactive renewal and consistent maintenance is needed to maintain system performance, while keeping the impact on customer bills manageable over the long-term. Over its proposed 5 year plan, **Entegrus** will …

- spend an estimated **$48 million** on on-going maintenance and the operation of the distribution system; and
- invest an estimated **$39 million** in new equipment and infrastructure priorities that will help ensure system reliability.

To fund this proposed plan, the **average small business customer in Entegrus' service area will see their rates increase by approximately $1.15 per month** on the distribution portion of their bill over the next five years. So, by 2020, the average small business customer will be paying an **estimated $5.76 more per month** on the distribution portion of their electricity bill, which is roughly the rate of inflation.

G30. Considering the cost of Entegrus' plan, would you say [READ LIST] …
**Rotate response codes "1 "and "3"**

The rate increase is reasonable and I support it 1
I don't like it, but I think the rate increase is necessary 2
The rate increase is unreasonable and I oppose it 3
Don't know (**DNR**) 98
Refused (**DNR**) 99

**Ask only if G30 = 1, 2 or 3**

G31. And why do you say that? [**OPEN**]

Don't know (**DNR**) 98
Refused (**DNR**) 99

## Rate Harmonization

[**PREAMBLE TO G33**] As you may know, Entegrus is comprised of the former Chatham-Kent ("Cha-Tum-Kent") Hydro, Middlesex Power, Dutton Hydro and Newbury Power distribution systems. As a result, Entegrus currently has four sets of legacy distribution rates, which differ slightly between communities.

Since the merger, Entegrus has invested millions of dollars in upgrades to standardize the entire system design to ensure greater efficiency and to ensure that all customers have similar levels of reliability. Entegrus now feels that all customers should pay the same rates for distribution services.

While this rate harmonization is <u>not</u> expected to result in any increases to residential customer rates, it will effect some local businesses. Some businesses will see their rates come down slightly and others will see their rates go up slightly. This adjustment to rates will ensure all businesses are paying the same rate for the services they receive from Entegrus.

G33. With this in mind, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree with the following statement:
***Entegrus customers should pay the same rates for the same level of service, regardless of where they live or operate a business.***

Strongly agree 1
Somewhat agree 2
Neither agree nor disagree (**DNR**) 3
Somewhat disagree 4
Strongly disagree 5
Depends on whose rates are change (**DNR**) 97
Don't know (**DNR**) 98
Refused (**DNR**) 99

**Asked only of GS customers**

GS1. If rate harmonization goes ahead, it is anticipated that the **average small business customer** in Chatham-Kent, Dutton and Newbury will see **no change** in their distribution rates, outside of the proposed rate application.

However, it is anticipated that the **average small business customer** in *Strathroy, Mount Brydges and Parkhill* may see a one-time increase of approximately $20, on top of any increases related to Entegrus' rate application, as this group of customers currently pays a bit less than it costs to service them.

Which of the following statements best describes how you feel about Entegrus' proposed rate harmonization?
[READ LIST; rotate response options 1 and 3]

1. It seem fair and I support it
2. While it seems fair, I don't support it
3. It seems unfair and I oppose it.
98. Don't know (**DNR**)

# H. Firmographics

These last few questions are for statistical purposes only and we remind you again that all of your responses are completely confidential.

H34. Which of the following best describes the sector in which your organization operates?

Restaurant 1
Retail 2
Commercial 3
Multi-residential 4
Hospitality (i.e. catering, hotel operations) 5
Manufacturing 6
Other [Please specify: _______________ ] 88
Don't know / Refused (DNR) 98

H35. Which of the following best describes the **hours of operation** of your organization? Would you say … **[READ LIST]**

We are open 24/7 1
We operate several shifts each day, but are not open 24/7 2
We operate during regular business hours only 3
We operate outside of regular business hours, but do not have shifts 4
Other (please specify): _______________________ 88
Don't know / Refused (DNR) 98

H36. And, which of the following best describes **when your organization operates** through the week? Would you say … [**READ LIST**]

We operate on weekdays only 1
We operate on weekdays and weekends 2
Other (please specify): _______________________ 88
Don't know / Refused (**DNR**) 98

H37. How many **full-time** employees work at your organization? [**record #]**

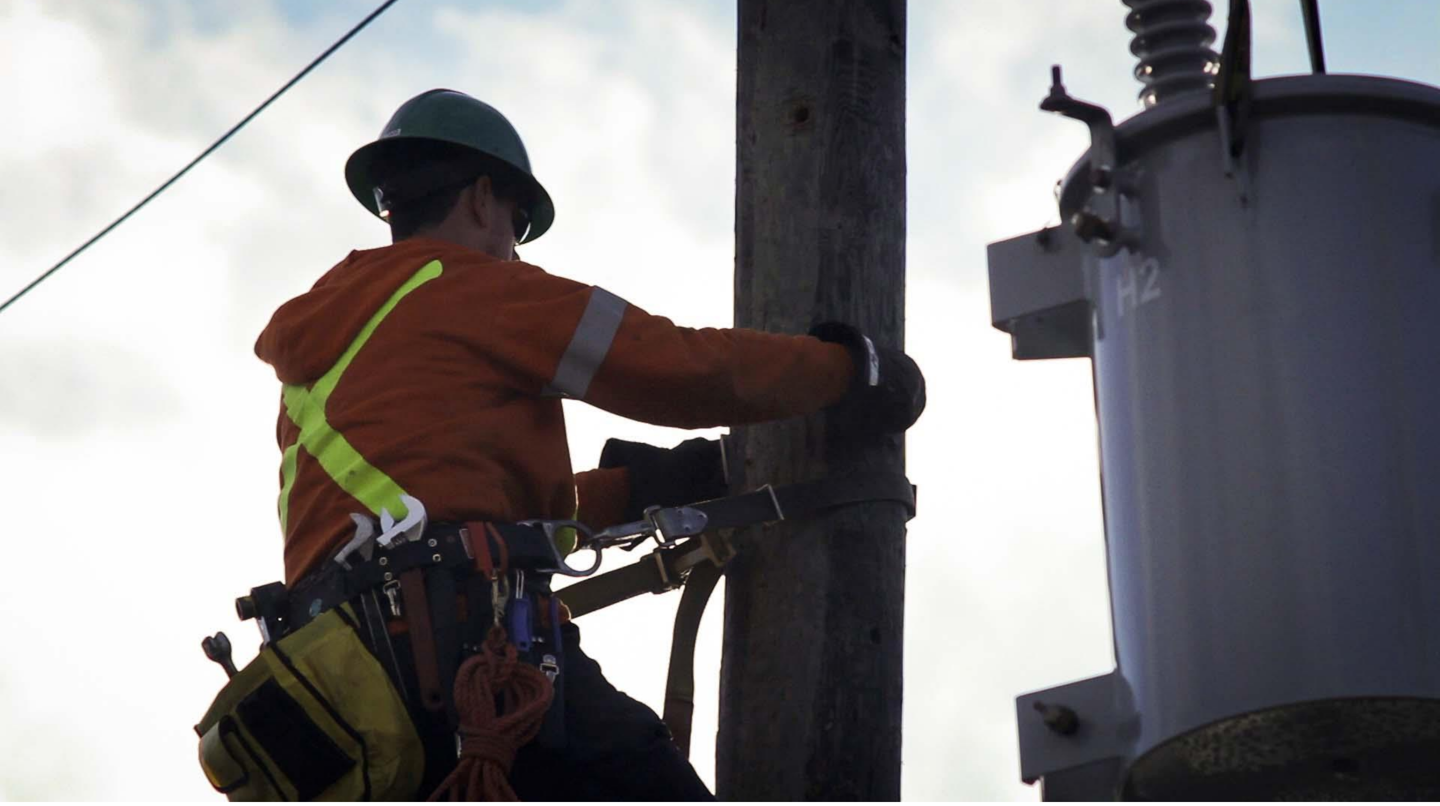
H38. Any how many **part-time** employees work at your organization? **[record #]**

## THANK and END SURVEY

Thank you very much for taking the time to complete this survey.

# Workbook Appendix:

## Entegrus' Distribution System Investment Plan Review



# 2016 RATE APPLICATION REVIEW

## Residential Customer Consultation Workbook

ENTEGRUS™

May 2015

**Entegrus Powerlines Inc. (Entegrus)** is the local distribution company responsible for electricity distribution in Chatham-Kent, Strathroy, Mount Brydges, Parkhill, Dutton-Dunwich and Newbury.

With approximately 95 employees, Entegrus operates and maintains a distribution system serving a population of approximately 125,000 with over 40,000 residential and business customers.

Entegrus is 90% owned by the Municipality of Chatham-Kent, and 10% by Corix Utilities.

# Table of Contents

# What’s this consultation about?

## The purpose of this customer consultation is to collect your feedback on Entegrus’ investment and spending plan to maintain the local distribution system over the five year period from 2016 to 2020.

Entegrus’ goal is to deliver safe and reliable electricity to homes and local businesses as efficiently as possible and at an affordable price.  However, there is a balancing act that all utilities must consider when planning for the future; system reliability vs. the cost to consumers. No distribution system delivers perfectly reliable electricity. Generally, the more reliable the system, the more expensive the system is to build and maintain.

This customer consultation is designed to collect your feedback on the reliability of the electricity distribution system and the spending decisions Entegrus will need to make over the next five years. Ultimately, this consultation will help Entegrus ensure alignment between its operational and capital investment plans and customers needs and preferences.

As an Entegrus customer, this is an opportunity for you to tell Entegrus what you think about the plan and the cost implications for you. This is also an opportunity for Entegrus to explain to its customers the challenges in operating and maintaining the local electricity distribution system, and more importantly how Entegrus intends to meet those challenges.

**To participate in this review, you do <u>not</u> need to be an expert.** The workbook explains key parts of the electrical distribution system, the challenges facing the system, Entegrus’ recent work to maintain the system, and the company’s budgetary plan for 2016 to 2020.

Entegrus does not expect you to make electrical engineering decisions. Entegrus wants to hear about the electricity issues that matter most to you and whether or not you feel the company’s spending and investing priorities seem reasonable.

This workbook is designed to give you enough background about these issues for you to develop an informed opinion.

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# What's the process that Entegrus must follow?

### How are electricity rates determined in Ontario?

The electricity industry in Ontario is regulated by the Ontario Energy Board (OEB), which recently developed a new regulatory requirement for electricity distributors, such as Entegrus, to gather customer preferences on distribution system investments.

Entegrus is funded by the distribution rates paid by its customers. Periodically, Entegrus is required to file an application with the OEB to determine the funding available to operate and maintain the distribution system. Entegrus must submit evidence to justify the amount of funding it needs to safely and reliably distribute electricity to its customers.

### As a customer, how are my interests protected?

Entegrus' evidence is assessed in an open and transparent public process known as a rate hearing. A number of public intervenors with electricity industry expertise submit their own evidence, in some cases challenging Entegrus' plans and assumptions. At the end of the process, the OEB weighs the evidence and decides on the rates Entegrus can charge for distribution.

### Why is my feedback important?

Your feedback will be presented to the OEB and public intervenors (who represent various ratepayer groups) when Entegrus files its rate application for 2016-2020. As part of the rate hearing process, the OEB will be reviewing how Entegrus acquired and responded to customer feedback in its planning process.

### Rate Application Process

1. Entegrus assesses system needs
2. **Collects customer needs and preferences**
3. Refines plan (where necessary)
4. Reports on how plan responds to customer input
5. Files plan with OEB
6. Questions & OEB rate hearing process
7. OEB sets Entegrus' distribution rates

**Innovative Research Group Inc.** has been engaged by Entegrus to collect participant feedback and will deliver it to Entegrus to assist them in shaping their rate application and distribution system plan.

# Consumer feedback on Ontario's electricity system

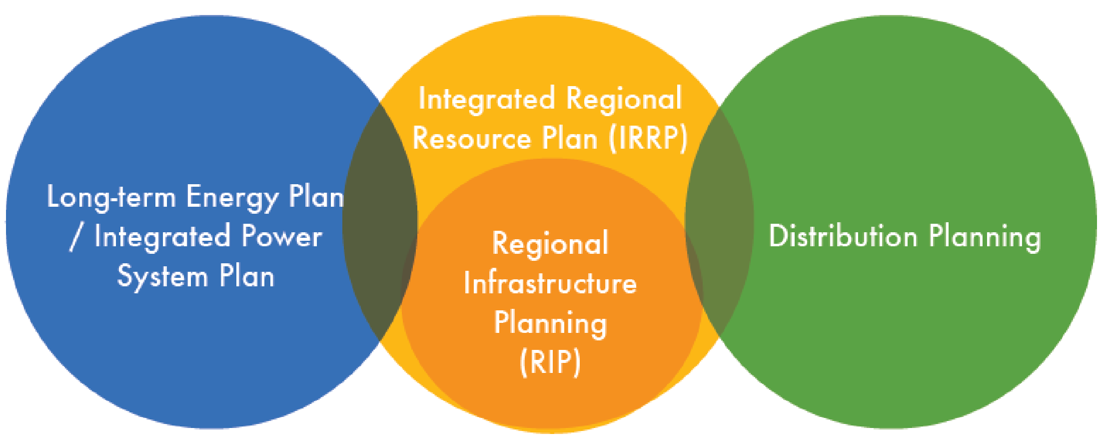
**There are a number of ways for consumers to voice their opinions on provincial, regional and local electricity issues. However, this consultation is about your local distribution system and your preferences on how Entegrus uses your money.**

**Distribution Planning:** This workbook and consultation concentrates on the plan for Entegrus' distribution system over the next five years. The graphic below shows the various planning initiatives ongoing across Ontario's electricity system. In addition to the short-term distribution plan being discussed in this workbook, there are other planning initiatives undertaken to ensure that the distribution system maintains reliability and works efficiently for the benefit of customers.

If you're interested in broader medium- and long-term electricity issues such as Ontario's Long-Term Energy Plan, regional planning, conservation planning and general energy policy in the province, there are other opportunities to provide your feedback.

> **Ontario's Long Term Energy Plan:** The Ontario Government's plan details how electricity will be generated and the longer-term conservation strategy for the province. It can be found at this website: http://www.energy.gov.on.ca/en/ltep/
>
> **Regional Planning:** The Independent Electricity System Operator (IESO) looks ahead to the future electricity needs of your region and how those needs can be addressed through conservation, local generation, and electricity from outside the region. You can follow the IESO's regional planning process at this website: http://www.powerauthority.on.ca/power-planning/regional-planning

## Electricity System Planning in Ontario




### Provincial System Planning

This involves more long-term planning on how Ontario's electricity system is designed and operated.

This includes planning on:

- Provincial electricity supply mix (e.g. greening the grid and phasing out coal power generation)
- System supply and demand forecasting
- Interconnections and grid design

### Regional Planning

Regional planning involves near- and medium-term plans to meet the needs of a region of the province, and ensure all key players (i.e. transmission and distribution operators) are coordinated moving forward.

This planning process is focused on considering whether conservation & local generation options have been considered, in addition to core infrastructure ("wires") solutions.

### Distribution System Planning

Distribution planning involves plans, both near- and longer-term, to ensure the local distribution system has the adequate infrastructure to meet required reliability and safety standards, and to otherwise meet the needs of customers.

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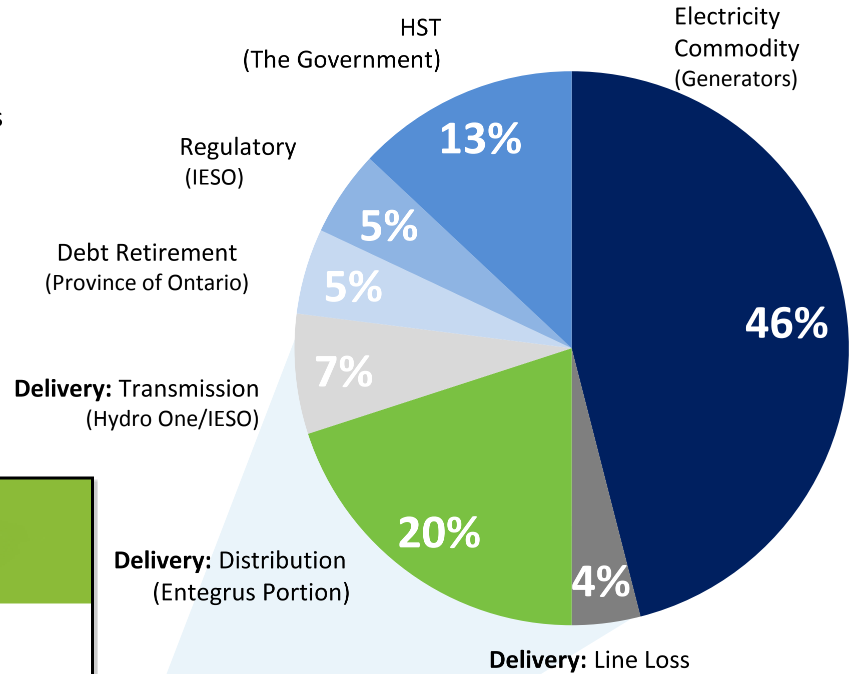
# Customer Electricity Bills

**Your Electricity Bill:** Every item and charge on your bill is mandated by the provincial government or regulated by the OEB. There are two distinct cost areas that make up the "Delivery" charge on your bill: ***distribution*** and ***transmission***. While Entegrus collects both, it remits the transmission charge to Hydro One. The distribution charges are what Entegrus uses to fund its utility needs. Distribution costs make up about 20% of the typical residential customer's (800 kWh per month) total electricity bill.

Entegrus' distribution rates are subject to the review and approval of the OEB. The revenues collected from customers covers Entegrus' capital investments and operating expenses.

**About 20% of the average residential electricity bill goes to Entegrus**




SAMPLE MONTHLY BILL STATEMENT
**Entegrus Powerlines Inc.**
**Chatham-Kent Rate Zone**

Account Number:
000 000 000 000 0000

Meter Number:
00000000

| | |
|---|---|
| **Your Electricity Charges** | |
| **Electricity** | |
| Off-Peak @ 8.00 ¢/kWh | 40.96 |
| Mid-Peak @ 12.200 ¢/kWh | 17.57 |
| On-Peak @ 16.100 ¢/kWh | 23.18 |
| **Delivery** | 43.10 |
| **Regulatory Charges** | 5.01 |
| **Debt Retirement Charge** | 5.60 |
| **Total Electricity Charges** | **$135.42** |
| HST | 17.60 |
| **Subtotal** | **$153.02** |
| **Ontario Clean Energy Benefit (-10%)** | (-15.30) |
| **Total Amount** | **$137.72** |

Current monthly distribution charges are approximately **$29 - $36 per month** for a typical Entegrus residential customer who consumes 800 kWh in a month, depending on which rate zone the customer is in. The sample bill statement to the left shows the Chatham-Kent rate zone.

It is estimated that – all things being equal – distribution charges will remain essentially flat in 2016, and will then increase gradually with inflation from 2017-2020. This includes the cost of the Entegrus plans to operate, maintain, and modernize its electricity distribution system.

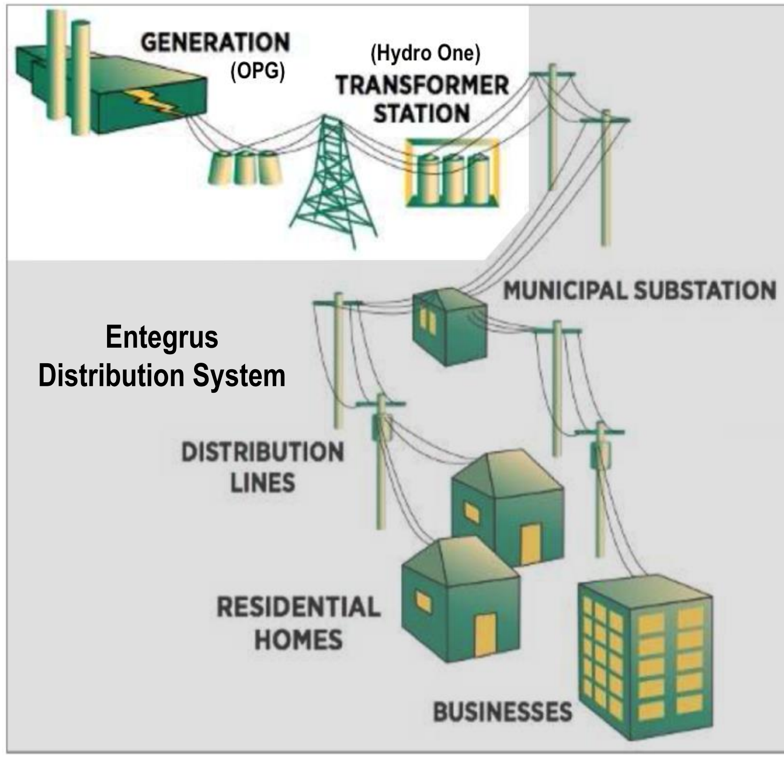
# Understanding Entegrus' Role in Ontario's Electricity System

**There are three main components to all electricity systems: generation, transmission and distribution.**

## Where Electricity Comes From

In Ontario, 70% of electricity is generated by Ontario Power Generation (**OPG**). This provincially-owned organization has **generation** stations across Ontario that produce electricity from hydroelectric, nuclear and fossil fuel sources.

Once electricity is generated, it must be delivered to urban and rural areas in need of power. This happens by way of high voltage **transmission stations** and interconnected lines that serve as highways for electricity. The province has more than 30,000 kilometres of transmission lines*, owned mostly by **Hydro One**.




## Entegrus

Entegrus is responsible for the last step of the journey: distributing electricity to customers in the region through our **distribution system**.

Every distribution system is unique with its own history and challenges.  In order to better understand Entegrus' current system, we first have to understand all of the different components and how they impact the way in which you receive electricity when you need it.

Entegrus' power is supplied at high voltage levels to nine transmission stations (TS) owned by Hydro One.  The high voltage electricity is then reduced and connected through 27.6kV feeder circuits.  Some of these feeder circuits are used to distribute power to various substations located throughout the communities Entegrus serves. These substations further transform the electricity voltage to lower voltage levels for distribution to the neighbourhoods within the communities. Some customers receive power directly from the 27.6kV system while others receive power via these substations. In either case, additional transformers are located near each customer, and transform the voltage one final time to levels safe to distribute through a home or business.

### Entegrus' Overhead System

The overhead system is made up of distribution lines that operate at either 4kV, 8kV, or 27.6kV.  Along the line, pole-top transformers step the voltage down. From there, the electricity is delivered to customers.

### Entegrus' Underground System

The underground system consists of a complex network of cables, vaults, cable chambers and transformers situated on concrete pads (padmount transformers). In residential areas, underground cables distribute electricity from substations (or TS's as the case may be) to padmount transformers located on customer boulevards. Like the overhead system, these transformers step the electricity down to a lower voltage, and electricity is delivered to customers.

*Source: IESO. The Power System, www.ieso.ca

# Electricity Grid 101:
# *How is Ontario's Electricity System Regulated?*

## The electricity system in Ontario is regulated by the following bodies:

### Ontario Ministry of Energy:
The Ontario Ministry of Energy sets energy policy.  It sets the rules and establishes key planning and regulatory agencies through legislation.

### Ontario Energy Board:
The mission of the Ontario Energy Board (OEB) is to promote a viable, sustainable and efficient energy sector that serves the public interest and assists consumers to obtain reliable energy services at reasonable cost.  It is an independent body established by legislation that sets the rules and regulations for the provincial electricity sector. One of the OEB's roles is to review the distribution plans of all electricity distributors and set their rates.

### The Independent Electricity System Operator:
The Independent Electricity System Operator (IESO) is responsible for short, medium and long-term electricity planning to ensure an adequate supply of electricity is available for Ontario residents and businesses.  It operates the grid in real-time to ensure that Ontario has the electricity it needs, where and when it needs it. The IESO receives directives from the Ministry of Energy (i.e. energy supply mix, Green Energy Act), but otherwise works at arm's-length from the government.

# Customer Feedback

1. Given what you know and what you have read so far, how well do you feel you understand the parts of the electricity system, how they work together and which services Entegrus is responsible for?
   - ❑ Very well
   - ❑ Somewhat well
   - ❑ Not very well
   - ❑ I don’t understand at all

2. Generally, how satisfied are you with the service you receive from Entegrus?
   - ❑ Very satisfied
   - ❑ Somewhat satisfied
   - ❑ Somewhat dissatisfied
   - ❑ Very dissatisfied
   - ❑ Don’t know

3. Is there anything in particular that Entegrus can do to improve its service to you?

# Entegrus’ Grid Today

**This section describes the construction of Entegrus’ distribution grid including its substations, overhead and underground systems. It also explains the company’s historical growth and current electrical infrastructure.**

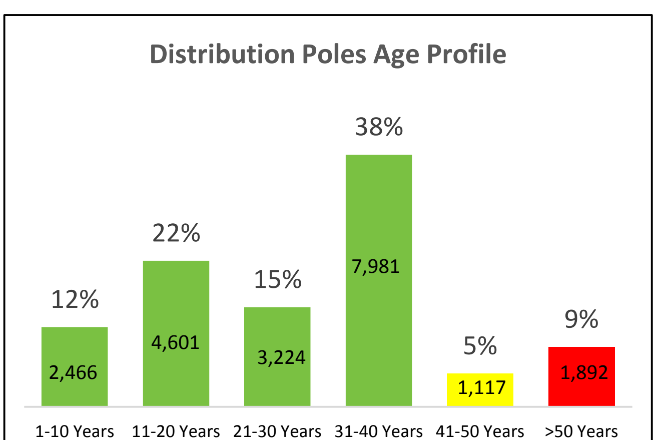
## Background on Entegrus’ Distribution System

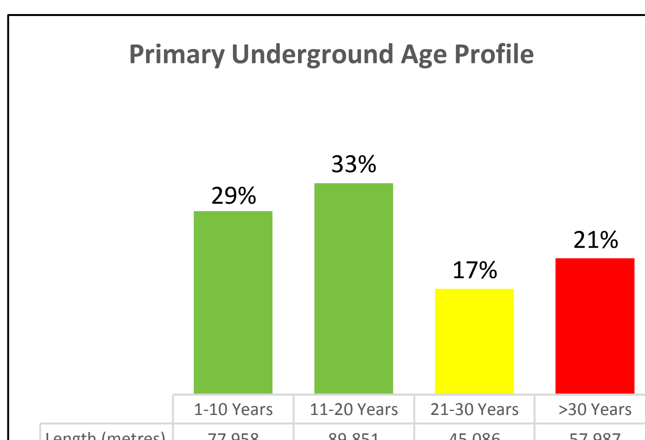
Entegrus was originally founded as Chatham Hydro in 1914. In 1998, Chatham-Kent Hydro (CK Hydro) was formed as an amalgamation of eleven former municipal electric utilities as part of the Chatham-Kent municipal amalgamation. Middlesex Power Distribution Corporation (serving Strathroy, Parkhill and Mt. Brydges) was acquired in 2005, followed by the acquisition of the former Dutton Hydro Limited and Newbury Power Corporation in 2009. The company name was changed to Entegrus Powerlines in 2012.

The history of Entegrus has resulted in a varied mix of equipment within the system, all of which needs to be managed according to the asset management practices of the pre-acquisition utilities. The system is now comprised of assets of varying age, and at varying points in their life span. Some of the older equipment is now obsolete, meaning that at times Entegrus has to commission the machining of parts to match the design of the older system.

In 2013, Entegrus hired the consulting firm METSCO to help establish a formalized asset management program. Using international engineering standards, METSCO reviewed all the data Entegrus currently maintains for its assets, evaluated the integrity of that information, recommended additional information for collection, assessed the health of the individual asset classes, and, using a risk-based approach, assisted Entegrus’ engineering team in ranking and prioritizing the asset replacement work required in order to minimize Entegrus’ operating costs.

This process helped confirm that Entegrus’ approach to capital renewal and preventative maintenance was successful in keeping the system up to date. The new approach to asset management will help Entegrus create better and more focused plans to continue to keep the system updated and deliver a better quality of service.

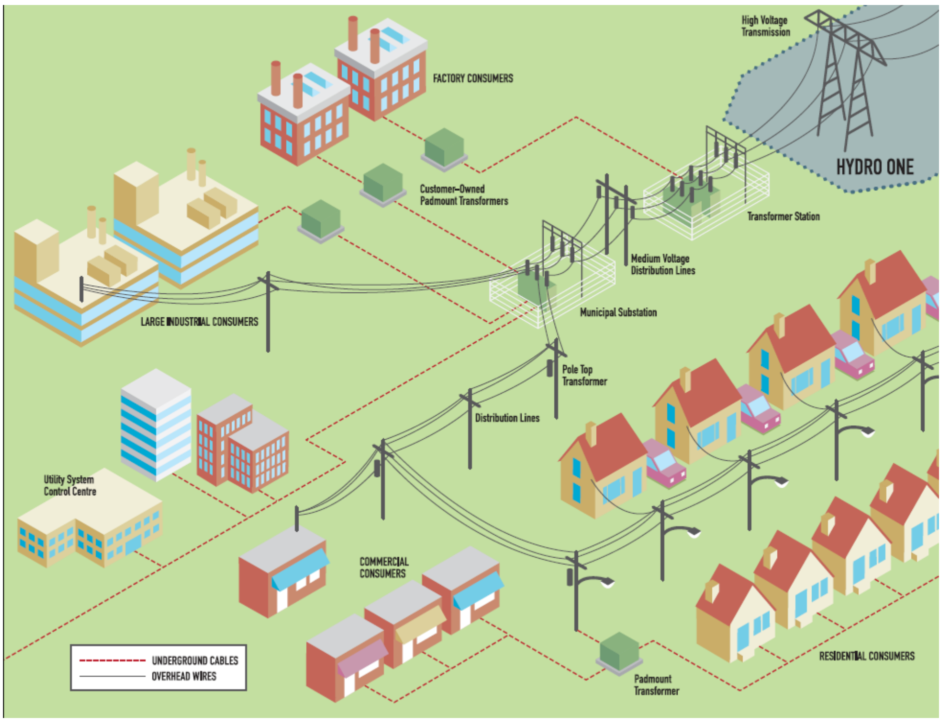


# Entegrus’ Grid Today

Every distribution system is unique with its own history and challenges. In order to better understand the current Entegrus system, we first have to understand all of the different components and how they impact the way in which you receive electricity when you need it. The diagram and terms below will help guide you through the system.

Entegrus’ distribution system is made up of a number of components which work together to transport electricity to homes and businesses across the communities it serves.




Entegrus’ service territory covers 96 square kilometers of urban area, encompassed within a 5,000 square kilometer geographic area.

The distribution system contains 680 km of overhead wires, 268 km of underground cables, and **17 municipal substations** to step down voltage from 27.6 kV to the remaining old 4 kV and 8 kV systems. (The remainder of the old 4 kV and 8 kV systems will be converted to the 27.6 kV system by 2025.)

Entegrus is served by a total of **9 transmission stations** which are owned and operated by Hydro One.

## Hydro One’s Transmission System:

**High Voltage Transmission** – Connects our distribution system to electricity generating stations across the province.

**Transmission Station** – Reduces high voltage electricity from transmission lines to medium voltage which is fed into Entegrus’ distribution stations.

## Entegrus’ Distribution System:

**Municipal Substations:** Municipal substations are a critical element of the electricity distribution system —they are the local hubs from where electricity is distributed to an area. Municipal substations contain:

**Transformers** - Important pieces of equipment that reduce the voltage of electricity from a high level to a level that can be safely distributed to your area.

**Feeder Circuits** - The wires that connect the transmission station to the broader distribution system in order to deliver electricity to customers.

**Breakers** - Devices that protect the distribution system by interrupting a circuit if a higher than normal amount of electricity is detected.

**Switches** - Control the flow of electricity and steer the current to the correct circuits.

# Entegrus' Grid Today: *Distribution System*

## Entegrus' Distribution System:

**Overhead System:** The overhead system includes the wires that are commonly seen across Entegrus' service area. The voltage of the overhead system can range from 4 kV (4,000 volts) to 27.6kV.

> **Wires** – There are 680 km of wire that carry electricity across the overhead distribution system.
>
> **Poles** – Wires are suspended from these, usually wooden (sometimes concrete), poles.
>
> **Pole Top Transformers** – These transformers are mounted near the top of utility poles and are needed to further step-down the voltage from the lines to the final connection to customers.

**Underground System:** The underground system includes 268 km of cable, which is directly buried and or installed in ducts. At certain intervals, underground service chambers (with manholes) are required to permit cables to be spliced together and to allow underground equipment such as switches to be housed.

An advantage of underground systems is that they are affected to a lesser extent by extreme weather. The disadvantage is that they are more expensive to install and maintain, and when there is a power outage it often takes longer to locate and repair a problem compared to overhead wires.

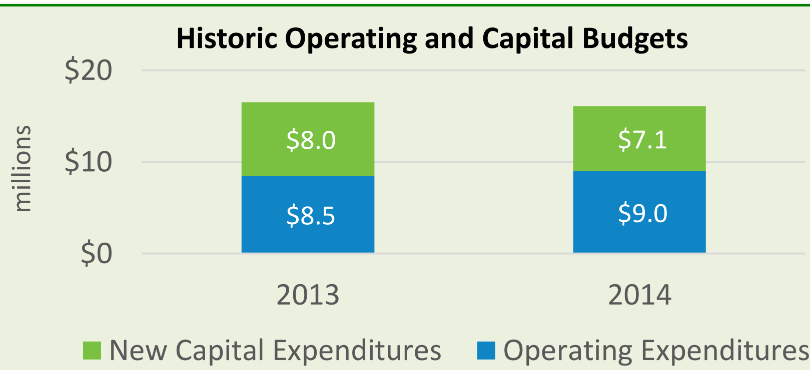
> **Underground Cables** – Convey the electricity in the underground system. Cables that connect the distribution stations and major industrial users to the distribution station are significantly larger than cables used to connect residential neighbourhoods.
>
> **Padmount Transformers** – Similar to transformers in the overhead system, these reduce the voltage to a lower level before final connection to customers. In the underground system there are concrete padmounted transformers, which are above ground transformers that are supplied by underground cable, and vault transformers, which are housed in underground chambers.

## Paying for the Distribution System?

As anyone who runs their own business would expect, Entegrus manages its spending in two budgets – an operating budget and a capital budget.

Entegrus' **operating budget** covers regularly recurring expenses such as the costs of running service vehicles, the payroll for employees, and the maintenance of distribution equipment and buildings.

Its **capital budget** covers items that, when purchased, do not need to be repurchased for some time and that have lasting benefits over many years. This can include much of the equipment that is part of the distribution system, such as poles, wires and transformers, major computer systems, and vehicles.




Managing the distribution system requires millions of dollars in maintenance, system renewal and running the day-to-day operations. In its last fiscal year (2014), Entegrus' operating expenses and capital expenditure totalled $16.1 million.

# Customer Feedback

4. How well do you feel you understand the important parts of the electricity system, how they work together, and which services Entegrus is responsible for?
   - ❑ Very well
   - ❑ Somewhat well
   - ❑ Not very well
   - ❑ I don't understand at all

5. The average Entegrus customer experiences one power outage per year. Do you recall how many outages you experienced in the past year?
   - ❑ None
   - ❑ One
   - ❑ Two
   - ❑ Three
   - ❑ Four
   - ❑ More than four
   - ❑ Don't know

No system delivers perfectly reliable electricity. There is a balancing act between reliability and the cost of running the system. Please answer the following questions:

6. How acceptable were the number of power outages you experienced over the last 12 months?
   - ❑ Very acceptable
   - ❑ Somewhat acceptable
   - ❑ Not very acceptable
   - ❑ Not acceptable at all
   - ❑ Did not have any power outages
   - ❑ Don't know

7. How many power outages do you feel are reasonable in a year?
   - ❑ No outage is acceptable
   - ❑ One
   - ❑ Two
   - ❑ Three
   - ❑ Four
   - ❑ More than four
   - ❑ Don't know

8. What do you feel is a reasonable duration for a power outage?
   - ❑ No outage is acceptable
   - ❑ 30 minutes
   - ❑ 1 hour
   - ❑ 2 hours
   - ❑ 3 hours
   - ❑ 4 hours or more
   - ❑ Don't know


**From the day-to-day to major storm events, there are a variety of ever-present pressures on Entegrus' operating and capital budget.**

Many of these expenditures are items over which Entegrus has little or no control – major storms, and the implementation of Smart Meters, for example.

Other costs are associated with preventative maintenance like replacing aging equipment. Entegrus has already undertaken several large scale projects, and more are planned.

**How does Entegrus determine the appropriate amount of capital spending related to existing infrastructure?**

Entegrus monitors the health of its electric infrastructure very closely. As part of its rate application, it must show the OEB third party reviews of the health of its system's assets. These asset health reviews help Entegrus prioritize which parts of its system get upgraded or rebuilt first.

**Has Entegrus previously set aside funds for required upgrades?**

The OEB does not allow utilities in Ontario (including Entegrus) to create reserve funds. If reserve funds were allowed, a utility would have to charge customers a premium on their rates to set money aside. Under OEB regulation, a utility can only charge customers the rate required to run the distribution system at a reliability standard set by regulatory bodies.

# Paying for Entegrus' Distribution System: *Capital Investment Drivers*

## Entegrus has developed a list of capital investment drivers and proposes investment programs based on these key drivers.

**Reliability:** There are two main measures of reliability in the distribution system:

1) How often does the power go out?
2) How long does it stay out?

To achieve maintained or improved reliability, projects are developed to improve asset performance and decrease the frequency and duration of power outages.

**Service Requests:** Entegrus has a legal obligation to connect customers to its distribution system. This includes both traditional demand customers (new homes and businesses) and distributed generation customers (e.g. micro-FIT customers who have contracts to sell electricity back to the grid such as rooftop solar panels). Requests can also include system modifications to support infrastructure development by government agencies, road authorities and developers.

**Support Capacity Delivery:** Where there are forecasted changes in demand that will limit the ability of the system to provide consistent service delivery or where it is incapable of meeting the demand requirements, new builds or expansion is required. This is the fundamental infrastructure that allows new customers to be hooked up to the distribution system and is paid for by new customers served over time.

**System Efficiency:** To provide customers with the best service possible, there is always a need to improve power outage restoration capability.

**Mandated Compliance:** Compliance with all legal and regulatory requirements and government directives, such as compliance with the Ministry of Energy, the Ontario Energy Board, the Independent Electricity System Operator and other regulations.

**Obsolescence:** Asset installations that no longer align with Entegrus' current operating practices or current standards. This can include those assets that:

- are no longer manufactured,
- lack spare parts,
- cannot be accessed,
- lack the ability to have maintenance performed on them,
- have operational constraints or conflicts, which can result in increased reliability and/or safety related risks.

**Aging or Poor Performing Equipment:** Where there is the imminent risk of failure due to age or condition deterioration, and these potential failures will result in severe reliability impacts to customers as well as potential safety risks to crew workers or to the public, remediation, through refurbishment or replacement, is required.

**Business Support Costs:** Entegrus is not just the local electricity distribution system itself, but a company that operates the system. As a company, it needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the system and customer information.

# Paying for Entegrus' Distribution System: *Capital Investments*

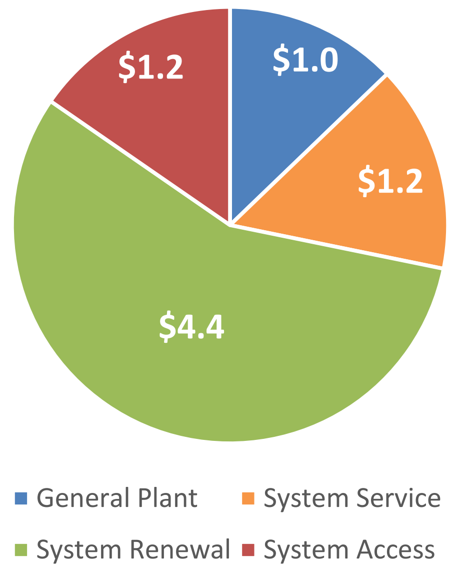
## What are the major issues Entegrus needs to address?

Over the years, Entegrus has worked hard to keep its equipment working well beyond its originally expected life, to get maximum value for money. However Entegrus' key challenge still comes from the need to replace aging equipment.

In 2016, the capital expenditures required to address system renewal, maintain system reliability and invest in other infrastructure priorities are estimated by Entegrus to be **$7.8 million**.

To assist us in prioritizing what needs to be replaced and by when, Entegrus uses an asset management model to drive replacement decisions. Using the information provided by the asset management model, Entegrus plans for four types of capital investment costs:

**2016 Forecasted* Capital Expenditures (millions)**




### System Access

**Definition**: Projects that respond to customer requests for new connections or new infrastructure development. These are usually a high priority, "must do" type of request

**Programs** (e.g.): Customer Connections, Relocating assets based on infrastructure needs

### System Renewal

**Definition**: Projects focused on replacing aging equipment in poor condition

**Programs** (e.g.): Distribution Station Refurbishment, Voltage Conversion, Underground Cable Replacement, Overhead Wire Replacement

### System Service

**Definition:** Primarily consisting of projects that improve system reliability

**Programs** (e.g.): Automated Switches, better distribution system monitoring equipment

### General Plant

**Definition**: Investments in supporting assets, such as tools, vehicles, buildings and information technology (IT) equipment that are needed so that we may perform our task to operate and maintain the distribution system

**Programs** (e.g.): IT, facilities, fleet

**These figures are subject to change upon final rate application submission.*

# Cost Drivers
## *Capital Investments*

**The challenges impacting the Entegrus distribution system can be broken down into 5 broad categories:**

**Aging Infrastructure**

- For the original utilities that now comprise Entegrus, much of their economic growth occurred between 1950 and 1970. The average age of Entegrus' 17 substation transformers is 50 years.
- Entegrus' substation transformers were made by 7 different manufacturers – some of whom are no longer in business, which adds to the challenge of sourcing replacement parts.
- Similarly, there are many poles and undergrounds cables in the system that have surpassed their expected lifespan.

**Voltage Conversion**

- Because Entegrus is comprised of various former distribution companies, not all of the equipment is the same. Some systems were designed for 4kV and 8kV, as opposed to the more modern 27.6kV system that is standard across the province.
- Bringing the older systems up to 27.6kV will allow for deployment of Smart Grid technologies, standardize construction practices (thereby reducing costs), reduce system loss, eliminate the need for outdated equipment and simplify the operation of the system.

**Separate Pockets of Distribution**

- The service area for Entegrus extends over an area of 5,000 $km^2$. Servicing each community requires significant travel. Being able to troubleshoot problems remotely will reduce and in some cases eliminate the need to send a crew out for repairs.
- Many towns are being serviced by long distribution feeders, which increases vulnerability to storms and accidents, resulting in more frequent outages. Extending new feeders to these towns would provide alternate feeds that could be used to restore power in less time.

**Economic Development**

- Entegrus considers the goal of aiding and encouraging economic development in its communities a top priority that benefits businesses as well as enhancing customers' standard of living.
- Power quality concerns have been increasing in recent years. In almost all cases, these are very short duration disturbances on the electrical grid that mostly impact new and highly sensitive industrial equipment.
- Neglecting investment in technology or asset renewal reduces the chances of attracting new businesses and jobs and increases the risk of losing existing businesses and jobs from the community.

**Increasing Cost of Electricity**

- Energy cost are rising and forecasted to continue to increase over the next few years. Customers expect that they should be able to manage their cost by using home automation, installing alternative energy sources as they wish (i.e. solar power), or by being able to monitor their electrical consumption. Entegrus is obligated to put into place the systems and opportunities for customers who wish to take advantage of these technologies to manage and lower their energy cost.

# Cost Drivers
## *Operating Expenses*

**In addition to its capital budget, Entegrus needs to consider its operating budget which also impacts customer bills.**

Cost drivers contributing to the operating budget can largely be attributed to on-going maintenance and management of the distribution system. An example of this cost driver is Entegrus' vegetation program, including tree trimming, designed to lessen the impact of falling tree branches on power lines.

### Customer Focus

- It is now an industry requirement for all utilities to demonstrate that they have consulted customers before applying for new rates.
- Entegrus embraces this concept and wants to gather ongoing customer feedback and input through website surveys and focus groups.
- Entegrus continues to enhance its online customer service offerings, this has included launching a new Entegrus website with a self-service portal, as well as launching Facebook and Twitter communication channels.
- Further, in 2010 Entegrus moved from bi-monthly billing to monthly billing, and also launched Time-of-Use billing.

### Industry Focus

- Industry regulation requires that Entegrus maintain compliance with various regulatory bodies in a complex provincial environment.
- The requirements to implement Smart Meters and to adopt the International Financial Reporting Standard ("IFRS") of accounting are examples of recent industry change.
- Meters are now more complex and require specialized troubleshooting. Entegrus installed many of its Smart Meters in 2006 and 2007. As these meters age, more focus is required on re-verification. Entegrus is now testing groups of these meters at intervals throughout their life spans rather than waiting for them to cease operating at end-of-life.
- The changeover to the IFRS accounting rules has resulted in the expensing of operational costs that we previously capitalized as assets.
- To ensure that Entegrus is in compliance with all regulatory codes, including new requirements and reporting, additional staffing and support resources have been added since 2010.

### Operational Effectiveness & Power Quality

- Consistent with industry best practice, Entegrus has established a formalized asset plan for distribution system assets. This includes asset health assessments and replacement prioritization rules.
- The plan will also include voltage conversion work to modernize the system in order to identify the causes of outages more quickly and reduce line losses.
- Entegrus will incur expenses for additional software and engineering resources as the distribution system plan is continuously updated.
- Another key focus is vegetation management. Vegetation in proximity to power lines can cause outages and power quality issues. After the Toronto ice storm of 2013, Entegrus began focusing on additional preventative vegetation management.
- Lastly, the age of Entegrus' assets, in particular its underground ductwork and cables, has required more preventative maintenance in recent years.

| Change between 2010 Approved Operating Budget and 2016 Request | |
|---|---|
| **2010 Proxy OEB Approved Operating Budget** | $7.9 |
| **Industry Focus:** | |
| **Meter Maintenance & Re-verification** | 0.2 |
| **IFRS Operational Expense Accounting Rules** | 0.3 |
| **Industry Regulation** | 0.3 |
| **Customer Focus:** | |
| **Customer Engagement & Communication** | 0.2 |
| **Web Enhancement & Self Service Options** | 0.2 |
| **Operational Effectiveness & Power Quality** | |
| **Distribution System Plan & Asset Management** | 0.2 |
| **Vegetation Management** | 0.1 |
| **Preventative Infrastructure Maintenance** | 0.1 |
| **Other, including administrative merger savings** | (0.2) |
| **2016 Request to the OEB *** | $9.3 |

* *These figures are subject to change upon final rate application submission*

# Finding Efficiencies and Cost Savings

Where possible, Entegrus has extended the life of its equipment through a rigorous repair and maintenance program in order to get maximum value for money. Some of this aging equipment can be "run to failure", meaning we can replace it after it ceases to function without significant customer impact.  However, other end-of-life equipment is more mission critical and cannot be "run to failure" – because failure could result in a public safety hazard or an unsupportable economic burden for our customers.

## *There are several other ways in which Entegrus works to find efficiencies and cost savings in the system:*

**Voltage Conversion Program:** Converting to a single higher voltage will eliminate antiquated equipment, reduce system losses, and reduce ongoing maintenance costs.

**"Kitting"**: Warehouse staff pre-assemble parts and equipment needed for specific repairs, which reduces the time needed for crews to complete maintenance and service tasks, thereby reducing costs.

**Remote Fault Indication:** Allows Entegrus to better diagnose outages before dispatching work crews. Reduces expensive after hours crew visits.

**Smart Meter Data:** Using Smart Meter data to diagnose outages and power quality issues reduces time and guess work, and helps resolve issues faster.

**Outage Management System:** Quickly and automatically identifies faults, notifies crews and provides information to help troubleshoot and identify the cause.

**SCADA:** An automated system that provides control of remote equipment. Helps determine the severity of a fault and remotely operates motorized equipment to restore power.

**Distribution Automation:** Increased automation in the system allows Entegrus to remotely re-route power and restore outages faster.

**Smart Grid Technology:** New and innovative technology enhances ability to resolve power quality issues in remote communities without having to send out a work crew.

**Enhanced Power Quality Metering:** Installing power quality meters at select commercial and industrial sites helps major customers resolve power quality issues so they can better understand and control their energy usage.

**Estimating and Scheduling Tool:** A new estimating and scheduling tool means Entegrus can more quickly and more accurately assemble an estimate and lay out work for construction crews.

**Group Buying Program:** Entegrus saves money by participating in a group buying program with other local utilities.  This means some types of equipment and materials can be purchased less expensively than would otherwise be the case.

**Labour Saving Equipment:** Specialized trucks and other equipment reduce manual labour, which reduces time and costs.

**Targeted Capital Projects:** These projects eliminate equipment from the system that is known to be high maintenance.

**Joint Venture with IHSA:** Entegrus has partnered with the Infrastructure Health & Safety Association to develop a local training facility. This saves travel costs and personnel costs.

**Development of Local Powerlines Maintainer Training Program:** Entegrus has taken a lead role in working with St. Clair College on the ongoing development of this program, which, in turn, assists Entegrus with succession planning for new lines staff.

**Social Media:** Entegrus uses social media to notify customers about outages and keep them informed about the progress toward restoration.

# Customer Feedback

9. With regards to projects focused on replacing aging equipment in poor condition, which of the following statements best represents your point of view?
   - ❑ Entegrus should invest what it takes to replace the system's aging infrastructure to maintain system reliability, even if that increases my monthly electricity bill by a few dollars over the next few years.
   - ❑ Entegrus should lower its investment in renewing the system's aging infrastructure to lessen the impact of any bill increase, even if that means more or longer power outages.
   - ❑ Don't know

10. As a company, Entegrus needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the system and customer information. Which of the following statements best represents your point of view?
    - ❑ Entegrus should find ways to make do with the buildings, equipment and IT systems it already has.
    - ❑ While Entegrus should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system safely, efficiently and reliably.
    - ❑ Don't know

11. How well do you feel you understand the cost drivers that Entegrus is responding to?
    - ❑ Very well
    - ❑ Somewhat well
    - ❑ Not very well
    - ❑ Not well at all
    - ❑ Don't know

12. How well do you think Entegrus is managing these cost drivers while meeting customer expectations and keeping rates reasonable?
    - ❑ Very well
    - ❑ Somewhat well
    - ❑ Not very well
    - ❑ Not well at all
    - ❑ Don't know

13. How satisfied are you with the efforts Entegrus has made to find efficiencies and cost savings in the distribution system?
    - ❑ Very satisfied
    - ❑ Somewhat satisfied
    - ❑ Not very satisfied
    - ❑ Not at all satisfied
    - ❑ Don't know

# What Entegrus' Plan Means for You

In 2016, it is anticipated that residential customers with an average monthly consumption of 800 kWh will not see any increase on the distribution portion of their electricity bills. It is expected that – all things being equal – distribution rates will remain flat. This is a result of Entegrus reflecting longer asset useful lives in its accounting, as well as the synergies of Entegrus merging four former utilities into one.

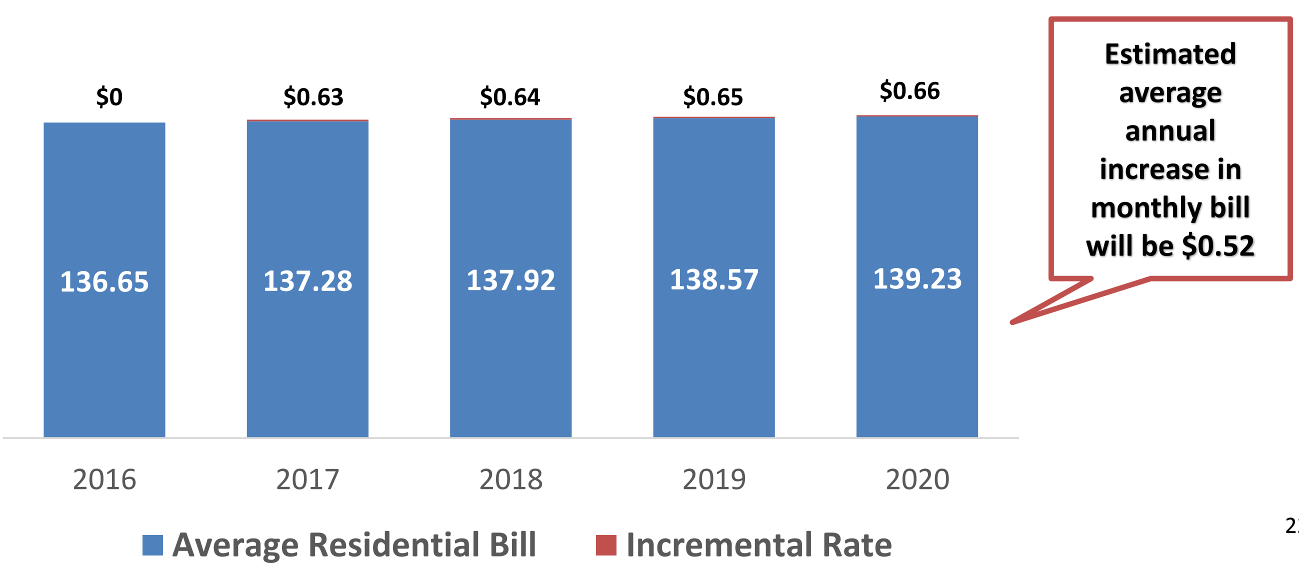
Beyond 2016, Entegrus forecasts gradual inflationary increases, consistent with the industry rate-setting process. Entegrus' forecasted increase over the next five years may see an average annual increase of $0.52 per month or 0.4% on the total bill for a residential customer with an average monthly consumption of 800 kWh.

As such by 2020, Entegrus forecasts that the average residential household will be paying an estimated $2.58 more per month on the distribution portion of their electricity bill.

The table below illustrates the 5 year forecasted change in rates.

## Estimated Typical Residential Annual Increase in Monthly Bill (5 year forecast)

| Year | Average Residential Bill | Distribution Portion of Bill | Incremental Rate Change from Current Typical | % Change |
|---|---|---|---|---|
| **2016** | $136.65 | $42.09 | $0.00 | 0% |
| **2017** | $137.28 | $42.72 | $0.63 | 0.5% |
| **2018** | $137.92 | $43.36 | $0.64 | 0.5% |
| **2019** | $138.57 | $44.01 | $0.65 | 0.5% |
| **2020** | $139.23 | $44.67 | $0.66 | 0.5% |



# Rate Harmonization

Prior to being acquired by what is now Entegrus, Middlesex Power, Dutton Hydro and Newbury Power each had their own local distribution rates. This means Entegrus currently has four sets of rates:

| | | |
|---|---|---|
| 1 | Chatham-Kent | The former Chatham-Kent Hydro territory |
| 2 | Strathroy, Parkhill & Mt. Brydges | The former Middlesex Power territory |
| 3 | Dutton | The former Dutton Hydro territory |
| 4 | Newbury | The former Newbury Power territory |

### *What is Rate Harmonization?*

Rate harmonization means bringing these four sets of distribution rates into one harmonized rate so that all Entegrus customers in the same rate class are paying the same for their electricity distribution. See the adjacent graphs.

This ensures customers pay the same cost for receiving the same level of service.

### *Why Harmonize Rates?*

- Provide more rate stability because one set of distribution rates for all customers is less volatile and subject to swings than four separate sets of rates.
- Improved customer service through reduced confusion over rates.
- Reduced administrative costs.
- The Ontario Energy Board (OEB) is working with local distribution companies across the province to harmonize rates after acquisitions.

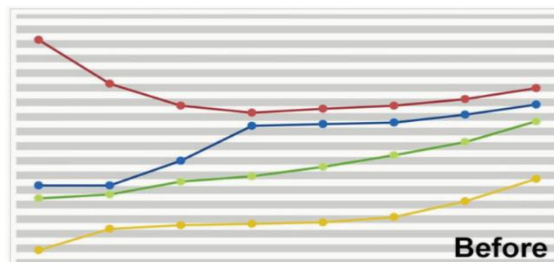
### *How Will It Impact Me?*

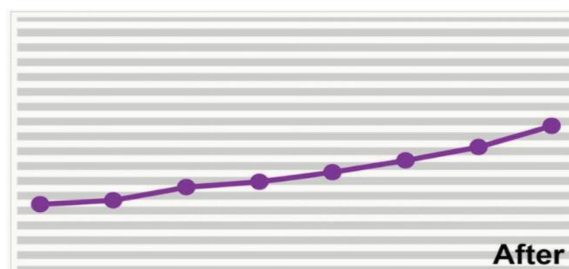
By its nature, a rate harmonization usually means that some customers will pay a little more, while others pay a little less.

However, Entegrus plans to operate, maintain, and modernize its electricity distribution system without an overall distribution rate increase in 2016. In terms of Residential customers, this means that the process of harmonizing rates is not anticipated to create any distribution rate increases versus the current distribution rates in any of the above-noted four rate zones.

### *Why Now?*

The OEB rules only allow rate harmonization to be done through a Cost of Service Application such as the one that is the focus of this consultation.




14. Which of the following best describes how you feel about rate harmonization?
    - ❑ It makes sense and I support it
    - ❑ I don't support it, but it is probably inevitable
    - ❑ I am opposed to it
    - ❑ Don't know

15. Do you think the Ontario Energy Board should support Entegrus in harmonizing its rates?
    - ❑ Yes
    - ❑ No
    - ❑ Don't know

# Customer Feedback

16. Now that you have a better sense of the operations of Entegrus, including the cost drivers, do you feel the proposed budget is reasonable?
    - ❑ Yes
    - ❑ No
    - ❑ Don't know

17. From what you have read here and what you may have heard elsewhere, does Entegrus' investment plan seem like it is going in the right direction or the wrong direction?
    - ❑ Right direction
    - ❑ Wrong direction
    - ❑ Don't know

18. How well did Entegrus' plan cover the topics you expected?
    - ❑ Very well
    - ❑ Somewhat well
    - ❑ Not very well
    - ❑ Not well at all
    - ❑ Don't know

If not very or not well at all, what is missing?

| |
|---|
| |

19. How well do you think Entegrus is planning for the future?
    - ❑ Very well
    - ❑ Somewhat well
    - ❑ Not very well
    - ❑ Not well at all
    - ❑ I don't know

20. Considering what you know about the local distribution system, which of the following best represents your point of view?
    - ❑ The rate increase is reasonable and I support it
    - ❑ I don't like it, but I think the rate increase is necessary
    - ❑ The rate increase is unreasonable and I oppose it
    - ❑ Don't know

# Final Thoughts

**Entegrus values your feedback. This is the first time the utility has conducted a review about its upcoming investment plan in this type of format.**

**Overall Impression**: What did you think about the workbook?

**Volume of Information**: Did Entegrus provide too much information, not enough, or just the right amount?

**Content Covered**: Was there any content missing that you would have liked to have seen included?

**Outstanding Questions**: Is there anything that you would still like answered?

**Suggestions for Future Consultations**: How would you prefer to participate in these consultations?

# Glossary

**Breakers**: Devices that protect the distribution system by interrupting a circuit if a higher than normal amount on power flow is detected.

**Distribution Station:** These substations are located near to the end-users. Distribution station transformers change the voltage to lower levels for use by end-users.

**Feeder Circuit:** Is a wire that connects the transmission station to the broader distribution system in order to deliver electricity to customers.

**General Plant**: Investments in things like tools, vehicles, buildings and information technology (IT) equipment that are needed to support the distribution system.

**Generation Station:** A facility designed to produce electric energy from another form of energy, such as fossil fuel, nuclear, hydroelectric, geothermal, solar thermal, and wind.

**Kilovolt (kV):** 1,000 volts (see "volt" below)

**Kilowatt (kW):** 1000 watts.

**Local Distribution Company (LDC):** In Ontario, these are the companies that take electricity from the transmission grid and distribute it around a community.

**OM&A:** Operations, Maintenance and Administration or operating budget.

**Substations:** Used to change AC voltages from one level to another and to switch generators, equipment and circuits and lines in and out of an electrical system.

**Switches**: These control the flow of electricity—they direct which supply of electricity is used and which circuits are energized. Distribution systems have switches installed at strategic locations to redirect power flows for load balancing or sectionalizing.

**System Access**: Projects required to respond to customer requests for new connections or new infrastructure development. These are usually a regulatory requirement to complete.

**System Renewal**: Projects to replace aging infrastructure in poor condition.

**System Service**: Primarily projects that improve reliability.

**Transmission lines:** Transmit high-voltage electricity from the generation source or substation to another substation in the electricity grid.

**Transformer:** Is an important piece of equipment that reduces the voltage of electricity from a high level to a level that can be safely distributed to your area or to your residence/business.

**Underground Cable:** A conductor with insulation, or a stranded conductor with or without insulation and other coverings (single-conductor cable), or a combination of conductors insulated from one another (multiple-conductor cable) with an intended use of being buried.

**Volt (V):** A unit of measure of the force, or 'push,' given the electrons in an electric circuit. One volt produces one ampere of current when acting on a resistance of one ohm.

**Watt (W):** The unit of electric power, or amount of work (J), done in a unit of time. One ampere of current flowing at a potential of one volt produces one watt of power.

**Wire:** A conductor wire or combination of wires not insulated from one another, suitable for carrying electric current.

# ATTACHMENT 1-K

Promotional Campaign to Information Customers of the Consultation

# Attachment 1-K

## Residential and Small General Service Workbook Entegrus Promotion Summary

### Website:

- Workbook was prominently advertised on the homepage of www.entegrus.com, directing customers to www.entegrus.com/workbook to learn more.

- Google Analytics shows www.entegrus.com/workbook received 1937 page views from May 21 – June 19th (1591 *unique* page views)

Google Analytics

Entegrus - http://www.entegrus.com Go to this report
Master View

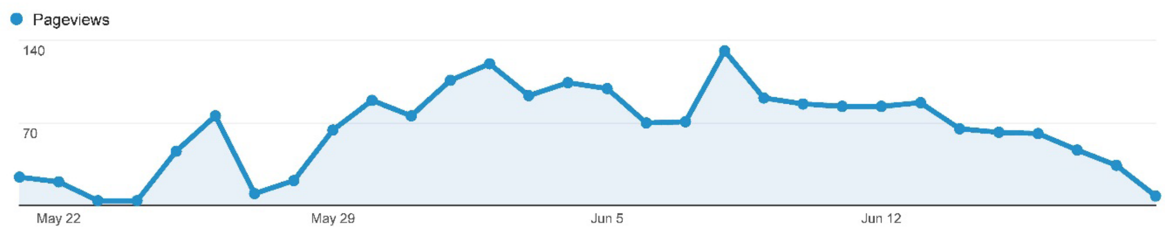
**Pages**

May 21, 2015 - Jun 19, 2015

ALL » PAGE: /workbook

All Sessions
11.16%

Explorer




| | Page | Pageviews | Unique Pageviews | Avg. Time on Page | Entrances | Bounce Rate | % Exit | Page Value |
|---|---|---|---|---|---|---|---|---|
| | | 1,937<br>% of Total: 11.16% (17,352) | 1,591<br>% of Total: 11.71% (13,586) | 00:04:18<br>Avg for View: 00:01:44 (147.90%) | 1,537<br>% of Total: 18.67% (8,233) | 73.99%<br>Avg for View: 45.58% (62.33%) | 77.39%<br>Avg for View: 47.45% (63.10%) | $0.00<br>% of Total: 0.00% ($0.00) |
| 1. | /workbook | 1,937(100.00%) | 1,591(100.00%) | 00:04:18 | 1,537(100.00%) | 73.99% | 77.39% | $0.00 (0.00%) |

Rows 1 - 1 of 1

- Page still active at: **http://entegrus.com/workbook** for reference.

**Press Release:**

A press release was issued in order gain media attention to encourage participation in the Entegrus residential workbook (next page).

**Resulting media coverage:**

- http://www.chathamdailynews.ca/2015/05/25/planning-for-infrastructure-investments
- http://blackburnnews.com/chatham/chatham-news/2015/05/30/entegrus-wants-customer-feedback/
- http://www.sydenhamcurrent.ca/2015/05/29/entegrus-is-looking-for-feedback/
- Also featured on 105.7 My FM News (Strathroy)

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**Entegrus Seeking Customer Feedback**

For Immediate Release

Friday, May 22, 2015. Entegrus is planning for the future and is looking for feedback. In order to collect this feedback, the company has launched an online workbook regarding its distribution system plan. The interactive workbook focuses on the investment and spending plans Entegrus has for the next 5 years to maintain the local distribution system, while continuing to safely, reliably and efficiently deliver the electricity local homes and businesses depend on. These plans will be the focus of Entegrus' upcoming rate application to the Ontario Energy Board (OEB) for rates effective May 1, 2016.

"Customer feedback is imperative to the Rate Application process in order to ensure our operational and capital goals are in line with customer needs and priorities," stated Jim Hogan, President & CEO of Entegrus. "We have developed a plan, and would like to hear from our customers on whether or not our plan addresses the electricity issues that matter most to them. This is the opportunity to provide specific feedback that will be taken into consideration in our final application."

The company has taken a number of steps to ensure customers will develop an informed opinion.

"We've posted an online workbook that will walk both residential and small business customers through the considerations Entegrus made in developing its plans," stated Hogan. "The workbook is designed to give customers background on the industry and other relevant factors that will help them to develop and share an informed opinion during this feedback process. A great amount of effort went into the development of the workbook, including Entegrus specific videos which summarize key topics."

Customer feedback will be presented to the OEB and public intervenors (who represent various ratepayer groups) when Entegrus files its 2016 rate application. As part of the rate hearing process, the OEB will be reviewing how Entegrus acquired and responded to customer feedback in its planning process. Entegrus encourages its residential and small business customers to participate in the online workbook, learn about the industry, and share their opinion on the Entegrus plans for the local electricity system.

As an incentive to participate, Entegrus will host a draw for five $250 prepaid credit cards from the respondents who complete the online survey.

Entegrus is also randomly recruiting customers to participate in focus groups on this topic. Customers selected will be contacted by phone.

The online workbook can be accessed through www.entegrus.com/workbook and will be available until Friday, June 19th.

###

- **Residential & Small General Service Rate Brochures:** The Entegrus Customer Engagement Workbook was advertised in the May Residential Rate Brochure, Distribution: 41 285. Distribution ran starting Thursday, May 21st for 4 weeks.


Entegrus wants your feedback on the future of its distribution services!

* WIN *
1 of 5
$250 Pre-Paid Credit Cards!

GIFT CARD

Here's How!

1. Visit our webpage
entegrus.com/workbook

2. View the online workbook and a series of short videos

Entegrus 2015 Workbook

3. Take the survey at the end of each section

4. Enter your contact information & you're entered to win!

Online workbook is available until
Friday, June 19th
Visit us online today to make your opinion count!
entegrus.com/workbook

**Pre-Authorized Payments** (registration through 'My Account' now available!)

Entegrus offers two payment options for pre-authorized payments:

**1. Full Payment by Due Date**
With your authorization, the total amount of your electric and/or water bill will be automatically withdrawn from your chequing account on the due date. You will continue to receive your regular bill indicating "PAP – Do Not Pay".

**2. Monthly Budget**
This plan will average your payments over 12 months. We review last year's hydro and water usage and estimate next year's hydro and water costs. This amount is reviewed and adjusted annually. With your authorization, payments will be withdrawn automatically from your chequing account on either the 1st, 15th or 20th of each month.

You may join either of these plans by completing this form and including a VOID cheque.

I authorize Entegrus Inc. and the Financial Institution designated to begin deductions for my pre-authorized payment. (Please attach void cheque)

Name: ____________________

Account #: ____________________

Address: ____________________

Town: __________ Postal Code: ________

Home Telephone: (    ) ____________

Work Telephone: (    ) ____________

**Type of Plan:** (check one)

**Full payment by due date:** ☐ **Monthly budget:** ☐

*Please note: due date is assigned by cycle billing*

*If monthly, please choose payment date:*
**1st** ☐ **15th** ☐ **20th** ☐

*Signature* ____________ *Date* ____________

*Return the above form to our office via fax or mail or complete online through 'My Account.'*

Tariff of Rates & Charges

Chatham-Kent

Residential & General Service < 50kW

Effective May 1, 2015

ENTEGRUS®

PO Box 70
Chatham, ON
N7M 5K2

Telephone: 1-866-804-7325
Fax: 519-351-4059

www.entegrus.com
Email: customerservice@entegrus.com

**Eblast to customers:**

- 6564 email addresses received the following eblast (next page), encouraging participation in the online workbook.
- **Average open rate of 60%**

ENTEGRUS®

# Participate in the 2015 Residential and Small Business Customer Consultation Workbook

**Complete the workbook and be entered to win 1 of 5 $250 prepaid credit cards!**

The purpose of this customer consultation is to collect your feedback on our investment and spending plan to maintain the local distribution system over the five year period from 2016 to 2020.

Our goal is to deliver safe and reliable electricity to homes and local businesses as efficiently as possible and at an affordable price. There is a balancing act that all utilities must consider when planning for the future; system reliability versus the cost to consumers. No distribution system delivers perfectly reliable electricity. Generally, the more reliable the system, the more expensive the system is to build and maintain.

**To participate in this review, you do not need to be an expert.** The workbook explains key parts of the electrical distribution system, the challenges facing the system, Entegrus' recent work to maintain the system, and the company's budgetary plan for 2016 to 2020. This workbook is designed to give you enough background about these issues for you to develop an informed opinion.

(Click here to launch workbook & proceed to external site)

Thank you for allowing us to better serve you.

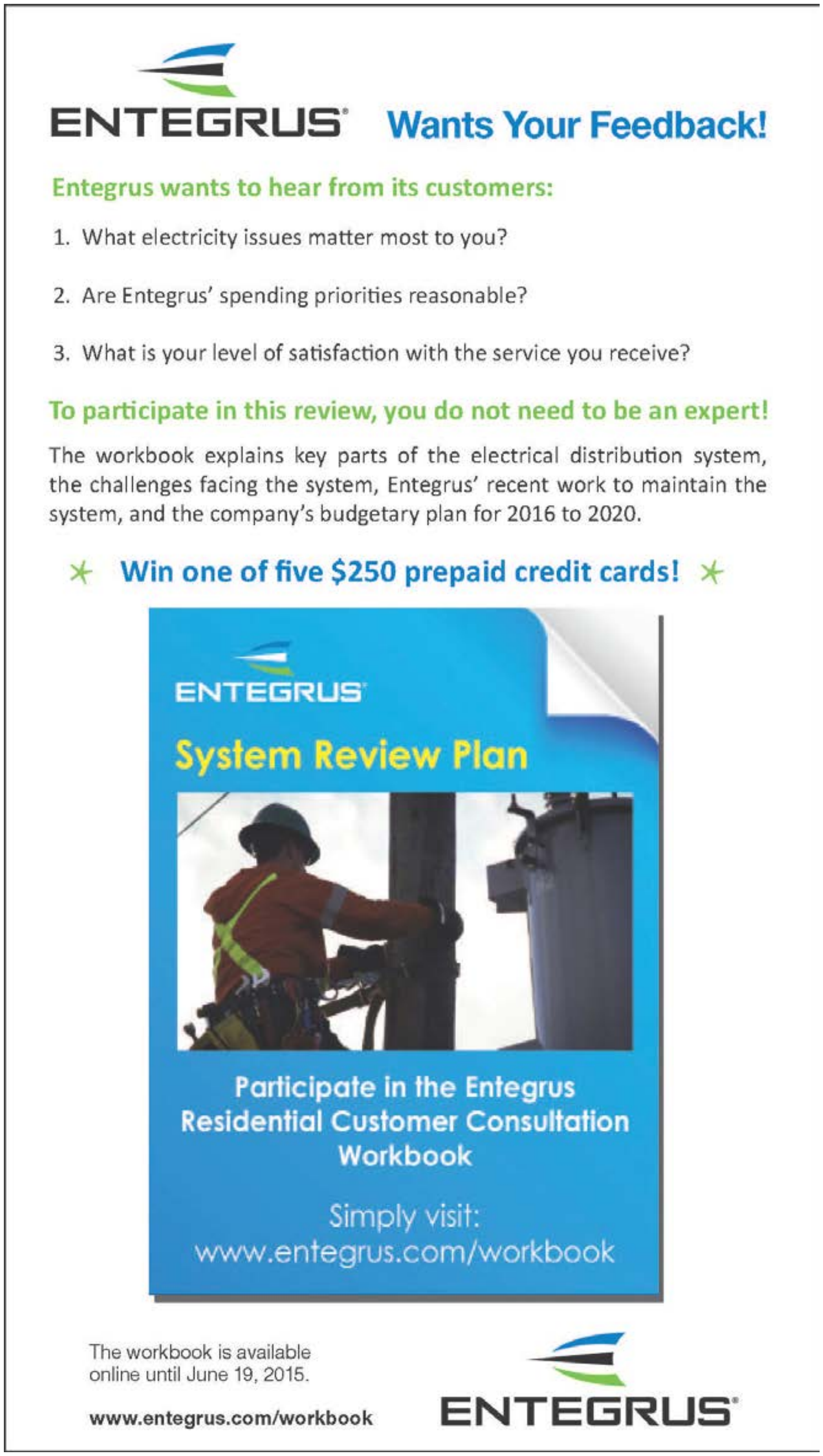
Sincerely,

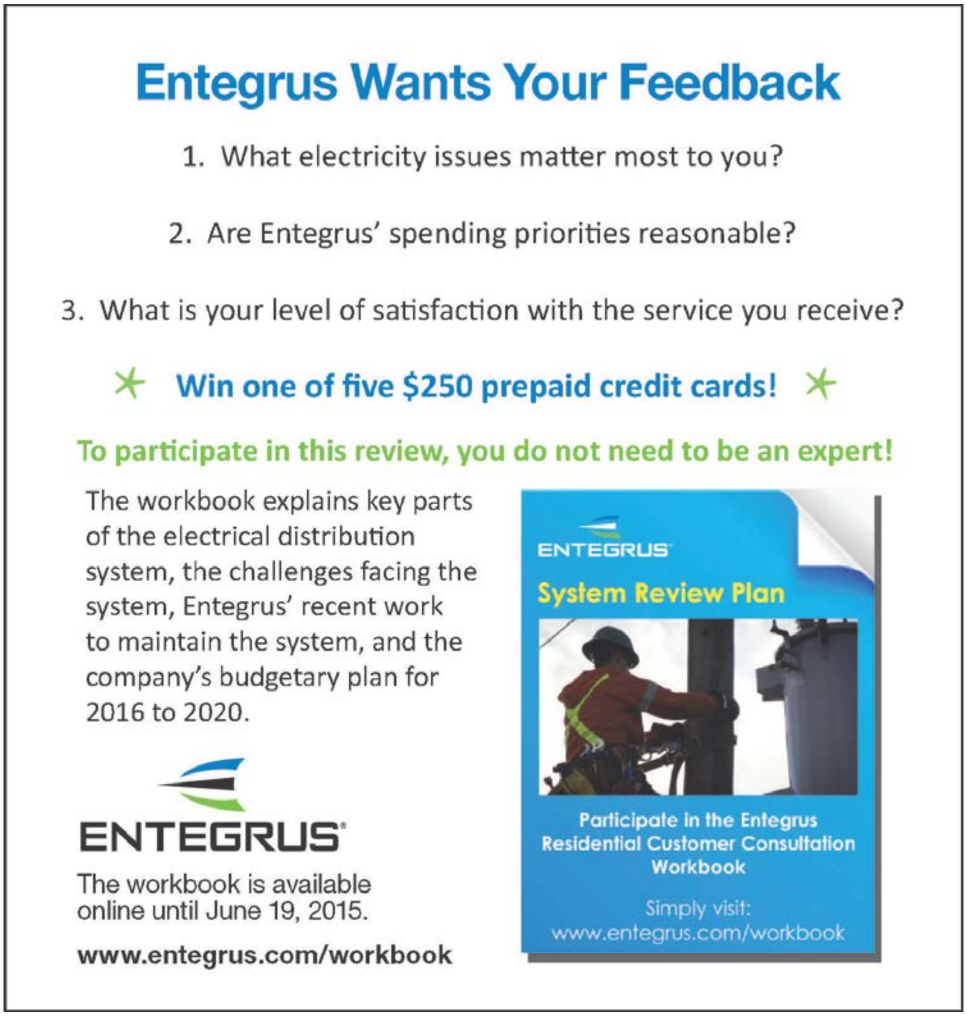
Entegrus Customer Service

**Newspaper Advertising:**

- **Smart Shopper Newspaper Advertisement**:
    - Front Cover, Full Page, Distribution 42 000
    - Distributed on Thursday, May 21

- **Newspaper Advertising:**
    - ¼ Page ad in the Chatham Daily News, Week of June 1, June 8 & June 15. Same schedule for the Strathroy Age Dispatch.






- **Online Advertising (including Social Media)**
  - Chatham Daily News, 105 000 impressions
  - Targeted Facebook Advertising (Specifically targeted the towns available: Chatham, Strathroy, Parkhill, Mount Brydges, Newbury, Ridgetown, Dresden, Tilbury, Blenheim, Erieau, Wheatley, Wallaceburg & Thamesville), gaining a reach of over 13 000 views, and 259 clicks.

**Entegrus**

Written by Sarah Regnier [?] · June 7 ·

Entegrus is seeking customer feedback. The online workbook is available until June 19th.

Participate today!

Complete the workbook and be entered to win one of five $250 pre-paid credit cards!

WWW.ENTEGRUSWORKBOOK.COM

Learn More

Like Comment Share

Lisa Mallory, Curt Watchorn, Mary Schweitzer and 9 others like this.

Top Comments

1 share

| 104 | 13.3K | 259 |
|---|---|---|
| Organic Reach | Paid Reach | Post Clicks |

**Commercial and Industrial Summary:**

**Commercial and Industrial Focus Group Promotion**

The C&I focus groups were promoted in tandem with Entegrus' Conservation event 'Power Play – Profiting from Sustainability & Electricity Conservation Strategies,' targeted towards Commercial and Industrial Customers in May of 2015.

**Telephone calls to customers:**

- 140 Telephone calls made to encourage participation made by Entegrus' Energy Efficiency Advisor (60%), Conservation Engineer (30%) & Corporate Communications Specialist (10%)

**Faxes to customers:**

- 30 fax numbers on file

**Event Invitations for Conservation event, featuring Commercial and Industrial Focus Group**

- 367 physical invitations mailed to local addresses of commercial customers in our service territory (example previous page)

**Online event invitations / registration for Conservation event, featuring Commercial and Industrial Focus Group**

- 567 Email addresses received the following email invitation, with the ability to respond and register online (next page)

POWER PLAY

*Profiting from Sustainability & Electricity Conservation Strategies*

# Agenda

Wednesday, May 27th, 2015

| | |
|---|---|
| 8:30am - 9:00am | **Registration**<br>(light refreshments available) |
| 9:00am - 9:10am | **Welcome Remarks**<br>Jim Hogan, President & CEO, Entegrus |
| 9:10am - 9:30am | **Local Case Study**<br>Daniel Josling, Entegrus |
| 9:30am - 9:50am | **Conservation Programs & Incentives**<br>Graham Smith, Independent Electricity System Operator (IESO) |
| 9:50am - 10:45am | **Keynote Speaker: Bob Willard**<br>Author: The NEW Sustainability Advantage |
| 10:45am - 11:00am | **Break** |
| 11:00am - 11:45am | **Success Story: Paul Rak**<br>President, VeriForm |
| 11:45am - 12:30pm | **Panel Q&A**<br>Featuring speakers Bob Willard & Paul Rak, Sean Brady (IESO), Tomo Matesic (Entegrus) |
| 12:30 - 2:00pm | **Lunch & Information Booths** |
| 1:30pm - 3:30pm | **Commercial and Industrial customer focus group on the Entegrus 2016 rate application. Separate registration required.** (Due to limited space we may not be able to accomodate all interested - you will receive a confirmation email if randomly selected to participate) |

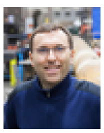
## Event Details

Join us for "Power Play - Profiting from Sustainability & Electricity Conservation Strategies."

This invitation-only event is exclusive to Entegrus commercial & industrial customers. Learn about conservation programs currently available, local case studies, and hear from two distinguished speakers:

 **Keynote Speaker:  Bob Willard**

Sustainability expert, Author, & sought-after speaker, Bob Willard is a leading expert on the business value of corporate sustainability strategies. Bob provides resources and tools to help organizations make the business case for sustainability & to prepare organizations to be "Future Fit." In most cases, energy conservation is the best (and easiest) place to start. Learn how companies are using sustainability strategies to ensure they remain competitive for years to come.

 **Success Story: Paul Rak**

Paul is President & CEO of VeriForm, a metal fabricating company in Cambridge, ON. Paul is responsible for implementing 90+ green energy projects over the past several years, has increased the size of their fabricating plant by 145%, all while reducing their monthly electricity cost by 58%. Along with several other initiatives that were not technologically challenging or expensive, Paul increased the company's annual operating profits nearly 100%.

A special Q & A panel will occur following the last presentation for customers to have the opportunity to "ask the experts." Lunch is provided, and representatives from Entegrus and the Independent Electricity Systems Operator will be present to answer any questions you may have.

An optional commercial and industrial focus group will run from 1:30 - 3:30pm, following this event.

# ATTACHMENT 1-L

Audited Financial Statements for
2012, 2013 and 2014

*Financial Statements of*

# ENTEGRUS POWERLINES INC.
(formerly Chatham-Kent Hydro Inc.)

*December 31, 2012*

## Management's Responsibility for Financial Reporting

Entegrus Powerlines Inc.'s management is responsible for the preparation and presentation of the financial statements and all other information included in this annual report. Management is also responsible for the selection and use of accounting principles that are appropriate in the circumstances, and for the internal controls over the financial reporting process to reasonably ensure that relevant and reliable information is produced. Financial statements are not precise in nature as they include certain amounts based on estimates and judgment. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control over the financial reporting process. The Board of Directors exercises this responsibility through its Audit Committee. This committee is comprised of four directors of companies within the Entegrus group, one of whom is a director of the Entegrus Powerlines Inc. Board. This committee meets with management and the external auditors to ensure that management responsibilities are properly discharged and to review the financial statements and other information included in the annual report before they are presented to the Board of Directors for approval. The financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

Deloitte LLP, an independent firm of Chartered Accountants, has been appointed by the Audit Committee and engaged to examine the accompanying financial statements in accordance with generally accepted auditing standards in Canada and provide an independent professional opinion. Their report is presented with the financial statements.

D Charron

**Dan Charron**
**President**

**Chris Cowell**
**Chief Financial & Regulatory Officer**

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Deloitte.

Deloitte LLP
One London Place
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Suite 700
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www.deloitte.ca

# Independent Auditor's Report

To the Chairman and Board Members of
Entegrus Powerlines Inc.

We have audited the accompanying financial statements of Entegrus Powerlines Inc. (formerly Chatham-Kent Hydro Inc.) which comprise the balance sheet as at December 31, 2012, and the statements of earnings, comprehensive income and retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

**Management's responsibility for the financial statements**

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

**Auditor's responsibility**

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

## Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Entegrus Powerlines Inc. as at December 31, 2012 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Deloitte LLP

Chartered Accountants
Licensed Public Accountants
April 19, 2013

## ENTEGRUS POWERLINES INC. (formerly Chatham-Kent Hydro Inc.)
## Balance Sheet
## December 31, 2012

| | 2012 | 2011 |
|---|---|---|
| | $ | $ |
| **ASSETS** | | |
| CURRENT | | |
| Cash and cash equivalents | **7,799,967** | 7,798,310 |
| Accounts receivable (Note 5) | **7,149,517** | 4,295,795 |
| Accounts receivable - unbilled revenue | **10,744,448** | 11,694,409 |
| Taxes receivable | **-** | 768,331 |
| Inventories | **786,343** | 774,224 |
| Prepaid expenses | **114,149** | 101,019 |
| | **26,594,424** | 25,432,088 |
| CAPITAL ASSETS (Note 6) | **62,468,809** | 57,664,111 |
| OTHER | | |
| Computer software (Note 6) | **171,848** | 230,648 |
| Deferred assets (Note 7) | **3,423,509** | 6,072,825 |
| Goodwill and intangible assets | **452,040** | 452,040 |
| Future income taxes (Note 17) | **3,282,682** | 2,869,132 |
| | **7,330,079** | 9,624,645 |
| | **96,393,312** | 92,720,844 |
| **LIABILITIES** | | |
| CURRENT | | |
| Accounts payable and accrued liabilities | **12,113,135** | 13,054,080 |
| Taxes payable | **470,354** | - |
| Due to related parties (Note 11) | **8,637,919** | 4,758,117 |
| Deferred revenue | **469,673** | 327,238 |
| Current portion of customer deposits | **1,133,532** | 1,675,080 |
| | **22,824,613** | 19,814,515 |
| LONG-TERM | | |
| Regulatory future income tax liability (Note 17) | **3,282,682** | 2,869,132 |
| Notes payable (Note 8) | **37,073,326** | 37,073,326 |
| Asset retirement obligation | **15,000** | 15,000 |
| Employee future benefits (Note 9) | **1,076,023** | 1,049,960 |
| Long-term portion of customer deposits | **3,179,145** | 2,642,776 |
| | **44,626,176** | 43,650,194 |
| | **67,450,789** | 63,464,709 |
| CONTINGENCY AND COMMITMENTS (Notes 12 and 18) | | |
| **SHAREHOLDER'S EQUITY** | | |
| Share capital (Note 13) | **28,154,623** | 28,154,623 |
| Retained earnings | **787,900** | 1,101,512 |
| | **28,942,523** | 29,256,135 |
| | **96,393,312** | 92,720,844 |

**ENTEGRUS POWERLINES INC. (formerly Chatham-Kent Hydro Inc.)**
**Statement of Earnings, Comprehensive Income and Retained Earnings**
**Year Ended December 31, 2012**

| | 2012 | 2011 |
|---|---|---|
| | $ | $ |
| SERVICE REVENUE | | |
| Residential | **38,875,311** | 36,001,128 |
| General service | **63,887,377** | 59,905,456 |
| Street lighting | **958,820** | 892,489 |
| | **103,721,508** | 96,799,073 |
| Change in unbilled revenue | **(646,352)** | (264,961) |
| | **103,075,156** | 96,534,112 |
| Retailer energy sales | **3,183,117** | 4,685,541 |
| | **106,258,273** | 101,219,653 |
| COST OF POWER | **88,648,371** | 83,785,228 |
| GROSS MARGIN ON SERVICE REVENUE | **17,609,902** | 17,434,425 |
| OTHER OPERATING REVENUE | **1,504,742** | 1,675,680 |
| OPERATING INCOME | **19,114,644** | 19,110,105 |
| OPERATING AND MAINTENANCE EXPENSE | | |
| Distribution | **3,546,002** | 3,464,352 |
| Regulatory | **107,662** | 2,147,831 |
| ADMINISTRATIVE EXPENSE | | |
| Billing and collection | **2,433,637** | 2,578,938 |
| General administration | **2,816,846** | 2,650,913 |
| Interest | **2,372,525** | 2,357,635 |
| DEPRECIATION AND AMORTIZATION | **4,518,725** | 4,383,951 |
| | **15,795,397** | 17,583,620 |
| EARNINGS BEFORE PAYMENTS IN LIEU OF TAXES | **3,319,247** | 1,526,485 |
| Provisions for payments in lieu of taxes (Note 17) | **1,032,859** | 410,422 |
| NET EARNINGS AND COMPREHENSIVE INCOME | **2,286,388** | 1,116,063 |
| RETAINED EARNINGS, BEGINNING OF YEAR | **1,101,512** | 385,449 |
| LESS DIVIDENDS | **(2,600,000)** | (400,000) |
| RETAINED EARNINGS, END OF YEAR | **787,900** | 1,101,512 |

**ENTEGRUS POWERLINES INC. (formerly Chatham-Kent Hydro Inc.)**
**Statement of Cash Flows**
**Year Ended December 31, 2012**

| | 2012 | 2011 |
|---|---|---|
| | $ | $ |
| OPERATING ACTIVITIES | | |
| Net earnings | **2,286,388** | 1,116,063 |
| Adjustments for: | | |
| Depreciation of capital assets | **5,694,316** | 5,045,108 |
| Depreciation of computer software | **135,770** | 106,399 |
| Amortization of contributed capital | **(250,385)** | (230,452) |
| Gain on disposal of capital assets | **(77,715)** | (109,157) |
| Employee future benefits | **26,063** | 41,738 |
| Changes in non-cash working capital items (Note 14) | **1,849,419** | 2,737,833 |
| Change in long-term customer deposits | **536,369** | (333,068) |
| | **10,200,225** | 8,374,464 |
| INVESTING ACTIVITIES | | |
| Change in deferred assets | **(207,234)** | (275,442) |
| Proceeds on disposal of capital assets | **369,370** | 118,655 |
| Additions to capital assets | **(7,683,733)** | (6,621,408) |
| Additions to computer software | **(76,971)** | (44,188) |
| | **(7,598,568)** | (6,822,383) |
| FINANCING ACTIVITIES | | |
| Dividends | **(2,600,000)** | (400,000) |
| NET CHANGE IN CASH AND CASH EQUIVALENTS | **1,657** | 1,152,081 |
| CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR | **7,798,310** | 6,646,229 |
| CASH AND CASH EQUIVALENTS, END OF YEAR | **7,799,967** | 7,798,310 |

See Note 14 for supplemental cash flow information.

## 1. NATURE OF OPERATIONS

*a) Incorporation and amalgamation*

Chatham-Kent Hydro Inc. ("CKH") was incorporated September 22, 2000 under the *Business Corporations Act (Ontario).* Effective January 1, 2012, CKH and a company under common control, Middlesex Power Distribution Corporation ("MPDC"), amalgamated to continue as Chatham-Kent Hydro Inc. Effective January 19, 2012, the name of the amalgamated entity was changed from Chatham-Kent Hydro Inc. to Entegrus Powerlines Inc. ("the Company").

The Company is wholly-owned by Entegrus Inc. ("EI"), which in turn is owned 90% by the Municipality of Chatham-Kent ("the Municipality") and 10% by Corix Utilities ("Corix"). The principal activity of the Company is to distribute electricity to customers within the Municipality of Chatham-Kent, Middlesex County and the County of Elgin, under a licence issued by the Ontario Energy Board ("OEB").

*b) Rate-regulated entity*

The Company is a regulated Local Distribution Company ("LDC") and has a distribution licence that is regulated by the OEB. The OEB has regulatory oversight of electricity matters in Ontario. The *Ontario Energy Board Act, 1998* sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles and filing process requirements for rate-setting purposes. The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers and the responsibility of ensuring the electricity distribution companies fulfill obligations to connect and service customers.

The Company is required to charge its customers for the following amounts (all of which, other than the distribution rates, represent a pass through of amounts payable to third parties):

- Electricity Price – The electricity price represents the commodity cost of electricity;
- Distribution Rate – The distribution rate is designed to recover the costs incurred by the Company in delivering electricity to customers and the OEB allowed rate of return;
- Global Adjustment – The difference between the rate paid to regulated and contracted electricity generators and the spot market price;
- Retail Transmission Rate – The retail transmission rate represents the wholesale costs incurred by the Company in respect of the transmission of electricity from generating stations to the local areas; and
- Wholesale Market Services Charge – The wholesale market services charge represents the cost of services provided by the Independent Electricity System Operator ("IESO") and the Ontario Power Authority ("OPA") to operate the wholesale electricity market and maintain the reliability of the power grid.

In order to operate in the Ontario electrical industry all market participants, including the Company, are required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations in the form of obtaining a credit rating, letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings.

## 1. NATURE OF OPERATIONS (continued)

*Market-based rate of return*

Rates for the Company continue to be based on the pre-amalgamation service territories until the Company's rates are rebased in 2016. At that time, the Company will consider whether rate harmonization would provide overall benefit to customers in all affected rate territories and be in accordance with good rate-making practices.

The OEB approved the former CKH to revise rates effective May 1, 2010, which resulted in approved rates that include a 9.85% rate of return on equity rebased at 2010 test year levels. The rate of return of 9.85% was in accordance with the OEB's cost of capital parameters at that time.

The OEB approved the former MPDC to revise rates effective May 1, 2006, which resulted in approved rates that include a 9.0% rate of return on equity rebased at 2004 test year levels. The rate of return of 9.0% was in accordance with the OEB's cost of capital parameters at that time.

*Incentive Rate Mechanism*

Between rate basing years, the OEB regulates the rates of the Company under an Incentive Rate Mechanism ("IRM") regime. The process includes a mechanistic approach to establishing rates with a rate rebasing approach (cost-of-service) every five years. The IRM rate setting process provides an increase in rates for inflationary cost increases with an offset for productivity gains.

The OEB allows for rate rebasing to be deferred for up to five years where there is a purchase or merger of LDC's. As a result of the amalgamation of CKH and MPDC, the OEB has approved the deferral of rate rebasing of the Company to 2016.

*Deferred assets*

Electricity distributors are required to reflect certain prescribed costs on their balance sheets until the manner and timing of distribution is determined by the OEB. These costs are:

- Transition costs resulting from preparation of Open Access;
- Settlement variance between amounts charged by the Company to customers (based on regulated rates) and corresponding cost of non-competitive electricity service incurred by it in the wholesale market administered by the IESO after May 1, 2002;
- The deferral of OEB annual cost assessments for the OEB's fiscal year 2004 and 2005;
- The deferral of incremental Ontario Municipal Employees' Retirement System ("OMERS") pension expenditures for fiscal years starting after January 1, 2005;
- Costs incurred to invest in and install a smart meter at all of our customer premises;
- Payments in lieu of taxes ("PILS") variances since the Company became taxable October 2002;
- Cost related to the *Green Energy and Green Economy Act, 2009*; and
- Costs incurred related to the Company's transition to International Financial Reporting Standards ("IFRS").

## 2. FUTURE ACCOUNTING CHANGES

*a) Changes in accounting framework*

On February 13, 2008, the Accounting Standards Board ("AcSB") of the Canadian Institute of Chartered Accountants ("CICA") confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles ("GAAP") for fiscal years beginning on or after January 1, 2011. Subsequently, on September 10, 2010, the AcSB decided to permit rate-regulated entities and certain affiliates to defer their IFRS adoption date to January 1, 2012. The Company is a qualifying entity for purposes of this deferral and elected to use the deferral offered by the AcSB.

On March 30, 2012, the AcSB announced an additional one year deferral for qualifying entities with rate-regulated activities. A further one year deferral was announced by the AcSB in September 2012. The Company has elected to use both of these deferrals. As a result, the Company's IFRS adoption date is currently set at January 1, 2014.

On February 13, 2013, the AcSB announced a decision to further extend the optional deferral to January 1, 2015. The Company will make a decision with respect to the use of this most recent deferral once a comprehensive financial, regulatory and operational impact assessment has been completed.

*b) Changes in accounting policies*

In July 2012, the OEB issued a letter to LDC's that provides direction on permitted accounting policies for depreciation expense and capitalization beginning in 2013. In this letter, the OEB states that it will require all LDC's to adopt IFRS-compliant depreciation and capitalization accounting policies effective January 1, 2013, regardless of whether the LDC has chosen to defer the adoption of IFRS as permitted by the AcSB. The OEB also approved the use of a new variance account to capture the financial differences arising as a result of adopting IFRS-compliant accounting policies in 2013. This variance account is to be disposed of as part of the LDC's next rate rebasing. Therefore, there will be no impact to net income as a result of these accounting policy changes.

As such, the Company will adopt IFRS-compliant accounting policies for depreciation and capitalization effective January 1, 2013. These policies will be selected in accordance with International Accounting Standard 16, "Property, Plant and Equipment" ("IAS 16"). IAS 16 provides more definitive guidance with respect to cost capitalization and componentization for depreciation purposes than that currently followed under Canadian GAAP.

Due to the absence of rate-regulated accounting guidance within Canadian GAAP, the Company follows regulatory accounting guidance found under US GAAP. In accordance with US GAAP Accounting Standards Codification Section 980, "Regulated Operations," the Company will adopt these changes prospectively with no retrospective restatement of prior periods.

## 3. SIGNIFICANT ACCOUNTING POLICIES

The financial statements have been prepared in accordance with Canadian GAAP and reflect the following policies as set forth in the Accounting Procedures Handbook issued by the OEB under the authority of the *Ontario Energy Board Act, 1998:*

*Regulation*

The Company is regulated by the OEB and any rate adjustments require OEB approval.

*Cash and cash equivalents*

Cash and cash equivalents consist of cash on hand and balances with the bank.

*Unbilled revenue*

Unbilled revenue is an estimate of customers' consumption of power from the last meter read to December 31st.

*Inventories*

Inventories are valued at the lower of cost and net realizable value with cost being determined using the weighted average method.

*Capital assets*

Capital assets are recorded at cost. Depreciation is calculated on a straight-line basis over the useful life of the asset as follows:

| | |
|---|---|
| Buildings and fixtures | 25 - 50 years |
| Distribution station equipment | 30 years |
| Distribution lines | 25 years |
| Distribution transformers | 25 years |
| Distribution meters | 25 years |
| General office equipment | 10 years |
| Computer equipment | 5 years |
| Rolling stock | 4 - 8 years |
| Tools | 10 years |
| System supervisory equipment | 15 years |
| Automated mapping facility management | 15 years |
| Services | 25 years |
| Contributions in aid of construction | 25 years |
| Supervisory control and data acquisition | 15 years |
| Smart meters | 3 - 15 years |
| Non-regulated generation assets | 25 years |

The Company recognizes work in process for larger capital investment projects that are not in service at the end of the year. When the capital investment projects are completed, they are transferred to the appropriate capital asset or computer software account. Depreciation of these assets will begin when they are placed in service.

## 3. SIGNIFICANT ACCOUNTING POLICIES (continued)

*Impairment of long-lived assets*

Long-lived assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. An impairment loss is recognized when their carrying value exceeds the total undiscounted cash flows expected from their use and eventual disposition. The amount of the impairment loss is determined as the excess of the carrying value of the asset over its fair value.

*Contributions in aid of construction*

Contributions in aid of construction consist of third party contributions toward the cost of constructing the Company's assets. For the year ended December 31, 2012, $564,961 (2011 - $507,424) of contributed capital has been charged to capital assets and recorded as an offset to capital assets. Amortization is on a straight-line basis over 25 years.

*Computer software*

Computer software is stated at cost less accumulated depreciation. Distribution software is depreciated over 5 years on a straight-line basis. Smart meter software is depreciated over 3 years on a straight-line basis.

*Goodwill*

Goodwill representing the excess of purchase price over fair value of the net identifiable assets of acquired businesses is tested for impairment annually or more frequently when an event or circumstance occurs that indicates that goodwill might be impaired. When the carrying amount exceeds the fair value, an impairment loss is recognized in the statement earnings in an amount equal to the excess.

*Intangible assets*

Intangible assets are recorded at their fair value at the acquisition date. As the Company's intangible assets have an indefinite life, they are not amortized to income. Intangible assets will be tested for impairment when events or changes in circumstances indicate that their carrying value may not be recoverable.

*Deferred assets*

Deferred assets consist of qualifying capital costs and related expenditures incurred in the preparation for market opening, investments in smart meters and other expenditures that are not currently recovered in rates. Also included in deferred assets are retail settlement variance accounts. These variances are for non-competitive energy services which are a pass through for the Company. Recovery of the deferred assets requires regulatory approval from the OEB.

## 3. SIGNIFICANT ACCOUNTING POLICIES (continued)

*Payments in lieu of taxes*

Under the *Electricity Act, 1998*, the Company is required to make payments-in-lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are recorded in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) and modified by the *Electricity Act, 1998*, and related regulations.

The Company recognizes future income tax assets and liabilities in accordance with CICA Section 3465, "Income Taxes." Section 3465 also contains guidance specific to rate-regulated enterprises that requires the Company to recognize a regulatory asset or liability for the amount of future income taxes expected to be recovered from or refunded to ratepayers and to present these amounts on a pre-tax basis in the financial statements. Accordingly, the Company has recorded a regulatory liability that has been included in long-term liabilities and an associated future income tax asset of $3,282,682 (2011 - $2,869,132). The liability will be paid through future rate reductions.

*Customer deposits*

Customer deposits are recorded when received or paid. Deposits earn interest at a rate of prime less 2%.

*Asset retirement obligations*

The Company recognizes the liability for a future asset retirement that results from acquisition, construction, development or normal operations. The liability for an asset retirement is initially recorded at its fair value in the year in which it is incurred and when a reasonable estimate of fair value can be made. The corresponding cost is capitalized as part of the related asset and is amortized over the asset's useful life. In subsequent years the liability is adjusted for changes resulting from the passage of time and revisions to either the timing or the amount of the original estimate of the undiscounted cash flows. The accretion of the liability to its fair value as a result of the passage of time is charged to earnings.

*Post-employment benefits other than pension*

The Company provides its current and retired employees with life insurance and medical benefits beyond those provided by government-sponsored plans. The cost of these benefits is expensed as earned through employment service.

*Use of estimates*

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

## 3. SIGNIFICANT ACCOUNTING POLICIES (continued)

*Revenue recognition and cost of power*

Service revenue is recorded on the basis of regular meter readings and estimated customer usage since the last meter reading date to the end of the year. The related cost of power is recorded on the basis of power used. Any discrepancies in the revenue collected and associated cost of power related to distribution are charged to deferred assets.

In accordance with the CICA's Emerging Issues Committee Abstract 123, "Reporting Revenue Gross as a Principal Versus Net as an Agent," costs to provide OPA programs have been netted against OPA revenues included in Other Operating Revenue. In 2011, costs of $177,799 were netted against revenues. Beginning in 2012, activities relating to OPA programs are recorded through accounts receivable and deferred revenue in the balance sheet and are no longer recorded through revenue and expenses in the statement of earnings.

*Financial instruments*

The AcSB decided that rate-regulated enterprises that are not public enterprises as defined in Section 1300, "Differential Reporting," will not be required to apply Sections 3862, "Financial Instruments – Disclosures," and 3863, "Financial Instruments – Presentation," and would continue to apply Section 3861, "Financial Instruments – Disclosure and Presentation." Therefore, in accordance with this decision, the Company continues to apply Section 3861.

Financial assets and financial liabilities are initially recognized at fair value and their subsequent measurement is dependent on their classification as described below. Their classification depends on the purpose, for which the financial instruments were acquired or issued, their characteristics and the Company's designation of such instruments. Settlement date accounting is used.

Classification

| | |
|---|---|
| Cash and cash equivalents | Held for trading |
| Accounts receivable | Loans and receivables |
| Accounts payable and accrued liabilities | Other liabilities |
| Due to related parties | Other liabilities |
| Current portion of customer deposits | Other liabilities |
| Notes payable | Other liabilities |
| Long-term portion of customer deposits | Other liabilities |

Held for trading

Held for trading financial assets are financial assets typically acquired for resale prior to maturity or that are designated as held for trading. They are measured at fair value at the balance sheet date. Fair value fluctuations including interest earned, interest accrued, gains and losses realized on disposal and unrealized gains and losses are included in other income.

## 3. SIGNIFICANT ACCOUNTING POLICIES (continued)

*Financial instruments (continued)*

Financial liabilities designated as held for trading are those non-derivative financial liabilities that the Company elects to designate on initial recognition as instruments that it will measure at fair value through other interest expense. These are accounted for in the same manner as held for trading assets. The Company has not designated any non-derivative financial liabilities as held for trading.

Loans and receivables

Loans and receivables are accounted for at amortized cost using the effective interest method.

Other liabilities

Other liabilities are recorded at amortized cost using the effective interest method and include all financial liabilities, other than derivative instruments.

Effective interest method

The Company uses the effective interest method to recognize interest income or expense which includes transaction costs or fees, premiums or discounts earned or incurred for financial instruments.

## 4. AMALGAMATION

Effective January 1, 2012, CKH and MPDC amalgamated to continue as Chatham-Kent Hydro Inc. The amalgamation was accounted for at historical cost in a manner similar to a pooling of interests. In connection with the amalgamation, the Company acquired assets and assumed liabilities of $16,228,585 and $11,562,475, respectively. The Company's total shareholder's equity increased by $4,666,110 as a result of the amalgamation. The prior year comparative figures have been restated as if the two companies have always been combined.

## 5. ACCOUNTS RECEIVABLE

| | **2012** | 2011 |
|---|---|---|
| | **$** | $ |
| Electrical energy | **3,937,174** | 3,381,278 |
| Other | **3,349,339** | 1,087,382 |
| | **7,286,513** | 4,468,660 |
| Allowance for doubtful accounts | **(136,996)** | (172,865) |
| Net accounts receivable | **7,149,517** | 4,295,795 |

## 6. CAPITAL ASSETS AND COMPUTER SOFTWARE

| | 2012 | | | 2011 |
|---|---|---|---|---|
| | **Cost** | **Accumulated Depreciation** | **Net Book Value** | Net Book Value |
| | **$** | **$** | **$** | $ |
| Plant and distribution system: | | | | |
| Land | **1,406,171** | **-** | **1,406,171** | 1,390,471 |
| Buildings and fixtures | **5,604,217** | **1,343,285** | **4,260,932** | 3,149,119 |
| Distribution station equipment | **1,604,840** | **863,317** | **741,523** | 761,388 |
| Station retirement obligation | **20,599** | **5,599** | **15,000** | 15,000 |
| Distribution system: | | | | |
| Overhead | **38,836,446** | **17,061,679** | **21,774,767** | 20,876,613 |
| Underground | **23,637,556** | **12,117,746** | **11,519,810** | 11,414,796 |
| Transformers | **21,439,194** | **10,200,865** | **11,238,329** | 11,122,855 |
| Meters | **3,940,117** | **1,510,814** | **2,429,303** | 1,826,145 |
| General office equipment | **325,888** | **201,897** | **123,991** | 82,745 |
| Computer equipment | **749,117** | **545,140** | **203,977** | 147,810 |
| Rolling stock | **4,051,932** | **2,823,359** | **1,228,573** | 1,792,919 |
| Tools | **1,299,488** | **1,037,000** | **262,488** | 236,630 |
| System supervisory equipment | **931,094** | **690,891** | **240,203** | 257,676 |
| Automated mapping facility | **2,364,407** | **1,489,558** | **874,849** | 864,819 |
| Services | **5,442,112** | **1,500,171** | **3,941,941** | 3,584,993 |
| Smart meters | **8,233,878** | **2,795,922** | **5,437,956** | 3,811,317 |
| Non-regulated generation assets | **110,161** | **5,051** | **105,110** | 110,161 |
| Work in process | **1,307,948** | **-** | **1,307,948** | 548,139 |
| | **121,305,165** | **54,192,294** | **67,112,871** | 61,993,596 |
| Contributions in aid of construction | **(6,594,753)** | **(1,950,691)** | **(4,644,062)** | (4,329,485) |
| Capital assets | **114,710,412** | **52,241,603** | **62,468,809** | 57,664,111 |
| Computer software | **987,435** | **815,587** | **171,848** | 230,648 |

Depreciation and amortization in the amount of $436,954 (2011 - $433,063) for rolling stock and $135,770 (2011 - $104,044) for computer software is included with relevant cost centres.

## 7. DEFERRED ASSETS

Deferred assets and liabilities arise as a result of the rate-making process. Regulatory assets represent future revenues associated with certain costs incurred in the current period or in prior periods that are expected to be recovered from customers in future periods through the rate setting process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers as a result of the rate setting process.

## 7. DEFERRED ASSETS (continued)

| | **2012** | 2011 |
|---|---|---|
| | **$** | $ |
| Costs | | |
| Retail settlement variance accounts | **2,019,275** | 1,603,454 |
| CDM and renewable energy | **122,309** | 145,526 |
| PILS | **-** | (634,058) |
| Other deferred/transition costs | **1,352,076** | 2,044,891 |
| Smart meters | **460,123** | 3,716,441 |
| Gross deferred assets | **3,953,783** | 6,876,254 |
| | | |
| Recoveries | | |
| Regulatory assets | **(527,925)** | (50,913) |
| Other deferred | **(2,349)** | (2,189) |
| Smart meters | **-** | (750,327) |
| Net deferred assets | **3,423,509** | 6,072,825 |

a) Retail settlement variance accounts

These accounts represent the variance between the revenue collected, using OEB approved rates for the non–competitive components of energy, and the corresponding cost of these non-competitive charges, beginning January 1, 2004 to the present. These variances will be held as a regulatory asset or liability, based on the expectation that the amounts held from one year to the next for rate setting purposes will be approved for collection from, or refund to, future customers. In the absence of regulatory treatment, net earnings in the current year would have decreased by $305,629 (2011 – decrease of $2,065,459).

b) Conservation and Demand Management ("CDM") and renewable energy

The Company incurred Green Energy initiative costs of $1,764 in 2012 (2011 - $153,563). These costs related to the *Green Energy and Green Economy Act, 2009* passed by the Ontario government. In 2009, the OEB approved a deferral account to collect these costs. The Company recovered $24,981 (2011 - $27,123) related to CDM in rates in 2012. In the absence of regulatory treatment, net earnings in the current year would have increased by $17,064 (2011 – increase of $122,450).

c) Payment in Lieu of Taxes

As prescribed by a regulatory rate order, income tax expense is recovered through customer rates based on the taxes payable method. Therefore, rates do not include the recovery of future income taxes related to temporary differences between tax basis of assets and liabilities and their carrying amounts for accounting purposes.

## 7. DEFERRED ASSETS (continued)

c) Payment in Lieu of Taxes (continued)

The OEB conducted a combined proceeding to address PILS variances accumulated in regulatory variance accounts for the period from October 1, 2001 to April 30, 2006. On June 24, 2011, the OEB issued its decision and provided guidelines for the calculation and further disposition of the balances accumulated in the PILS regulatory variance accounts. The Company reviewed the balance of its PILS account for this period and applied the guidelines provided by the OEB. As a result, a regulatory expense of $2,147,831 was recognized in 2011. The Company applied for disposition of the December 31, 2011 liability of $634,058 in March 2012. Final OEB approval of this disposition was received in October 2012. In the absence of regulatory treatment, net earnings in the current year would have decreased by $466,033 (2011 – increase of $1,353,539).

c) Other deferred/transition costs

This balance includes OEB-specific costs incurred that are not currently in rates. These costs will be applied for in the next rate rebasing application to the OEB. At year-end, the balance relating to these costs was $91,584 (2011 – $146,869). As well, the OEB has authorized distributors to apply for other deferred costs including Loss Revenue Adjustment Mechanism ("LRAM") due to Demand Management Programs to their customers that have resulted in decreased kWh consumption. This amount may be claimed in a subsequent rate year as compensation for loss of revenue. At the end of 2012, the LRAM balance was $92,218 (2011 – $136,391). Other ongoing deferred projects include Line Loss Improvements, Conversions, AM/FM, Rate Rebasing and IFRS costs for $1,251,781 (2011 – $1,813,591).

In the May 2010 rate approval by the OEB, the Company was instructed to record the value of the savings resulting from the change to Harmonized Sales Tax effective July 1, 2010. This represents a payable of $83,507 (2011 - $51,960).

In the absence of regulatory treatment, net earnings in the current year would have increased by $509,219 (2011 – increase of $120,318).

d) Smart meters

As of December 31, 2011, the Company had incurred total costs related to the implementation of smart meters of $3,716,441. The Company applied for disposition of this balance in July 2012. Final OEB approval of this disposition was received in November 2012. As part of this disposition, deferred costs of $2,856,550 were transferred to capital assets. In the absence of regulatory treatment, net earnings in the current year would have decreased by $257,661 (2011 – decrease of $150,069).

## 7. DEFERRED ASSETS (continued)

e) Regulatory asset dispositions

This balance represents the remaining amounts to be refunded to or recovered from ratepayers arising from dispositions that have been approved by the OEB. The balance in the account is a net credit of $527,925 (2011 – $50,933 credit). In the absence of regulatory treatment, net earnings for the current year would have increased by $350,604 (2011 – increase of $65,005).

## 8. NOTES PAYABLE

The notes payable include a $23,523,326 note due to the Municipality at an interest rate of 5.87% and a $4,300,000 note to EI at an interest rate of 7.25%, the latter of which was issued upon the acquisition of the former MPDC by EI on June 30, 2005. In 2009, a further $1,000,000 was issued to EI in relation to the acquisition of Dutton and Newbury at an interest rate of 7.62%. Lastly, in 2010, notes payable totalling $8,250,000 were issued to EI at an interest rate of 5.87%. The notes payable have no set repayment term and interest payable monthly. Interest expense for the year amounted to $2,253,036 (2011 - $2,263,578).

## 9. EMPLOYEE FUTURE BENEFITS

The Company measures its accrued benefit obligation as at December 31 of each year. The Company pays certain medical and life insurance benefits on behalf of its retired and current employees. The accrued benefit liability at December 31, 2012 was $1,076,023 (2011 - $1,049,960). The most recent actuarial valuation of the benefit plans for funding purposes was as of December 31, 2010 and the next required valuation will be as of December 31, 2013.

Information about the Company's defined benefit plan is as follows:

| | **2012** | 2011 |
|---|---|---|
| | **$** | $ |
| Accrued benefit liability, beginning of year | **1,049,960** | 1,008,222 |
| Expense for the year | **74,661** | 53,887 |
| Transfers to other plans | **(48,598)** | - |
| Employer contributions | **-** | (12,149) |
| Estimated accrued benefit liability, end of year | **1,076,023** | 1,049,960 |

The main actuarial assumptions employed for the valuation are as follows:

*General inflation*

Future inflation levels, as measured by changes in the Consumers Price Index ("CPI"), were assumed to be 2.5% in 2012 and thereafter.

## 9. EMPLOYEE FUTURE BENEFITS (continued)

*Interest (discount) rate*

The present value of the future benefits and the expense for the year ended December 31, 2012 were determined using a discount rate of 4.41% (2011 – 5.32%). This corresponds to the OEB approved non-arm's length cost of debt rate for 2012.

*Health costs*

Health costs were assumed to increase at 8% per year for 10 years after the valuation date, and then at the CPI rate plus 1% thereafter.

*Dental costs*

Dental costs were assumed to increase at the CPI rate plus 1% for 2012 and thereafter.

*Salary growth rate*

Salary growth rate was assumed to increase at a rate of 3.5% for 2012 and thereafter.

## 10. PENSION AGREEMENT

The Company provides a pension plan for its employees through the OMERS. OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund") and provides pensions for employees of Ontario municipalities, local boards, public utilities, and school boards. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. As there is insufficient information to apply defined benefit plan accounting, defined contribution plan accounting has been used by the Company. The Company's contribution for employees' current service in 2012 was $360,832 (2011 - $317,956).

## 11. RELATED PARTY TRANSACTIONS

The Company provided the following services in the normal course of operations to the Municipality:

| | **2012** | 2011 |
|---|---|---|
| | **$** | $ |
| Energy (at commercial rates) | **5,346,067** | 5,085,907 |
| Streetlight maintenance | **190,764** | 203,571 |
| | **5,536,831** | 5,289,478 |

## 11. RELATED PARTY TRANSACTIONS (continued)

The Municipality provided the following services in the normal course of operations to the Company:

| | **2012** | 2011 |
|---|---|---|
| | **$** | $ |
| Asset management | **226,406** | 219,169 |

Entegrus Services Inc. ("ESI") is wholly owned by EI. ESI has provided the following services in the normal course of operations to the Company:

| | **2012** | 2011 |
|---|---|---|
| | **$** | $ |
| Billing, collection, administrative and data services | **5,192,702** | 4,895,029 |

Included in the costs above are deferred costs of $100,000 (2011 - $312,824) that are reflected on the balance sheet. At December 31, 2012, the Company had an outstanding balance payable to ESI in the amount of $8,637,919 (2011 - $4,758,117).

All related party transactions are recorded at the exchange amounts.

## 12. CONTINGENCY

*Class Action Suit*

An action had been brought under the *Class Proceedings Act, 1992*. The plaintiff class sought restitution for amounts paid to Toronto Hydro and to other Ontario municipal electric utilities ("MEUs") who received late payment penalties ("LPP") which constitute interest at an effective rate in excess of 60% per year, contrary to section 347 of the *Criminal Code*.

On July 22, 2010, the Ontario Superior Court of Justice approved a settlement of the LPP Class Action. Pursuant to the terms of the settlement, the Company made payments totalling $160,402 in June 2011.

In its IRM filing for 2011 distribution rates, the Company requested that the OEB hold a generic hearing to determine if all costs and damages incurred in this litigation and settlement are recoverable from customers and, if so, the form and timing of recovery from customers.

A generic hearing on this matter was convened by the OEB. On February 22, 2011, the OEB released its Decision and Order on the LPP generic hearing. The OEB found that the costs were prudently incurred and as such could be recovered from customers. The approved recovery period for the Company was one year beginning in May 2011. At December 31, 2012, there was no remaining balance receivable relating to this recovery (2011 - $62,183).

## 13. SHARE CAPITAL

The share capital of the Company consists of the following:

Authorized
Unlimited number of voting common shares without par value
Unlimited number of Class A preference shares without par value
Unlimited number of Class B preference shares without par value
Unlimited number of Class C preference shares without par value

| | **2012** | 2011 |
|---|---|---|
| | **$** | $ |
| Issued | | |
| 2,000 common shares | **28,154,623** | 28,154,623 |

## 14. SUPPLEMENTAL CASH FLOW INFORMATION

*Changes in non-cash working capital items*

| | **2012** | 2011 |
|---|---|---|
| | **$** | $ |
| Accounts receivable | **(2,853,722)** | 718,441 |
| Accounts receivable - unbilled revenue | **949,961** | 200,588 |
| Taxes receivable | **768,331** | (455,900) |
| Inventories | **(12,119)** | 64,594 |
| Prepaid expenses | **(13,130)** | 43,233 |
| Accounts payable and accrued liabilities | **(940,945)** | 712,924 |
| Taxes payable | **470,354** | (127,703) |
| Due to related parties | **3,879,802** | 1,545,093 |
| Deferred revenue | **142,435** | 327,238 |
| Current portion of customer deposits | **(541,548)** | (290,675) |
| | **1,849,419** | 2,737,833 |

A refund of payments in lieu of taxes of $205,827 (2011 – payments of $985,824) was received and interest of $2,372,525 (2011 - $2,357,635) was paid during the year.

## 15. FINANCIAL INSTRUMENTS

*Fair value*

The Company's recognized financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, due to related parties, customer deposits and notes payable.

The fair values of cash and cash equivalents, accounts receivable, unbilled revenue, accounts payable and accrued liabilities and due to related parties approximate their carrying amounts due to their short-term nature. As there is no secondary market for customer deposits, the calculation of their fair value with appropriate reliability is impractical.

## 15. FINANCIAL INSTRUMENTS (continued)

*Fair value (continued)*

The notes payable include a $23,523,326 promissory note payable to the Municipality at an interest rate of 5.87% and a $4,300,000 promissory note to EI at an interest rate of 7.25%, the latter of which was issued upon the acquisition of the former MPDC by EI on June 30, 2005. In 2009, a further $1,000,000 was issued to EI in relation to the acquisition of Dutton and Newbury at an interest rate of 7.62%. Lastly, in 2010, promissory notes payable totalling $8,250,000 were issued to EI at an interest rate of 5.87%. There is no "term length" associated with any of the promissory notes.

In order to determine fair value of the notes payable, comparison was made to the approved interest rate from the OEB. The OEB approves the rate of return on the debt portion of "Cost of Capital" for non-arm's length transactions. An interest rate of 4.41% has been approved by the OEB through the rate setting process for rates effective May 2012.

Using the OEB approved non-arm's length cost of debt of 4.41%, the annual interest expense would be reduced by approximately $618,000.

*Credit risk*

The Company is exposed to credit risk from its customers. The Company has a large number of diverse customers for the most part minimizing concentration of risk. There are a select group of manufacturing-based corporations that pose a significant increase in risk due to the current state of the economy as well as the future outlook for the economy. Close monitoring of this sector is currently being examined through internal and external credit rating resources. The Company continues to utilize special payment arrangements and security deposits to reduce this risk to an acceptable level.

## 16. CAPITAL DISCLOSURES

The Company's main objectives when managing capital are to:

- ensure ongoing access to funding to maintain and improve the electricity distribution system of LDC; and
- maintain a capital structure comparable for regulated activities as approved by the OEB's deemed debt-to-equity structure in our rates.

As at December 31, 2012, the Company's definition of capital includes shareholder's equity and long-term debt. This definition has remained unchanged from December 31, 2011. As at December 31, 2012, shareholder's equity amounts to $28,942,523 (2011 - $29,256,135) and long-term debt amounts to $37,073,326 (2011 - $37,073,326).

The 2012 capital structure approved by the OEB in rates was 40% Equity, 56% Long-Term Debt and 4% Short-Term Debt. The OEB-approved capital structure is unchanged from 2011. The Company's 2012 actual capital structure was 44% Equity (2011 - 44%) and 56% Long-Term Debt (2011 - 56%).

## 17. PAYMENTS IN LIEU OF TAXES

The reconciliation between the combined Federal and Ontario statutory tax rate and the effective rate of income taxes is as follows:

| | **2012** | 2011 |
|---|---|---|
| | **$** | $ |
| Earnings before payments in lieu of taxes | **3,319,247** | 1,526,485 |
| Statutory income tax rate (percent) | **26.50%** | 28.25% |
| Statutory income tax rate applied to earnings | **879,600** | 431,232 |
| Increase / (decrease) resulting from: | | |
| Temporary differences between accounting and tax basis of assets and liabilities | **147,905** | (25,071) |
| Permanent differences | **5,354** | 4,261 |
| Provision for income taxes | **1,032,859** | 410,422 |
| Effective rate of income tax (percent) | **31.12%** | 26.89% |

*Future income taxes*

The long-term future income tax asset of $3,282,682 (2011 - $2,869,132) includes the following:

| | **2012** | 2011 |
|---|---|---|
| | **$** | $ |
| Temporary differences related to capital assets and deferred assets | **2,889,320** | 2,514,147 |
| Temporary difference related to employee future benefits | **393,362** | 354,985 |
| | **3,282,682** | 2,869,132 |

## 18. COMMITMENTS

The Company has entered into Service Level agreements with Entegrus Services Inc., on a year to year basis, to have them provide the services of billing, account collections, customer inquiries and meter reading as well as administrative services such as office space usage, rate submission support, accounting and budgeting support. The value of this contract is $5,192,702 (2011 - $4,895,029).

The Company entered into an agreement with Utilismart Corporation for the services of a data collection system, data storage and access to specific software and systems. The terms of the agreement were extended for five years commencing April 1, 2009. Annual payments made by the Company were $25,859 in 2011. At the beginning of 2012, this agreement was transferred from the Company to ESI.

## 18. COMMITMENTS (continued)

The Company previously entered into an agreement with an unrelated party to perform meter reading and associated services on behalf of the Company on a year to year basis. The cost of this service to the Company was $56,124 in 2011. For 2012, this agreement was renewed by ESI.

The Company renewed an agreement with the Township of Strathroy-Caradoc to lease a portion of the premises known as 351 Frances Street, Strathroy, Ontario for a period of five years effective July 1, 2010. The cost of the lease is $62,535 annually plus 60% of shared operating costs. The Company's share of operating costs were $47,327 (2011 - $43,099).

The Company renewed an agreement with the Township of Strathroy-Caradoc to provide the services of billing of water services for a period of five years effective July 1, 2010. Contracts for maintenance of streetlight and traffic lights as well as installation of water meters are renewed annually. Revenues received for these services was $121,232 (2011 - $381,975).

*Financial Statements of*

# ENTEGRUS POWERLINES INC.
(formerly Chatham-Kent Hydro Inc.)

*December 31, 2013*

## Management's Responsibility for Financial Reporting

Entegrus Powerlines Inc.'s management is responsible for the preparation and presentation of the financial statements and all other information included in this annual report. Management is also responsible for the selection and use of accounting principles that are appropriate in the circumstances, and for the internal controls over the financial reporting process to reasonably ensure that relevant and reliable information is produced. Financial statements are not precise in nature as they include certain amounts based on estimates and judgment. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control over the financial reporting process. The Board of Directors exercises this responsibility through its Audit Committee. This committee is comprised of four directors of companies within the Entegrus group, one of whom is a director of the Entegrus Powerlines Inc. Board. This committee meets with management and the external auditors to ensure that management responsibilities are properly discharged and to review the financial statements and other information included in the annual report before they are presented to the Board of Directors for approval. The financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

Deloitte LLP, an independent external audit firm, has been appointed by the Audit Committee and engaged to examine the accompanying financial statements in accordance with generally accepted auditing standards in Canada and provide an independent professional opinion. Their report is presented with the financial statements.

D Charron

**Dan Charron**
**President**

**Chris Cowell**
**Chief Financial & Regulatory Officer**

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# Independent Auditor's Report

To the Chairman and Board Members of
Entegrus Powerlines Inc.

We have audited the accompanying financial statements of Entegrus Powerlines Inc. (formerly Chatham-Kent Hydro Inc.) which comprise the balance sheet as at December 31, 2013, and the statements of earnings, comprehensive income and retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

**Management's responsibility for the financial statements**

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

**Auditor's responsibility**

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

**Opinion**

In our opinion, the financial statements present fairly, in all material respects, the financial position of Entegrus Powerlines Inc. as at December 31, 2013 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Deloitte LLP

Chartered Professional Accountants, Chartered Accountants
Licensed Public Accountants
April 25, 2014

**ENTEGRUS POWERLINES INC. (formerly Chatham-Kent Hydro Inc.)**
**Balance Sheet**
**December 31, 2013**

| | 2013 | 2012 |
|---|---|---|
| | $ | $ |
| **ASSETS** | | |
| CURRENT | | |
| Cash and cash equivalents | **7,508,843** | 7,799,967 |
| Accounts receivable (Note 4) | **6,539,098** | 7,149,517 |
| Accounts receivable - unbilled revenue | **13,602,458** | 10,744,448 |
| Taxes receivable | **897,882** | - |
| Inventories | **727,004** | 786,343 |
| Prepaid expenses | **92,994** | 114,149 |
| | **29,368,279** | 26,594,424 |
| CAPITAL ASSETS (Note 5) | **65,849,883** | 62,468,809 |
| OTHER | | |
| Computer software (Note 5) | **676,451** | 171,848 |
| Deferred assets (Note 6) | **3,006,707** | 3,423,509 |
| Goodwill and intangible assets | **367,304** | 452,040 |
| Future income taxes (Note 15) | **3,211,562** | 3,282,682 |
| | **7,262,024** | 7,330,079 |
| | **102,480,186** | 96,393,312 |
| **LIABILITIES** | | |
| CURRENT | | |
| Accounts payable and accrued liabilities | **15,582,384** | 12,128,135 |
| Taxes payable | **-** | 470,354 |
| Due to related parties (Note 10) | **8,836,351** | 8,637,919 |
| Deferred revenue | **347,611** | 469,673 |
| Current portion of customer deposits | **1,019,035** | 1,133,532 |
| | **25,785,381** | 22,839,613 |
| LONG-TERM | | |
| Regulatory future income tax liability (Note 15) | **3,211,562** | 3,282,682 |
| Notes payable (Note 7) | **37,073,326** | 37,073,326 |
| Employee future benefits (Note 8) | **2,711,308** | 1,076,023 |
| Long-term portion of customer deposits | **3,378,301** | 3,179,145 |
| | **46,374,497** | 44,611,176 |
| | **72,159,878** | 67,450,789 |
| COMMITMENTS (Note 16) | | |
| **SHAREHOLDER'S EQUITY** | | |
| Share capital (Note 11) | **28,154,623** | 28,154,623 |
| Retained earnings | **2,165,685** | 787,900 |
| | **30,320,308** | 28,942,523 |
| | **102,480,186** | 96,393,312 |

**ENTEGRUS POWERLINES INC. (formerly Chatham-Kent Hydro Inc.)**
**Statement of Earnings, Comprehensive Income and Retained Earnings**
**Year Ended December 31, 2013**

| | 2013 | 2012 |
|---|---|---|
| | $ | $ |
| SERVICE REVENUE | | |
| Residential | 39,727,793 | 38,875,311 |
| General service | 68,754,517 | 63,887,377 |
| Street lighting | 995,200 | 958,820 |
| | 109,477,510 | 103,721,508 |
| Change in unbilled revenue | 2,508,152 | (646,352) |
| | 111,985,662 | 103,075,156 |
| Retailer energy sales | 3,433,386 | 3,183,117 |
| | 115,419,048 | 106,258,273 |
| COST OF POWER | 96,951,040 | 88,648,371 |
| GROSS MARGIN ON SERVICE REVENUE | 18,468,008 | 17,609,902 |
| OTHER OPERATING REVENUE | 1,338,061 | 1,504,742 |
| OPERATING INCOME | 19,806,069 | 19,114,644 |
| OPERATING AND MAINTENANCE EXPENSE | | |
| Distribution | 4,238,466 | 3,546,002 |
| Regulatory | 602,341 | 107,662 |
| ADMINISTRATIVE EXPENSE | | |
| Billing and collection | 2,487,307 | 2,433,637 |
| General administration | 2,885,546 | 2,816,846 |
| Interest | 2,386,015 | 2,372,525 |
| DEPRECIATION AND AMORTIZATION | 3,662,294 | 4,518,725 |
| | 16,261,969 | 15,795,397 |
| EARNINGS BEFORE PAYMENTS IN LIEU OF TAXES | 3,544,100 | 3,319,247 |
| Provision for payments in lieu of taxes (Note 15) | 866,315 | 1,032,859 |
| NET EARNINGS AND COMPREHENSIVE INCOME | 2,677,785 | 2,286,388 |
| RETAINED EARNINGS, BEGINNING OF YEAR | 787,900 | 1,101,512 |
| LESS DIVIDENDS | (1,300,000) | (2,600,000) |
| RETAINED EARNINGS, END OF YEAR | 2,165,685 | 787,900 |

**ENTEGRUS POWERLINES INC. (formerly Chatham-Kent Hydro Inc.)**
**Statement of Cash Flows**
**Year Ended December 31, 2013**

| | **2013** | 2012 |
|---|---|---|
| | **$** | $ |
| OPERATING ACTIVITIES | | |
| Net earnings | **2,677,785** | 2,286,388 |
| Adjustments for: | | |
| Depreciation of capital assets | **4,198,654** | 5,694,316 |
| Depreciation of computer software | **484,246** | 135,770 |
| Amortization of contributed capital | **(277,238)** | (250,385) |
| Gain on disposal of capital assets | **(95,130)** | (77,715) |
| Employee future benefits | **1,635,285** | 26,063 |
| Change in long-term customer deposits | **199,156** | 536,369 |
| Changes in non-cash working capital items (Note 12) | **(119,211)** | 1,849,419 |
| | **8,703,547** | 10,200,225 |
| INVESTING ACTIVITIES | | |
| Change in deferred assets | **(215,873)** | (207,234) |
| Proceeds on disposal of capital assets | **300,676** | 369,370 |
| Additions to capital assets | **(6,790,625)** | (7,683,733) |
| Additions to computer software | **(988,849)** | (76,971) |
| | **(7,694,671)** | (7,598,568) |
| FINANCING ACTIVITIES | | |
| Dividends paid | **(1,300,000)** | (2,600,000) |
| NET CHANGE IN CASH AND CASH EQUIVALENTS | **(291,124)** | 1,657 |
| CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR | **7,799,967** | 7,798,310 |
| CASH AND CASH EQUIVALENTS, END OF YEAR | **7,508,843** | 7,799,967 |

See Note 12 for supplemental cash flow information.

## 1. NATURE OF OPERATIONS

*a) Incorporation and amalgamation*

Chatham-Kent Hydro Inc. ("CKH") was incorporated September 22, 2000 under the *Business Corporations Act (Ontario)*. Effective January 1, 2012, CKH and a company under common control, Middlesex Power Distribution Corporation ("MPDC"), amalgamated to continue as Chatham-Kent Hydro Inc. Effective January 19, 2012, the name of the amalgamated entity was changed from Chatham-Kent Hydro Inc. to Entegrus Powerlines Inc. ("the Company").

The Company is wholly-owned by Entegrus Inc. ("EI"), which in turn is owned 90% by the Municipality of Chatham-Kent ("the Municipality") and 10% by Corix Utilities ("Corix"). The principal activity of the Company is to distribute electricity to customers within the Municipality of Chatham-Kent, Middlesex County and the County of Elgin, under a licence issued by the Ontario Energy Board ("OEB").

*b) Rate-regulated entity*

The Company is a regulated Local Distribution Company ("LDC") and has a distribution licence that is regulated by the OEB. The OEB has regulatory oversight of electricity matters in Ontario. The *Ontario Energy Board Act, 1998* sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles and filing process requirements for rate-setting purposes. The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity and the responsibility of ensuring the electricity distribution companies fulfill obligations to connect and service customers.

The Company is required to charge its customers for the following amounts (all of which, other than the distribution rates, represent a pass through of amounts payable to third parties):

- Electricity Price – The electricity price represents the commodity cost of electricity;
- Distribution Rate – The distribution rate is designed to recover the costs incurred by the Company in delivering electricity to customers and the OEB allowed rate of return;
- Global Adjustment – The difference between the rate paid to regulated and contracted electricity generators and the spot market price;
- Retail Transmission Rate – The retail transmission rate represents the wholesale costs incurred by the Company in respect of the transmission of electricity from generating stations to the local areas; and
- Wholesale Market Services Charge – The wholesale market services charge represents the cost of services provided by the Independent Electricity System Operator ("IESO") and the Ontario Power Authority to operate the wholesale electricity market and maintain the reliability of the power grid.

In order to operate in the Ontario electrical industry all market participants, including the Company, are required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations in the form of obtaining a credit rating, letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings.

## 1. NATURE OF OPERATIONS (continued)

*Market-based rate of return*

Rates for the Company continue to be based on the pre-amalgamation service territories until the Company's rates are rebased in 2016. At that time, the Company will consider whether rate harmonization would provide overall customer benefits and be in accordance with good rate-making practices.

The OEB approved the former CKH to revise rates effective May 1, 2010, which resulted in approved rates that include a 9.85% rate of return on equity rebased at 2010 test year levels. The rate of return of 9.85% was in accordance with the OEB's cost of capital parameters at that time.

The OEB approved the former MPDC to revise rates effective May 1, 2006, which resulted in approved rates that include a 9.0% rate of return on equity rebased at 2004 test year levels. The rate of return of 9.0% was in accordance with the OEB's cost of capital parameters at that time.

*Incentive Rate Mechanism*

Between rate basing years, the OEB regulates the rates of the Company under an Incentive Rate Mechanism ("IRM") regime. The process includes a mechanistic approach to establishing rates with a rate rebasing approach (cost-of-service) every five years. The IRM rate setting process provides an increase in rates for inflationary cost, partially offset by expected productivity and efficiency gains established by the OEB.

The OEB allows for rate rebasing to be deferred for up to five years where there is a purchase or merger of LDC's. As a result of the amalgamation of CKH and MPDC, the OEB has approved the deferral of rate rebasing of the Company to 2016.

*Deferred assets*

Electricity distributors are required to reflect certain prescribed costs on their balance sheets until the manner and timing of distribution is determined by the OEB. These costs include:

- Settlement variance between amounts charged by the Company to customers (based on regulated rates) and corresponding cost of non-competitive electricity service incurred by it in the wholesale market administered by the IESO after May 1, 2002;
- Costs incurred to invest in and install a smart meter at all of our customer premises;
- Cost related to the *Green Energy and Green Economy Act, 2009*; and,
- Costs incurred and accumulated financial differences related to the Company's transition to International Financial Reporting Standards ("IFRS").

## 2. ACCOUNTING CHANGES

*a) Current changes in accounting policies*

In July 2012, the OEB issued a letter to LDC's that provided direction on permitted accounting policies for depreciation expense and capitalization beginning in 2013. In this letter, the OEB stated that it would require all LDC's to adopt IFRS-compliant depreciation and capitalization accounting policies effective January 1, 2013, regardless of whether the LDC had chosen to defer the adoption of IFRS as permitted by the Accounting Standards Board ("AcSB") of the Canadian Institute of Chartered Accountants ("CICA"). The OEB also approved the use of a new variance account to capture the financial differences arising as a result of adopting IFRS-compliant accounting policies for depreciation and capitalization in 2013. This variance account is to be disposed of as part of the LDC's next rate rebasing. Therefore, there is no impact to net income as a result of these accounting policy changes.

As such, the Company has adopted IFRS-compliant accounting policies for depreciation and capitalization effective January 1, 2013. These policies were selected in accordance with IAS 16, *Property, Plant and Equipment.* IAS 16 provides more definitive guidance with respect to cost capitalization and componentization for depreciation purposes than that currently followed under Canadian generally accepted accounting principles ("GAAP").

Due to the absence of rate-regulated accounting guidance within Canadian GAAP, the Company follows regulatory accounting guidance found under US GAAP. In accordance with US GAAP Accounting Standards Codification Section 980, *Regulated Operations*, the Company will adopt these changes prospectively with no retrospective restatement of prior periods. The effect of these changes in the year ended December 31, 2013 was to increase Distribution and Regulatory expenses by $510,540 and $602,341, respectively, and to decrease Depreciation and Amortization expense by $1,112,881.

*b) Future changes in accounting framework*

On February 13, 2008, the AcSB confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian GAAP for fiscal years beginning on or after January 1, 2011. Subsequently, on September 10, 2010, the AcSB decided to permit rate-regulated entities and certain affiliates to defer their IFRS adoption date to January 1, 2012. The Company is a qualifying entity for purposes of this deferral and elected to use the deferral offered by the AcSB.

On March 30, 2012, the AcSB announced an additional one year deferral for qualifying entities with rate-regulated activities. Further one year deferrals were announced by the AcSB in September 2012 and February 2013. The Company has elected to use all deferrals made available by the AcSB. As a result, the Company's IFRS adoption date is currently set at January 1, 2015.

## 3. SIGNIFICANT ACCOUNTING POLICIES

The financial statements have been prepared in accordance with Canadian GAAP and reflect the following policies as set forth in the Accounting Procedures Handbook issued by the OEB under the authority of the *Ontario Energy Board Act, 1998:*

*Regulation*

The Company is regulated by the OEB and any rate adjustments require OEB approval.

*Cash and cash equivalents*

Cash and cash equivalents consist of cash on hand and balances with the bank.

*Unbilled revenue*

Unbilled revenue is an estimate of customers' consumption of power from the last meter read to December 31st.

*Inventories*

Inventories are valued at the lower of cost and net realizable value with cost being determined using the weighted average method.

*Capital assets*

Capital assets are recorded at cost. Depreciation is calculated on a straight-line basis over the useful life of the asset as follows:

| | |
|---|---|
| Buildings and fixtures | 20 – 50 years |
| Distribution station equipment | 15 – 45 years |
| Distribution system – overhead | 45 – 60 years |
| Distribution system – underground | 20 – 55 years |
| Distribution transformers | 35 – 45 years |
| Distribution meters | 25 years |
| General office equipment | 10 years |
| Computer equipment | 3 years |
| Rolling stock | 7 – 15 years |
| Tools | 5 years |
| System supervisory equipment | 20 years |
| Automated mapping/facilities management | 15 years |
| Services | 40 – 50 years |
| Smart meters | 15 years |
| Non-regulated generation assets | 25 years |

The Company recognizes work in process for larger capital projects that are not in service at the end of the year. When the capital projects are completed, they are transferred to the appropriate capital asset or computer software account. Depreciation of these assets will begin when they are placed in service.

## 3. SIGNIFICANT ACCOUNTING POLICIES (continued)

*Impairment of long-lived assets*

Long-lived assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. An impairment loss is recognized when their carrying value exceeds the total undiscounted cash flows expected from their use and eventual disposition. The amount of the impairment loss is determined as the excess of the carrying value of the asset over its fair value.

*Contributions in aid of construction*

Contributions in aid of construction consist of third party contributions toward the cost of constructing the Company's assets. Contributions received are recorded as an offset to capital assets and amortized on a straight-line basis over 25 years.

*Computer software*

Computer software is stated at cost less accumulated depreciation. Depreciation is calculated on a straight-line basis over useful lives ranging from 3 to 5 years.

*Goodwill*

Goodwill representing the excess of purchase price over fair value of the net identifiable assets of acquired businesses is tested for impairment annually or more frequently when an event or circumstance occurs that indicates that goodwill might be impaired. When the carrying amount exceeds the fair value, an impairment loss is recognized in the statement earnings in an amount equal to the excess.

*Intangible assets*

Intangible assets are recorded at their fair value at the acquisition date. As the Company's intangible assets have an indefinite life, they are not amortized to income. Intangible assets will be tested for impairment when events or changes in circumstances indicate that their carrying value may not be recoverable.

*Deferred assets*

Deferred assets consist of qualifying capital costs and related expenditures incurred in the preparation for market opening, investments in smart meters and other expenditures that are not currently recovered in rates. Also included in deferred assets are retail settlement variance accounts. These variances are for non-competitive energy services which are a pass through for the Company. Recovery of the deferred assets requires regulatory approval from the OEB.

## 3. SIGNIFICANT ACCOUNTING POLICIES (continued)

*Payments in lieu of taxes*

Under the *Electricity Act, 1998*, the Company is required to make payments-in-lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are recorded in accordance with the rules for computing income taxes and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) and modified by the *Electricity Act, 1998*, and related regulations.

The Company recognizes future income tax assets and liabilities in accordance with CICA Section 3465, *Income Taxes*. Section 3465 also contains guidance specific to rate-regulated enterprises that requires the Company to recognize a regulatory asset or liability for the amount of future income taxes expected to be recovered from or refunded to ratepayers and to present these amounts on a pre-tax basis in the financial statements. Accordingly, the Company has recorded a regulatory liability that has been included in long-term liabilities and an associated future income tax asset of $3,211,562 (2012 - $3,282,682). The liability will be paid through future rate reductions.

*Customer deposits*

Customer deposits are recorded when received or paid. Deposits earn interest at a rate of prime less 2%.

*Asset retirement obligations*

The Company recognizes the liability for a future asset retirement that results from acquisition, construction, development or normal operations. The liability for an asset retirement is initially recorded at its fair value in the year in which it is incurred and when a reasonable estimate of fair value can be made. The corresponding cost is capitalized as part of the related asset and is amortized over the asset's useful life. In subsequent years the liability is adjusted for changes resulting from the passage of time and revisions to either the timing or the amount of the original estimate of the undiscounted cash flows. The accretion of the liability to its fair value as a result of the passage of time is charged to earnings.

*Employment benefits other than pension*

The Company provides its current and retired employees with life insurance and medical benefits beyond those provided by government-sponsored plans. The cost of these benefits is actuarially determined annually as at December 31. The cost is determined using the projected unit credit method and assumptions including interest rates, salary escalation, retirement ages of employees, mortality rates, and health care costs.

*Use of estimates*

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Unbilled revenue is a significant estimate that is subject to material measurement uncertainty. Actual results could differ from those estimates.

## 3. SIGNIFICANT ACCOUNTING POLICIES (continued)

*Revenue recognition and cost of power*

Service revenue is recorded on the basis of regular meter readings and estimated customer usage since the last meter reading date to the end of the year. The related cost of power is recorded on the basis of power used. Any discrepancies in the revenue collected and associated cost of power related to distribution are charged to deferred assets.

*Financial instruments*

The AcSB decided that rate-regulated enterprises that are not public enterprises as defined in Section 1300, *Differential Reporting*, will not be required to apply Sections 3862, *Financial Instruments – Disclosures*, and 3863, *Financial Instruments – Presentation*, and would continue to apply Section 3861, *Financial Instruments – Disclosure and Presentation.* Therefore, in accordance with this decision, the Company continues to apply Section 3861.

Financial assets and financial liabilities are initially recognized at fair value and their subsequent measurement is dependent on their classification as described below. Their classification depends on the purpose, for which the financial instruments were acquired or issued, their characteristics and the Company's designation of such instruments. Settlement date accounting is used.

<u>Classification</u>

| | |
|---|---|
| Cash and cash equivalents | Held for trading |
| Accounts receivable | Loans and receivables |
| Accounts payable and accrued liabilities | Other liabilities |
| Due to related parties | Other liabilities |
| Current portion of customer deposits | Other liabilities |
| Notes payable | Other liabilities |
| Long-term portion of customer deposits | Other liabilities |

<u>Held for trading</u>

Held for trading financial assets are financial assets typically acquired for resale prior to maturity or that are designated as held for trading. They are measured at fair value at the balance sheet date. Fair value fluctuations including interest earned, interest accrued, gains and losses realized on disposal and unrealized gains and losses are included in other income.

Financial liabilities designated as held for trading are those non-derivative financial liabilities that the Company elects to designate on initial recognition as instruments that it will measure at fair value through other interest expense. These are accounted for in the same manner as held for trading assets. The Company has not designated any non-derivative financial liabilities as held for trading.

## 3. SIGNIFICANT ACCOUNTING POLICIES (continued)

*Financial instruments (continued)*

Loans and receivables

Loans and receivables are accounted for at amortized cost using the effective interest method.

Other liabilities

Other liabilities are recorded at amortized cost using the effective interest method and include all financial liabilities, other than derivative instruments.

Effective interest method

The Company uses the effective interest method to recognize interest income or expense which includes transaction costs or fees, premiums or discounts earned or incurred for financial instruments.

## 4. ACCOUNTS RECEIVABLE

| | **2013** | 2012 |
|---|---|---|
| | **$** | $ |
| Electrical energy | **4,408,268** | 3,937,174 |
| Other | **2,267,500** | 3,349,339 |
| | **6,675,768** | 7,286,513 |
| Allowance for doubtful accounts | **(136,670)** | (136,996) |
| Net accounts receivable | **6,539,098** | 7,149,517 |

## 5. CAPITAL ASSETS AND COMPUTER SOFTWARE

| | 2013 | | | 2012 |
|---|---|---|---|---|
| | **Cost** | **Accumulated Depreciation** | **Net Book Value** | Net Book Value |
| | $ | $ | $ | $ |
| Plant and distribution system: | | | | |
| Land | **1,369,163** | **-** | **1,369,163** | 1,406,171 |
| Buildings and fixtures | **5,735,864** | **1,442,252** | **4,293,612** | 4,260,932 |
| Distribution station equipment | **1,910,507** | **923,992** | **986,515** | 741,523 |
| Station retirement obligation | **20,599** | **5,599** | **15,000** | 15,000 |
| Distribution system: | | | | |
| Overhead | **41,464,589** | **17,647,161** | **23,817,428** | 21,774,767 |
| Underground | **24,545,444** | **13,288,857** | **11,256,587** | 11,519,810 |
| Transformers | **22,784,657** | **10,595,607** | **12,189,050** | 11,238,329 |
| Meters | **3,940,117** | **1,685,085** | **2,255,032** | 2,429,303 |
| General office equipment | **340,597** | **223,363** | **117,234** | 123,991 |
| Computer equipment | **833,182** | **830,588** | **2,594** | 203,977 |
| Rolling stock | **5,010,667** | **3,092,723** | **1,917,944** | 1,228,573 |
| Tools | **1,340,477** | **1,195,190** | **145,287** | 262,488 |
| System supervisory equipment | **1,140,548** | **711,564** | **428,984** | 240,203 |
| Automated mapping/facilities management | **2,866,558** | **1,680,995** | **1,185,563** | 874,849 |
| Services | **6,085,415** | **1,551,590** | **4,533,825** | 3,941,941 |
| Smart meters | **9,006,003** | **3,449,952** | **5,556,051** | 5,437,956 |
| Non-regulated generation assets | **887,815** | **25,258** | **862,557** | 105,110 |
| Work in process | **62,000** | **-** | **62,000** | 1,307,948 |
| | **129,344,202** | **58,349,776** | **70,994,426** | 67,112,871 |
| Contributions in aid of construction | **(7,372,472)** | **(2,227,929)** | **(5,144,543)** | (4,644,062) |
| Capital assets | **121,971,730** | **56,121,847** | **65,849,883** | 62,468,809 |
| Computer software | **1,899,551** | **1,223,100** | **676,451** | 171,848 |

Depreciation and amortization in the amount of $310,171 (2012 - $436,954) for rolling stock and $484,246 (2012 - $135,770) for computer software is included with relevant cost centres.

## 6. DEFERRED ASSETS

Deferred assets and liabilities arise as a result of the rate-making process. Regulatory assets represent future revenues associated with certain costs incurred in the current period or in prior periods that are expected to be recovered from customers in future periods through the rate setting process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers as a result of the rate setting process.

| | **2013** | 2012 |
|---|---|---|
| | **$** | $ |
| Costs | | |
| Retail settlement variance accounts | **1,901,952** | 2,019,275 |
| Renewable energy | **6,332** | 122,309 |
| Smart meters | **410,460** | 460,123 |
| Other deferred costs | **170,222** | 1,352,076 |
| Gross deferred assets | **2,488,966** | 3,953,783 |
| Amounts to be recovered (refunded) | | |
| Regulatory assets | **517,741** | (527,925) |
| Other deferred | **-** | (2,349) |
| Net deferred assets | **3,006,707** | 3,423,509 |

a) Retail settlement variance accounts

These accounts represent the variance between the revenue collected, using OEB approved rates for the non–competitive components of energy, and the corresponding cost of these non-competitive charges. These variances will be held as a regulatory asset or liability, based on the expectation that the amounts held from one year to the next for rate setting purposes will be approved for collection from, or refund to, future customers. In the absence of regulatory treatment, net earnings in the current year would have increased by $86,232 (2012 – decrease of $305,629).

b) Renewable energy

The Company incurred renewable energy costs of $6,332 in 2013 (2012 - $1,764). These costs related to the *Green Energy and Green Economy Act, 2009* passed by the Ontario government. In 2009, the OEB approved a deferral account to collect these costs. In 2013, the Company transferred $122,309 of previously incurred renewable energy costs to capital assets (2012 - recovery of $24,981). In the absence of regulatory treatment, net earnings in the current year would have decreased by $4,654 (2012 – increase of $17,064).

## 6. DEFERRED ASSETS (continued)

c) Smart meters

In July 2012, the Company applied for disposition of $3,716,441 in costs related to the implementation of smart meters. Final OEB approval of this disposition was received in November 2012. As part of this disposition, deferred costs of $2,856,550 were transferred to capital assets in 2012. The remaining balance in this account represents legacy assets that, as directed by the OEB, continue to be amortized over their original useful lives until the Company's rates are rebased in 2016. In the absence of regulatory treatment, net earnings in the current year would have increased by $36,502 (2012 – decrease of $257,661).

d) Other deferred costs

This balance includes costs and accumulated financial differences related to various ongoing projects (such as IFRS transition and rate rebasing) that are not currently in rates. The Company will apply for recovery of these costs in its next rate rebasing in 2016. At year-end, the balance relating to these costs was $121,118 (2012 – $1,343,365). As well, the OEB has authorized LDC's to recover lost revenue relating to Conservation and Demand Management programs that have resulted in decreased customer consumption and/or demand. Amounts claimed and subject to future recovery are recorded in the Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA"). At the end of 2013, the LRAMVA balance was $166,872 (2012 – $92,218).

In the May 2010 rate approval by the OEB, the Company was instructed to record the value of the savings resulting from the change to Harmonized Sales Tax effective July 1, 2010. This represents a payable of $117,768 (2012 - $83,507).

In the absence of regulatory treatment, net earnings in the current year would have increased by $868,662 (2012 – increase of $509,219).

e) Regulatory asset disposition

This balance represents the remaining amounts to be refunded to or recovered from ratepayers arising from dispositions that have been approved by the OEB. The balance in the account is a net debit of $517,741 (2012 – $527,925 credit). In the absence of regulatory treatment, net earnings for the current year would have decreased by $768,564 (2012 – increase of $350,604).

## 7. NOTES PAYABLE

The notes payable include a $23,523,326 note due to the Municipality at an interest rate of 5.87% and a $4,300,000 note to EI at an interest rate of 7.25%, the latter of which was issued upon the acquisition of the former MPDC by EI on June 30, 2005. In 2009, a further $1,000,000 was issued to EI in relation to the acquisition of Dutton and Newbury at an interest rate of 7.62%. Lastly, in 2010, notes payable totalling $8,250,000 were issued to EI at an interest rate of 5.87%. The notes payable have no set repayment term and interest payable monthly. In 2013, interest expense recognized relating these notes payable was $2,253,036 (2012 - $2,253,036).

## 8. EMPLOYEE FUTURE BENEFITS

The Company pays certain medical and life insurance benefits on behalf of its retired and current employees. The Company measures its accrued benefit obligation as at December 31 of each year. The accrued benefit liability at December 31, 2013 was $2,711,308 (2012 - $1,076,023). The most recent actuarial valuation of the benefit plans for funding purposes was as of December 31, 2013 and the next required valuation will be as of December 31, 2016.

Information about the Company's defined benefit plan is as follows:

| | **2013** | 2012 |
|---|---|---|
| | **$** | $ |
| Accrued benefit liability, beginning of year | **1,076,023** | 1,049,960 |
| Expense for the year | **50,038** | 74,661 |
| Transfers from/(to) other plans | **1,745,786** | (48,598) |
| Employer contributions | **(160,539)** | - |
| Estimated accrued benefit liability, end of year | **2,711,308** | 1,076,023 |

The main actuarial assumptions employed for the valuation are as follows:

*General inflation*

Future inflation levels, as measured by changes in the Consumers Price Index ("CPI"), were assumed to be 2.5% in 2013 and thereafter.

*Interest (discount) rate*

The present value of the future benefits and the expense for the year ended December 31, 2012 were determined using a discount rate of 4.12% (2012 – 4.41%). This corresponds to the OEB approved non-arm's length cost of debt rate for 2012.

*Health costs*

Health costs were assumed to increase at 8% per year for 10 years after the valuation date, and then at the CPI rate plus 1% thereafter.

*Dental costs*

Dental costs were assumed to increase at the CPI rate plus 1% for 2013 and thereafter.

## 9. PENSION AGREEMENT

The Company provides a pension plan for its employees through the OMERS. OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund") and provides pensions for employees of Ontario municipalities, local boards, public utilities, and school boards. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. As there is insufficient information to apply defined benefit plan accounting, defined contribution plan accounting has been used by the Company. The Company's contribution for employees' current service in 2013 was $419,199 (2012 - $360,832).

## 10. RELATED PARTY TRANSACTIONS

The Company provided the following services in the normal course of operations to the Municipality:

| | **2013** | 2012 |
|---|---|---|
| | **$** | $ |
| Energy (at commercial rates) | **5,814,611** | 5,346,067 |
| Streetlight maintenance | **192,317** | 190,764 |
| | **6,006,928** | 5,536,831 |

The Municipality provided the following services in the normal course of operations to the Company:

| | **2013** | 2012 |
|---|---|---|
| | **$** | $ |
| Asset management | **245,443** | 226,406 |

Entegrus Services Inc. ("ESI") is wholly owned by EI. ESI has provided the following services in the normal course of operations to the Company:

| | **2013** | 2012 |
|---|---|---|
| | **$** | $ |
| Billing, collection, administrative and data services | **5,257,759** | 5,192,702 |

At December 31, 2013, the Company had an outstanding balance payable to ESI in the amount of $8,836,351 (2012 - $8,637,919).

All related party transactions are recorded at the exchange amounts.

## 11. SHARE CAPITAL

The share capital of the Company consists of the following:

| | 2013 | 2012 |
|---|---|---|
| | $ | $ |
| Issued | | |
| 2,000 common shares | **28,154,623** | 28,154,623 |

## 12. SUPPLEMENTAL CASH FLOW INFORMATION

*Changes in non-cash working capital items*

| | 2013 | 2012 |
|---|---|---|
| | $ | $ |
| Accounts receivable | **610,419** | (2,853,722) |
| Accounts receivable - unbilled revenue | **(2,858,010)** | 949,961 |
| Taxes receivable | **(897,882)** | 768,331 |
| Inventories | **59,339** | (12,119) |
| Prepaid expenses | **21,155** | (13,130) |
| Accounts payable and accrued liabilities | **3,454,249** | (940,945) |
| Taxes payable | **(470,354)** | 470,354 |
| Due to related parties | **198,432** | 3,879,802 |
| Deferred revenue | **(122,062)** | 142,435 |
| Current portion of customer deposits | **(114,497)** | (541,548) |
| | **(119,211)** | 1,849,419 |

Payments in lieu of taxes of $1,855,505 (2012 – $205,827) and interest of $2,386,015 (2012 - $2,372,525) were paid during the year.

## 13. FINANCIAL INSTRUMENTS

*Fair value*

The Company's recognized financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, due to related parties, customer deposits and notes payable. The fair values of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities and due to related parties approximate their carrying amounts due to their short-term nature. As there is no secondary market for customer deposits, the calculation of their fair value with appropriate reliability is impractical.

The notes payable include a $23,523,326 promissory note payable to the Municipality at an interest rate of 5.87% and a $4,300,000 promissory note to EI at an interest rate of 7.25%, the latter of which was issued upon the acquisition of the former MPDC by EI on June 30, 2005. In 2009, a further $1,000,000 was issued to EI in relation to the acquisition of Dutton and Newbury at an interest rate of 7.62%. Lastly, in 2010, promissory notes payable totalling $8,250,000 were issued to EI at an interest rate of 5.87%. There is no "term length" associated with any of the promissory notes.

## 13. FINANCIAL INSTRUMENTS (continued)

*Fair value (continued)*

In order to determine fair value of the notes payable, comparison was made to the approved interest rate from the OEB. The OEB approves the rate of return on the debt portion of "Cost of Capital" for non-arm's length transactions. An interest rate of 4.12% has been approved by the OEB through the rate setting process for rates effective May 2013.

Using the OEB approved non-arm's length cost of debt of 4.12%, the annual interest expense would be reduced by approximately $726,000.

*Credit risk*

The Company is exposed to credit risk from its customers. The Company has a large number of diverse customers for the most part minimizing concentration of risk. There are a select group of manufacturing-based corporations that pose a significant increase in risk due to the current state of the economy as well as the future outlook for the economy. Close monitoring of this sector is currently being examined through internal and external credit rating resources. The Company continues to utilize special payment arrangements and security deposits to reduce this risk to an acceptable level.

## 14. CAPITAL DISCLOSURES

The Company's main objectives when managing capital are to:

- ensure ongoing access to funding to maintain and improve the electricity distribution system of LDC; and
- maintain a capital structure comparable for regulated activities as approved by the OEB's deemed debt-to-equity structure in our rates.

As at December 31, 2013, the Company's definition of capital includes shareholder's equity and long-term debt. This definition has remained unchanged from December 31, 2012. As at December 31, 2013, shareholder's equity amounts to $30,320,308 (2012 - $28,942,523) and long-term debt amounts to $37,073,326 (2012- $37,073,326).

In 2013, the capital structure approved by the OEB in rates was 40% Equity, 56% Long-Term Debt and 4% Short-Term Debt. The OEB-approved capital structure is unchanged from 2012. The Company's 2013 actual capital structure was 45% Equity (2012 - 44%) and 55% Long-Term Debt (2012 - 56%).

## 15. PAYMENTS IN LIEU OF TAXES

The reconciliation between the combined Federal and Ontario statutory tax rate and the effective rate of income taxes is as follows:

| | **2013** | 2012 |
|---|---|---|
| | **$** | $ |
| Earnings before payments in lieu of taxes | **3,544,100** | 3,319,247 |
| Statutory income tax rate (percent) | **26.50%** | 26.50% |
| Statutory income tax rate applied to earnings | **939,187** | 879,600 |
| Increase / (decrease) resulting from: | | |
| Temporary differences between accounting and tax basis of assets and liabilities | **(76,216)** | 147,905 |
| Permanent differences | **3,344** | 5,354 |
| Provision for income taxes | **866,315** | 1,032,859 |
| Effective rate of income tax (percent) | **24.44%** | 31.12% |

*Future income taxes*

The long-term future income tax asset of $3,211,562 (2012 - $3,282,682) includes the following:

| | **2013** | 2012 |
|---|---|---|
| | **$** | $ |
| Temporary differences related to capital assets and deferred assets | **2,228,608** | 2,889,320 |
| Temporary difference related to employee future benefits | **982,954** | 393,362 |
| | **3,211,562** | 3,282,682 |

## 16. COMMITMENTS

In 2013, the Company renewed an agreement with the Municipality of Strathroy-Caradoc to lease a portion of the premises known as 351 Frances Street, Strathroy, Ontario until December 31, 2016. The cost of the lease in 2013 was $62,535 (2012 - $62,535). In addition, the Company is required to pay 60% of shared operating costs. For the year ended December 31, 2013, the Company's share of operating costs was $32,833 (2012 - $47,327).

In 2010, the Company renewed an agreement with the Municipality of Strathroy-Caradoc to provide the services of billing of water services for a period of five years effective July 1, 2010. Contracts for maintenance of streetlight and traffic lights as well as installation of water meters are renewed annually. Revenues received for these services was $127,016 (2012 - $121,232).

*Financial Statements of*

# ENTEGRUS POWERLINES INC.

*December 31, 2014*

## Management's Responsibility for Financial Reporting

Entegrus Powerlines Inc.'s management is responsible for the preparation and presentation of the financial statements and all other information included in this annual report. Management is also responsible for the selection and use of accounting principles that are appropriate in the circumstances, and for the internal controls over the financial reporting process to reasonably ensure that relevant and reliable information is produced. Financial statements are not precise in nature as they include certain amounts based on estimates and judgment. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control over the financial reporting process. The Board of Directors exercises this responsibility through its Audit Committee. This committee is comprised of four directors of companies within the Entegrus group, one of whom is a director of the Entegrus Powerlines Inc. Board. This committee meets with management and the external auditors to ensure that management responsibilities are properly discharged and to review the financial statements and other information included in the annual report before they are presented to the Board of Directors for approval. The financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

Deloitte LLP, an independent external audit firm, has been appointed by the Audit Committee and engaged to examine the accompanying financial statements in accordance with generally accepted auditing standards in Canada and provide an independent professional opinion. Their report is presented with the financial statements.

Jim Hogan

**Jim Hogan**
**President and CEO**

**Chris Cowell**
**Chief Financial & Regulatory Officer**
**& VP Administration**

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# Independent Auditor's Report

To the Chairman and Board Members of
Entegrus Powerlines Inc.

We have audited the accompanying financial statements of Entegrus Powerlines Inc. which comprise the balance sheet as at December 31, 2014, and the statements of earnings, comprehensive income and retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

**Management's responsibility for the financial statements**

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

**Auditor's responsibility**

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

**Opinion**

In our opinion, the financial statements present fairly, in all material respects, the financial position of Entegrus Powerlines Inc. as at December 31, 2014 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Deloitte LLP

Chartered Professional Accountants, Chartered Accountants
Licensed Public Accountants
April 17, 2015

**ENTEGRUS POWERLINES INC.**
**Balance Sheet**
**December 31, 2014**

| | 2014 | 2013 |
|---|---|---|
| | $ | $ |
| **ASSETS** | | |
| CURRENT | | |
| Cash and cash equivalents | **3,714,286** | 7,508,843 |
| Accounts receivable (Note 4) | **7,163,799** | 6,539,098 |
| Accounts receivable - unbilled revenue | **12,499,188** | 13,602,458 |
| Taxes receivable | **1,636,515** | 897,882 |
| Due from related parties (Note 10) | **375,346** | - |
| Inventories | **756,533** | 727,004 |
| Prepaid expenses | **277,302** | 92,994 |
| | **26,422,969** | 29,368,279 |
| CAPITAL ASSETS (Note 5) | **71,658,460** | 66,526,334 |
| OTHER | | |
| Regulatory assets (Note 6) | **6,663,041** | 3,726,816 |
| Goodwill and intangible assets | **367,304** | 367,304 |
| Future income taxes (Note 15) | **1,477,114** | 3,211,562 |
| | **8,507,459** | 7,305,682 |
| | **106,588,888** | 103,200,295 |
| **LIABILITIES** | | |
| CURRENT | | |
| Accounts payable and accrued liabilities | **15,690,447** | 15,582,384 |
| Due to related parties (Note 10) | **-** | 8,836,351 |
| Deferred revenue | **175,267** | 347,611 |
| Current portion of customer deposits | **1,358,986** | 1,019,035 |
| | **17,224,700** | 25,785,381 |
| LONG-TERM | | |
| Regulatory liabilities (Note 6) | **4,307,511** | 3,931,671 |
| Notes payable (Note 7) | **47,073,326** | 37,073,326 |
| Employee future benefits (Note 8) | **2,651,999** | 2,711,308 |
| Long-term portion of customer deposits | **2,573,293** | 3,378,301 |
| | **56,606,129** | 47,094,606 |
| | **73,830,829** | 72,879,987 |
| COMMITMENT (Note 16) | | |
| **SHAREHOLDER'S EQUITY** | | |
| Share capital (Note 11) | **28,154,623** | 28,154,623 |
| Retained earnings | **4,603,436** | 2,165,685 |
| | **32,758,059** | 30,320,308 |
| | **106,588,888** | 103,200,295 |

**ENTEGRUS POWERLINES INC.**
**Statement of Earnings, Comprehensive Income and Retained Earnings**
**Year Ended December 31, 2014**

| | 2014 | 2013 |
|---|---|---|
| | $ | $ |
| SERVICE REVENUE | | |
| Residential | **43,715,015** | 39,727,793 |
| General service | **73,148,122** | 68,754,517 |
| Street lighting | **1,034,354** | 995,200 |
| | **117,897,491** | 109,477,510 |
| Change in unbilled revenue | **(816,384)** | 2,508,152 |
| | **117,081,107** | 111,985,662 |
| Retailer energy sales | **5,318,633** | 3,433,386 |
| | **122,399,740** | 115,419,048 |
| COST OF POWER | **103,652,003** | 96,951,040 |
| GROSS MARGIN ON SERVICE REVENUE | **18,747,737** | 18,468,008 |
| OTHER OPERATING REVENUE | **1,681,958** | 1,338,061 |
| OPERATING INCOME | **20,429,695** | 19,806,069 |
| OPERATING AND MAINTENANCE EXPENSE | | |
| Distribution | **4,189,175** | 3,716,285 |
| Regulatory | **1,677,655** | 602,341 |
| ADMINISTRATIVE EXPENSE | | |
| Billing and collection | **2,274,499** | 2,487,307 |
| General administration | **2,857,369** | 2,885,546 |
| Interest | **2,351,208** | 2,386,015 |
| DEPRECIATION AND AMORTIZATION | **3,601,671** | 4,184,475 |
| | **16,951,577** | 16,261,969 |
| EARNINGS BEFORE PAYMENTS IN LIEU OF TAXES | **3,478,118** | 3,544,100 |
| (Recovery of) provision for payments in lieu of taxes (Note 15) | **(359,633)** | 866,315 |
| NET EARNINGS AND COMPREHENSIVE INCOME | **3,837,751** | 2,677,785 |
| RETAINED EARNINGS, BEGINNING OF YEAR | **2,165,685** | 787,900 |
| LESS DIVIDENDS | **(1,400,000)** | (1,300,000) |
| RETAINED EARNINGS, END OF YEAR | **4,603,436** | 2,165,685 |

**ENTEGRUS POWERLINES INC.**
**Statement of Cash Flows**
**Year Ended December 31, 2014**

| | 2014 | 2013 |
|---|---|---|
| | $ | $ |
| OPERATING ACTIVITIES | | |
| Net earnings | **3,837,751** | 2,677,785 |
| Adjustments for: | | |
| Depreciation of capital assets | **3,601,671** | 4,184,475 |
| Gain on disposal of capital assets | **(38,789)** | (95,130) |
| Employee future benefits | **(59,309)** | 1,635,285 |
| Change in regulatory assets and liabilities | **(825,937)** | (215,873) |
| Change in long-term customer deposits | **(805,008)** | 199,156 |
| Changes in non-cash working capital items (Note 12) | **(1,042,700)** | (119,211) |
| | **4,667,679** | 8,703,547 |
| INVESTING ACTIVITIES | | |
| Proceeds on disposal of capital assets | **45,646** | 300,676 |
| Additions to capital assets | **(7,107,882)** | (7,558,287) |
| | **(7,062,236)** | (7,694,671) |
| FINANCING ACTIVITIES | | |
| Dividends paid | **(1,400,000)** | (1,300,000) |
| NET CHANGE IN CASH AND CASH EQUIVALENTS | **(3,794,557)** | (291,124) |
| CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR | **7,508,843** | 7,799,967 |
| CASH AND CASH EQUIVALENTS, END OF YEAR | **3,714,286** | 7,508,843 |

See Note 12 for supplemental cash flow information.

## 1. NATURE OF OPERATIONS

*Incorporation and amalgamation*

Entegrus Powerlines Inc. ("the Company") was incorporated September 22, 2000 under the *Business Corporations Act (Ontario).* In 2012, Chatham-Kent Hydro Inc. ("CKH") and Middlesex Power Distribution Corporation ("MPDC") amalgamated to continue as Chatham-Kent Hydro Inc. Subsequently, the name of the amalgamated entity was changed from Chatham-Kent Hydro Inc. to Entegrus Powerlines Inc.

The Company is wholly-owned by Entegrus Inc. ("EI"), which in turn is owned 90% by the Municipality of Chatham-Kent ("the Municipality") and 10% by Corix Utilities ("Corix"). The principal activity of the Company is to distribute electricity to customers within the Municipality of Chatham-Kent, Middlesex County and the County of Elgin, under a licence issued by the Ontario Energy Board ("OEB").

*Rate-regulated entity*

The Company is a regulated Local Distribution Company ("LDC") and has a distribution licence that is regulated by the OEB. The OEB has regulatory oversight of electricity matters in Ontario. The *Ontario Energy Board Act, 1998* sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles and filing process requirements for rate-setting purposes. The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity and the responsibility of ensuring the electricity distribution companies fulfill obligations to connect and service customers.

The Company is required to charge its customers for the following amounts (all of which, other than the distribution rates, represent a pass through of amounts payable to third parties):

- Electricity Price – The electricity price represents the commodity cost of electricity;
- Distribution Rate – The distribution rate is designed to recover the costs incurred by the Company in delivering electricity to customers and the OEB allowed rate of return;
- Global Adjustment – The difference between the rate paid to regulated and contracted electricity generators and the spot market price;
- Retail Transmission Rate – The retail transmission rate represents the wholesale costs incurred by the Company in respect of the transmission of electricity from generating stations to the local areas; and
- Wholesale Market Services Charge – The wholesale market services charge represents the cost of services provided by the Independent Electricity System Operator ("IESO") and the Ontario Power Authority to operate the wholesale electricity market and maintain the reliability of the power grid.

In order to operate in the Ontario electrical industry all market participants, including the Company, are required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations in the form of obtaining a credit rating, letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings.

## 1. NATURE OF OPERATIONS (continued)

*Market-based rate of return*

Rates for the Company continue to be based on the pre-amalgamation service territories until the Company's rates are rebased in 2016. At that time, the Company will consider whether rate harmonization would provide overall customer benefits and be in accordance with good rate-making practices.

The OEB approved the former CKH to revise rates effective May 1, 2010, which resulted in approved rates that include a 9.85% rate of return on equity rebased at 2010 test year levels. The rate of return of 9.85% was in accordance with the OEB's cost of capital parameters at that time.

The OEB approved the former MPDC to revise rates effective May 1, 2006, which resulted in approved rates that include a 9.0% rate of return on equity rebased at 2004 test year levels. The rate of return of 9.0% was in accordance with the OEB's cost of capital parameters at that time.

*Incentive Rate Mechanism*

Between rate basing years, the OEB regulates the rates of the Company under an Incentive Rate Mechanism ("IRM") regime. The process includes a mechanistic approach to establishing rates with a rate rebasing approach (cost-of-service) every five years. The IRM rate setting process provides an increase in rates for inflationary cost, partially offset by expected productivity and efficiency gains established by the OEB.

The OEB allows for rate rebasing to be deferred for up to five years where there is a purchase or merger of LDC's. As a result of the amalgamation of CKH and MPDC, the OEB has approved the deferral of rate rebasing of the Company to 2016.

*Regulatory assets and liabilities*

Electricity distributors are required to reflect certain prescribed costs on their balance sheets until the manner and timing of distribution is determined by the OEB. These costs include:

- Settlement variance between amounts charged by the Company to customers (based on regulated rates) and corresponding cost of non-competitive electricity service incurred by it in the wholesale market administered by the IESO after May 1, 2002;
- Costs incurred to invest in and install a smart meter at all of our customer premises;
- Cost related to the *Green Energy and Green Economy Act, 2009*; and,
- Costs incurred and accumulated financial differences related to the Company's transition to International Financial Reporting Standards ("IFRS").

## 2. CHANGE IN ACCOUNTING FRAMEWORK

On February 13, 2008, the Accounting Standards Board ("AcSB") of the Canadian Institute of Chartered Accountants ("CICA") confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles ("GAAP") for fiscal years beginning on or after January 1, 2011. Subsequently, on September 10, 2010, the AcSB decided to permit rate-regulated entities and certain affiliates to defer their IFRS adoption date to January 1, 2012. The Company is a qualifying entity for purposes of this deferral and elected to use the deferral offered by the AcSB.

On March 30, 2012, the AcSB announced an additional one year deferral for qualifying entities with rate-regulated activities. Further one year deferrals were announced by the AcSB in September 2012 and February 2013. The Company has elected to use all deferrals made available by the AcSB. As a result, the Company's IFRS adoption date is currently set at January 1, 2015.

## 3. SIGNIFICANT ACCOUNTING POLICIES

The financial statements have been prepared in accordance with Canadian GAAP and reflect the following policies as set forth in the Accounting Procedures Handbook issued by the OEB under the authority of the *Ontario Energy Board Act, 1998:*

*Regulation*

The Company is regulated by the OEB and any rate adjustments require OEB approval.

*Cash and cash equivalents*

Cash and cash equivalents consist of cash on hand and balances with the bank.

*Unbilled revenue*

Unbilled revenue is an estimate of customers' consumption of power from the last meter read to December 31st.

*Inventories*

Inventories are valued at the lower of cost and net realizable value with cost being determined using the weighted average method.

## 3. SIGNIFICANT ACCOUNTING POLICIES (continued)

*Capital assets*

Capital assets are recorded at cost. Depreciation is calculated on a straight-line basis over the useful life of the asset as follows:

| | |
|---|---|
| Buildings and fixtures | 20 – 50 years |
| Distribution station equipment | 15 – 45 years |
| Distribution system – overhead | 45 – 60 years |
| Distribution system – underground | 20 – 55 years |
| Distribution transformers | 35 – 45 years |
| Distribution meters | 25 years |
| General office equipment | 10 years |
| Computer hardware | 3 years |
| Computer software | 3 – 10 years |
| Rolling stock | 7 – 15 years |
| Tools | 5 years |
| System supervisory equipment | 20 years |
| Automated mapping | 15 years |
| Services | 40 – 50 years |
| Smart meters | 15 years |
| Non-regulated generation assets | 25 years |

The Company recognizes work in process for larger capital projects that are not in service at the end of the year. When the capital projects are completed, they are transferred to the appropriate capital asset account. Depreciation of these assets will begin when they are placed in service.

*Impairment of long-lived assets*

Long-lived assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. An impairment loss is recognized when their carrying value exceeds the total undiscounted cash flows expected from their use and eventual disposition. The amount of the impairment loss is determined as the excess of the carrying value of the asset over its fair value.

*Contributions in aid of construction*

Contributions in aid of construction consist of third party contributions toward the cost of constructing the Company's assets. Contributions received are recorded as an offset to capital assets and amortized on a straight-line basis over 25 years.

*Goodwill*

Goodwill representing the excess of purchase price over fair value of the net identifiable assets of acquired businesses is tested for impairment annually or more frequently when an event or circumstance occurs that indicates that goodwill might be impaired. When the carrying amount exceeds the fair value, an impairment loss is recognized in the statement earnings in an amount equal to the excess.

## 3. SIGNIFICANT ACCOUNTING POLICIES (continued)

*Intangible assets*

Intangible assets are recorded at their fair value at the acquisition date. As the Company's intangible assets have an indefinite life, they are not amortized to income. Intangible assets will be tested for impairment when events or changes in circumstances indicate that their carrying value may not be recoverable.

*Regulatory assets and liabilities*

Regulatory assets and liabilities consist of qualifying capital costs and related expenditures incurred that are not currently recovered in rates. Also included in regulatory assets and liabilities are retail settlement variance accounts. These variances are for non-competitive energy services which are a pass through for the Company. Disposition of the regulatory assets and liabilities requires regulatory approval from the OEB.

*Payments in lieu of taxes*

Under the *Electricity Act, 1998*, the Company is required to make payments-in-lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are recorded in accordance with the rules for computing income taxes and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) and modified by the *Electricity Act, 1998*, and related regulations.

The Company recognizes future income tax assets and liabilities in accordance with CPA Canada Handbook Section 3465, *Income Taxes*. Section 3465 also contains guidance specific to rate-regulated enterprises that requires the Company to recognize a regulatory asset or liability for the amount of future income taxes expected to be recovered from or refunded to ratepayers and to present these amounts on a pre-tax basis in the financial statements. Accordingly, the Company has recorded a regulatory liability that has been included in long-term liabilities and an associated future income tax asset of $1,477,114 (2013 - $3,211,562). The liability will be settled through future rate reductions.

*Customer deposits*

Customer deposits are recorded when received or paid. Deposits earn interest at a rate of prime less 2%.

*Asset retirement obligations*

The Company recognizes the liability for a future asset retirement that results from acquisition, construction, development or normal operations. The liability for an asset retirement is initially recorded at its fair value in the year in which it is incurred and when a reasonable estimate of fair value can be made. The corresponding cost is capitalized as part of the related asset and is amortized over the asset's useful life. In subsequent years the liability is adjusted for changes resulting from the passage of time and revisions to either the timing or the amount of the original estimate of the undiscounted cash flows. The accretion of the liability to its fair value as a result of the passage of time is charged to earnings.

## 3. SIGNIFICANT ACCOUNTING POLICIES (continued)

*Employment benefits other than pension*

The Company provides its current and retired employees with life insurance and medical benefits beyond those provided by government-sponsored plans. The cost of these benefits is actuarially determined annually as at December 31. The cost is determined using the projected unit credit method and assumptions including interest rates, salary escalation, retirement ages of employees, mortality rates, and health care costs.

*Use of estimates*

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Unbilled revenue is a significant estimate that is subject to material measurement uncertainty. Actual results could differ from those estimates.

*Revenue recognition and cost of power*

Service revenue is recorded on the basis of regular meter readings and estimated customer usage since the last meter reading date to the end of the year. The related cost of power is recorded on the basis of power used. Any discrepancies in the revenue collected and associated cost of power related to distribution are charged to regulatory assets or liabilities.

*Financial instruments*

The AcSB decided that rate-regulated enterprises that are not public enterprises as defined in Section 1300, *Differential Reporting*, will not be required to apply Sections 3862, *Financial Instruments – Disclosures*, and 3863, *Financial Instruments – Presentation*, and would continue to apply Section 3861, *Financial Instruments – Disclosure and Presentation.* Therefore, in accordance with this decision, the Company continues to apply Section 3861.

Financial assets and financial liabilities are initially recognized at fair value and their subsequent measurement is dependent on their classification as described below. Their classification depends on the purpose, for which the financial instruments were acquired or issued, their characteristics and the Company's designation of such instruments. Settlement date accounting is used.

<u>Classification</u>

| | |
|---|---|
| Cash and cash equivalents | Held for trading |
| Accounts receivable | Loans and receivables |
| Due from related parties | Loans and receivables |
| Accounts payable and accrued liabilities | Other liabilities |
| Due to related parties | Other liabilities |
| Current portion of customer deposits | Other liabilities |
| Notes payable | Other liabilities |
| Long-term portion of customer deposits | Other liabilities |

## 3. SIGNIFICANT ACCOUNTING POLICIES (continued)

*Financial instruments (continued)*

Held for trading

Held for trading financial assets are financial assets typically acquired for resale prior to maturity or that are designated as held for trading. They are measured at fair value at the balance sheet date. Fair value fluctuations including interest earned, interest accrued, gains and losses realized on disposal and unrealized gains and losses are included in other income.

Financial liabilities designated as held for trading are those non-derivative financial liabilities that the Company elects to designate on initial recognition as instruments that it will measure at fair value through other interest expense. These are accounted for in the same manner as held for trading assets. The Company has not designated any non-derivative financial liabilities as held for trading.

Loans and receivables

Loans and receivables are accounted for at amortized cost using the effective interest method.

Other liabilities

Other liabilities are recorded at amortized cost using the effective interest method and include all financial liabilities, other than derivative instruments.

Effective interest method

The Company uses the effective interest method to recognize interest income or expense which includes transaction costs or fees, premiums or discounts earned or incurred for financial instruments.

## 4. ACCOUNTS RECEIVABLE

| | **2014** | 2013 |
|---|---|---|
| | **$** | $ |
| Electrical energy | **4,848,660** | 4,408,268 |
| Other | **2,475,728** | 2,267,500 |
| | **7,324,388** | 6,675,768 |
| Allowance for doubtful accounts | **(160,589)** | (136,670) |
| Net accounts receivable | **7,163,799** | 6,539,098 |

## 5. CAPITAL ASSETS

| | 2014 | | | 2013 |
|---|---|---|---|---|
| | **Cost** | **Accumulated Depreciation** | **Net Book Value** | Net Book Value |
| | **$** | **$** | **$** | $ |
| Plant and distribution system: | | | | |
| Land | **1,369,163** | **-** | **1,369,163** | 1,369,163 |
| Buildings and fixtures | **6,192,705** | **1,652,665** | **4,540,040** | 4,293,612 |
| Distribution station equipment | **1,987,188** | **990,620** | **996,568** | 986,515 |
| Station retirement obligation | **20,599** | **5,599** | **15,000** | 15,000 |
| Distribution system: | | | | |
| Overhead | **44,032,505** | **18,285,070** | **25,747,435** | 23,817,428 |
| Underground | **25,757,537** | **14,047,942** | **11,709,595** | 11,256,587 |
| Transformers | **23,897,084** | **11,019,833** | **12,877,251** | 12,189,050 |
| Meters | **3,940,117** | **1,845,074** | **2,095,043** | 2,255,032 |
| General office equipment | **519,386** | **269,346** | **250,039** | 117,234 |
| Computer hardware | **1,636,812** | **1,390,950** | **245,862** | 2,594 |
| Computer software | **3,541,321** | **1,497,403** | **2,043,918** | 676,451 |
| Rolling stock | **5,214,078** | **3,168,533** | **2,045,545** | 1,917,944 |
| Tools | **1,488,866** | **1,279,606** | **209,261** | 145,287 |
| System supervisory equipment | **1,099,350** | **697,357** | **401,993** | 428,984 |
| Automated mapping | **3,063,717** | **1,867,433** | **1,196,284** | 1,185,563 |
| Services | **6,685,187** | **1,680,929** | **5,004,258** | 4,533,825 |
| Smart meters | **8,973,125** | **3,635,648** | **5,337,477** | 5,556,051 |
| Non-regulated generation assets | **879,207** | **60,829** | **818,379** | 862,557 |
| Work in process | **60,000** | **-** | **60,000** | 62,000 |
| | **140,357,947** | **63,394,835** | **76,963,112** | 71,670,877 |
| Contributions in aid of construction | **(7,834,617)** | **(2,529,965)** | **(5,304,652)** | (5,144,543) |
| Capital assets | **132,523,331** | **60,864,871** | **71,658,460** | 66,526,334 |

## 6. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-making process. Regulatory assets represent future revenues associated with certain costs incurred in the current period or in prior periods that are expected to be recovered from customers in future periods through the rate setting process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers as a result of the rate setting process.

## 6. REGULATORY ASSETS AND LIABILITIES (continued)

Regulatory asset and liability balances at December 31 are comprised of the following:

| | **2014** | 2013 |
|---|---|---|
| | **$** | $ |
| Regulatory assets: | | |
| Retail settlement variance accounts | **5,347,317** | 1,901,952 |
| Legacy meters | **362,515** | 410,460 |
| Other regulatory assets | **953,209** | 896,663 |
| Regulatory balances to be recovered | **-** | 517,741 |
| | **6,663,041** | 3,726,816 |
| Regulatory liabilities: | | |
| Future income taxes | **1,477,114** | 3,211,562 |
| Accounting changes under Canadian GAAP | **2,279,997** | 602,341 |
| Regulatory balances to be refunded | **398,643** | - |
| Other regulatory liabilities | **151,757** | 117,768 |
| | **4,307,511** | 3,931,671 |

*Regulatory assets*

a) Retail settlement variance accounts

These accounts represent the variance between the revenue collected using OEB approved rates for the non–competitive components of energy and the corresponding cost of these non-competitive charges. The net amount of these variances are held as a regulatory asset or liability, based on the expectation that the amounts held from one year to the next for rate setting purposes will be approved for collection from, or refund to, future customers. In the absence of regulatory treatment, net earnings in the current year would have decreased by $2,532,343 (2013 – increase of $86,232).

b) Legacy meters

The balance in this account represents legacy metering assets that, as directed by the OEB, continue to be amortized over their original useful lives until the Company's rates are rebased in 2016. In the absence of regulatory treatment, net earnings in the current year would have increased by $35,239 (2013 – increase of $36,502).

c) Other regulatory assets

Other regulatory assets include various deferred amounts in connection with Green Energy programs, Lost Revenue Adjustment Mechanism variances and IFRS transition expenditures. In the absence of regulatory treatment, net earnings in the current year would have decreased by $41,561 (2013 – increase of $486,003).

## 6. REGULATORY ASSETS AND LIABILITIES (continued)

*Regulatory liabilities*

a) Future income taxes

This balance represents the amount expected to be refunded in rates arising from timing differences in the recognition of future income tax assets (see Note 15). In the absence of regulatory treatment, net earnings for the current year would have decreased by $1,274,819 (2013 – decrease of $52,273).

b) Accounting changes under Canadian GAAP

In 2012, the OEB issued a directive that required LDC's reporting under Canadian GAAP to adopt IFRS-compliant depreciation and capitalization accounting policies effective January 1, 2013, regardless of whether the LDC had chosen to defer the adoption of IFRS as permitted by the AcSB. This balance represents the financial differences arising as a result of adopting those IFRS-compliant policies. It will be disposed of as part of the Company's next rate rebasing and refunded to ratepayers through future rate reductions. There is no impact to net earnings as a result of these accounting policy changes.

c) Regulatory balances to be recovered/refunded

This balance represents the remaining amounts to be refunded to or recovered from ratepayers arising from dispositions that have been approved by the OEB. In the absence of regulatory treatment, net earnings for the current year would have increased by $673,542 (2013 – decrease of $770,291).

d) Other regulatory liabilities

Other regulatory liabilities include amounts recorded as a result of the implementation of Harmonized Sales Tax ("HST"). In the May 2010 rate approval by the OEB, the Company was instructed to record the value of the savings resulting from the change to HST effective July 1, 2010. In the absence of regulatory treatment, net earnings for the current year would have increased by $24,982 (2013 – increase of $25,182).

## 7. NOTES PAYABLE

The notes payable include a $23,523,326 note due to the Municipality at an interest rate of 5.87% and a $4,300,000 note to EI at an interest rate of 7.25%, the latter of which was issued upon the acquisition of the former MPDC by EI on June 30, 2005. In 2009, a further $1,000,000 was issued to EI in relation to the acquisition of Dutton and Newbury at an interest rate of 7.62%. In 2010, notes payable totalling $8,250,000 were issued to EI at an interest rate of 5.87%. Lastly, on December 31, 2014, a $10,000,000 note was issued to EI at an interest rate of 4.88%. The notes payable have no set repayment term and interest is payable monthly. In 2014, interest expense recognized relating to these notes payable was $2,253,036 (2013 - $2,253,036).

## 8. EMPLOYEE FUTURE BENEFITS

The Company pays certain medical and life insurance benefits on behalf of its retired and current employees. The Company measures its accrued benefit obligation as at December 31 of each year. The accrued benefit liability at December 31, 2014 was $2,651,999 (2013 - $2,711,308). The most recent actuarial valuation of the benefit plans for funding purposes was as of December 31, 2013 and the next required valuation will be as of December 31, 2016.

Information about the Company's defined benefit plan is as follows:

| | **2014** | 2013 |
|---|---|---|
| | **$** | $ |
| Accrued benefit liability, beginning of year | **2,711,308** | 1,076,023 |
| Expense for the year | **96,706** | 50,038 |
| Transfers from other plans | - | 1,745,786 |
| Employer contributions | **(156,015)** | (160,539) |
| Accrued benefit liability, end of year | **2,651,999** | 2,711,308 |

The main actuarial assumptions employed for the valuation are as follows:

*General inflation*

Future inflation levels, as measured by changes in the Consumers Price Index ("CPI"), were assumed to be 2.5% in 2014 and thereafter.

*Interest (discount) rate*

The present value of the future benefits and the expense for the year ended December 31, 2014 were determined using a discount rate of 4.88% (2013 – 4.12%). This corresponds to the OEB approved non-arm's length cost of debt rate for 2014.

*Health costs*

Health costs were assumed to increase at 8% per year for 10 years after the valuation date, and then at the CPI rate plus 1% thereafter.

*Dental costs*

Dental costs were assumed to increase at the CPI rate plus 1% for 2014 and thereafter.

## 9. PENSION AGREEMENT

The Company provides a pension plan for its employees through the OMERS. OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund") and provides pensions for employees of Ontario municipalities, local boards, public utilities, and school boards. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. As there is insufficient information to apply defined benefit plan accounting, defined contribution plan accounting has been used by the Company. The Company's contribution for employees' current service in 2014 was $434,986 (2013 - $419,199).

## 10. RELATED PARTY TRANSACTIONS

*Municipality of Chatham-Kent*

The Company provided the following services in the normal course of operations to the Municipality:

| | **2014** | 2013 |
|---|---|---|
| | **$** | $ |
| Energy (at commercial rates) | **6,012,516** | 5,814,611 |
| Streetlight maintenance | **201,163** | 192,317 |
| | **6,213,679** | 6,006,928 |

The Municipality provided the following services in the normal course of operations to the Company:

| | **2014** | 2013 |
|---|---|---|
| | **$** | $ |
| Asset management | **245,745** | 245,443 |

All related party transactions with the Municipality were recorded at their exchange amounts.

*Entegrus Services Inc.*

Entegrus Services Inc. ("ESI") is wholly owned by EI. ESI has provided the following services in the normal course of operations to the Company:

| | **2014** | 2013 |
|---|---|---|
| | **$** | $ |
| Billing, collection, administrative and data services | **5,347,896** | 5,257,759 |

Related party transactions with ESI completed in the normal course of business were recorded at their exchange amounts.

## 10. RELATED PARTY TRANSACTIONS (continued)

*Entegrus Services Inc. (continued)*

On December 31, 2014, the Company purchased various assets from ESI at a purchase price of $1,845,701. The purchase price represented the total carrying amount of the assets in ESI's financial records at December 31, 2014. The assets purchased and their respective carrying amounts are provided below:

| | $ |
|---|---|
| Working capital: | |
| Accounts receivable | **73,540** |
| Prepaid expenses | **139,389** |
| | **212,929** |
| Capital assets: | |
| General office equipment | **149,270** |
| Computer hardware | **256,846** |
| Computer software | **1,084,949** |
| Rolling stock | **108,429** |
| Tools | **33,278** |
| | **1,632,772** |
| Total purchase price | **1,845,701** |

At December 31, 2014, the Company had an outstanding balance receivable from ESI in the amount of $375,346 (2013 – payable of $8,836,351).

## 11. SHARE CAPITAL

The share capital of the Company consists of the following:

| | **2014** | 2013 |
|---|---|---|
| | **$** | $ |
| Issued | | |
| 2,000 common shares | **28,154,623** | 28,154,623 |

## 12. SUPPLEMENTAL CASH FLOW INFORMATION

*Changes in non-cash working capital items*

| | 2014 | 2013 |
|---|---|---|
| | | $ |
| Accounts receivable | **(551,161)** | 610,419 |
| Accounts receivable - unbilled revenue | **1,103,270** | (2,858,010) |
| Taxes receivable/payable | **(738,633)** | (1,368,236) |
| Due to/from related parties | **(1,057,398)** | 198,432 |
| Inventories | **(29,529)** | 59,339 |
| Prepaid expenses | **(44,919)** | 21,155 |
| Accounts payable and accrued liabilities | **108,063** | 3,454,249 |
| Deferred revenue | **(172,344)** | (122,062) |
| Current portion of customer deposits | **339,951** | (114,497) |
| | **(1,042,700)** | (119,211) |

Payments in lieu of taxes of $379,000 (2013 – $1,855,505) and interest of $2,351,208 (2013 - $2,386,015) were paid during the year.

## 13. FINANCIAL INSTRUMENTS

*Fair value*

The Company's recognized financial instruments consist of cash and cash equivalents, accounts receivable, due from related parties, accounts payable and accrued liabilities, due to related parties, customer deposits and notes payable. The fair values of cash and cash equivalents, accounts receivable, due from related parties, accounts payable and accrued liabilities and due to related parties approximate their carrying amounts due to their short-term nature. As there is no secondary market for customer deposits, the calculation of their fair value with appropriate reliability is impractical.

The notes payable include a $23,523,326 note due to the Municipality at an interest rate of 5.87% and a $4,300,000 note to EI at an interest rate of 7.25%, the latter of which was issued upon the acquisition of the former MPDC by EI on June 30, 2005. In 2009, a further $1,000,000 was issued to EI in relation to the acquisition of Dutton and Newbury at an interest rate of 7.62%. In 2010, notes payable totalling $8,250,000 were issued to EI at an interest rate of 5.87%. Lastly, on December 31, 2014, a $10,000,000 note was issued to EI at an interest rate of 4.88%. There is no "term length" associated with any of the promissory notes.

In order to determine fair value of the notes payable, comparison was made to the approved interest rate from the OEB. The OEB approves the rate of return on the debt portion of "Cost of Capital" for non-arm's length transactions. An interest rate of 4.88% has been approved by the OEB through the rate setting process for rates effective January 2014.

Using the OEB approved non-arm's length cost of debt of 4.88%, the annual interest expense would be reduced by approximately $461,000.

## 13. FINANCIAL INSTRUMENTS (continued)

*Credit risk*

The Company is exposed to credit risk from its customers. The Company has a large number of diverse customers for the most part minimizing concentration of risk. There are a select group of manufacturing-based corporations that pose a significant increase in risk due to the current state of the economy as well as the future outlook for the economy. Close monitoring of this sector is currently being examined through internal and external credit rating resources. The Company continues to utilize special payment arrangements and security deposits to reduce this risk to an acceptable level.

## 14. CAPITAL DISCLOSURES

The Company's main objectives when managing capital are to:

- ensure ongoing access to funding to maintain and improve the electricity distribution system of LDC; and
- maintain a capital structure comparable for regulated activities as approved by the OEB's deemed debt-to-equity structure in our rates.

As at December 31, 2014, the Company's definition of capital includes shareholder's equity and long-term debt. This definition has remained unchanged from December 31, 2013. As at December 31, 2014, shareholder's equity amounts to $32,758,059 (2013 - $30,320,308) and long-term debt amounts to $47,073,326 (2013 - $37,073,326).

In 2014, the capital structure approved by the OEB in rates was 40% Equity, 56% Long-Term Debt and 4% Short-Term Debt. The OEB-approved capital structure is unchanged from 2013. The Company's 2014 actual capital structure was 41% Equity (2013 - 45%) and 59% Long-Term Debt (2013 - 55%).

## 15. PAYMENTS IN LIEU OF TAXES

The reconciliation between the combined Federal and Ontario statutory tax rate and the effective rate of income taxes is as follows:

| | **2014** | 2013 |
|---|---|---|
| | **$** | $ |
| Earnings before payments in lieu of taxes | **3,478,118** | 3,544,100 |
| Statutory income tax rate (percent) | **26.50%** | 26.50% |
| Statutory income tax rate applied to earnings | **921,701** | 939,187 |
| Increase / (decrease) resulting from: | | |
| Temporary differences between accounting and tax basis of assets and liabilities | **(1,284,224)** | (76,216) |
| Permanent differences | **2,890** | 3,344 |
| (Recovery of) provision for income taxes | **(359,633)** | 866,315 |
| Effective rate of income tax (percent) | **-10.34%** | 24.44% |

*Future income taxes*

The long-term future income tax asset is comprised of the following:

| | **2014** | 2013 |
|---|---|---|
| | **$** | $ |
| Temporary differences related to capital assets and deferred assets | **515,543** | 2,228,608 |
| Temporary difference related to employee future benefits | **961,571** | 982,954 |
| | **1,477,114** | 3,211,562 |

## 16. COMMITMENT

In 2013, the Company renewed an agreement with the Municipality of Strathroy-Caradoc to lease a portion of the premises known as 351 Frances Street, Strathroy, Ontario until December 31, 2016. The cost of the lease in 2014 was $63,786 (2013 - $62,535). In addition, the Company is required to pay 60% of shared operating costs. For the year ended December 31, 2014, the Company's share of operating costs was $33,205 (2013 - $32,833).

## 17. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the current year's presentation.

# ATTACHMENT 1-M

## Reconciliation of Audited Financial Statements to RRR Trial Balances

**Entegrus Powerlines Inc.**
**USOA Income Statement**
**Year Ending December 31, 2012**

| Statement | Income Statement |
|---|---|

| Sum of Ending Balance | | | |
|---|---|---|---|
| **Cayenta Statement Class 1** | **Cayenta Statement Class 2** | **USOA Account** | **Total** |
| **07 Revenue** | **25 Revenue** | 4006 | -$23,128,786 |
| | | 4020 | -$1,830,401 |
| | | 4025 | -$590,675 |
| | | 4030 | -$29,999 |
| | | 4035 | -$43,832,318 |
| | | 4050 | $742,941 |
| | | 4055 | -$3,183,117 |
| | | 4062 | -$6,139,320 |
| | | 4066 | -$5,933,623 |
| | | 4068 | -$4,408,367 |
| | | 4075 | -$314,707 |
| | | 4080 | -$17,609,902 |
| | **25 Revenue Sum** | | **-$106,258,273** |
| | **26 Other Operating Income** | 4080 | -$142,532 |
| | | 4082 | -$53,186 |
| | | 4084 | -$1,462 |
| | | 4205 | -$179,109 |
| | | 4210 | -$159,245 |
| | | 4220 | -$11,253 |
| | | 4225 | -$258,141 |
| | | 4235 | -$472,092 |
| | | 4355 | -$73,609 |
| | | 4375 | -$11,110 |
| | | 4380 | $56,702 |
| | | 4390 | -$61,327 |
| | | 4405 | -$138,379 |
| | **26 Other Operating Income Sum** | | **-$1,504,742** |
| **07 Revenue Sum** | | | **-$107,763,015** |
| **08 Cost of Power** | **27 Cost of Power** | 4705 | $71,852,354 |
| | | 4708 | $6,139,320 |
| | | 4714 | $5,933,623 |
| | | 4716 | $4,408,367 |
| | | 4750 | $314,707 |
| | **27 Cost of Power Sum** | | **$88,648,371** |
| **08 Cost of Power Sum** | | | **$88,648,371** |
| **09 Operating and Maintenace** | **28 Distribution** | 4715 | $32,568 |
| | | 5005 | $275,685 |
| | | 5012 | $0 |
| | | 5016 | $50,328 |
| | | 5017 | $24,421 |
| | | 5020 | $60,482 |
| | | 5025 | $15,542 |

**Entegrus Powerlines Inc.**
**USOA Income Statement**
**Year Ending December 31, 2012**

| Statement | Income Statement |
|---|---|

| Sum of Ending Balance | | | |
|---|---|---|---|
| **Cayenta Statement Class 1** | **Cayenta Statement Class 2** | **USOA Account** | **Total** |
| **09 Operating and Maintenace** | **28 Distribution** | 5035 | $2,482 |
| | | 5040 | $174,073 |
| | | 5045 | $68,701 |
| | | 5055 | $0 |
| | | 5065 | $194,224 |
| | | 5070 | $21,376 |
| | | 5075 | $2,948 |
| | | 5105 | $310,344 |
| | | 5114 | $198,852 |
| | | 5120 | $69,696 |
| | | 5125 | $137,215 |
| | | 5130 | $185,603 |
| | | 5135 | $183,739 |
| | | 5145 | $2,825 |
| | | 5150 | $9,602 |
| | | 5155 | $77,255 |
| | | 5160 | $38,786 |
| | | 5175 | $242,254 |
| | | 5410 | $20,789 |
| | | 5420 | $18,971 |
| | | 5610 | $12,535 |
| | | 5620 | $113,328 |
| | | 5630 | $115,700 |
| | | 5635 | $17,609 |
| | | 5645 | $9,243 |
| | | 5655 | $248,098 |
| | | 5665 | $28,570 |
| | | 5675 | $582,158 |
| | **28 Distribution Sum** | | **$3,546,002** |
| | **29 Regulatory Expense** | 5655 | $56,702 |
| | | 6310 | $50,960 |
| | **29 Regulatory Expense Sum** | | **$107,662** |
| **09 Operating and Maintenace Sum** | | | **$3,653,664** |
| **10 Administrative Expense** | **30 Billing and Collection** | 5305 | $290,497 |
| | | 5310 | $57,102 |
| | | 5315 | $1,315,468 |
| | | 5320 | $593,391 |
| | | 5335 | $177,179 |
| | **30 Billing and Collection Sum** | | **$2,433,637** |
| | **31 General Administration** | 5410 | $54,633 |
| | | 5610 | $1,206,940 |
| | | 5615 | $263,221 |

**Entegrus Powerlines Inc.**
**USOA Income Statement**
**Year Ending December 31, 2012**

| Statement | Income Statement |
|---|---|

| Sum of Ending Balance | | | |
|---|---|---|---|
| **Cayenta Statement Class 1** | **Cayenta Statement Class 2** | **USOA Account** | **Total** |
| **10 Administrative Expense** | **31 General Administration** | 5620 | $54,732 |
| | | 5630 | $276,277 |
| | | 5635 | $108,249 |
| | | 5645 | $253,664 |
| | | 5655 | $201,924 |
| | | 5665 | $53,160 |
| | | 5670 | $113,493 |
| | | 6205 | $230,554 |
| | **31 General Administration Sum** | | **$2,816,846** |
| | **32 Interest** | 6030 | $2,253,036 |
| | | 6035 | $107,527 |
| | | 6215 | $11,962 |
| | **32 Interest Sum** | | **$2,372,525** |
| **10 Administrative Expense Sum** | | | **$7,623,009** |
| **11 Depreciation and Amortization** | **33 Depreciation and Amortization** | 4380 | $4,661 |
| | | 5705 | $4,746,387 |
| | **33 Depreciation and Amortization Sum** | | **$4,751,048** |
| **11 Depreciation and Amortization Sum** | | | **$4,751,048** |
| **12 Provisions for PILs** | **34 Provisions for PILs** | 6110 | $1,032,859 |
| | **34 Provisions for PILs Sum** | | **$1,032,859** |
| **12 Provisions for PILs Sum** | | | **$1,032,859** |
| **#N/A** | **#N/A** | 5005 | -$28,093 |

**Entegrus Powerlines Inc.**
**USOA Balance Sheet**
**Year Ending December 31, 2012**

| Statement | Balance Sheet |
|---|---|

| Sum of Ending Balance | | | |
|---|---|---|---|
| **Cayenta Statement Class 1** | **Cayenta Statement Class 2** | **USOA Account** | **Total** |
| **01 Current Assets** | **01 Cash and cash Equivalents** | 1005 | $7,798,067 |
| | | 1010 | $1,900 |
| | **01 Cash and cash Equivalents Sum** | | **$7,799,967** |
| | **02 Accounts Receivable** | 1100 | $3,937,174 |
| | | 1102 | -$1,721 |
| | | 1104 | $2,322,210 |
| | | 1110 | $1,028,850 |
| | | 1130 | -$136,996 |
| | **02 Accounts Receivable Sum** | | **$7,149,517** |
| | **03 Accounts Receivable - Unbilled Revenue** | 1120 | $10,744,448 |
| | **03 Accounts Receivable - Unbilled Revenue Sum** | | **$10,744,448** |
| | **06 Inventories** | 1330 | $786,343 |
| | **06 Inventories Sum** | | **$786,343** |
| | **07 Prepaid Expenses** | 1180 | $114,149 |
| | **07 Prepaid Expenses Sum** | | **$114,149** |
| **01 Current Assets Sum** | | | **$26,594,424** |
| **02 Capital Assets** | **08 Capital Assets** | 1805 | $452,262 |
| | | 1808 | $904,693 |
| | | 1820 | $1,625,439 |
| | | 1830 | $10,183,983 |
| | | 1835 | $28,652,463 |
| | | 1840 | $3,815,056 |
| | | 1845 | $19,822,500 |
| | | 1850 | $21,439,194 |
| | | 1855 | $5,442,112 |
| | | 1860 | $11,814,340 |
| | | 1905 | $953,909 |
| | | 1908 | $4,699,524 |
| | | 1915 | $325,888 |
| | | 1920 | $1,108,774 |
| | | 1930 | $4,051,932 |
| | | 1940 | $1,249,436 |
| | | 1980 | $931,094 |
| | | 1990 | $2,364,407 |
| | | 1995 | -$6,594,753 |
| | | 2055 | $1,005,664 |
| | | 2075 | $412,446 |
| | | 2105 | -$52,236,555 |
| | | 2180 | -$5,051 |
| | | 1935 | $35,460 |
| | | 1945 | $8,719 |
| | | 1955 | $5,873 |
| | **08 Capital Assets Sum** | | **$62,468,809** |

**Entegrus Powerlines Inc.**
**USOA Balance Sheet**
**Year Ending December 31, 2012**

| Statement | Balance Sheet |
|---|---|

| Sum of Ending Balance | | | |
|---|---|---|---|
| **Cayenta Statement Class 1** | **Cayenta Statement Class 2** | **USOA Account** | **Total** |
| **02 Capital Assets Sum** | | | **$62,468,809** |
| **03 Other Assets** | **05 Computer Software** | 1925 | $549,062 |
| | | 2105 | -$377,214 |
| | **05 Computer Software Sum** | | **$171,848** |
| | **09 Deferred Assets** | 1508 | $1,342,943 |
| | | 1518 | -$195,698 |
| | | 1520 | $840 |
| | | 1521 | $0 |
| | | 1531 | $0 |
| | | 1534 | $121,011 |
| | | 1535 | $1,298 |
| | | 1548 | $144,423 |
| | | 1550 | $772,305 |
| | | 1555 | $460,123 |
| | | 1556 | $0 |
| | | 1562 | $0 |
| | | 1580 | -$1,949,993 |
| | | 1584 | $435,126 |
| | | 1586 | $886,876 |
| | | 1588 | $622,197 |
| | | 1595 | -$493,517 |
| | | 1525 | $5,483 |
| | | 1563 | $0 |
| | | 1570 | $0 |
| | | 1582 | $9,212 |
| | | 1589 | $1,260,881 |
| | **09 Deferred Assets Sum** | | **$3,423,509** |
| | **10 Future Income Taxes** | 2350 | $3,282,682 |
| | **10 Future Income Taxes Sum** | | **$3,282,682** |
| | **Goodwill** | 1610 | $84,736 |
| | | 2060 | $367,304 |
| | **Goodwill Sum** | | **$452,040** |
| **03 Other Assets Sum** | | | **$7,330,079** |
| **04 Current Liabilities** | **13 Accounts Payable and Accrued Liabilities** | 1200 | -$13,098 |
| | | 2205 | -$10,396,690 |
| | | 2220 | -$231,386 |
| | | 2240 | $10,503 |
| | | 2250 | -$1,331,418 |
| | | 2290 | $0 |
| | | 2292 | -$151,046 |
| | **13 Accounts Payable and Accrued Liabilities Sum** | | **-$12,113,135** |
| | **14 Taxes Payable** | 2294 | -$470,354 |
| | **14 Taxes Payable Sum** | | **-$470,354** |

**Entegrus Powerlines Inc.**
**USOA Balance Sheet**
**Year Ending December 31, 2012**

| Statement | Balance Sheet |
|---|---|

| Sum of Ending Balance | | | |
|---|---|---|---|
| **Cayenta Statement Class 1** | **Cayenta Statement Class 2** | **USOA Account** | **Total** |
| **04 Current Liabilities** | **15 Due to Related Parties** | 1200 | $0 |
| | | 2240 | -$8,637,919 |
| | **15 Due to Related Parties Sum** | | **-$8,637,919** |
| | **16 Deferred Revenue** | 2425 | -$469,673 |
| | **16 Deferred Revenue Sum** | | **-$469,673** |
| | **17 Current Portion of Customer Deposites** | 2210 | -$1,133,532 |
| | **17 Current Portion of Customer Deposites Sum** | | **-$1,133,532** |
| **04 Current Liabilities Sum** | | | **-$22,824,613** |
| **05 Long-Term Liabilities** | **18 Regulatory Future Income Tax Liability** | 2350 | -$3,282,682 |
| | **18 Regulatory Future Income Tax Liability Sum** | | **-$3,282,682** |
| | **19 Notes Payable** | 2550 | -$37,073,326 |
| | **19 Notes Payable Sum** | | **-$37,073,326** |
| | **20 Asset Retirement Obligation** | 2320 | -$15,000 |
| | **20 Asset Retirement Obligation Sum** | | **-$15,000** |
| | **21 Employee Future Benefits** | 2306 | -$1,076,023 |
| | **21 Employee Future Benefits Sum** | | **-$1,076,023** |
| | **22 Long-term Portion of Customer Deposits** | 2335 | -$3,179,145 |
| | **22 Long-term Portion of Customer Deposits Sum** | | **-$3,179,145** |
| **05 Long-Term Liabilities Sum** | | | **-$44,626,175** |
| **06 Shareholder's Equity** | **23 Share Capital** | 3005 | -$28,154,623 |
| | **23 Share Capital Sum** | | **-$28,154,623** |
| | **24 Retained Earnings** | 3045 | -$1,101,512 |
| | | 3049 | $2,600,000 |
| | **24 Retained Earnings Sum** | | **$1,498,488** |
| **06 Shareholder's Equity Sum** | | | **-$26,656,135** |

# Entegrus Powerlines Inc.
# USOA Income Statement
# Year Ending December 31, 2013

| Statement | Income Statement |
|---|---|

| Sum of Ending Balance | | | |
|---|---|---|---|
| **Cayenta Statement Class 1** | **Cayenta Statement Class 2** | **USOA Account** | **Total** |
| **07 Revenue** | **25 Revenue** | 4006 | -$23,680,605 |
| | | 4020 | -$2,180,160 |
| | | 4025 | -$625,352 |
| | | 4030 | -$31,395 |
| | | 4035 | -$47,520,618 |
| | | 4050 | -$2,420,121 |
| | | 4055 | -$3,537,730 |
| | | 4062 | -$5,495,823 |
| | | 4066 | -$6,376,332 |
| | | 4068 | -$4,509,245 |
| | | 4075 | -$321,087 |
| | | 4076 | -$252,573 |
| | | 4080 | -$18,549,079 |
| | | 4380 | $81,072 |
| | **25 Revenue Sum** | | **-$115,419,048** |
| | **26 Other Operating Income** | 4080 | -$150,788 |
| | | 4082 | -$45,072 |
| | | 4084 | $15,172 |
| | | 4205 | -$196,468 |
| | | 4210 | -$164,701 |
| | | 4220 | -$13,491 |
| | | 4225 | -$252,224 |
| | | 4235 | -$324,461 |
| | | 4355 | -$180,353 |
| | | 4360 | $85,222 |
| | | 4375 | -$416 |
| | | 4380 | $6,828 |
| | | 4390 | -$21,525 |
| | | 4405 | -$95,784 |
| | **26 Other Operating Income Sum** | | **-$1,338,061** |
| **07 Revenue Sum** | | | **-$116,757,108** |
| **08 Cost of Power** | **27 Cost of Power** | 4705 | $79,995,981 |
| | | 4708 | $5,495,823 |
| | | 4714 | $6,376,332 |
| | | 4716 | $4,509,245 |
| | | 4750 | $321,087 |
| | | 4751 | $252,572 |
| | **27 Cost of Power Sum** | | **$96,951,040** |
| **08 Cost of Power Sum** | | | **$96,951,040** |
| **09 Operating and Maintenace** | **28 Distribution** | 4715 | $30,207 |
| | | 5005 | $274,722 |
| | | 5012 | $493 |
| | | 5016 | $51,302 |

# Entegrus Powerlines Inc.
## USOA Income Statement
## Year Ending December 31, 2013

| Statement | Income Statement |
|---|---|

| Sum of Ending Balance | | | |
|---|---|---|---|
| **Cayenta Statement Class 1** | **Cayenta Statement Class 2** | **USOA Account** | **Total** |
| **09 Operating and Maintenace** | **28 Distribution** | 5017 | $41,154 |
| | | 5020 | $44,194 |
| | | 5025 | $13,092 |
| | | 5035 | $1,353 |
| | | 5040 | $141,745 |
| | | 5045 | $41,378 |
| | | 5055 | $12 |
| | | 5065 | $209,925 |
| | | 5070 | $9,940 |
| | | 5075 | $2,188 |
| | | 5105 | $202,065 |
| | | 5114 | $173,568 |
| | | 5120 | $62,067 |
| | | 5125 | $394,731 |
| | | 5130 | $132,113 |
| | | 5135 | $194,647 |
| | | 5145 | $2,810 |
| | | 5150 | $137,386 |
| | | 5155 | $46,329 |
| | | 5160 | $59,895 |
| | | 5175 | $192,566 |
| | | 5410 | $16,765 |
| | | 5420 | $14,276 |
| | | 5610 | $74,230 |
| | | 5620 | $142,791 |
| | | 5630 | $90,444 |
| | | 5635 | $21,655 |
| | | 5645 | $4,677 |
| | | 5655 | $221,607 |
| | | 5665 | $28,904 |
| | | 5675 | $641,055 |
| | **28 Distribution Sum** | | **$3,716,285** |
| | **29 Regulatory Expense** | 4305 | $602,341 |
| | | 5655 | $0 |
| | | 6310 | $0 |
| | **29 Regulatory Expense Sum** | | **$602,341** |
| **09 Operating and Maintenace Sum** | | | **$4,318,625** |
| **10 Administrative Expense** | **30 Billing and Collection** | 5305 | $291,093 |
| | | 5310 | $57,408 |
| | | 5315 | $1,416,230 |
| | | 5320 | $575,445 |
| | | 5335 | $147,130 |
| | **30 Billing and Collection Sum** | | **$2,487,307** |

**Entegrus Powerlines Inc.**
**USOA Income Statement**
**Year Ending December 31, 2013**

| Statement | Income Statement |
|---|---|

| Sum of Ending Balance | | | |
|---|---|---|---|
| **Cayenta Statement Class 1** | **Cayenta Statement Class 2** | **USOA Account** | **Total** |
| **10 Administrative Expense** | **31 General Administration** | 5410 | $98,403 |
| | | 5610 | $1,348,057 |
| | | 5615 | $157,571 |
| | | 5620 | $90,606 |
| | | 5630 | $182,325 |
| | | 5635 | $74,066 |
| | | 5645 | $265,169 |
| | | 5655 | $292,414 |
| | | 5665 | $53,190 |
| | | 5670 | $93,191 |
| | | 6205 | $230,554 |
| | **31 General Administration Sum** | | **$2,885,546** |
| | **32 Interest** | 6030 | $2,268,211 |
| | | 6035 | $117,804 |
| | | 6215 | $0 |
| | **32 Interest Sum** | | **$2,386,015** |
| **10 Administrative Expense Sum** | | | **$7,758,867** |
| **11 Depreciation and Amortization** | **33 Depreciation and Amortization** | 4380 | $20,206 |
| | | 5705 | $4,164,269 |
| | **33 Depreciation and Amortization Sum** | | **$4,184,475** |
| **11 Depreciation and Amortization Sum** | | | **$4,184,475** |
| **12 Provisions for PILs** | **34 Provisions for PILs** | 6110 | $866,315 |
| | **34 Provisions for PILs Sum** | | **$866,315** |
| **12 Provisions for PILs Sum** | | | **$866,315** |
| **Grand Total** | | | **-$2,677,785** |

**Entegrus Powerlines Inc.**
**USOA Balance Sheet**
**Year Ending December 31, 2013**

| Statement | Balance Sheet |
|---|---|

| Sum of Ending Balance | | | |
|---|---|---|---|
| **Cayenta Statement Class 1** | **Cayenta Statement Class 2** | **USOA Account** | **Total** |
| **01 Current Assets** | **01 Cash and cash Equivalents** | 1005 | $7,506,037 |
| | | 1010 | $2,806 |
| | **01 Cash and cash Equivalents Sum** | | **$7,508,843** |
| | **02 Accounts Receivable** | 1100 | $4,408,268 |
| | | 1102 | -$1,826 |
| | | 1104 | $867,783 |
| | | 1110 | $1,401,543 |
| | | 1130 | -$136,670 |
| | **02 Accounts Receivable Sum** | | **$6,539,098** |
| | **03 Accounts Receivable - Unbilled Revenue** | 1120 | $13,602,458 |
| | **03 Accounts Receivable - Unbilled Revenue Sum** | | **$13,602,458** |
| | **04 Taxes Receivable** | 1180 | $897,882 |
| | **04 Taxes Receivable Sum** | | **$897,882** |
| | **06 Inventories** | 1330 | $727,004 |
| | **06 Inventories Sum** | | **$727,004** |
| | **07 Prepaid Expenses** | 1180 | $92,994 |
| | **07 Prepaid Expenses Sum** | | **$92,994** |
| **01 Current Assets Sum** | | | **$29,368,279** |
| **02 Capital Assets** | **08 Capital Assets** | 1805 | $452,262 |
| | | 1808 | $841,903 |
| | | 1820 | $1,931,106 |
| | | 1830 | $11,299,039 |
| | | 1835 | $30,165,550 |
| | | 1840 | $4,067,794 |
| | | 1845 | $20,477,650 |
| | | 1850 | $22,784,657 |
| | | 1855 | $6,085,415 |
| | | 1860 | $12,509,732 |
| | | 1905 | $916,900 |
| | | 1908 | $4,893,961 |
| | | 1915 | $340,597 |
| | | 1920 | $1,192,839 |
| | | 1925 | $76,732 |
| | | 1930 | $5,010,667 |
| | | 1940 | $1,290,425 |
| | | 1980 | $1,140,548 |
| | | 1990 | $2,866,560 |
| | | 1995 | -$7,372,472 |
| | | 2055 | $62,000 |
| | | 2075 | $887,815 |
| | | 2105 | -$56,096,591 |
| | | 2180 | -$25,258 |
| | | 1935 | $35,460 |

**Entegrus Powerlines Inc.**
**USOA Balance Sheet**
**Year Ending December 31, 2013**

| Statement | Balance Sheet |
|---|---|

| **Sum of Ending Balance** | | | |
|---|---|---|---|
| **Cayenta Statement Class 1** | **Cayenta Statement Class 2** | **USOA Account** | **Total** |
| **02 Capital Assets** | **08 Capital Assets** | 1945 | $8,719 |
| | | 1955 | $5,873 |
| | **08 Capital Assets Sum** | | **$65,849,883** |
| **02 Capital Assets Sum** | | | **$65,849,883** |
| **03 Other Assets** | **05 Computer Software** | 1925 | $1,899,551 |
| | | 2105 | -$1,223,100 |
| | **05 Computer Software Sum** | | **$676,451** |
| | **09 Deferred Assets** | 1508 | $581,255 |
| | | 1518 | -$219,298 |
| | | 1520 | $0 |
| | | 1521 | $0 |
| | | 1531 | $0 |
| | | 1534 | $6,332 |
| | | 1535 | $0 |
| | | 1548 | $150,340 |
| | | 1550 | $810,575 |
| | | 1555 | $410,460 |
| | | 1556 | $0 |
| | | 1562 | $0 |
| | | 1580 | -$1,461,362 |
| | | 1584 | $287,867 |
| | | 1586 | $1,153,920 |
| | | 1588 | $841,969 |
| | | 1595 | $517,741 |
| | | 1525 | $0 |
| | | 1563 | $0 |
| | | 1570 | $0 |
| | | 1582 | $9,323 |
| | | 1551 | $28,520 |
| | | 1568 | $192,097 |
| | | 1576 | -$602,341 |
| | | 1589 | $300,099 |
| | | 1592 | -$789 |
| | **09 Deferred Assets Sum** | | **$3,006,707** |
| | **10 Future Income Taxes** | 2350 | $3,211,562 |
| | **10 Future Income Taxes Sum** | | **$3,211,562** |
| | **Goodwill** | 1610 | $0 |
| | | 2060 | $367,304 |
| | **Goodwill Sum** | | **$367,304** |
| **03 Other Assets Sum** | | | **$7,262,025** |
| **04 Current Liabilities** | **13 Accounts Payable and Accrued Liabilities** | 1200 | $0 |
| | | 2205 | -$13,793,623 |
| | | 2220 | -$353,962 |

**Entegrus Powerlines Inc.**
**USOA Balance Sheet**
**Year Ending December 31, 2013**

| Statement | Balance Sheet |
|---|---|

| **Sum of Ending Balance** | | | |
|---|---|---|---|
| **Cayenta Statement Class 1** | **Cayenta Statement Class 2** | **USOA Account** | **Total** |
| **04 Current Liabilities** | **13 Accounts Payable and Accrued Liabilities** | 2240 | $0 |
| | | 2250 | -$1,244,338 |
| | | 2290 | $0 |
| | | 2292 | -$175,461 |
| | | 2320 | -$15,000 |
| | **13 Accounts Payable and Accrued Liabilities Sum** | | **-$15,582,384** |
| | **15 Due to Related Parties** | 1200 | $0 |
| | | 2240 | -$8,836,351 |
| | **15 Due to Related Parties Sum** | | **-$8,836,351** |
| | **16 Deferred Revenue** | 2425 | -$347,611 |
| | **16 Deferred Revenue Sum** | | **-$347,611** |
| | **17 Current Portion of Customer Deposites** | 2210 | -$1,019,035 |
| | **17 Current Portion of Customer Deposites Sum** | | **-$1,019,035** |
| **04 Current Liabilities Sum** | | | **-$25,785,381** |
| **05 Long-Term Liabilities** | **18 Regulatory Future Income Tax Liability** | 2350 | -$3,211,562 |
| | **18 Regulatory Future Income Tax Liability Sum** | | **-$3,211,562** |
| | **19 Notes Payable** | 2550 | -$37,073,326 |
| | **19 Notes Payable Sum** | | **-$37,073,326** |
| | **21 Employee Future Benefits** | 2306 | -$2,711,308 |
| | **21 Employee Future Benefits Sum** | | **-$2,711,308** |
| | **22 Long-term Portion of Customer Deposits** | 2335 | -$3,378,301 |
| | **22 Long-term Portion of Customer Deposits Sum** | | **-$3,378,301** |
| **05 Long-Term Liabilities Sum** | | | **-$46,374,497** |
| **06 Shareholder's Equity** | **23 Share Capital** | 3005 | -$28,154,623 |
| | **23 Share Capital Sum** | | **-$28,154,623** |
| | **24 Retained Earnings** | 3045 | -$787,900 |
| | | 3049 | $1,300,000 |
| | **24 Retained Earnings Sum** | | **$512,100** |
| **06 Shareholder's Equity Sum** | | | **-$27,642,523** |
| **Grand Total** | | | **$2,677,785** |

**Entegrus Powerlines Inc.**
**RRR 2.1.13: Balance Sheet Reconciliation**
**Year Ending December 31, 2014**

| Statement | Balance Sheet |
|---|---|

| Sum of ACTUAL_ APPROVED<br>Cayenta Class | Cayenta Subclass | USoA | Total |
|---|---|---|---|
| **01 Current Assets** | **A) Cash and Cash equivalents** | 1005 | $3,712,147 |
| | | 1010 | $2,139 |
| | **A) Cash and Cash equivalents Total** | | **$3,714,286** |
| | **B) Accounts Receivable** | 1100 | $4,848,660 |
| | | 1102 | -$2,006 |
| | | 1104 | $913,242 |
| | | 1110 | $1,564,492 |
| | | 1130 | -$160,589 |
| | **B) Accounts Receivable Total** | | **$7,163,799** |
| | **C) Accounts Receivable Unbilled Revenue** | 1120 | $12,499,188 |
| | **C) Accounts Receivable Unbilled Revenue Total** | | **$12,499,188** |
| | **D) Taxes Receivable** | 2294 | $1,636,515 |
| | **D) Taxes Receivable Total** | | **$1,636,515** |
| | **E) Due from related parties** | 1200 | $375,346 |
| | **E) Due from related parties Total** | | **$375,346** |
| | **F) Inventories** | 1330 | $756,533 |
| | **F) Inventories Total** | | **$756,533** |
| | **G) Prepaid Expenses** | 1180 | $277,302 |
| | **G) Prepaid Expenses Total** | | **$277,302** |
| **01 Current Assets Total** | | | **$26,422,969** |
| **02 Capital Assets** | **A) Capital** | 1805 | $452,262 |
| | | 1808 | $879,182 |
| | | 1820 | $1,987,188 |
| | | 1830 | $12,329,432 |
| | | 1835 | $31,703,073 |
| | | 1840 | $4,481,314 |
| | | 1845 | $21,276,224 |
| | | 1850 | $23,897,084 |
| | | 1855 | $6,685,187 |
| | | 1860 | $12,913,243 |
| | | 1905 | $916,900 |
| | | 1908 | $5,334,122 |
| | | 1915 | $519,386 |
| | | 1920 | $1,636,813 |
| | | 1925 | $3,541,320 |
| | | 1930 | $5,214,078 |
| | | 1935 | $35,460 |
| | | 1940 | $1,438,814 |
| | | 1945 | $8,719 |
| | | 1955 | $5,873 |
| | | 1980 | $1,099,350 |
| | | 1990 | $3,063,717 |
| | | 1995 | -$7,834,617 |

**Entegrus Powerlines Inc.**
**RRR 2.1.13: Balance Sheet Reconciliation**
**Year Ending December 31, 2014**

| Statement | Balance Sheet |
|---|---|

| Sum of ACTUAL_ APPROVED Cayenta Class | Cayenta Subclass | USoA | Total |
|---|---|---|---|
| **02 Capital Assets** | **A) Capital** | 2055 | $60,000 |
| | | 2075 | $879,207 |
| | | 2105 | -$60,804,042 |
| | | 2180 | -$60,829 |
| | **A) Capital Total** | | **$71,658,460** |
| **02 Capital Assets Total** | | | **$71,658,460** |
| **03 Other Assets** | **A) Regulatory Assets** | 1508 | $656,625 |
| | | 1518 | -$237,084 |
| | | 1534 | $24,755 |
| | | 1548 | $158,338 |
| | | 1550 | $937,670 |
| | | 1551 | $25,308 |
| | | 1555 | $362,515 |
| | | 1568 | $273,072 |
| | | 1580 | -$1,308,971 |
| | | 1582 | $9,434 |
| | | 1584 | $373,796 |
| | | 1586 | $1,842,440 |
| | | 1588 | $1,311,980 |
| | | 1589 | $2,234,406 |
| | | 1592 | -$1,243 |
| | **A) Regulatory Assets Total** | | **$6,663,041** |
| | **B) Goodwill and intangible assets** | 2060 | $367,304 |
| | **B) Goodwill and intangible assets Total** | | **$367,304** |
| | **C) Future Income Tax** | 2350 | $1,477,113 |
| | **C) Future Income Tax Total** | | **$1,477,113** |
| **03 Other Assets Total** | | | **$8,507,458** |
| **04 Current Liabilities** | **A) Accounts payable and accrued liabilities** | 2205 | -$13,919,976 |
| | | 2220 | -$402,945 |
| | | 2250 | -$1,180,937 |
| | | 2292 | -$171,591 |
| | | 2320 | -$15,000 |
| | **A) Accounts payable and accrued liabilities Total** | | **-$15,690,448** |
| | **C) Deferred Revenue** | 1536 | -$170,265 |
| | | 2425 | -$5,002 |
| | **C) Deferred Revenue Total** | | **-$175,267** |
| | **D) Current portion of customer deposits** | 2210 | -$1,358,986 |
| | **D) Current portion of customer deposits Total** | | **-$1,358,986** |
| **04 Current Liabilities Total** | | | **-$17,224,701** |
| **05 Long-Term Liabilities** | **A) Regulatory Liabilities** | 1508 | -$151,364 |
| | | 1576 | -$2,279,996 |
| | | 1592 | -$394 |
| | | 1595 | -$398,643 |

**Entegrus Powerlines Inc.**
**RRR 2.1.13: Balance Sheet Reconciliation**
**Year Ending December 31, 2014**

| Statement | Balance Sheet |
|---|---|

| **Sum of ACTUAL_ APPROVED** | | | |
|---|---|---|---|
| **Cayenta Class** | **Cayenta Subclass** | **USoA** | **Total** |
| **05 Long-Term Liabilities** | **A) Regulatory Liabilities** | 2350 | -$1,477,113 |
| | **A) Regulatory Liabilities Total** | | **-$4,307,510** |
| | **B) Notes payable** | 2550 | -$47,073,326 |
| | **B) Notes payable Total** | | **-$47,073,326** |
| | **C) Employee future benefits** | 2306 | -$2,651,999 |
| | **C) Employee future benefits Total** | | **-$2,651,999** |
| | **D) Long-term portion of customer deposits** | 2335 | -$2,573,294 |
| | **D) Long-term portion of customer deposits Total** | | **-$2,573,294** |
| **05 Long-Term Liabilities Total** | | | **-$56,606,128** |
| **06 Shareholder's Equity** | **A) Share capital** | 3005 | -$28,154,623 |
| | **A) Share capital Total** | | **-$28,154,623** |
| | **B) Retained earnings** | 3045 | -$2,165,685 |
| | | 3049 | $1,400,000 |
| | **B) Retained earnings Total** | | **-$765,685** |
| **06 Shareholder's Equity Total** | | | **-$28,920,308** |
| **Grand Total** | | | **$3,837,751** |

**Entegrus Powerlines Inc.**
**RRR 2.1.13: Income Statement Reconciliation**
**Year Ending December 31, 2014**

| Statement | Income Statement |
|---|---|

| Sum of ACTUAL_ APPROVED | | | |
|---|---|---|---|
| **Cayenta Class** | **Cayenta Subclass** | **USoA** | **Total** |
| **01 Revenue** | **A) Revenue** | 4006 | -$26,851,438 |
| | | 4020 | -$2,294,386 |
| | | 4025 | -$665,013 |
| | | 4030 | -$33,954 |
| | | 4035 | -$51,376,453 |
| | | 4050 | $113,979 |
| | | 4055 | -$5,219,986 |
| | | 4062 | -$5,359,395 |
| | | 4066 | -$6,645,125 |
| | | 4068 | -$4,627,344 |
| | | 4075 | -$317,076 |
| | | 4076 | -$375,811 |
| | | 4080 | -$18,747,737 |
| | **A) Revenue Total** | | **-$122,399,740** |
| **01 Revenue Total** | | | **-$122,399,740** |
| **02 Cost of Power** | **A) Cost of Power** | 4705 | $86,327,251 |
| | | 4708 | $5,359,395 |
| | | 4714 | $6,645,125 |
| | | 4716 | $4,627,344 |
| | | 4750 | $317,076 |
| | | 4751 | $375,811 |
| | **A) Cost of Power Total** | | **$103,652,003** |
| **02 Cost of Power Total** | | | **$103,652,003** |
| **03 Other Revenue** | **A) Other Revenue** | 4082 | -$37,977 |
| | | 4084 | -$773 |
| | | 4086 | -$151,936 |
| | | 4205 | -$200,760 |
| | | 4210 | -$176,427 |
| | | 4220 | -$6,020 |
| | | 4225 | -$312,004 |
| | | 4235 | -$515,020 |
| | | 4355 | -$38,787 |
| | | 4375 | -$51,715 |
| | | 4380 | $14,584 |
| | | 4390 | -$16,007 |
| | | 4405 | -$197,867 |
| | | 5315 | $8,750 |
| | **A) Other Revenue Total** | | **-$1,681,958** |
| **03 Other Revenue Total** | | | **-$1,681,958** |
| **04 Operating and Maintenance Expense** | **A) Distribution** | 5005 | $387,191 |
| | | 5010 | $43,067 |
| | | 5016 | $36,297 |
| | | 5017 | $31,481 |

**Entegrus Powerlines Inc.**
**RRR 2.1.13: Income Statement Reconciliation**
**Year Ending December 31, 2014**

| Statement | Income Statement | | |
|---|---|---|---|

| Sum of ACTUAL_ APPROVED<br>Cayenta Class | Cayenta Subclass | USoA | Total |
|---|---|---|---|
| | | 5020 | $56,792 |
| | | 5025 | $13,326 |
| | | 5035 | $2,510 |
| | | 5040 | $212,824 |
| | | 5045 | $45,721 |
| | | 5055 | $4,472 |
| | | 5065 | $261,005 |
| | | 5070 | $25,600 |
| | | 5075 | $4,599 |
| | | 5105 | $270,999 |
| | | 5114 | $119,043 |
| | | 5120 | $128,726 |
| | | 5125 | $205,124 |
| | | 5130 | $152,682 |
| | | 5135 | $251,290 |
| | | 5145 | $5,601 |
| | | 5150 | $11,046 |
| | | 5155 | $76,086 |
| | | 5160 | $20,084 |
| | | 5175 | $315,673 |
| | | 5195 | $0 |
| | | 5410 | $28,409 |
| | | 5420 | $21,268 |
| | | 5610 | $21,291 |
| | | 5620 | $123,861 |
| | | 5630 | $95,055 |
| | | 5640 | $1,144 |
| | | 5645 | $153,224 |
| | | 5655 | $290,864 |
| | | 5665 | $28,915 |
| | | 5675 | $479,889 |
| | | 6105 | $240,965 |
| | | 6205 | $23,054 |
| | **A) Distribution Total** | | **$4,189,175** |
| | **B) Regulatory** | 4305 | $1,677,655 |
| | **B) Regulatory Total** | | **$1,677,655** |
| **04 Operating and Maintenance Expense Total** | | | **$5,866,830** |
| **05 Administrative Expense** | **A) Billing and collection** | 5305 | $302,856 |
| | | 5310 | $28,176 |
| | | 5315 | $1,190,992 |
| | | 5320 | $514,467 |
| | | 5335 | $238,008 |
| | **A) Billing and collection Total** | | **$2,274,499** |

**Entegrus Powerlines Inc.**
**RRR 2.1.13: Income Statement Reconciliation**
**Year Ending December 31, 2014**

| Statement | Income Statement |
|---|---|

| Sum of ACTUAL_ APPROVED<br>Cayenta Class | Cayenta Subclass | | USoA | Total |
|---|---|---|---|---|
| **05 Administrative Expense** | **B) General Administration** | | 5410 | $144,456 |
| | | | 5610 | $1,336,378 |
| | | | 5615 | $153,552 |
| | | | 5620 | $138,708 |
| | | | 5630 | $196,692 |
| | | | 5635 | $98,652 |
| | | | 5645 | $81,732 |
| | | | 5655 | $335,988 |
| | | | 5665 | $60,396 |
| | | | 5670 | $95,316 |
| | | | 6205 | $215,500 |
| | **B) General Administration Total** | | | **$2,857,370** |
| | **C) Interest** | | 6030 | $2,269,007 |
| | | | 6035 | $82,201 |
| | **C) Interest Total** | | | **$2,351,208** |
| **05 Administrative Expense Total** | | | | **$7,483,077** |
| **06 Depreciation and Amortization** | | **0** | 4380 | $35,571 |
| | | | 5705 | $3,566,100 |
| | **0 Total** | | | **$3,601,671** |
| **06 Depreciation and Amortization Total** | | | | **$3,601,671** |
| **07 Provision for PILs** | | **0** | 6110 | -$359,633 |
| | **0 Total** | | | **-$359,633** |
| **07 Provision for PILs Total** | | | | **-$359,633** |
| **Grand Total** | | | | **-$3,837,751** |

# ATTACHMENT 1-N

## Rating Agency Report

STANDARD & POOR'S
RATINGS SERVICES
McGRAW HILL FINANCIAL

# RatingsDirect®

## Research Update:

# Entegrus Inc. 'A' Rating Affirmed; Financial Risk Profile Score Revised To "Intermediate" From "Modest"

**Primary Credit Analyst:**
Stephen R Goltz, Toronto (416) 507-2592; stephen.goltz@standardandpoors.com

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Andrew Ng, Toronto (416) 507-2545; andrew.ng@standardandpoors.com

## Table Of Contents

Research Update:

# Entegrus Inc. 'A' Rating Affirmed; Financial Risk Profile Score Revised To "Intermediate" From "Modest"

## Overview

- We are affirming our 'A' long-term corporate credit on Entegrus Inc.
- We are revising our financial risk profile on the company to "intermediate" from "modest."
- The revision reflects our assessment of Entegrus' increased adjusted debt resulting from its plan to pay back a loan to its owner.
- We are also revising our financial policy modifier on the company to "neutral" from "negative."
- As well, we are revising our management and governance score to "satisfactory" from "fair."

## Rating Action

On June 2, 2015, Standard & Poor's Ratings Services affirmed its 'A' long-term corporate credit rating on Ontario-based local electricity distribution company Entegrus Inc. The outlook is stable.

At the same time, Standard & Poor's revised its assessment of Entegrus' financial risk profile to "intermediate" from "modest." In addition, Standard & Poor's revised its financial policy modifier score on the company to "neutral" from "negative" and its management and governance score to "satisfactory" from "fair," in accordance with its corporate criteria framework. The revision has no effect on the rating.

## Rationale

We assess Entegrus' financial risk profile as intermediate. For the company, we use the low-volatility table, reflecting the "very low" industry risk associated with regulated utilities and the supportive regulatory framework.

The revised financial risk assessment reflects our view of Entegrus' plan to pay back C$17 million, classified as a current liability, to its owner, the Municipality of Chatham-Kent. To do this, the company plans to issue long-term debt. Based on the increased debt, we forecast lower adjusted funds from operations (AFFO)-to-debt of 18%-21% for 2015 and 2016, consistent with our intermediate category.

With the higher debt, we believe Entegrus is operating close to the deemed capital structure that the Ontario Energy Board (OEB) has established. As such, we do not expect much divergence from there ratios during our two-year forecast period. This led to the revision in our financial policy modifier.

We are also revising our assessment of management and governance score to "satisfactory" from "fair". The revision reflects our view Entegrus has demonstrated a history of not incurring unexpected declines in earnings or cash flow from operational risks through its consistent level of operational effectiveness. We also believe that a loss of key personnel is unlikely to affect operations and cash flow as the company has sufficient staffing and there is a pool of qualified people who could fill any vacant roles.

We view Entegrus' business risk profile as "excellent," largely supported by our assessment of the OEB's regulatory framework as "strong." We view the regulatory process as transparent, consistent, and predictable. The board publishes details of all hearings and the rationale supporting its decisions. Supporting consistency and predictability are the use of standard methodology applied to all utilities in its jurisdiction, including a transparent formula for allowed returns, and a consistent deemed capital structure that has not changed for many years. In addition, during times of change, the regulator follows a public process of study and consultation that allows management to adjust to new regulatory or market developments.

Our base-case scenario includes the following assumptions:

- The regulatory regime will be relatively stable, and Entegrus will not experience any material, adverse regulatory decisions and energy costs are passed through
- The company will continue to earn close to its allowed return on equity (ROE) on its deemed capital structure
- It will not make any material, debt-financed unregulated investments
- Distribution revenue will increase 1.45% (1.60% inflation, and a 0.15% stretch factor) under the incentive rate making (IRM) framework for 2015 and 2016

During this IRM period, we expect rates to rise annually by inflation minus a productivity factor. The relatively low inflation, combined with the productivity and stretch factors, might challenge Entegrus' ability to earn the allowed ROE over the long term. Nevertheless, in our base-case scenario, we expect AFFO-to-debt of 18%-21%.

## Liquidity

We consider Entegrus' liquidity "adequate." We expect that liquidity sources will be adequate to cover uses more than 1.1x in the next 12 months. We further expect that in the event of a 10% EBITDA decline, the company's sources of funds would still exceed its uses.

Principal liquidity sources include:

- Projected FFO of approximately C$7.5 million in 2015
- Cash and cash equivalents of approximately C$3.7 million

Principal liquidity uses include:
- Maintenance capital expenditures of approximately C$4.0 million in 2015
- Dividends of about C$2.6 million

## Outlook

The stable outlook reflects Standard & Poor's assessment of Entegrus' predictable and stable cash flows from its low-risk, regulated distribution business. The outlook also reflects our expectation that the company will continue to focus on its core regulated business during our two-year outlook horizon.

### Downside scenario

Although we don't expect it, a downgrade would require Entegrus to demonstrate sustained deterioration of its forecast AFFO-to-debt near 13%. This could happen as a result of a material, adverse regulatory ruling but is more likely to be the result of a significant increase in leverage.

### Upside scenario

We believe an upgrade is unlikely during our two-year outlook horizon. However, we could raise the rating if we forecast that Entegrus' adjusted FFO-to-debt will improve to greater than 23% consistently.

## Ratings Score Snapshot

Corporate Credit Rating: A/Stable/--

Business Risk: Excellent
- Country Risk: Very low
- Industry Risk: Very low
- Competitive position: Excellent

Financial Risk: Intermediate
- Cash flow/Leverage: Intermediate

Anchor: a

Modifiers
- Diversification/Portfolio effect: Neutral (no impact)
- Capital Structure: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Financial policy: Neutral (no impact)
- Management and governance: Satisfactory (no impact)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: a

## Related Criteria And Research

### Related Criteria

- Rating Government-Related Entities: Methodology And Assumptions, March 25, 2015
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Corporate Methodology, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Methodology: Industry Risk, Nov. 19, 2013
- Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012

## Ratings List

Rating Affirmed

| | |
|---|---|
| Entegrus Inc. | |
| Corporate credit rating | A/Stable/-- |

Complete ratings information is available to subscribers of RatingsDirect at www.globalcreditportal.com and at www.spcapitaliq.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com. Use the Ratings search box located in the left column.

# ATTACHMENT 1-O

## Corporate Governance Policies and Documents

**ENTEGRUS POWERLINES INC.**

**BOARD OF DIRECTORS MANDATE AND CHARTER**

**Mandate for the Board of Directors**

## 1. OBJECTIVES

The Board of Directors ("**Board**") of **ENTEGRUS POWERLINES INC.** (the "**Corporation**") is responsible for overseeing and monitoring all significant aspects of the management of the business and affairs of the Corporation.

The Board has determined that it would be appropriate for the Board to adopt a written mandate describing its responsibilities and duties in relation to its oversight of the business and affairs of the Corporation.

The Board is appointed by and represents Entegrus Inc. ("Shareholder") and is obligated to act in the best interests of the Corporation.

## 2. COMPOSITION OF THE BOARD OF DIRECTORS

The Board shall consist of a minimum of seven (7) members and shall serve at the pleasure of the Shareholder and the Shareholder shall appoint the Board annually.

The Board Chair shall be appointed from among the Board's directors. The Board shall provide the Chair with a position description.

The qualifications for nomination, appointment and continuing service on the Board as a Director are set forth in the By-law.

Members of the Board shall be entitled to receive such remuneration for acting as members of the Board as may be determined from time to time by the Board on recommendation of Entegrus Inc.'s Compensation and Governance Committee upon approval of the Shareholder.

**Board of Governors' Charter**

The Board's Charter outlines how the Board of Directors will satisfy the requirements set forth in it's mandate. This Charter comprises:

- Operating Principles
- Operating Procedures
- Specific Responsibilities and Duties

## 3. OPERATING PRINCIPLES

The Board shall fulfill its responsibilities within the context of the following principles:

**3.1 Board Values**

The Board of Directors will act in accordance with the Board's policies and industry best practices as applicable.

**3.2 Communications**

The Chair and members of the Board expect to have direct, open and frank communications throughout the year with the Board Chair and Management, as applicable.

**3.4 Meeting Agenda**

The Board meeting agendas shall be the responsibility of the Board Chair. The President and Chief Executive Officer will develop meeting agendas in consultation with the Board Chair, Board members and assigned Management.

**3.5 Board Expectations and Information Needs**

The Board shall communicate its expectations to Management with respect to the nature, timing and extent of its information needs. The Board expects that written material supporting agenda items will be received from Management at least one week in advance of the meeting dates.

**3.6 In-Camera Meetings**

At each meeting of the Board, the members of the Board shall meet at their discretion in private sessions that allow the Board to discuss matters (a) amongst themselves, and (b) with Management. Actionable items resulting from these sessions will be recorded in the minutes in accordance with Guidelines for *in camera* meetings.

**3.7 Adequate Resources**

In all instances where the Board Chair or the Board believes that in order to properly discharge their fiduciary obligations to the Corporation it is necessary to obtain the advice of external experts, the Chair shall engage the necessary experts subject to prior notice and approval of the Board. The Board shall be kept apprised of both the selection of the experts and the expert's findings by the Board Chair at regular Board meetings.

The Board shall consider from time to time its resources including the adequacy of the information provided to it with respect to oversight of the Management of the Corporation and shall confer with Management with respect to its findings.

Members of the Board shall have the right, for the purpose of discharging their respective powers and responsibilities, to inspect any relevant records of the Corporation and its affiliates.

**3.8 Board Self-Assessment**

The Board shall annually review, discuss and assess its own performance and individual member's performance. In addition, the Board shall annually review its role and responsibilities and complete an online Board survey. The Board shall reconsider its Mandate and Charter at least annually and report to the Compensation and Governance Committee with any recommendations for change.

## 4. OPERATING PROCEDURES

The Board shall fulfill its responsibilities within the context of the following procedures:

### 4.1 Frequency and Calling of Board Meetings

The Board shall meet at least quarterly and more frequently if circumstances dictate. Meetings shall be held at the call of the Board Chair or a majority of the Directors. Notice of a meeting of the Board will be given not less than seven (7) days before the meeting is to take place.

The meetings of the Board shall ordinarily include the Secretary and shall periodically include other senior officers as may be appropriate and as may be desirable to enable the Board to become familiar with the Corporation's management team.

### 4.2 Quorum

A majority of the Directors will constitute a quorum for the transaction of all matters and Business before the Board. In the absence of the Corporate Secretary, the Board Chair shall designate a person to act as the Secretary of the meeting.

### 4.3 Secretary of Board Meetings

Unless the Board otherwise specifies, the Corporate Secretary shall act as secretary of all meetings of the Board. In the absence of the Corporate Secretary, the Board Chair shall designate a person to act as the Secretary of the meeting.

The Corporate Secretary shall keep minutes of its meetings in which shall be recorded all actions taken by the Board. Such minutes shall be made available to Board members at their request and all such minutes shall be approved by the Board for entry in the records of the Corporation.

### 4.4 Chair of Board Meetings

In the absence of the Board Chair at any meeting of the Board, the Chair of the Board may delegate a Board member to perform the duties of the Chair or the Board members present may elect one among them to perform the duties of the Chair.

### 4.5 Minutes of Board Meetings

A copy of the minutes of each meeting of the Board shall be provided to each member of the Board within thirty (30) calendar days from the meeting date.

## 5. SPECIFIC RESPONSIBILITIES AND DUTIES

### 5.1 General Responsibilities

(a) The Board shall oversee the management and affairs of the Corporation. In doing so, the Board shall establish a productive working relationship with the President and Chief Executive Officer and other members of senior management.

(b) The officers of the Corporation, headed by the President and Chief Executive Officer, shall be responsible for general day to day management of the Corporation and for making recommendations to the Board with respect to long term strategic, financial, organization and related objectives.

(c) The roles and responsibilities of the Board are intended to primarily focus on the formulation of long term strategic, financial and organizational goals for the Corporation and on the monitoring of management performance. Without limitation, the Board shall (i) oversee management-driven strategic planning process and approve the Corporation's strategic plan, (ii) assess the principal risks of the Corporation's business and ensure appropriate systems are in place to manage such risks, (iii) select, monitor and evaluate the President and Chief Executive Officer for the Corporation and oversee succession planning at the senior management level, (iv) oversee the communications policies of the Corporation and (v) monitor the effectiveness of the Corporation's internal control and management information systems to safeguard corporate assets.

(d) The Board shall review and approve the Corporation's financial objectives, short and long-term business plans for the Corporation's businesses and monitor performance in accordance with such plans. The Board shall also approve significant capital allocations and expenditures and:

(i) transactions out of the ordinary course of business;

(ii) all matters that would be expected to have a major impact on the Shareholders;

(iii) the appointment of any person to any position that would qualify such person as an Officer of the Corporation, and

(iv) any amendments to the Corporation's pension plan(s).

(e) The Board will oversee the Corporation's compliance with laws and regulations, which includes overseeing the Corporation's compliance with all applicable OEB policies and procedures.

(f) With respect to significant risks and opportunities affecting the Corporation, the Board may impose such limits on the business activity of the Corporation as may be in the interests of the Corporation and the Shareholders.

(g) The Board shall when required for director recruitment consider the skills and competencies of the Board from the perspective of determining what additional skills and competencies would be helpful to the Board. The identification of specific candidates for consideration shall be the responsibility of the Compensation and Governance Committee which shall be guided by the findings of the Board in relation to competencies and skills.

(h) The Board will ensure that the Corporation has the appropriate policies and procedures in place to establish just and reasonable rates which are:

(i) Consistent with similar utilities in comparable growth areas and as may be permitted by the *Ontario Energy Board Act*;

(ii) Intended to enhance the value of the Corporation; and

(iii) Consistent with the encouragement of economic development and activity within the communities that are served

(i) The Board will adopt prudent financial standards with respect to the affairs of the Corporation and periodically will review the Corporation's performance as to service quality and other factors used by the OEB in setting the rates the Corporation may charge to its customers and other similar financial and regulatory prudence standards.

(j) The Board shall perform such other functions as are prescribed by law, as are assigned to the Board in the Corporation's By-Law and as it may from time to time determine in accordance with the plenary powers of the Board.

(k) The Board shall receive at each Board meeting reports on health, safety and environmental matters as they affect the Corporation and its business.

(l) The Board shall provide an orientation program for new Directors and continuing education opportunities for all Directors.

(m) The Board will review and approve the annual business plan along with the operating and capital budgets.

(n) The Board shall approve the selection of the external auditors and the related remuneration and terms of engagement.

(o) The Board may, from time to time, meet with the external auditors *in camera* in the absence of Management.

**5.2 Senior Management**

(a) The Board will approve a position description for the President and Chief Executive Officer.

(b) The Board will review with the Compensation and Governance Committee the objectives set for the President and Chief Executive Officer and performance in relation to such objectives.

(c) The Board will review with the Compensation and Governance Committee the objectives of the Executive Team as provided by the President and CEO.

**5.3 Communications**

(a) The Board will annually review and approve the Corporation's annual financial statements.

(b) The Board will periodically review the means by which the Corporation can communicate with the Shareholder including the opportunity to do so at the annual general meeting and communication interfaces through the Corporation's website.

**5.4 Communication Process**

The Board will ensure an effective process is established and applied for the communication of initiatives between the Board, the Corporation, and external stakeholders.

### 5.5 Other Business

The Board will consider any other matter referred to the Board by Entegrus Inc.

## 6. ACCOUNTABILITY

(a) The Board Chair will report on the deliberations of the Board annually; and

(b) The Board will review this Mandate and Charter each year at its third quarter meeting to assess its adequacy and endeavor to keep its members abreast of “best practices” and recommend changes.

# Appendix A

# Board Orientation Process

**Appendix A**

**ENTEGRUS INC.**

**BOARD ORIENTATION/ONBOARDING MANUAL/PROCESS**

**Board Orientation Manual**

Board Orientation Manual (the "Manual") is one of the key elements to the board development process. The manual is the foundation for a committed, knowledgeable and effective Board.

As new directors are appointed, the manual should be provided at the start of their term. The manual assists them with understanding their purpose, the organization and its operations, the functions of the Board and the expectations of each Director.

The manual is developed by the President and CEO in consultation with the Chair of the Board/Committees, and Shareholders.

The attached is a comprehensive list of items included in the board manual.

**Board Orientation Process**

After the appointment of a new director and before the first Board meeting, schedule a meeting between the new Board member and with the key individuals in the Corporation. (President and CEO)

Provide the new Director with Board Orientation/Onboarding manual. (President and CEO)

Obtain signatures from the new Director on forms as per the Corporation's By-law and applicable acts (Consent, Confidentiality, Disclosure Questionnaire, and Indemnity). (President and CEO)

At the new Director's first Board meeting, introduce to all current Board members and Executive Management Team and discuss with the new member options for Committee involvement. (Board Chair)

Consideration to assign a mentor Board member to work with the new Director. (Board Chair)

| BOARD ORIENTATION/ONBOARDING MANUAL LIST | |
|---|---|
| **ITEM** | **DESCRIPTION** |
| **A** | Organizational Charts |
| **B** | Board and Committee Charters |
| **C** | Shareholder Agreement |
| **D** | Visions, Mission and Values |
| **E** | Business Plan |
| **F** | Latest Annual General Meeting Report |
| **G** | Ontario Energy Board |
| **H** | Board Members, Executives Biographies and Contacts |
| **I** | Board Survey |
| **J** | Executive Compensation Strategy |

# Appendix B

# Code of Conduct

**Appendix B**

# CODE OF CONDUCT FOR DIRECTORS

## Section 1: Governance Guidelines

### 1.1 Purpose

The Directors of Entegrus Inc. and its subsidiaries are committed to maintaining the highest standards for ethical business conduct and carrying out their responsibilities in a manner that inspires the confidence and trust of our shareholder and community. Accordingly, the Board has adopted this Code of Conduct for Directors as a guide to achieving these goals.

### 1.2 Definitions

(a) "Board" means the board of directors of the Corporation.

(b) "Corporation" means Entegrus Inc. and/or any of its subsidiaries.

(c) "Director" means a director of the Corporation.

(d) "Directors' Code" means this Code of Conduct for Directors.

(e) "Employee Code" means the Corporation's Employee Code of Conduct.

### 1.3 Guidelines

In performing their Board and Board Committee functions, our Directors will:

(a) Act diligently, openly, honestly and in good faith.

(b) Provide leadership in advancing the Corporation's's Vision, Mission and Values.

(c) Discharge their duties, as members of the Board and of any Board Committees on which they serve, in accordance with their good faith business judgment and in the best interests of the Corporation.

(d) Become and remain familiar with the Corporation's business and the economic and competitive environment in which the Corporation operates and understand the Corporation's principal business plans, strategies and objectives; operational results and financial condition; and relative marketplace position.

(e) Commit the time necessary to prepare for, attend (in person, telephone or video conference, as appropriate) and actively participate in regular and special meetings of the Board and of the Board Committees on which they serve.

(f) Inform the Chair of the Board and the Chair of the Compensation and Governance Committee of changes in their employment, town or city of residence, other board positions, and relationships with other business, charitable and governmental entities, and other events, circumstances or conditions that may or may appear to, interfere with their ability to perform their Board or Board Committee duties.

(g) Maintain the confidentiality of all material non-public information about the Corporation, its business and affairs.

(h) Comply with all applicable provincial and federal laws.

(i) Abide by the Employee Code as set out in section 1.4 below.

(j) Abide by all by-laws, codes, policies and guidelines approved by the Board which are applicable to Directors.

## 1.4 Application of the Employee Code

### (1) Non-management Directors

Directors of the Corporation will be bound by and comply with all sections of the Employee Code (Appendix A).

### (2) Interpretation

Unless the context suggests otherwise, in interpreting the Employee Code as it applies to Directors:

(a) The term “Employee” means “Director” or “Board Chair”;

The Employee Code is to be interpreted so as to enhance and supplement the Directors’ Code. Where there is any inconsistency between the terms of the Employee Code and the terms of the Directors’ Code, the terms of the Directors’ Code will prevail to the extent of such inconsistency.

## Section 2: Conflict of Interest Policy

### 2.1 Policy Statement

Directors must avoid situations where their private interests conflict with or may appear to conflict with the best interests of the Corporation or the exercise of good judgment concerning the Corporation. A conflict of interest may arise where:

(a) A Director's personal interests are or may appear to be at odds with the interests of the Corporation; or

(b) A Director, Family Member or Associate receives an improper benefit or advantage as a result of the Director's relationship with the Corporation;

(c) A Director misuses information obtained in the course of acting as a Director or exploits for personal advantage his/her position or relationships with the Corporation for personal gain.

Directors have an obligation to declare any actual, potential, or perceived conflict of interest and resolve it in favour of the Corporation as described in this Policy. This Policy has been adopted by the Board in order to ensure that Directors comply with all applicable legal requirements and follow best practices when dealing with conflicts of interest.

Certain conflict of interest rules apply to Directors under the provisions of the Ontario *Business Corporations Act* (the "OBCA"). This Policy summarizes the OBCA conflict of interest requirements in Section 2.3 below, and sets out additional best practice requirements in Section 2.4 below.

### 2.2 Definitions

(a) "Associate" means a natural person or Entity with whom the Director has a significant business or personal relationship.

(b) "Entity" means a sole proprietorship, partnership, unincorporated association, unincorporated syndicate, unincorporated organization, trust, or corporation and a natural person in his or her capacity as trustee, executor, administrator, or other legal representative.

(c) "Family Member" means the Director's spouse, the child or parent of the Director or of the Director's spouse, or an individual who resides in the same household as the Director.

(d) "Material Contract" means a material contract or transaction or a proposed material contract or transaction with the Corporation;

(e) "Material Interest or Relationship" means any personal activity, relationship, association, or interest that could be reasonably expected to interfere with the exercise of a Director's independent and impartial judgment, recommendation, or assessment of facts in any given circumstance.

### 2.3 OBCA Requirements

#### (1) Minimum Standards

The OBCA sets out rules regarding the disclosure of conflicts of interest with which Directors must comply. The Board considers the OBCA rules to be minimum standards which are to be met in addition to the other requirements of this Policy. Under the OBCA, the disclosure procedure described below is to be followed where a Director:

(a) is a party to a Material Contract; or

(b) is a director or an officer of, or has a material interest in, any individual or Entity who is a party to a Material Contract.

The OBCA requirements apply regardless of whether the Material Contract calls for approval by the Board.

### (2) **Procedure to Follow**

If a Director has a conflict of interest, the Director must disclose in writing to the Corporation or must request to have entered into the minutes of a meeting of the Board the nature and extent of the Director's interest. Under the OBCA, a Director must make such disclosure:

(a) at the meeting at which the Material Contract is first considered;

(b) if the Director was not then interested in the Material Contract, at the first meeting after he or she becomes so interested;

(c) if the Director becomes interested after a Material Contract is made or entered into, at the first meeting after he or she becomes so interested;

(d) if a person who is interested in a Material contract or transaction later becomes a Director, at the first meeting after he or she becomes a Director;

If the Director does not attend all or any Board meetings, or if the Material Contract does not require Board approval, the Director must disclose in writing to the Corporation or request to have entered in the minutes of meetings of Directors the nature and extent of his or her interest immediately after the Director becomes aware of the Material Contract.

A Director with any conflict of interest must not attend any part of a Board meeting at which the Material Contract is discussed and must not vote on any resolution to approve the Material Contract, except where the Material Contract:

(a) Relates primarily to his/her remuneration as a director of the Corporation; or

(b) Is a policy of insurance for the Director.

**ENTEGRUS INC.**

# BOARD OF DIRECTORS EDUCATION AND TRAINING POLICY

## 1.0 OBJECTIVES

The Board of Directors ("**Board**") of **ENTEGRUS INC.** (the "**Corporation**") is responsible for overseeing and monitoring all significant aspects of the management of the business and affairs of the Corporation. It is important that the Directors have the opportunity and take part in professional development to enhance their skills and knowledge, which, as a Director, that will assist them in providing good oversight of the Corporation.

## 2.0 DIRECTOR EDUCATION AND TRAINING

When an individual becomes a Director of the Corporation, the Corporation will:

(a) Provide an Orientation Manual that will have all the important information that the Director requires to become familiar with the Corporation and the industry;
(b) The Executives will schedule a meeting to provide an overview of the Orientation Manual and the Corporation;
(c) The Chair and the President and CEO will be available for any additional meeting requests that the Director may have in order to prepare themselves for being a Director;
(d) Encourage Director Education and Training and will budget $10,000 annually to support the Director Education and Training; and
(e) Directors may request additional Director Education and Training funding that will require approval by the Board

**ENTEGRUS INC.**

**ROLE OF THE BOARD OF DIRECTORS**

## 1.0 OBJECTIVES

The Board of Directors (“**Board**”) of **ENTEGRUS INC.** (the “**Corporation**”) is responsible for overseeing and monitoring all significant aspects of the management of the business and affairs of the Corporation.

## 2.0 ROLE OF THE BOARD

The role of the Board is to provide stewardship of the organization and to add to the long-term success of the Corporation, through attending to the following key items:

(a) Fulfill their responsibilities as outlined in the Shareholder Agreement;
(b) Lead the Corporation in a way that is consistent with the Core Values;
(c) Work with the Executives in preparing, approving and delivering on an annual strategic plan;
(d) Oversee the performance of the Corporation and ensure there are appropriate reporting and monitoring of the Corporation’s activities;
(e) Approve strategies that will grow the value of the Corporation;
(f) Ensure all reporting requirements that are outlined in the Shareholder Agreement are adhered to;
(g) The Board will hire and oversee the performance of the President and CEO; and
(h) The Board will appoint Board members to the subsidiaries that are consistent with the Shareholder Agreement, laws and regulations.

## 3.0 ROLE OF THE DIRECTORS

Serving as a trusted advisor to the President and CEO in developing and implementing the strategic plan, the Directors will play a key role in the following activities:

(i) Being an active participant by preparing for meetings, attending meetings and asking challenging questions at the meetings;
(j) Reviewing outcomes and metrics created by the Corporation for evaluating its impact, and regularly measuring its performance and effectiveness using those metrics: reviewing agenda and supporting materials prior to Board and Committee meetings;

(k) Approving the annual strategic plan, budgets, audit reports, and material business decisions; being informed of, and meeting all legal and fiduciary responsibilities;
(l) Contributing to the annual performance evaluation of the President and CEO
(m) Working with the President and CEO and other Board members to ensure that Board resolutions are carried out;
(n) Serving on committees and taking on special assignments; and
(o) Be committed to professional development as a Board member of the Corporation.

## 4.0 ROLE OF THE CHAIR

The Chair oversees all Board meetings and will be:

(a) Organized and follow all rules and regulations;
(b) Open minded and encourage Board members to voice their views; and
(c) A trusted individual that gains the respect of the Board, Shareholders and Executives.

The Chair will play a key role in the following activities:

(a) Call meetings of the Board and Shareholders;
(b) Work with the President and CEO set the agenda for meeting direction and scope;
(c) Run the meetings effectively;
(d) Support and supervise the President and CEO;
(e) Ensure the organization is managed effectively; and
(f) Along with the President and CEO, act as a figure head for the Corporation.

The role and responsibilities of the Chair are more demanding than other Director roles and will require more time commitment.

**ENTEGRUS INC.**

**AUDIT COMMITTEE MANDATE AND CHARTER**

**The Board's Mandate for the Audit Committee**

The Board of Directors (the "**Board**") of **ENTEGRUS INC.** is responsible for overseeing and monitoring all significant aspects of the management of the business and affairs of Entegrus Inc. and its affiliates (collectively, the "Corporation").

**MISSION STATEMENT**

The Audit Committee's mission is to assist the Board in fulfilling its obligations by overseeing and monitoring the Corporation's financial accounting and reporting process and the integrity of the Corporation's financial statements and its internal control over financial reporting and the external audit process and the review of the Corporation's risk profile. To fulfill this mission, the Audit Committee has received this mandate and has been delegated certain authorities that it may exercise on behalf of the Board.

**1. FINANCIAL REPORTING OBJECTIVE**

Financial reporting and disclosure constitutes a significant aspect of the management of the business and affairs of the Corporation. The objective of the Board's monitoring of the Corporation's financial reporting and disclosure (Financial Reporting Objective) is to gain reasonable assurance that:

a) the Corporation complies with all applicable laws, regulations, rules, policies and other requirements relating to financial reporting and disclosure, including those of the Ontario Energy Board ("OEB");

b) the major accounting principles and policies, significant judgments and disclosures which underlie, or are incorporated in the Corporation's financial statements, are the most appropriate in the prevailing circumstances;

c) the Corporation's financial statements present fairly the Corporation's financial position and performance in accordance with CGAAP, International Financial Reporting Standards ("IFRS") and the policies of the OEB and constitute a fair presentation of the Corporation's financial condition; and

d) appropriate information concerning the financial position and financial performance of the Corporation is disseminated to the Board and all other stakeholders in a timely manner. The

Board has established a committee of the Board, known as the Audit Committee (the "Committee"). This Committee has developed this Charter, which, inter alia, describes the activities in which the Committee will engage for the purpose of gaining reasonable assurance that the Financial Reporting Objective is being met.

## 2. FINANCIAL MANAGEMENT OBJECTIVE

The objective of the Committee is to gain reasonable assurance that:

(a) there is appropriate fairness and transparency in financial reporting;

(b) operating and capital budgets are appropriate to the needs of the Corporation;

(c) there is proper control over assets and liabilities; and

(d) appropriate review of operating statements is conducted by Management in a timely manner.

## 3. COMPOSITION OF THE COMMITTEE

The Committee shall be appointed annually by the Board and consist of a minimum of three members and a maximum of five members, with all members being members of the Corporation's Board. The Committee Chair and the members of the Committee shall be nominated by the Governance and Compensation Committee, and approved by the Board. There must be at least one (1) member from each of the Corporation's Board. The Chair shall be a Board member. The Committee may appoint ad-hoc non-voting members to the Committee, as required, to assist the Committee in fulfilling its mandate.

## 4. RELIANCE ON MANAGEMENT AND EXPERTS

In contributing to the Committee discharging its duties under this Charter each member of the Committee shall be entitled to rely in good faith upon financial statements of the Corporation represented to him or her by Management of the Corporation or in a written report of the external auditors on the fair presentation of the financial position of the Corporation in accordance with CGAAP or IFRS and any report of a lawyer, accountant, or other person whose profession lends credibility to a statement made by any such person.

Good faith reliance means that the Committee member has considered the relevant issues, questioned the information provided and assumptions used and assessed whether the analysis provided by Management or the expert is reasonable. Generally, good faith reliance does not require that the member question the honesty, competency and integrity of Management or the expert unless there is a reason to doubt their honesty, competency and integrity.

## 5. LIMITATIONS ON THE COMMITTEE'S DUTIES

In contributing to the Committee's discharging of its duties, each member of the Committee shall be obliged only to exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. Nothing in this charter is intended, or may be construed, to impose on any member of the Committee a standard of care or diligence that is in any way more onerous or extensive than the standard to which all Board members are subject. The essence of the Committee's duties is monitoring and reviewing to gain reasonable assurance, but not to ensure, that it's Financial Reporting Objective and Financial Management Objective are being met and to enable the Committee to report thereon to the Board.

## 6. FINANCE & AUDIT CHARTER

The Committee's Charter outlines how the Committee will satisfy the requirements set forth by the Board in its Mandate. This Charter comprises:

- Operating Principles
- Operating Procedures
- Specific Responsibilities and Duties

## 7. OPERATING PRINCIPLES

The Committee shall fulfill its responsibilities within the context of the following principles:

### 7.1 Committee Values

The Committee members will act in accordance with the Board's policies and industry best practices, as applicable.

### 7.2 Communications

The Chair and members of the Committee expect to have direct, open and frank communications throughout the year with assigned Management, the Board Chair, other Committee Chairs, the external auditors, the internal auditors, and other key Committee advisors, as applicable.

### 7.3 Financial Literacy

All Committee members shall be financially literate, which shall mean that they have the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements. The role of the Committee can only be fulfilled if its members are well informed. A process of continuing education shall be maintained that includes briefings and information on emerging issues and risks.

### 7.4 Work Plan

The Committee will review its annual work plan at its third quarter meeting in each fiscal year. In addition, the Committee, in consultation with assigned Management, the Board Chair, the external auditors, and the internal auditors shall develop and participate in a process for review of significant accounting and reporting issues, including complex or unusual transactions and other areas that have the potential to impact the Corporation's financial disclosure.

### 7.5 Meeting Agenda

The Committee meeting agendas shall be the responsibility of the Committee Chair. The Corporate Secretary will develop meeting agendas in consultation with Committee Chair, Committee members, assigned Management, Board Chair, the external auditors, and the internal auditors as applicable from time to time.

**7.6 Committee Expectations and Information Needs**

The Committee shall communicate its expectations to assigned Management, the external auditors, and the internal auditors with respect to the nature, timing and extent of its information needs. The Committee expects that written material supporting agenda items will be received from assigned Management, the external auditors, and the internal auditors at least seven days in advance of meeting dates. The President and CEO and the CFO are required to attend the meetings of the Committee. The Committee Chair may request the attendance of other Corporation Officials.

**7.7 External Resources**

To assist the Committee in discharging its responsibilities, the Committee may, in addition to the external auditors and the internal auditors, at the expense of the Corporation, retain one or more persons having special expertise.

**7.8 In-Camera Meetings**

At each meeting of the Committee, the members of the Committee shall meet at their discretion in private sessions that allow the Committee to discuss matters (a) amongst themselves, (b) with Management, (c) with internal auditor and (d) with external auditors. Actionable items resulting from these sessions will be recorded in the minutes in accordance with Guidelines for *in camera* meetings.

**7.9 The External Auditors**

The external auditors shall be accountable to the Board through the Committee. The external auditors shall report on all material issues or potentially material issues to the Committee.

**7.10 The Internal Auditor**

The Committee may appoint an Internal Auditor at its discretion. If an internal auditor is appointed the internal auditor shall be accountable to the Board through the Committee. The internal auditor shall report on all material issues or potentially material issues to the Committee.

**7.11 Access to Carry-Out Committee's Duties**

The Committee working in consultation with the CFO shall be given full access to the Corporation's internal accounting staff, Management, other staff, external auditors, and internal auditors as necessary to carry out the Committee's duties. While acting within the scope of its stated purpose, the Committee shall have all the authority of, but shall remain subject to, the Board.

**7.12 Adequate Resources**

The Committee should have adequate resources to discharge its duties as mentioned in this mandate subject to prior budget provision. Members of the Committee shall be entitled to receive such remuneration for acting as members of the Committee as the Board may determine from time to time consistent with its remuneration policies for all Board and Committee members. In all instances where the Committee believes that in order to properly discharge their fiduciary obligations to the Corporation it is necessary to obtain the advice of external experts, the Chair shall engage the necessary experts subject to prior notice and approval of the Board. The Board shall be kept apprised of both the selection of the experts and the experts' findings through the Committee's regular verbal reports by its Chair at regular Board meetings.

## 8. OPERATING PROCEDURES

(a) The Committee shall annually review, discuss and assess its own performance and individual member's performance as part of Board self-assessment process. In addition, the Committee shall annually review its role and responsibilities, as set out in this Charter.

(b) The Committee shall meet at every quarter, or more frequently as circumstances dictate. Meetings shall be held at the call of the Committee Chair or upon the request of two members of the Committee, or the Management or at the request of the internal auditors or external auditors. The request to be made to the Chair of the Committee and the Chair of the Committee may determine the necessity of the meeting. A quorum shall be a majority of the voting members of the Committee. Each voting member will be entitled to one vote and the Committee Chair will not have a second or casting vote in the case of an equality of votes. No Proxies shall be permitted.

(c) Unless the Committee otherwise specifies, the Corporate Secretary, shall act as Secretary of all meetings of the Committee. In the absence of the Corporate Secretary the Chair of the Committee shall designate a person to act as the Secretary of the meeting.

(d) In the absence of the Chair of the Committee at any meeting of the Committee, the Chair may delegate a Committee member to perform the duties of the Chair or the Committee members present may elect one among them to perform the duties of the Chair.

(e) Committee will maintain minutes of its meetings which will be filed with the minutes of the Board of Directors. A copy of the Minutes of each meeting of the Committee shall be provided to each member of the Committee, within twenty (20) calendar days from the meeting date. Minutes of Committee meetings will be made available to the Board of Directors upon approval of those minutes by the Committee members.

(f) The Committee, through its Chair, will provide verbal reports outlining issues, actions, and recommendations to the Board at regular Board meetings.

## 9. SPECIFIC RESPONSIBILITIES AND DUTIES

To fulfill its responsibilities and duties, the Committee shall:

### 9.1 Financial Reporting

(a) While the Committee has the responsibilities and powers set forth in this Mandate, it shall not be its duty to plan or conduct audits or to determine that the Corporation's financial statements and disclosures are complete and accurate and in accordance with CGAAP or IFRS and applicable rules and regulations; these are responsibilities of Management and the external auditors. Management, not the Committee or the external auditors, is responsible for preparing complete and accurate financial statements and disclosures in accordance with CGAAP or IFRS and other applicable rules and regulations. The Committee needs to understand and assess the financial statements and related information. Accordingly, the Committee must review the Corporation's interim and annual financial statements and the annual Management Representation Letter with assigned Management and the external auditors (annual statements only) to gain reasonable assurance that the statements, present fairly the Corporation's financial position and performance, are in accordance with CGAAP or IFRS and the policies of the OEB, and constitute a fair presentation of the Corporation's financial condition, and report thereon in a timely manner to the Board before such statements are approved by the Board;

(b) receive from the external auditors reports on their audit of the annual financial statements;

(c) receive from Management a copy of the Representation Letter, provided to the external auditors, and receive from Management any additional representations required by the Committee;

(d) review and, if appropriate, recommend approval to the Board prior to publication of all news releases and publications issued by the Corporation with respect to the Corporation's financial statements including, if applicable, the Annual Report and Management Discussion & Analysis; and

(e) if applicable, satisfy itself that adequate procedures are in place for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation's financial statements in order to satisfy itself that such information is fairly presented.

**9.2 Financial Management**

(a) Review the appropriateness of all of the Corporation's present and proposed accounting policies and all major issues regarding accounting principles and financial statement presentations (including any significant changes in the Corporation's selection or application of accounting principles).

(b) receive from Management, and review, the Corporation's annual business plan, together with the operating and capital budgets, to ensure that they are appropriate for the needs of the Corporation; receive and review quarterly updates on capital spending progress.

(c) review banking arrangements, signing authorities, and cash management controls to ensure that they are appropriate to the needs of the Corporation. Review issues relating to liquidity, capital resources and contingencies that could affect liquidity. Review all plans for treasury operations including financial derivatives and hedging activities. Review all material off-balance-sheet transactions, contingent liabilities and transactions with related parties;

(d) review annually the financial staff succession planning;

(e) receive periodic reports from Management for information on significant changes to current pricing and any related implications on profitability; consider any other matter relating to the financial management of the Corporation referred to the Committee by the Board; and

(f) review the report prepared by management on all Ontario Energy Board cost of service rate filings.

**9.3 Investment Monitoring**

(a) Review the Investment Policy at least annually and make necessary amendments;

(b) evaluate and recommend to the Board, the appointment of Investment Managers, if required, taking into account criteria including relevant experience and expertise, structure of the organization, suitability of investment style, turnover of personnel, capacity and servicing capabilities, investment performance record, including consistency of performance and risk, and investment management fees;

(c) monitor investment results on a minimum of a quarterly basis according to the return objectives defined in the Investment Policy;

(d) review, at least annually, the Investment Manager's performance;

(e) report quarterly on the Corporation's investment status and holdings to the Board; and

(f) review all investments and transactions that could adversely affect the return on the Corporation's investments that are brought to the Committee's attention by, including but not limited to, the external auditor or Management.

**9.4 Financial Risk and Uncertainty**

The Committee shall gain reasonable assurance that financial risk is being effectively managed and mitigated by:

(a) reviewing with Management the Corporation's tolerance for financial risk;

(b) identifying and monitoring significant financial risks facing the Corporation;

(c) evaluating and considering the Corporation's policies and any proposed changes thereto for managing these significant financial risks;

(d) reviewing plans, processes and programs to manage and mitigate such risks;

(e) reviewing policies, and compliance therewith, that require significant actual or potential liabilities, contingent or otherwise, to be reported to the Board in a timely fashion;

(f) receiving and review a report from Management and the Corporations Insurance broker consultants on the adequacy of insurance coverage maintained by the Corporation for general liability, employee fidelity, and business interruption;

(g) regularly reporting its findings to the Board; and

(h) reviewing regularly with Management, the external auditors, the internal auditors and the Corporation's legal counsel, any legal claim or other contingency that could have a material effect on the financial position of the Corporation and the manner in which these matters have been disclosed and/or provided for in the financial statements.

**9.5 Financial Controls and Control Deviations**

(a) Review the processes Management has put in place to maintain appropriate internal controls and monitor compliance with internal control policies;

(b) receive from the internal auditor and external auditors, at least annually, their assessment of the control environment; and

(c) receive regular reports from Management, the internal auditor, the external auditors and the Corporation's legal counsel on all significant deviations or indications/detection of fraud and the corrective activity undertaken in respect thereto.

**9.6 Internal Control and Information Systems**

(a) Review and obtain reasonable assurance that the internal control and information systems are operating effectively to produce materially accurate, appropriate, and timely management and financial information;

(b) obtain reasonable assurance by discussions with and reports from Management, the internal auditor and the external auditors that the information systems, security of information and business recovery plans are adequate and reliable, and that the internal control systems and procedures are properly designed and effectively implemented;

(c) review adequacy of accounting and finance resources, as required; and

(d) undertake any and all required investigations, and other actions, in relation to the suspected material non-compliance with accounting policies, internal controls or use of the services of external and/or internal auditors or other third parties, as deemed appropriate, to ascertain whether any non-compliance has occurred and thereafter, if deemed appropriate, report on such matters to the Board.

**9.7 Compliance with Laws and Regulations**

(a) Review regular reports (Statutory Declarations) from Management with respect to the Corporation's compliance with laws and regulations having a material impact on the financial statements including: tax and financial reporting laws and regulations; legal withholding requirements; other laws and regulations which expose the members of Board to liability;

(b) confirm with Management that the Corporation is in compliance with laws and regulations having a material impact on the financial statements including: tax and financial reporting laws and regulations; legal withholding requirements; other laws and regulations which expose the members of Board to liability; and

(c) discuss with Corporation's legal counsel any significant legal, compliance or regulatory matters that may have a material effect specifically related to the financial statements of the Corporation or on the compliance policies of the Corporation.

**9.8 Risk Management**

(a) Review regular reports from Management assessing the major strategic, reputational, and operational risks facing the Corporation.

(b) Review management's risk management framework/process regarding risks identification, management, monitoring, and reporting of risks

**9.9 Relationship with the External Auditors**

(a) Recommend to the Board and Shareholder the selection and appointment of the external auditors;

(b) recommend to the Board the remuneration and the terms of engagement of the external auditors;

(c) if necessary, recommend to Board the removal of the current external auditors and replacement with new external auditors;

(d) review the performance of the external auditors at least annually;

(e) receive annually from the external auditors an acknowledgement in writing that their primary responsibility and accountability are to the Committee (Engagement Letter);

(f) receive a report annually from the external auditors with respect to their independence (Independence Letter), such report to include a disclosure of all engagements and fees related thereto for non-audit services provided to the Corporation;

(g) establish a policy with Management which non-audit services do not require pre- approval. Bring to the attention of the Chair of the Committee all requests for all other non-audit services to be performed by the external auditors for the Corporation before such work is commenced and a policy for permitting the Committee Chair to approve such services up to an amount of $10,000 without consulting the Committee.

(h) be satisfied that there is no threat to the external auditors objectivity and independence in the conduct of the audit from providing such services;

(i) review with the external auditors the scope of the audit, the areas of special emphasis to be addressed in the audit, the materiality levels which the external auditors propose to employ, areas of audit risk, staffing of the audit, and timetable;

(j) meet at least annually in-camera with the external auditors in the absence of Management to discuss any matters that the Committee believes should be discussed. In addition it should determine, inter alia, that no management restrictions have been placed on the scope and extent of the audit examination by the external auditors or the reporting of their findings to the Committee;

(k) be satisfied of the existence of effective communication processes between Management and external auditors to assist the Committee to monitor objectively the quality and effectiveness of the relationship among the external auditors, Management and the Committee;

(l) receive reports on the work of the external auditors and the resolution of disagreements between Management and the external auditors with respect to financial reporting. Obtain explanations from management and where necessary the external auditors, as to why certain issues might remain unadjusted; and

(m) request that the external auditors provide to the Committee, at least annually, a written report describing the external auditors' internal quality assurance policies and procedures as well as any material issues raised in the most recent internal quality assurance reviews, or any inquiry or investigation conducted by government or regulatory authorities (including the Ontario Energy Board).

**9.10 Relationship with the Internal Auditor** (if one is appointed)

(a) Establish with the internal auditor the Committee's expectations of the internal audit function;

(b) appoint the internal auditor;

(c) review the performance and reports of the internal auditor on a quarterly basis;

(d) receive annually from the internal auditor an acknowledgement in writing that their primary responsibility and accountability are to the Committee (Engagement Letter);

(e) annually review a report on the internal audit function with respect to the terms of reference, organization, staffing, independence, performance and effectiveness of the internal audit services, receive, approve and monitor the execution of the annual internal audit plan, including the financial risk management measures proposed by the internal auditor, and obtain assurances in respect of conformity with the Canadian Institute of Chartered Accountants (CICA)'s professional standards and with the Institute of Internal Auditors (IIA) and other regulatory bodies' requirements, and recommendations of management and of the internal auditor;

(f) review significant internal audit findings and recommendations and management's response thereto;

(g) to perform integrated financial risk management with the assistance of internal auditor once in every twelve months.

**9.11 Other Responsibilities**

(a) Investigate any matters that, in the Committee's discretion, fall within the Committee's duties;

(b) review and approve the Corporation's policies with respect to the hiring of partners, employees and former partners and employees of the current and former external auditors;

(c) work with the CEO on any appointment or any dismissal of the CFO or internal auditor and then recommend to the Board the applicable appointment or removal of the CFO or internal auditor and a report to be provided to the Committee;

(d) any changes to the internal audit functions to be intimated to the Committee;

(e) establish procedures for the confidential receipt, retention and treatment of complaints received by the Corporation and/or Board regarding the Corporation's accounting, internal accounting controls or auditing matters; and the confidential anonymous submission, retention and treatment of concerns by employees regarding questionable accounting or auditing matters; and require that all such matters be reported to the Committee together with a description of the resolution of the complaints or concerns and thereafter report these matters to the Board; and

(f) monitor the key financial performance indicators set out in the annual business plan.

## 10 ACCOUNTABILITY:

**10.1** The Committee shall review corporate policies that are within the scope of the roles and responsibilities specified by these terms of reference prior to submission for approval by the Board; monitor compliance on a regular basis; and ensure these policies are periodically reviewed and kept current.

**10.2** The Committee shall perform such other duties as may be assigned to it by the Board from time to time or as may be required by applicable law.

**10.3** The Committee will annually review its Mandate and Charter, policies and procedures each year at its third quarter meeting to assess its adequacy and endeavour to keep them abreast of "best practices" for a Finance and Audit Committee. Any proposed amendments to the Mandate and Charter, policies or procedures will be submitted to the Board through the Governance Committee and if agreed to by the Board, will thereafter be put into effect.

**ENTEGRUS INC.**

**GOVERNANCE AND COMPENSATION**

**COMMITTEE**

MANDATE AND CHARTER

**The Board's Mandate for the Governance and Compensation Committee**

## 1. OBJECTIVE

The Board of Directors (the "**Board**") of **ENTEGRUS INC.** is responsible for overseeing and monitoring all significant aspects of the management of the business and affairs of Entegrus Inc. and its affiliates (collectively, the "Corporation"). With respect to ENTEGRUS INC. ("EI"), this responsibility is shared with the Board of Directors of EI.

Governance and organizational effectiveness of the Board and strategy and Executive compensation constitute significant aspects of the management of the Board's business and affairs.

To assist the Board in fulfilling its responsibilities, the Board has established a committee of the Board known as the Governance and Compensation Committee (the "Committee") to advise the Board with respect to governance, Executive compensation and related matters and to make recommendations to the Board relating to these matters.

The Committee shall develop and present to the Board, for its approval, a Charter which includes a description of the activities in which the Committee will engage for the purpose of advising and making recommendations to the Board with respect to governance, Executive compensation and related matters.

## 2. COMPOSITION

The Committee shall be appointed annually by the Board and consist of a minimum of three (3) members and a maximum of five (5) members, with all members being Board members. The Committee Chair and the members of the Committee shall be nominated by the Governance and Compensation Committee of the Board, and approved by the Board. There will be one (1) member from each shareholder representative and at least one (1) member must be from the Entegrus Powerlines Board. The Chair shall be a Board member. The Committee may appoint ad-hoc non-voting members to the Committee, as required, to assist the Committee in fulfilling its Mandate.

**Governance & Risk Committee Charter**

The Committee's Charter outlines how the Committee will satisfy the requirements set forth by the Board in its Mandate. This Charter comprises:

Operating Principles

Operating Procedures

Specific Responsibilities and Duties

## 3. OPERATING PRINCIPLES

The Committee shall fulfill its responsibilities within the context of the following principles:

### 3.1 Committee Values

The Committee members will act in accordance with the Board's policies and industry best practices, as applicable.

### 3.2 Communications

The Chair and members of the Committee expect to have direct, open and frank communications throughout the year with the Board Chair, other Committee Chairs and Management, as applicable.

### 3.3 Committee Work plan

The Corporate Secretary in consultation with the Committee and Management shall develop an annual Committee work plan responsive to the Committee's responsibilities as set out in this Charter and update it every 12 months.

The Committee will review its annual work plan at its third quarter meeting in each fiscal year.

### 3.4 Meeting Agenda

The Committee meeting agendas shall be the responsibility of the Committee Chair. The Corporate Secretary will develop meeting agendas in consultation with the Committee Chair, Committee members, the Board Chair and assigned Management.

### 3.5 Committee Expectations and information needs

The Committee shall communicate its expectations to Management with respect to the nature, timing and extent of its information needs. The Committee expects that written material supporting agenda items will be received from Management at least seven days in advance of the meeting dates.

### 3.6 In-Camera Meetings

At each meeting of the Committee, the members of the Committee shall meet at their, discretion in private sessions that allow the Committee to discuss matters (a) amongst themselves, and (b) with management. Actionable items resulting from these sessions will be recorded in the minutes in accordance with Guidelines for *in camera* meetings.

**3.7 Adequate Resources**

The Committee should have adequate resources to discharge its duties as mentioned in this mandate subject to prior budget provision. Members of the Committee shall be entitled to receive such remuneration for acting as members of the Committee as the Board may determine from time to time consistent with its remuneration policies for all Board and Committee members.

**3.8** In all instances where the Committee believes that in order to properly discharge their fiduciary obligations to the Corporation it is necessary to obtain the advice of external experts, the Chair shall engage the necessary experts subject to prior notice and approval of the Board. The Board shall be kept apprised of both the selection of the experts and the experts findings through the Committee's regular verbal reports by its Chair at regular Board meetings.

## 4. OPERATING PROCEDURES

**4.1 Committee Self-Assessment**

The Committee shall annually review, discuss and assess its own performance and individual members' performance. In addition, the Committee shall annually review its role and responsibilities. The Committee shall reconsider its Mandate and Charter at least annually and report to the Board with any recommendations for change.

**4.2 Frequency and calling of Committee meetings**

The Committee shall meet every quarter or more frequently as circumstances dictate. Meetings shall be held at the call of the Chair of the Committee or upon the request to the Chair of the Committee by two members of the Committee or the Management.

**4.3 Quorum**

A quorum shall be a majority of the voting members of the Committee. Each voting member will be entitled to one vote and the Committee Chair will not have a second or casting vote in the case of an equality of votes. No proxies shall be permitted.

**4.4 Secretary of Committee meetings**

Unless the Committee otherwise specifies, the Corporate Secretary shall act as Secretary of all meetings of the Committee. In the absence of the Secretary, the Chair of the Committee shall designate a person to act as the Secretary of the meeting.

**4.5 Chair of Committee meetings**

In the absence of the Chair of the Committee at any meeting of the Committee, the Chair of the Committee may delegate a Committee member to perform the duties of the Chair or the Committee members present may elect one among them to perform the duties of the Chair.

**4.6 Minutes of Committee meetings**

The Committee will maintain minutes of its meetings which will be filed with the minutes of the Board of Directors. A copy of the Minutes of each meeting of the Committee shall be provided to each member of the Committee within 20 calendar days from the meeting date. Minutes of Committee meetings will be made available to the Board of Directors upon approval of those minutes by the Committee members.

## 5. SPECIFIC RESPONSIBILITIES AND DUTIES REGARDING GOVERNACE

To fulfill its responsibilities and duties to advise the Board with respect to governance, and related matters of organizational effectiveness and strategic planning and risk management and to make recommendations to the Board relating to these matters, the Committee shall in consultation with the President and CEO:

**5.1 Governance structure**

Make recommendations to the Board respecting the governance structure of the Board and the Corporation.

**5.2 Board and Committee policies**

Oversee the development of and any amendments to the Board and Committee policies.

**5.3 Position Descriptions**

Oversee the development and any amendments of position descriptions for the Officers of the Board.

**5.4 Corporate and Regulatory Compliance Best Practices**

Review and monitor industry best practices regarding all corporate and regulatory governance standards and practices applicable to the Corporation and make recommendations as appropriate from time to time.

**5.5 Disclosure**

Review and approve the disclosure with respect to corporate governance practices required to be included in any regulatory filings of the Corporation or before any public disclosure thereof by the Corporation.

**5.6 Self Assessment**

Develop and make recommendations to the Board on, and oversee the process for annual assessment and evaluation of the performance of the Board, the Board Chair, the Board members and the Board's Committees.

**5.7 Orientation**

Review, monitor and make recommendations regarding the orientation and ongoing development of existing and new Directors, Officers and Committee members.

**5.8 Review of Corporate Documents**

Annually review (i) the Board Reference Manual outlining the policies and procedures by which the Board will operate (ii) the Corporation's by-laws, articles, and (iii) any changes in applicable corporate laws to ensure their continued adequacy and relevance. Oversee the development of, and any amendments to, the Mandate and Charter of the Board and of all Committees of the Board, and the Chair role description of the Board Chair and Committee Chairs.

**5.9 Meetings**

Assess the needs of the Board in terms of the frequency and location of Board, Committee, and Members meetings, meeting agendas, discussion papers, reports and information, and the conduct of the meetings and make recommendations to the Board as required.

**5.10 Strategic Planning**

Provide input during the strategic planning process within the Corporation and review, recommend to the Board for approval and monitor the strategic plan including fundamental financial and business strategies and objectives.

**5.11 Key Performance Indicators**

(1) Receive and regularly review summary reports of specified performance indicators; monitor progress on strategic initiatives; monitor compliance with Code of Conduct, identify problem areas where further investigation may be warranted.

(2) Establish for Board approval, appropriate performance indicators relating to strategic, risk, and organizational performance.

**5.12 Communication Process**

Ensure an effective process is established and applied for the communication of strategic and risk management initiatives among the Board, the organization, and external stakeholders.

**5.13 Advise Board**

Advise the Board on matters of non-financial policy, public affairs, inter-corporation affairs and inter-local distribution company affairs.

**5.14 Other Matters**

Consider any other matter relating to the governance and organizational effectiveness of the Board referred to the Committee by the Board.

## 6. SPECIFIC ROLES AND RESPONSIBILITES REGARDING COMPENSATION

The Committee will advise and make recommendations to the Board relating to the following matters, in consultation with the President and CEO:

(a) consider and review the succession plans for the executive management of the Corporation, namely the President and CEO and all Executives;

(b) consider and approve the Objectives and the total compensation including the specific salary increases of the Vice Presidents;

(c) consider and recommend the Objectives and the total compensation including the specific salary increases of the President and CEO to the Board for approval;

(d) consider and approve the performance evaluation for the Executives of the corporation including President and CEO;

(e) consider and approve the recommendation to the Board on the total compensation program and benefit program for the executive management of the Corporation;

(f) review with the President and CEO the total compensation program for the executive management of the Corporation before any decision or approval is made concerning such or any recommendation is made to the Board on changes to the total compensation program;

(g) report to the Board on the factors considered by the Committee in approving the total compensation program for the executive management of the Corporation;

(h) consider, review and approve any new, significant or special employment contracts or arrangements for senior management of the Corporation that may be different in principle from those already in place and used by the Corporation;

(i) review and approve the recommendation to the Board on the Corporation's compensation and benefit plans;

(j) review and approve the Corporation's Human Resources Policies, including the Employee Code of Conduct;

(k) provide input to the Board Chair in conducting the annual performance review of the President and CEO by the Board Chair and the Committee Chair;

(l) perform such other duties as may from time to time be assigned to it by the Board and accepted by the Committee as appropriate duties for it to undertake;

(m) hire a consultant to provide recommendations on Executive compensation strategy, implementation, comparators and recommendations. The consultant will report to the Chair and would be assisted by the President and CEO.

The Committee shall have the right, for the purposes of discharging the powers and responsibilities as defined in its Charter, Mandate and Work Plan, to inspect any relevant records of the Corporation with the exception of any documentation held by the Corporation containing private and confidential information with respect to the senior management of the Corporation or any other employee.

**ACCOUNTABILITY**

The Committee will report on its deliberations to the Board through verbal reports by its Chair at regular Board meetings.

The Committee will review its Mandate and Charter each year at its third quarter meeting to assess adequacy and endeavour to keep Committee members abreast of "best practices" for a Governance and Risk Committee. Any proposed amendments to the Mandate and Charter will be submitted by the Committee to the Board and if agreed to by the Board, will thereafter be put into effect.

**ENTERUS INC.**

**ENVIRONMENTAL AND HEALTH**

**AND SAFETY COMMITTEE**

**MANDATE AND CHARTER**

**The Board's Mandate for the Environmental and Health and Safety Committee**

## 1. OBJECTIVE

The Board of Directors ("Board") of Entegrus Inc. is responsible for overseeing and monitoring all significant aspects of the management of the business and affairs of Entegrus Inc. and its affiliates (collectively, the "Corporation"). With respect to Entegrus Inc. ("EI"), this responsibility is shared with the Board of Directors of EI.

Environmental and Health and Safety are critical to the success of the Corporation.

To assist the Board in fulfilling its responsibilities, the Board has established a Committee of the Board known as the Environmental and Health and Safety Committee (the "Committee") to advise the Board with respect to:

(a) health and safety practices and annual safety objectives and training plans;
(b) review and assess health and safety risk mitigation;
(c) handling and storing of environmentally sensitive material, and

To fulfill their objective the Committee has received this mandate and has been delegated certain authorities that it may exercise on behalf of the Board.

## 2. COMPOSITION OF THE COMMITTEE

The Committee shall be appointed annually by the Board and consist of a minimum of three (3) and a maximum of five (5) members, with all members being from the Corporation's Board. The Committee Chair and the members of the Committee shall be nominated by the Governance and Compensation Committee of the Board, and approved by the Board. The Chair shall be appointed by the Governance and Compensation Committee of the Board. The Committee may appoint ad-hoc non-voting members to the Committee, as required, to assist the Committee in fulfilling its mandate.

**EHS Charter**

The Committee's Charter outlines how the Committee will satisfy the requirements set forth by the Board in its Mandate. This Charter comprises:

Operating Principles

Operating Procedures

Specific Responsibilities and Duties

## 3. OPERATING PRINCIPLES

The Committee shall fulfill its responsibilities within the context of the following principles:

### 3.1 Committee Values

The Committee members will act in accordance with Board policies and industry best practices, as applicable.

### 3.2 Communications

The Chair and members of the Committee expect to have direct, open and frank communications throughout the year with the Board Chair, other Committee Chairs and Management, as applicable.

The Board Chair shall communicate on behalf of the Committee and the Board directly with the President and CEO with respect to EHS issues and concerns.

### 3.3 Committee Work Plan

The Corporate Secretary in consultation with the Committee and Management shall develop an annual Committee Work Plan responsive to the Committee's responsibilities as set out in this Charter and update it every 12 months.

The Committee will review its annual work plan at its third quarter meeting in each fiscal year.

### 3.4 Meeting Agenda

The Committee meeting agendas shall be the responsibility of the Committee Chair. The Corporate Secretary will develop meeting agendas in consultation with the Committee Chair, Committee members, the Board Chair and Management.

### 3.5 Committee Expectations and Information Needs

The Committee shall communicate its expectations to Management with respect to the nature, timing and extent of its information needs. The Committee expects that written material supporting agenda items will be received from Management at least seven days in advance of the meeting dates.

### 3.6 In Camera Meetings

At each meeting of the Committee, the members of the Committee shall meet at their discretion in private sessions that allow the Committee to discuss matters (a) amongst themselves, and (b) with management. Actionable items resulting from these sessions will be recorded in the minutes in accordance with Guidelines for *in camera* meetings.

### 3.7 Adequate Resources

The Committee should have adequate resources to discharge its duties as mentioned in this mandate subject to prior budget provision. Members of the Committee shall be entitled to receive such remuneration for acting as members of the Committee as the Board may determine from time to time consistent with its remuneration policies for all Board and Committee members. In all instances where the Committee believes that in order to properly discharge their fiduciary obligations to the Corporation it is necessary to obtain the advice of external experts, the Chair shall engage the necessary experts subject to prior notice and approval of the Board. The Board shall be kept apprised of both the selection of the experts and the experts findings through the Committee’s regular verbal reports by its Chair at regular Board meetings.

## 4. OPERATING PROCEDURES

The Committee shall fulfill its responsibilities within the context of the following procedures:

### 4.1 Frequency and Calling of Committee Meetings

The Committee shall meet every quarter or more frequently as circumstances dictate. Meetings shall be held at the call of the Chair of the Committee or upon the request of two members of the Committee or management.

### 4.2 Quorum

10A quorum shall be a majority of the voting members of the Committee. Each voting member will be entitled to one vote and the Committee Chair will not have a second or casting vote in the case of an equality of votes. No proxies shall be permitted

### 4.3 Secretary of Committee Meetings

Unless the Committee otherwise specifies, the Corporate Secretary shall act as secretary of all meetings of the Committee. In the absence of the Secretary, the Chair of the Committee shall designate a person to act as the Secretary of the meeting.

### 4.4 Chair of Committee Meetings

In the absence of the Chair of the Committee at any meeting of the Committee, the Chair of the Committee may delegate a Committee member to perform the duties of the Chair or the Committee members present may elect one among them to perform the duties of the Chair.

### 4.5 Minutes of Committee Meetings

The Committee will maintain minutes of its meetings which will be filed with the minutes of the Board of Directors. A copy of the Minutes of each meeting of the Committee shall be provided to each member of the Committee within twenty (20) calendar days from the meeting date. Minutes of Committee meetings will be made available to the Board of Directors upon approval of those minutes by the Committee.

## 5. ROLES & RESPONSIBILITIES

### 5.1 Specific Responsibilities and Duties

The Committee will advise and make recommendations to the Board relating to the following matters, in consultation with the President and CEO:

(a) consider and review the EHS annual plan and monitor its implementation on a quarterly basis;

(b) consider and review the EHS risk mitigation plans;

(a) consider and approve the annual EHS;

(d) provide EHS summaries at each Board meeting;

(e) Attend to two (2) site vists a year by at least 1 (one) committee member;

(f) perform such other duties as may from time to time be assigned to it by the Board and accepted by the Committee as appropriate duties for it to undertake.

The Committee shall have the right, for the purposes of discharging the powers and responsibilities as defined in its Charter and Mandate, to inspect any relevant records of the Corporation with the exception of any documentation held by the Corporation containing private and confidential information with respect to the senior management of the Corporation or any other employee.

### 5.2 Maintaining Integrity

The Committee shall ensure that senior management review its systems and documentation, and monitors the controls and procedures within the Corporation in order to maintain its integrity including its internal controls and procedures for human resources reporting and compliance with privacy legislation and all relevant employment related legislation.

### 5.3 Key Performance Indicators

The Committee shall receive and regularly review reports of specified performance indicators.

### 5.4 Communication Process

The Committee shall ensure an effective process is established and applied for the communication of the EHS programs between the Board and the Corporation.

### 5.5 Other Business

The Committee shall consider any other relevant matters relating to the discharge of its Mandate and Charter or referred to it by the Board.

## 6. ACCOUNTABILITY:

**6.1** The Committee will report on its deliberations to the Board through verbal reports by its Chair at regular Board meetings.

**6.2** The Committee will review its Mandate and Charter each year at its to assess its adequacy and endeavour to keep Committee members abreast of "best practices" for an EHS Committee. Any proposed amendments to the Mandate and Charter will be submitted to the Board through the Governance and Compensation Committee and if agreed to by the Board, will thereafter be put into effect.

# ATTACHMENT 1-P

## Transition to MIFRS Summary Impact

### Board Appendix 2-Y

# Appendix 2-Y
## Summary of Impacts to Revenue Requirement from Transition to MIFRS

| Revenue Requirement Component | 2016 MIFRS | 2016 CGAAP without policy changes | Difference | Reasons why the revenue requirement component is different under |
|---|---|---|---|---|
| Closing NBV 2015 | $ 74,926,228 | $ 71,340,808 | $ 3,585,420 | Depreciation - decrease in depreciation expense under MIFRS; Capitalization - decrease in capital under MIFRS |
| Closing NBV 2016 | $ 78,351,864 | $ 73,516,117 | $ 4,835,747 | Depreciation - decrease in depreciation expense under MIFRS; Capitalization - decrease in capital under MIFRS |
| Average NBV | $ 76,639,046 | $ 72,428,463 | $ 4,210,583 | |
| Working Capital | $ 9,917,527 | $ 9,866,856 | $ 50,671 | Capitalization - increase in OM&A under MIFRS |
| Rate Base | $ 86,556,573 | $ 82,295,318 | $ 4,261,255 | |
| | | | | |
| **Return on Rate Base** | $ 5,606,789 | $ 5,330,659 | $ 276,129 | Impact of above-noted changes to capitalization and depreciation policies |
| | | | $ - | |
| OM&A | $ 9,495,813 | $ 8,879,372 | $ 616,441 | Capitalization - increase in OM&A under MIFRS |
| Depreciation | $ 3,849,791 | $ 5,716,559 | $ (1,866,768) | Depreciation - decrease in depreciation expense under MIFRS |
| PILs or Income Taxes | $ 159,910 | $ 724,256 | $ (564,346) | Depreciation - increase in Schedule 1 addback under CGAAP; Capitalization - increase CCA for higher capital under CGAAP |
| Property Taxes | $ 243,162 | $ 243,162 | $ - | |
| Other Expenses | $ 23,040 | $ 23,040 | $ - | |
| | | | $ - | |
| Less: Revenue Offsets | $ (1,188,521) | $ (1,188,521) | $ - | |
| | | | $ - | |
| | | | $ - | |
| | | | $ - | |
| **Total Base Revenue Requirement** | $ 18,189,984 | $ 19,728,528 | $ (1,538,544) | |

Applicants must provide a summary of the dollar impacts of MIFRS to each component of the revenue requirement (e.g. rate base, operating costs, etc.), including the overall impact on the proposed revenue requirement. Accordingly, the applicants must identify financial differences and resulting revenue requirement impacts arising from the adoption of MIFRS as compared to CGAAP prior to capitalization and depreciation policy changes. Applicants should explain the financial differences and may separate the differences arising from changes in capitalization and depreciation policy versus the adoption of IFRS.