CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

April 29, 2016

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
Suite 2700
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli:

RE: CANADIAN NIAGARA POWER INC.,
2017 ELECTRICITY DISTRIBUTION RATE APPLICATION
EB-2016-0061

Please find accompanying this letter, two (2) copies of CNPI's 2017 Electricity Distribution Rate Application. Coincidently with this written submission, a PDF version has been filed via the Board's Regulatory Electronic Submission System.

In addition, the following files accompany the Application and have been submitted via the Board's Regulatory Electronic Submission System:

- 2016_COS_Checklist.xlsx
- 2017 EDR Rate Design_Res Mitigation.xlsx
- 2017 EDR Rate Design.xlsx
- 2017_EDDVAR_Continuity_Schedule_CoS.xlsx
- 2017_EDDVAR_Continuity_Schedule_CoS_unlock_Appendix 3A.xlsx
- CNPI 2016_Cost_Allocation_Model.xlsm
- CNPI Dist 2016_Filing_Requirements_Chapter2_Appendices.xlsm
  (2-C for 2013 – 2017 filed separately from other Chapter 2 Appendicies)
- CNPI Distribution System Plan.pdf
- CNPI Load Forecast.xlsx
- CNPI_Tracked_Changes_Tariff.xlsx
- Deferral Variance Account Workform.xlsm

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- Income Tax Model.xlsx
- Revenue Requirement Workform.xlsm
- RTSR Workform.xlsm
- Smart Meter Model.xlsm

If you have any questions in connection with the above matter, please do not hesitate to contact the undersigned at (905) 872-0330 extension 3279.

Yours truly,

Original Signed by:

Gregory Beharriell
Manager, Regulatory Affairs

Enclosures

CANADIAN NIAGARA POWER INC.
APPLICATION FOR APPROVAL OF ELECTRICITY RATES
EFFECTIVE JANUARY 1, 2017

MANAGEMENT DISCUSSION AND ANALYSIS ("MD&A")

Overview

Canadian Niagara Power Inc. ("CNPI" or "the Company") is a licensed electricity distributor (ED-2002-0572) incorporated pursuant to the Ontario Business Corporations Act. CNPI owns and operates electricity distribution infrastructure serving over 28,500 residential and commercial customers in Fort Erie, Gananoque and Port Colborne. CNPI is a wholly-owned subsidiary of FortisOntario Inc. ("FortisOntario"), headquartered in Fort Erie, Ontario. CNPI is also a licensed transmitter (ET-2003-0073). CNPI is organized into two business units, CNPI – Distribution and CNPI – Transmission. The distribution business units operate as CNPI from its Fort Erie office to service its Fort Erie and Port Colborne service territories. In its Gananoque service territory, the distribution business unit operates as Eastern Ontario Power ("EOP"). CNPI operates a small work centre in Gananoque to provide for day-to-day operational needs of the area. These resources are supplemented and supported from both CNPI's Fort Erie office, and from CNPI's affiliate, Cornwall Electric.

The majority of CNPI's distribution system (all of its Fort Erie service territory and the vast majority of its Port Colborne service territory) is supplied from the IESO-controlled grid. The portions of CNPI's distribution system that attract low voltage charges include CNPI's EOP service territory, which is fully embedded within Hydro One's distribution system through a single point of supply from Hydro One's 44 kV system as well as a very small section of CNPI's Port Colborne distribution system which is supplied from Hydro One's Crowland M13 feeder.

CNPI prepares a consolidated five-year business plan for its distribution and transmission businesses. When preparing its five-year business plans, CNPI does so in accordance with the principles described in the Renewed Regulatory Framework for Electricity (the "RRFE"). Details of the interaction between the various RRFE outcomes, and discussion of how the balance of these outcomes impacted the current Application are provided at Exhibit 1, Tab 10, Schedule 2.

CNPI's most current five-year business plan covers the 2016-2020 period (the "Business Plan"), which is attached at Appendix 'A' to this schedule.

CNPI's "Core Values" are set out in its Business Plan. They define who CNPI is and how it operates. They also reflect the beliefs, philosophy, and commitment of CNPI's employees and shareholders. They are as follows:

- Respect for People: Treat others, as you would have others treat you. Honesty, integrity and ethics are never compromised (aligns with RRFE performance outcome Customer Focus).
- Safety and the Environment: Demonstrate a personal, unrelenting commitment to safety and environmental excellence. Protect yourself, your fellow employees, the public and our environment (aligns with RRFE performance outcome Customer Focus).
- Financial Success: Produce solid earnings, with dividends that meet the expectations of shareholders. Grow shareholder value through prudent equity investments and business partnerships. Ensure that debt obligations are always met in a timely manner and to the satisfaction of our creditors (aligns with RRFE performance outcome Financial Performance).
- Customer Service: Everyone has customers. Determine your customers' needs by listening. When you can meet these needs, do so. When you cannot, tell them that you cannot, or tell them who can. When in doubt about how to treat a customer, do what you believe is right. When serving customers, be pleasant, courteous and accurate; smile, act professionally and enjoy yourself. Attitudes are contagious (aligns with RRFE performance outcome Customer Focus).
- Productivity: Effective teamwork combined with employee innovation produces productivity gains. Employees are encouraged to pursue opportunities to implement new ideas and methods that enhance overall individual and team performance. Remember…if you have a better way to do something – just do it (aligns with RRFE performance outcome Operational Effectiveness).

- Community Involvement: Each of us has an obligation to support the communities that support us. This means time as much as money. Success is measured by the reaction of community leaders and the opinions expressed by community residents (aligns with RRFE performance outcome Customer Focus), Operational Effectiveness, and Public Policy Responsiveness.

As discussed below, these Core Values give rise to CNPI initiatives and goals that are aligned with the performance outcomes set out in the RRFE, those being:

I. Customer Focus: services are provided in a manner that responds to identified customer preferences;
II. Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;
III. 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
IV. Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable

CNPI's MD&A has been organized based on the RRFE scorecard, such that the following topics as they relate to CNPI distribution objectives and plans are discussed:

I. RRFE Performance Outcome - Customer Focus
    i. Customer Focus Performance Category - Customer Satisfaction
    ii. Customer Focus Performance Category - Service Quality

II. RRFE Performance Outcome - Operational Effectiveness
    i. Operational Effectiveness Performance Category – Safety
    ii. Operational Effectiveness Performance Category - System Reliability
    iii. Operational Effectiveness Performance Category - Asset Management

iv. Operational Effectiveness Performance Category - Cost Control

III. RRFE Performance Outcome - Public Policy Responsiveness

i. Public Policy Responsiveness Category - Conservation and Demand Management

ii. Public Policy Responsiveness Category - Connection of Renewable Generation

IV. RRFE Performance Outcome - Financial Performance

i. Financial Performance Category

RRFE Performance Outcomes

I. RRFE Performance Outcome - Customer Focus

i. Customer Focus Performance Category - Customer Satisfaction

CNPI's Customer Engagement Strategy (Exhibit 1, Tab 3, Schedule 1) is divided into three categories and encompasses a number of initiatives and best practices. These are: A) customer communications; B) initiatives specific to the Application; and C) future initiatives. Each of these categories is described below.

***A) Customer Engagement Strategy - Customer Communications*:**

The following are some of the ways CNPI communicates, seeks feedback and interacts with its customers:

Monthly Calendar Billing: Monthly billing provides the opportunity to interact with customers on a frequent basis. Monthly invoices are either sent via mail or electronically and include bill inserts and semi-annual newsletter providing customers with current information related to the industry, the Company and their electricity bills. Furthermore, customers have told CNPI that comparing month over month electricity bills would be beneficial in assisting them in making decisions related to energy consumption. Therefore, in late 2012, CNPI made the decision to move to monthly calendar billing, aligning the bill period to a calendar month. This allows true monthly comparisons for CNPI's customers. While, resulting in a fundamental change to the billing schedule and internal business practices, the needs of the customers were the driving factor in making this change. This billing period also reduces the complexity of the customer invoice during rate changes.

Website: CNPI's website is continuously updated to provide an enhanced customer experience with a goal of providing customers easy access to an abundance of information. As products and services are launched, for example e-Billing, MyHydroEye and social media, changes are made accordingly.

Social Media: In 2014, CNPI launched a social media campaign including Facebook and Twitter to further interact and communicate with its customers. The customer survey results indicated that 10 per cent of customers surveyed preferred to receive communications via social media channels. This number is expected to grow. CNPI's social media following has continually increased since the launch. Contests were held to promote the new communication channels. Currently, social media is not used during after business hours, but future initiatives involve after hours monitoring of social media by a third party to keep customers informed during all power outages. This will be implemented in June 2016.

Customer Surveys: CNPI has utilized residential customer surveys for the past ten years. Prior to 2015, the telephone survey was completed by Corporate Research Associates Inc. The survey was conducted by fully trained interviewers who asked a series of questions, with an average survey length of time of 8 minutes. The chart below outlines CNPI's results from 2011-2014.

	2011	**2012**	**2013**	**2014**
Overall Satisfaction	80	89	81	80
Reliability and Safety	89	95	95	90
Quality of Service	85	91	91	87

In 2015, CNPI moved to a new survey provider, UtilityPULSE, to be more consistent with other LDCs in the province. The survey sample size was expanded and general service customers were included. UtilityPULSE completed 410 telephone interviews with residential and general service customers in the fall of 2015. The phone numbers were randomly selected and were stratified so that 85 per cent of the interviews were conducted with residential and 15 per cent with general service customers. CNPI's 2015 satisfaction score was higher than both the national and Ontario averages. Satisfaction is defined as happening when utility core services meet or exceed customers' needs, wants or expectations. CNPI's results as compared to the both the national and Ontario scores are listed below.

CNPI's SATISFACTION SCORES – Electricity customers' satisfaction		
CNPI	**National**	**Ontario**
94%	89%	88%

Departmental Strategy: Customers have continuously told CNPI that their preferred method of communication is via the telephone, specifically during a power outage. The chart below reiterates CNPI's customers' overwhelming preference of speaking to representatives via the telephone:

	Telephone	**Email**	**Utility Website**	**Social Media**	**Mail**	**In Person**
Ontario LDCs	84%	5%	2%	1%	0%	0%
CNP	89%	4%	2%	2%	0%	3%

In response to this, CNPI has maintained very personal service and ensures that all customers have access to speak to a live agent. The chart below outlines CNPI's call statistics from 2011-2015. With various changes to the electricity industry over the past several years, customer telephone inquiries have become increasingly complex. As such, customer service representatives ("CSR") require more time to assist customers with their concerns resulting in the longer call durations. This is a contributing factor to the decrease in the percentage of calls answered within thirty seconds, although call centre statistics have remained strong and CNPI continues to far exceed the OEB benchmark of 65 per cent of calls being answered within 30 seconds.

Telephone accessibility	**2011**	**2012**	**2013**	**2014**	**2015**
Total general inquiry telephone calls	39,985	36,052	38,704	42,361	39,803
Total general inquiry telephone calls answered within 30 seconds	33,839	30,485	31,956	33,140	30,279
% of general inquiry telephone calls answered within min standards (65%)	85%	85%	83%	78%	76%

Longer call handle times directly align with First Contact Resolution. CNPI's 2015 result for First Contact Resolution on the OEB scorecard was 99 per cent. While calls may take longer to answer, the customer is able to resolve their issue or concern in one call the vast majority of times.

In response to customer satisfaction survey results, customers identified proactive outage communications as the most important item they were willing to pay more for each month and thus an important area where CNPI could improve overall service levels, CNPI has entered into a project to provide enhanced call answer services to its customers. Leveraging the services of UtilAssist (PowerAssist), customers will have more access to a live CSR through an increased number of after business hours inbound telephone lines. Current providers have a limited number of inbound telephone lines which can result in busy signals when customers are trying to contact CNPI. PowerAssist's CSRs have access to customer data to provide a higher level of customer interaction during the call. This service will be expanded in late 2016 for all inbound power outage calls.

Town Council Meeting Presentations: CNPI endeavors to meet annually with town counsel and town leaders to provide an overview of the previous years' capital and maintenance programs and will also provide an update on the coming years' initiatives.

Community Involvement: Interacting with the community has always been a focus of CNPI. CNPI has been awarded the highest recognition from the United Way of Niagara Falls and Greater Fort Erie for its dedication to the community. Dinners are served annually by employees at the local soup kitchens, as well as participation in community parades and other community events throughout the year. Employees also participate annually in the Big Bike Event for the Heart & Stroke Association.

School awareness events have proven to be a very useful way to increase electrical safety awareness while promoting Energy Conservation at the primary level.

Annually, CNPI hosts Grade 9 students for the *Take Our Kids to Work™* national program. The students learn about the utility industry, various career opportunities, as well complete the Passport to Safety Training. The program supports career development by helping students connect school, the world of work, and their own futures.

Public Safety: CNPI engages in a number of on-going initiatives with a focus on public safety. Regular messaging is sent out via social media in conjunction with Electrical Safety Authority ("ESA") campaigns. Semi-annual company newsletters include a safety message. The Company's website dedicates resources to electrical safety. School age children are made aware of the importance of electrical safety through presentations held at each school in the service territory, on a four (4) year rotation.

In addition to the Customer Satisfaction surveys completed for CNPI in 2015, UtilityPulse was also engaged to complete surveys in relation to “Public Awareness of Electrical Safety”. On completion of this survey, UtilityPulse generated a “Public Safety Awareness Index Score” for CNPI and other LDC’s. Province-wide scores ranged from 77% to 86%, with both average and median Index Scores of 82%. CNPI’s score of 81% suggests that members of the public are generally well-informed about the safety hazards associated with electrical distribution systems, but also that further education and engagement would be beneficial. The detailed results reveal that there is some confusion amongst respondents over safety precautions in the case of downed power lines or in cases involving vehicle contact. This underscores the need to make public safety considerations an important part of selection criteria for capital and maintenance programs with the goal of significantly reducing the probability that these types of situations will occur.

Local Service Provider Information Night: CNPI hosts an annual information session for local service providers who work for customers and prospective customers in the CNPI service territories. Participants include local builders, electricians, realtors, etc. The information session provides an opportunity to communicate with these parties on changes to connection requirements and service repairs. Parties also have the opportunity to provide feedback to CNPI on various processes.

Contractor Pre-Qualification Session: CNPI hosts a bi-annual contractor information session for contractors employed by CNPI. As well, representatives from the local office of the ESA are present. The event discusses public safety issues, customer service topics regarding interactions between CNPI and the contractor community as well any changes to CNPI’s customer connection process.

Emergency Responder Information Night: CNPI hosts training on a three (3) year rotation for staff of local fire, police and paramedical services. A review of electrical fundamentals and an overview of electrical safety and processes related to emergency situations are reviewed.

Joint Use Partner Interaction: CNPI meets regularly with local representatives from Bell and other Joint Use customers to discuss each company's upcoming and ongoing capital and maintenance projects. The purpose of these meetings is to ensure all parties can coordinate resources for demand work initiated by a joint use request as well as to monitor the progress of work related to these joint use requests.

CNPI will continue its on-going efforts of engaging its customers through this multi-channeled model. By utilizing this model, customers can actively provide feedback and be aware of the Company's on-going activities while staying current with industry changes. Overall, this approach presents many channels for customers to actively engage with CNPI, allowing CNPI to incorporate useful feedback into the operation of its distribution business.

B) Customer Engagement Strategy - Initiatives Specific to this Application

Capital: In response to the Board's Filing Requirements to engage customers on the specific proposals contained in this Application, in addition to the annual customer survey, in January 2016, CNPI retained UtilityPULSE to design, collect feedback and provide detailed information on customer preferences. In March 2016, residential focus group sessions were held in Niagara and Gananoque with a total of 32 participants, and general service focus group sessions were held in Niagara and Gananoque with a total of 25 participants. The goal of the focus group sessions was to engage customers in dialogue to gain a better understanding of the findings from the telephone interviews from the annual survey referred to above and to capture their thoughts and ideas on CNPI's rate application process and Distribution System Plan ("DSP").

Each of the focus group sessions followed a prescribed format where a CNPI executive and the UtilityPULSE moderator welcomed attendees followed by the CNPI executive providing a 15-20 minute overview of the organization and the DSP.

Focus group participants were provided an opportunity to ask questions of CNPI personnel, who then left the room. The moderator facilitated the session by sequencing the questions consistently in each session. In addition, every participant was given the opportunity to voluntarily complete a brief paper-based questionnaire and/or to provide written comments. Of the 57 people who attended the sessions, 51 provided responses.

Based on this customer feedback, CNPI's DSP and Distribution Asset Management Plan ("DAMP") include ongoing maintenance and upkeep initiatives to ensure reliable delivery of electricity. An example of a project to improve reliability is the distribution automation program, as set out at section 5.4 of the Business Plan and described in Section 5.4.6.8 of the DSP. The distribution automation program is a multi-year initiative aimed at improving service reliability and availability for CNPI's customers. The program introduces field based automated switching and protection devices to CNPI's overhead distribution system. Based on analysis of reliability statistics, CNPI targets sections of feeders with poor performance and implements automation to mitigate outage frequency and duration.

The installations typically consist of a motor operated switch or recloser coupled with a protective relay and control device. The resulting installation is capable of remote interrogation and operation via CNPI's SCADA system. This improves response time and overall outage restoration time during unplanned events. The protection elements incorporated into these intelligent field devices limits feeder exposure to faults, dramatically reducing the number of customers affected by an unplanned event.

OM&A: When customers were asked about what services they are willing to pay for each month, tree trimming was rated second as it is recognized it will improve system reliability. The DSP addresses this ongoing need and outlines plans to continue a three-year tree trimming program.

Customer Services: In 2014, SAP "dunning" enhancements streamlined the process by which customers are notified of overdue accounts. The replacement of mailed reminder notices with an automated telephone call has resulted in a savings of approximately $12,000. This allows customers to be notified in a more timely fashion of overdue amounts on their hydro accounts. Technological enhancements have reduced manual processing through automations with Canada Post Xpress post software to more efficiently issue final collection notices to customers. As well, regulatory requirements are tracked with the capability of the software to identify where the collection notice is in the delivery cycle.

In response to customer satisfaction survey results, 60 per cent of residential customers and 58 per cent of general service customers indicated a preference to receive information about outages via a recorded message. CNPI has developed a process to pro-actively identify customers affected by power interruptions resulting from system repairs/upgrades. Automated phone calls via OnecallNow.com are generated prior to the outage giving customers the opportunity to make any necessary arrangements for their electrical service. Customers identified proactive outage communications as the most important item they were willing to pay more for each month and thus an important area where CNPI could improve overall service levels. CNPI has entered into a project to provide enhanced call answer services to its customers. Leveraging the services of UtilAssist (PowerAssist) customers will have more access to a live CSR through an increased number of after-business hours inbound telephone lines. Current providers have a limited number of inbound telephone lines which can result in busy signals when customers are trying to contact CNPI. PowerAssist CSR's have access to customer data to provide a higher level of customer interaction during the call. This service will be expanded in late 2016 for all inbound power outage calls.

Customers have indicated that they want access to their time-of-use ("TOU") and interval data to help them make informed decisions about their energy usage. As such, CNPI has provided all TOU customers the MyHydroEye on-line resource which allows customers to review usage data. This allows customers to adjust their consumption patterns which influence electricity bill amounts. The product also provides forecast bill results in the event the customer has enrolled with a retailer. For large users, UtiliSmart Settlement Manager is available providing more detailed and individualized data around the composition of the customers' invoice as well as load information. In 2016, customers with MIST meters will also be able to access the Settlement Manager to review their usage data and assist them in managing their electricity costs.

In 2014, CNPI introduced social media as a means to further interact and communicate with its customers. Currently, approximately 10 per cent of customers surveyed in 2014 preferred to receive communications via social media channels, and this number is expected to grow. As a result of the customers' feedback, CNPI launched both Facebook and Twitter. CNPI's social media following has continued to increase since the launch. Contests were held to promote the new communication channels and utilization continues to grow. Currently, social media is not used during power outages but future initiatives involving after hours monitoring of social media by a third party to keep customers informed during all power outages will be implemented in June, 2016.

C) Customer Engagement Strategy - Future Initiatives

Many steps have been taken to ensure that the needs and wants of CNPI's customers are considered as the company prepares plans for capital and maintenance initiatives.

Survey results indicate that 73 per cent of customers feel that CNPI provides good value for their money. This well exceeds the Ontario benchmark of 66 per cent and the national benchmark of 67 per cent. However, CNPI strives to continually improve the customer experience.

The future will include more self-service options for customers, improved outage communications, leveraging social media and websites to provide 24/7 customer updates during power outages, key account management and will continue to request feedback from its customers through on line surveys and in person dialogue.

ii. Customer Focus Performance Category - Service Quality

CNPI has consistently exceeded the Electricity Service Quality Requirements ("ESQR") minimum standards in accordance with Section 7.0 of the Distribution System Code over the past five years. The table below summarizes the Service Quality Indicator standards met by CNPI for the period 2011 to 2015.

Indicator	OEB Minimum Standard	2011	2012	2013	2014	2015
Low Voltage Connections	90.0%	95.9%	95.7%	93.1%	96.0%	93.6%
High Voltage Connections	90.0%	---	0.0%	0.0%	0.0%	0.0%
Telephone Accessibility	65.0%	84.6%	84.6%	82.6%	78.0%	76.1%
Appointments Met	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Written Response to Enquires	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Emergency Urban Response	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Emergency Rural Response	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Telephone Call Abandon Rate	10.0%	2.3%	2.8%	2.5%	4.0%	4.6%
Appointment Scheduling	90.0%	99.2%	99.5%	99.2%	98.0%	97.0%
Rescheduling a Missed Appointment	100.0%	---	0.0%	0.0%	0.0%	0.0%
Reconnection Performance Standard	85.0%	---	100.0%	100.0%	100.0%	100.0%

II. RRFE Performance Outcome - Operational Effectiveness

i. Operational Effectiveness Performance Category - Safety

In order to provide consistency and cost efficiencies with regards to Health, Safety & Environment ("HS&E"), CNPI operates as part of a consolidated FortisOntario HS&E organization. An integral component of FortisOntario's operations is its HS&E department and its systematic approach to proactively managing safety and the environment.

FortisOntario utilizes an integrated management system for HS&E, consistent with the standards of OHSAS 18001 (Health & Safety) and ISO 14001 (Environment) and developed within the context of FortisOntario's structure. The management system is based upon the premise of "Plan, Do, Check and Act". Both of these standards have been developed based on a foundation of a strong "Internal Responsibility System". This is a key value contained in the *Occupational Health and Safety Act*. All HS&E responsibilities are identified through the management system and have been clearly assigned to constituents within FortisOntario and CNPI including: the Board of Directors, the Executive, Departments (Managers, Supervisors and workers) and Committees (Executive Environmental & Safety Committee, Central Environmental & Safety Committee, Joint Health & Safety Committee and Environmental Leadership Team). FortisOntario's HS&E department consists of two full time employees and two employees with combined responsibilities (one with Lines and HS&E responsibilities and one with Vegetation Management and HS&E responsibilities) managing the five FortisOntario business units with approximately 200 employees and 42 facilities (offices & sub-stations) across Ontario. Each of these utilities/service territories inherently possess unique HS&E challenges associated with their geographical location and operational differences, and benefit from a standardized approach to managing HS&E. The following is an overview of FortisOntario's HS&E departmental functions.

- Hazard Assessment
- Legal Compliance
- Performance Indicators
- Training

- Audits and Inspections

One of the core principles consistent to both of the standards associated with the FortisOntario HS&E management system is the need for continual improvement. The HS&E department explores new ideas and facilitates recommendations to improve the system, and to promote HS&E responsibility. In an industry in which technology is evolving rapidly, and in an environment where CNPI's workers are exposed to risk, it is imperative that CNPI continues to commit the appropriate resources to sustain its current level of HS&E performance. In that regard, CNPI has consistently achieved high levels of success in the areas of health, safety and environmental management. CNPI has gone almost fourteen (14) years without a high risk lost time occurrence.

ii. Operational Effectiveness Performance Category - System Reliability

CNPI takes system reliability seriously and does not rely solely on regulation as the impetus to maintain performance levels. CNPI subscribes to the philosophy that meeting customer expectation for system performance is part of its asset management objectives. CNPI prepares reports on a monthly, quarterly, and annual basis for all service quality indicators. These reports are then analyzed to assess system performance. Reports are also filed with the OEB at the prescribed intervals.

In terms of performance, CNPI monitors the metrics to determine what trends, if any, are developing. The reliability indicators assist in developing the programs within the Asset Management Plan through cause analysis. Significant work takes place in specific areas. where trend analysis indicates deficiencies.

Notwithstanding that there are yearly fluctuations; the overall outage trends are positive in that the frequency (SAIFI) and duration (SAIDI) are trending lower provided consideration is given to significant events. Yearly fluctuations can result from variations in weather such as extreme lightning, excessive snowfalls, and ice storms.

A key objective of the CNPI DAMP is to maintain a high level of distribution system reliability. Capital investments are aimed at improving or maintaining reliability by proactively upgrading deteriorating facilities and adding system capacity to avoid overloads. Investments are also made to ensure that sufficient system redundancy exists so that customers can be supplied from alternate paths in emergency or planned outage situations. Investments in technology such as SCADA monitoring and control provide real-time system information that facilitates the rapid identification of system problems and remote switching that improves the efficiency of outage response.

In addition to the capital investments, maintenance programs and operational practices are also aimed at improving reliability. For example, in its service territories, CNPI maintains industry-standard systematic vegetation management programs to ensure that appropriate clearances are maintained between power lines and surrounding vegetation. In forced outage situations, outage response efforts focus on locating and isolated faulted areas promptly so that the most affected customers can be restored from alternate paths. When system components must be taken out of service for planned maintenance, switching is carried out so as to minimize disruption to customers.

The application of SCADA technology allied to Control Room oversight is a key component of CNPI operations, and also impacts upon reliability performance. CNPI's Niagara Region Control Room is currently staffed on a 5 day / 8 hour basis, and after-hours on-call personnel are equipped with the capability to remotely access the SCADA system from offsite locations using laptop computers. Alarms from the SCADA system are also routed to on-call personnel via smart-phones. These initiatives allow for efficient identification of system problems after-hours, which is an essential component of effective outage response.

CNPI's Gananoque territory is controlled by the Control Room located at CNPI's affiliate, Cornwall Electric. SCADA upgrades have been implemented in Cornwall that provide the same level of after-hours capability as exists in CNPI's Niagara Region.

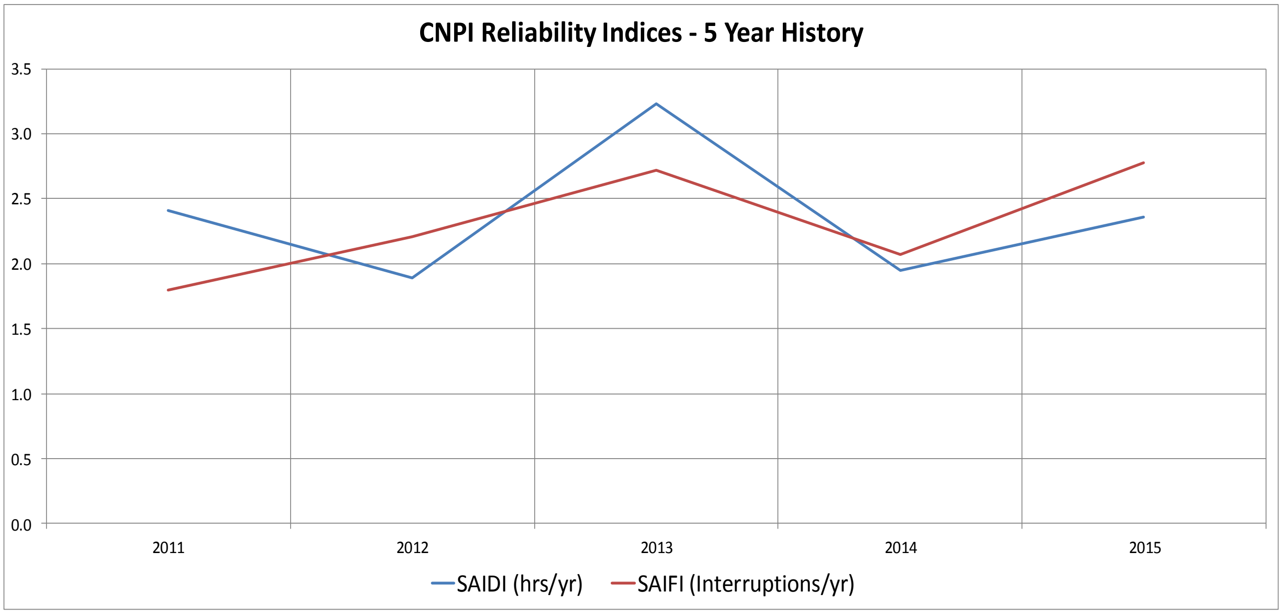
CNPI maintains MS Access databases of all outages that occur on its distribution systems. This allows for the tracking and analysis of reliability performance. SAIDI and SAIFI indices are computed from the data. These indices are defined as follows:

- SAIDI, *System Average Interruption Duration Index* – reflects the total outage time to the average customer over a period of one year.
- SAIFI, *System Average Interruption Frequency Index* – reflects the number of interruptions to the average customer over a period of one year.

Indices are computed on a monthly and annual basis. Data is submitted to the OEB in accordance with regulatory requirements. In addition, data is also analyzed internally by CNPI to identify reliability trends and potential areas for reliability improvement.

Reliability indices for CNPI for the five-year time period 2011-2015 are shown in the table below. The data excludes outages due to Loss of Supply.

Year	2011	2012	2013	2014	2015	Average
SAIDI (hours)	2.41	1.89	3.23	1.95	2.36	**2.37**
SAIFI	**1.80**	**2.21**	**2.72**	**2.07**	**2.78**	**2.32**



As an example of the type of reliability analysis that CNPI performs, several inferences can be drawn from the data displayed above. In 2013, both SAIDI and SAIFI exceeded the five year historical average. In 2015, SAIFI again exceeded the historical average. The analysis presented at Exhibit 2, Tab 8, Schedule 1 explains that these anomalies are due in large part to severe weather events causing widespread outages across much of its Niagara service area. In some cases, the weather events were in excess of CNPI's design criteria. The analysis presents an alternate set of outage statistics, with these severe events removed.

CNPI's Business Plan addresses system reliability at section 5.5:

> As one of the key indicators monitored by the OEB, CNPI continues to focus on system reliability. O&M programs such as equipment inspection and maintenance will effectively prevent power outages and provide valuable information for developing capital projects. Capital projects such as replacement of end-of-life assets, installation of redundant capacity, and upgrading of protection and control systems will effectively reduce outage frequency, areas impacted by outages, and outage restoration time.

iii. Operational Effectiveness Performance Category - Asset Management

The fundamental objective of the CNPI's DAMP is to prudently and efficiently manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement of all distribution assets in a sustainable manner that maximizes safety and customer reliability, while minimizing costs, in the short and long terms.

This objective is met through the application of thorough and sound planning, prudent and justified budgeting, ongoing oversight, documentation, and review of all efforts and expenditures while implementing the documented capital and operating plans.

CNPI maintains a comprehensive DAMP which outlines the operating and capital processes, activities, and expenditures that are necessary to ensure that CNPI continues to provide the safe, reliable, and efficient distribution of electricity to its customers. The DAMP is reviewed annually and adjustments to the plan are made based on changes in legislation, codes and regulations, system performance reviews, safety assessments, infrastructure studies, and customer feedback.

CNPI's DAMP is provided as an Appendix to its Distribution System Plan at Exhibit 2, Tab 2, Schedule 1, Appendix A.

iv. Operational Effectiveness Performance Category - Cost Control

A) Efficiency Assessment

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC on behalf of the OEB to produce a single efficiency ranking. The electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs. The model developed by Pacific Economics Group to predict a distributor's costs relies on a data set that includes all distributors in Ontario. For 2014, CNPI was placed in Group 4, indicating that actual costs are within +/- 25% of predicted costs.

B) Total Cost per Customer

CNPI's total cost per customer from 2010 to 2014 as reported on CNPI's 2014 scorecard was as follows:

Total Cost per Customer

2010	**2011**	**2012**	**2013**	**2014**
$715	$727	$679	$726	$749

Total cost is calculated as the sum of CNPI’s OM&A costs, including depreciation and financing costs. This amount is then divided by the total number of customers that CNPI serves to determine Total Cost per Customer. The cost performance result for 2014 is $749 /customer which is a 3.2% increase over 2013. However, CNPI’s Total Cost per Customer has increased on average by only 1.3% per annum over the period 2010 through 2014. This compares favourably with the Consumers Price Index (“CPI”) over the same period.

Historical cost measures are reflective of the fact that 80% of CNPI's service territory is located in rural areas, subject to more severe weather due to its location on the shore of Lake Erie (Lake Ontario for Eastern Ontario Power’s service territory) with its prevailing winds and lake effect precipitation, and the operation and maintenance of several distribution substations.

CNPI will continue to replace distribution assets proactively along a carefully managed timeframe in a manner that balances system risks and customer rate impacts. CNPI will continue to seek and implement productivity and system reliability improvement initiatives to help offset some of the costs associated with future system enhancements. Customer engagement initiatives will continue in order to ensure customers have an opportunity to share their viewpoint on CNPI’s capital spending plans.

In this regard, CNPI's Business Plan provides at section 5.4:

> To improve operational efficiencies, management is focusing on technology deployment and improving system automation. After implementing

Geographic Information System ("GIS") and Outage Management System ("OMS") at FortisOntario, distribution asset databases, field engineering tools, and mobile computing applications will be developed over the next five years. The distribution asset databases include construction, inspection and maintenance records, and detailed technical attributes for all major distribution equipment in the system and in inventory. The field engineering tools provide technicians and field workers with all system technical information and design capacity. These tools will reduce the number of field visits for project development. Mobile computing applications include up-to-date system maps, electronic forms for equipment inspection and maintenance records, and better tools to document standards, procedures, and other information. System outage maps will also be developed and these maps will provide real-time power outage information to improve customer communication.

CNPI continues to improve system automation through substation breaker upgrades, relay replacement, installation SCADA controlled reclosers and switches, SCADA upgrades, and communication upgrades. The objectives of system automation are to reduce the areas impacted by power outages through more accurately identifying power outages and reducing restoration time.

Some of the sources of cost savings and efficiencies expected to be achieved over the 2017-2021 period are summarized by CNPI's DSP at section 5.2.1.2:

- Targeted Asset Replacement Programs: These programs reduce costs when compared to more 'random' replacement programs. CNPI is currently conducting a multi-year pole testing program to determine the present condition of all poles. This is expected to identify those poles that might require replacement, and is further assessing these results to determine their probable remaining useful lives. CNPI has incorporated these results in its capital program planning to ensure that as many problematic poles as possible are addressed as CNPI carries out its various programs.

- Distribution Automation ("DA"): DA has a clear impact on reliability statistics, but is also a labour savings option when applied on protection and switching devices that are remote from the service centre.

- Standardized Designs: Standard Designs save money both by reducing the engineering costs of the project as well as reducing installation costs and material stock costs. CNPI is part of the Utilities Standard Forum ("USF") group, which has standardized installation drawings for use in the projects in this DSP.

- Mobile Computing: Devices such as portable computing devices to replace paper-based data collection and processes will improve operational efficiency, reduce the possibility of data translation errors, and provide cost savings at the time of collection, and the time of data entry.

  CNPI is using or presently deploying mobile technology to:

  - Provide automatically-updated digital maps sourced from its GIS system to ensure all operating staff have up-to-date information about the CNPI distribution system at a reduced cost. These cost reductions are due to reduced labor in map production, and significant reductions in paper and ink.

  - Provide a 'Mobile Document Library' to ensure that field staff have complete and up-to-date access to documents like Standards, Procedures, Policies, and 3rd party documents from the Ministry of labour and MTO.

  - Provide an engineering field tool for on-site design and data capture of proposed projects. This tool is fully integrated with the CNPI GIS and SAP systems to reduce input error and improve response and reply times when other stakeholders, such as customers, are involved.

- Distribution System Line-Loss Reduction: distribution system losses are being improved through renewal and voltage conversion projects. Among its other benefits, voltage conversion usually results in distribution lines operating at higher nominal voltages. This results in correspondingly lower line currents, which directly impacts the resulting line-losses.

In addition to a number of smaller projects to upgrade distribution lines and operate them at a higher system voltage, CNPI has some multi-year projects underway that will significantly reduce system losses:

- Fort Erie North 4.8kV Delta to 8.3 kV Wye Conversion Program
- Fort Erie Ridgeway 4.8kV Delta to 8.3 kV Wye Conversion Program
- EOP West Line 4.16kV to 27.6kV Wye Voltage Conversion Program

C) Total Cost per km of Line

CNPI's total cost per km of line from 2010 to 2014 as reported on CNPI's 2014 scorecard was as follows:

2010	**2011**	**2012**	**2013**	**2014**
$19,893	$20,204	$18,790	$20,275	$21,202

CNPI's 2014 rate is $21,202 per km of line, a 4.6% increase over 2013. However, CNPI's Total Cost per km has increased on average by only 1.8% per annum over the period 2010 through 2014. This compares favourably with the CPI over the same period.

As outlined in Total Cost per Customer above, historical cost measures are reflective of the fact that 80% of CNPI's service territory is located in rural areas, subject to more severe weather due to its location on the shore of Lake Erie (Lake Ontario for Eastern Ontario Power's service territory) with its prevailing winds and lake effect precipitation, and the operation and maintenance of several distribution substations. CNPI performs a comprehensive series of programs to meet all legal and regulatory requirements, with special emphasis on public safety, optimizing reliability, meeting customers' needs, and general cost control.

As outlined on Total Cost per Customer above, CNPI will continue to replace distribution assets proactively along a carefully managed timeframe in a manner that balances system risks and customer rate impacts. CNPI will continue to seek and implement productivity and system reliability improvement initiatives to help offset some of the costs associated with future system enhancements. Customer engagement initiatives will continue in order to ensure customers have an opportunity to share their viewpoint on CNPI's capital spending plans.

III. RRFE Performance Outcome - Public Policy Responsiveness

i. Public Policy Responsiveness Performance Category - Conservation and Demand Management ("CDM")

On the basis of the IESO's "2011 – 2014 Final Results Report" issued on September 1, 2015, CNPI achieved 54.6% of its Net Annual Peak Demand Savings and 82.6% of its Net Energy Savings. CNPI fully leveraged the suite of IESO province-wide demand management programs and placed emphasis on supporting the conservation efforts of large commercial, industrial and institutional customers. CNPI had been challenged in its efforts to meet the assigned target due to a significant reduction in customer demand and energy consumption in 2011, which has continued into 2014 with a decline in customer demand coupled with business closures. This resulted in significant adverse economic impacts affecting the entire service territory. Due to these negative economic impacts, a lack of growth and decline in the larger customer base, the CNPI service territories have seen a dramatic overall decline in energy throughput and system demand since 2008; the year that was used as the base year to set the mandated targets.

Nevertheless, CNPI's CDM team remains active in the delivery of energy efficient programs to residential and business customers. In addition to one-on-one customer interviews and visits, the CDM team has also undertaken customer specific or segmented focus groups throughout the year. As an example, CNPI engaged its larger industrial customers in a presentation by the IESO on the Global Adjustment. At this same presentation, the CDM team informed the customers about Demand Response programs, and how the customer can affect their Global Adjustment charge. The CDM group participates in numerous events throughout the year, promoting both the residential and commercial CDM programs. A detailed listing of events attended during the 2011 – 2015 timeframe is outlined in the table below.

Event/Promotion	Location	Customer Target	Event Date	Event Days	Outreach Potential	Program
CNPI						
Employee Awareness Day	Douglas Memorial Hospital-FE	Res, C&I, Ind	Sep 12 2012	0.5	50	All Programs
Social Agency meeting	County Office-Brockville	Res	Dec 3 2012	0.5	Gananoque	HAP
Social Agency meeting	Fort Erie - CNP offices	Res	Dec 6 2012	0.5	Fort Erie/Port Colborne	HAP
Kingston Home Show	Cataraqui Sports Complex	Res, C&I, Ind	Apr 5-7 2013	3	500	All Programs
Learn to Earn	Clarion Hotel - FE	Contractors	Apr 12 2013	0.5	30	All Business Programs
Learn to Save	Clarion Hotel - FE	C&I, Ind	Apr 12 2013	0.5	50	All Business Programs
FE Town Council	Fort Erie	Res	Jan 21 2013	0.5	Fort Erie	HAP Presentation
Conservation Showcase	Black Creek Retirement Community	Res	May 10 2013	0.5	75	All For Home Programs
Springfest	Stevensville Community Hall	Res	Jun 1 2013	1	100	All For Home Programs
Ribfest/Craft Fair	Gananoque Town Square	Res, C&I, Ind	Jun 28-30 2013	3	Gananoque	All Programs
United Way Golf Classic	Bridgewater Golf Club	C&I, Ind, Contractors	Aug 12 2013	1	150	All Business Programs
Business Trade Show	Fort Erie Chamber of Commerce	Res, C&I, Ind, Contractors	Sep 26 2013	0.5	500	All Programs
Niagara Region SOE Symposium	White Oaks Conference Resort-NOTL	C&I, Ind, Contractors	Oct 24 2013	1		All Business Programs
Coupon Event	Cdn Tire - Gananoque	Res, C&I, Ind	May 16 2014	1	50	All Programs
Chalk The Walk	Gananoque Town Square	Res, C&I, Ind	May 17 2014	1	100	All Programs
Springfest	Stevensville Community Hall	Res	Jun 7 2014	1	100	All For Home Programs
United Way Golf Classic	Bridgewater Golf Club	C&I, Ind, Contractors	Jul 14 2014	1	150	All Business Programs
Business Trade Show	Fort Erie Chamber of Commerce	Res, C&I, Ind, Contractors	Sep 25 2014	0.5	500	All Programs
Business Trade Show	PC Chamber of Commerce	Res, C&I, Ind, Contractors	Nov 6 2014	0.5	150	All Programs
FE Santa Claus Parade	Fort Erie	Res	Nov 24 2014	0.5	Fort Erie	All For Home Programs
FE Lioness Monthly Meeting	Ridgeway	Res	Dec 4 2014	0.5	20	All For Home Programs
PC Santa Claus Parade	Port Colborne	Res	Dec 6 2014	0.5	Port Colborne	All For Home Programs
Abor Group - HAP	FE Native Center	Res-Aboriginal	Apr 7 2015	0.5	50	HAP
United Way Golf Classic	Bridgewater Golf Club	C&I, Ind, Contractors	Jul 13 2015	1	150	All Business Programs
Employee Energy Awareness Day	Durez - Fort Erie	Res	Aug 12 2015	0.5	80	All For Home Programs
Business Trade Show	Fort Erie Chamber of Commerce	Res, C&I, Ind, Contractors	Sep 17 2015	0.5	500	All Programs
Coupon Event	Cdn Tire - FE/PC	Res	Sep 26 2015	1	200	All For Home Programs
Lunch & Learn	FE Lions Senior Center	Res	Oct 20 2015	0.25	20	All For Home Programs
Business Trade Show	PC Chamber of Commerce	Res, C&I, Ind, Contractors	Nov 5 2015	0.5	150	All Programs
FE Santa Claus Parade	Fort Erie	Res	Nov 21 2015	0.5	Fort Erie	All For Home Programs
PC Santa Claus Parade	Port Colborne	Res	Dec 5 2015	0.5	Port Colborne	All For Home Programs

At a number of the events in the table above, the CDM team works in conjunction with the Customer Service department. These events provide an excellent platform to communicate with customers directly regarding the promotion of service offerings such as e-Billing, MyHydroEye, power outage notifications etc. As a result of this, a further understanding is gained about the needs of our customers, which help decide on future offerings for program delivery.

As a result of feedback from residential customers, CNPI will be promoting an IESO sponsored pilot program for its residential customers starting in April 2016. This program will allow residential customers to receive up to $500 in free energy efficiency measures. The objective of the Direct Mail Pilot Program is to provide select residential (non-low income) customers with an opportunity to order a customized Energy Saving Kit, to help them reduce their energy consumption. Participants will visit a website and be asked a series of questions to help identify their eligibility and determine which rebates they qualify for. Once all questions are answered, the customer will proceed to a shopping cart. Depending on how they responded to questions asked, specific rebates will be applied to the shopping cart items, for the customer to select and checkout. The customer will not only have the option to select free items based on the questions answered, but also purchase additional measures at a regular or reduced price, to further enhance the efficiency of their home.

Engagement and consultation with stakeholders including the IESO (formerly the OPA), customers, trade allies and associations, and government organizations have occurred frequently and on an ongoing basis as part of engagement, promotion and delivery of CDM programs. CNPI continues to be involved with a number of provincial LDC's to identify and pursue opportunities for collaboration on design and implementation of programs that satisfy regional needs and requirements. CNPI will continue to participate in engagement and consultation as it is a key component for market research, program design and development, and implementation of individual and regional CDM programs.

ii. Public Policy Responsiveness Performance Category - Connection of Renewable Energy Generation

As outlined in Section 5.4.3 of the DSP, CNPI faces significant transmission system constraints related to the connection of Renewable Energy Generation ("REG") in its Niagara service territory. In its Eastern Ontario Power ("EOP") service territory, connection of REG projects could be complicated by the embedded nature of the CNPI distribution system, however CNPI has not received any applications from a DG proponent served by its EOP operating region to connect a DG larger than 500kW.

Based on historical demand, CNPI does not intend to make any pre-emptive REG investments in its system to allow for additional large (i.e. greater than 10kW) DG projects unless and until one or more DG applications are received that would require such an expansion. CNPI had no plans to make any REG investments in the period from 2016 to 2021.

In 2014, CNPI connected twenty-three (23) new micro-embedded generation facilities (microFIT projects of less than 10 kW). All but one facility were connected within the prescribed time frame of five business days. Only one facility was connected on the sixth day. The minimum acceptable performance level for this measure is 90% of the time. CNPI works closely with its customers and their contractors to make the connection process as streamlined and transparent as possible.

IV. RRFE Performance Outcome - Financial Performance

CNPI has historically maintained financial ratios in line with Board expectations and industry norms. More detailed information is provided in the Financial Ratios section of 2014 Scorecard MD&A, at Exhibit 1, Tab 10, Schedule 1, Appendix A. CNPI expects that its financial viability will be maintained as a result of the current Application, and that the plans presented are sustainable in the long term. No significant variations in financial ratios are expected within the 5-year period following this Application.

Appendix A
Business Plan

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CANADIAN
NIAGARA POWER INC.

2016-2020 Five-Year Business Plan
Presented to the Board of Directors
of Canadian Niagara Power Inc.
at the Meeting of November 30, 2015

~ CONFIDENTIAL ~

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APPENDICES

1.0 EXECUTIVE SUMMARY

The primary focus of the Business Plan centers on Management achieving continued improvement in overall operational efficiencies, making prudent rate base investments and driving regulatory performance to enhance earnings while pursuing further expansion of its core regulated T&D businesses in Niagara and Gananoque. The document reflects a planning horizon from 2016 to 2020, and includes a comprehensive set of financial forecasts in support of the initiatives for that period.

Management has identified the following seven areas, which represent the most important strategic issues facing the Company over the next five years:

- Economic Outlook & Energy Policy
- Regulatory
- Operational Performance
- Safety, Health & Environmental
- Human Resources
- Information Technology
- Financial Performance

The Five-Year Business Plan, which follows, outlines specific objectives and targets in support of CNPI's overall corporate vision of being recognized throughout Ontario as a well-respected, well-managed, and profitable growth vehicle for its parent Company, FortisOntario Inc.

CNPI is an Ontario based regulated electric utility holding company. CNPI has investments in the following areas:

- **DISTRIBUTION (REGULATED)** – Distribution systems in the Niagara region at Fort Erie and Port Colborne and Gananoque. CNPI serves approximately 28,800 customers through 1,011 km of distribution lines.

- **TRANSMISSION (REGULATED)** – 33 km of lines in the Niagara area, including an interconnection with New York at Fort Erie.

2.0 CORPORATE PROFILE

2.1 VISION AND CORE VALUES

CORPORATE VISION

CNPI will be recognized throughout Ontario as a respected, well managed, and profitable growth company for its parent company, FortisOntario, through its sustained commitment to core business growth and increased returns from existing operations. CNPI will strive to deliver results that continue to enhance shareholder value while maintaining an unwavering commitment to its Core Values.

OBJECTIVES

The Corporation will continue to focus on these primary objectives:

i) Earnings: Generate annual net earnings from its distribution and transmission business sufficient to achieve a return on equity commensurate with well-run Canadian utilities.

ii) Operational Performance: Ensuring the safe and effective management of its core utility business functions and the achievement of its key performance benchmarks.

CORE VALUES

CNPI's Core Values define what the Company is and how it operates. They reflect the beliefs, philosophy, and commitment of the Company's employees and shareholders. A demonstrated commitment to these values is a prerequisite for individual employee success. Management will treat Respect for People as a condition of employment.

Management employees are expected to demonstrate a commitment to the Company's Core Values. All employees will be held accountable for behaving in a manner consistent with these Core Values.

THE CORE VALUES OF CANADIAN NIAGARA POWER INC.

RESPECT FOR PEOPLE: Treat others, as you would have others treat you. Honesty, integrity and ethics are never compromised.

SAFETY AND THE ENVIRONMENT: Demonstrate a personal, unrelenting commitment to safety and environmental excellence. Protect yourself, your fellow employees, the public and our environment.

FINANCIAL SUCCESS: Produce solid earnings, with dividends that meet the expectations of shareholders. Grow shareholder value through prudent equity investments and business partnerships. Ensure that debt obligations are always met in a timely manner and to the satisfaction of our creditors.

CUSTOMER SERVICE: Everyone has customers. Determine your customers' needs by listening. When you can meet these needs, do so. When you cannot, tell them that you cannot, or tell them who can. When in doubt about how to treat a customer, do what you believe is right. When serving customers, be pleasant, courteous and accurate; smile, act professionally and enjoy yourself. Attitudes are contagious.

PRODUCTIVITY: Effective teamwork combined with employee innovation produces productivity gains. Employees are encouraged to pursue opportunities to implement new ideas and methods that enhance overall individual and team performance. Remember…if you have a better way to do something – just do it.

COMMUNITY INVOLVEMENT: Each of us has an obligation to support the communities that support us. This means time as much as money. Success is measured by the reaction of community leaders and the opinions expressed by community residents.

3.0 ECONOMIC OUTLOOK & ENERGY POLICY

3.1 ECONOMIC OUTLOOK

The combination of the collapse in oil prices and the tumbling Canadian dollar are supporting modest growth of Ontario's economy. Real GDP is expected to expand to 2.0 per cent in 2015, and 2.3 percent in 2016. Over the long-term, i.e., 2015 to 2035, Ontario's real annual GDP is expected to grow at 2.1 per cent compared to 2.4 per cent for the past 20 years. The Province's deficit for 2015 is estimated at $10.9 billion; $1.6 billion less than projected one year ago, with the continued goal of a balanced budget by 2018.[1]

Ontario's key economic indicators for 2014-2016 are as follows:

	2014	2015F	2016F
REAL GDP (%Δ)	2.3	2.03	2.3
CPI (%Δ)	2.3	1.3	2.3
UNEMPLOYMENT	7.3	6.8	6.8
HOUSING STARTS (000S)	59	64	64

Over the next 18 months, the IESO estimates that approximately 2,200 megawatts of new generation will come online, including 1,500 MW of wind, 10 MW of hydroelectric, 300 MW of gas, 380 MW of solar and 40 MW of biofuels. During normal weather conditions, reserve requirements are expected to be met for the summer of 2015. For the first time in 10 years, Ontario was winter peaking in 2014, but is expected to return to summer peaking in 2015, with more typical weather patterns. A combination of embedded solar and wind generation, conservation, time-of-use rates, and the Industrial Conservation Initiative (i.e., eligible customers are charged the global adjustment based on their percentage contribution to the top five peak demand hours each year) will result in a decline in peak demand and relatively flat energy demand over the forecast period.[2]

[1] Conference Board of Canada: Provincial Long-term Economic Forecast 2015 Edition; Provincial Outlook Executive Summary – Spring 2015; and Provincial Outlook Full Report Summer 2015.

[2] IESO – 18 Month Outlook March and June 2015

In May 2015, the IESO signed a 500 MW seasonal capacity sharing agreement with Hydro Québec. The agreement takes advantage of the Province's complimentary seasonal peaks. The capacity will be shared "like-for-like" with no monetary exchange, allowing Quebec to import up to 500 MW during the winter months and Ontario to import up to 500 MW during the summer months. Ontario will continue to have a surplus baseload generation with the amount increasing with the addition of new renewable generation and the decline in grid demand.

The distribution service territory of Canadian Niagara Power Inc. ("CNPI") (Fort Erie, Port Colborne, Gananoque) is expected to experience continued flat energy sales relating to the weaker economic conditions and overall conservation and demand management initiatives. Over the medium term, CNPI has growth potential including the Canadian Motor Speedway and associated infrastructure (e.g., new hotel and commercial development), housing developments especially in Ridgeway area, and expanding the Niagara Parks Marina in the Niagara River.

3.2 PROVINCIAL ENERGY POLICY

The Province has announced changes to the electricity system in response to the work recently completed by the Premier's Advisory Council on Government Assets. Firstly, they will be broadening (up to 60%) the private sector ownership of Hydro One Networks by taking it public through an Initial Public Offering ("IPO") with the intent to unlock billions in value for investment in major infrastructure projects, such as roads, highways, bridges and transit. Secondly, they announced a deal to proceed with the sale of Hydro One Brampton to or with Enersource Corporation, PowerStream Holdings Inc. and Horizon Holdings Inc., intended to catalyze consolidation in the Greater Toronto Area ("GTA") and to strengthen competition in the distribution sector by increasing the number of Local Distribution Companies ("LDCs") with the capacity to drive further consolidation. Thirdly, their plans to reduce the tax burden on LDC's involved in sales or mergers of municipally-owned LDCs, which is addressed in more detail in the Distribution Growth section of this report.

The Province has also signaled their continued support for renewable energy and conservation measures with their plans to offer more Fit and microFit renewable energy contracts and an additional $1.4 billion in new funding over the next five years for local LDC delivered conservation and demand management ("CDM") initiatives in support of targeted load reductions. The Liberal's green energy policies, and the cost associated with replacing the coal fired generation, have created growing concerns that Ontarians are being disadvantaged due to the subsidies needed to support renewables. Various consumer groups and the opposition have raised concerns that Ontario consumers now pay the highest delivered electricity rates in North America, which is placing the Province in a non-competitive position compared to neighbouring jurisdictions. Over the next five years, typical industrial electricity bills are expected to rise 33 per cent in nominal terms. The price increases will be more rapid for residential users: a 42.4 per cent increase over 2015-2018.

On June 2, 2015, the Ministry of Energy tabled new legislation to amend the Ontario Energy Board Act ("OEB Act"), entitled "Strengthening Consumer Protection and Electricity System Oversight Act". Some of the main legislative amendments proposed including measures to enhance consumer protection, provide further opportunities for consumer advocacy, clarifying the role of LDCs and their affiliates, extending the Ontario Energy Board's ("OEB") emergency powers to transmission, enhancing the oversight of utility transactions and the ability for government to prioritize critical transmission infrastructure.

Management's initial review of this proposed legislation has highlighted specific areas that could have a direct effect on future business activities of CNPI.

<u>Enhanced Consumer Protection</u>

The proposed legislation would allow the OEB to establish measures to enhance the extent of the current representation of the interests of consumer groups in OEB proceedings. While providing additional opportunities for consumer representation is on the surface a positive process, this could lead to more time consuming and costly proceedings before the OEB absent any tangible value to either consumers or regulated utilities engaged in the process.

<u>Creation of Transmission Infrastructure</u>

Presently, the Ministry of Energy has the ability to issue directives regarding transmission connections for renewable energy generation. In the case of new transmission systems, the

OEB has historically required a formal needs assessment through the use of a Section 92 ("Leave to Construct") application. Under the proposed new legislation, the Cabinet would be allowed to determine key transmission infrastructure deemed to be essential for the public good and as a result, designated licensees would not be required to go through a "needs" test by the OEB. This type of "fast tracking" of key transmission projects could pave the way for new development to move forward in a more expeditious and cost effective manner. FortisOntario is currently assessing the potential of utilizing this approach on the transmission project under development to Pickle Lake and the remote northern First Nation communities.

4.0 REGULATORY

4.1 REGULATORY FRAMEWORK

The OEB's regulatory framework, provides for three rate-setting methods for distributors including 4th Generation Incentive ("4th Generation IR"): suitable for most distributors including CNPI; Custom Incentive: designed for those distributors with large or highly variable capital requirements, and an Annual Incentive Rate-setting Index: applicable for distributors with limited incremental capital requirements.

The framework also allows for Z-factors, an incremental capital module ("ICM"), and off-ramps. Z-factors are for material costs with causation due to unforeseen circumstances that are clearly outside of Management's control. ICMs are intended to address the treatment of capital investment needs that arise during non-rebasing years, which are incremental and above the OEB's materiality threshold (i.e., based on capex over depreciation). Off ramps allow for an LDC to terminate or modify its existing rate-setting methodology before the end of a normal rate period due to excessive over or under earnings with a return on equity dead band of ±300 basis points.

4.2 4TH GENERATION IR

Distribution rates under the 4th Generation IR are based on a forward test year cost of service application and subsequently indexed by the 4th generation price cap adjustment formula. The annual adjustment formula will be based on inflation less an X-factor whereby the X-factor is the sum of a productivity factor and stretch factor. For the 2016rate setting year, the inflation factor is 2.1%. Based on the total cost benchmarking model, the Board determined that the appropriate value for the productivity factor is zero percent.

The X-factor is the stretch factor, which is designed to ensure the customer shares in anticipated incremental efficiency gains or alternatively called the “consumer dividend.” Distributors will be allocated in one of six cohorts. The stretch factor assignments are based on the results of a statistical cost benchmarking study designed to make inferences on individual distributors’ cost efficiency. An econometric model is used to predict the level of cost associated with each distributor’s operating conditions. Distributors that had actual cost that was lower than that predicted by the model were assigned lower stretch factors than those that did not.

The ranges for each cohort are as follows:

Cohort I (0.00%): Cost < 25% of Predicted
Cohort II (0.15%): Cost Between -10% and -25% of Predicted
Cohort III (0.30%): Cost Between +10% and -10% Predicted
Cohort IV (0.45%): Cost Between +10% and +25% Predicted
Cohort V (0.60%): Cost > 25% of Predicted

For the 2016 rate year, CNPI is in cohort IV with a stretch factor of 0.45%; the 2016 net price cap adjustments for CNPI is 1.65% (2.1%-0%-0.45%).

For the 2016 rate year, both CNPI will apply for electricity distribution rates effective January 1, 2016, using the 4th Generation IR. The stretch factor assignments and inflation factors for the 2016 rate year are not yet published. Historically, CNPI has been assigned to cohort IV and API has been assigned to cohort V.

The OEB’s cohort assignments are challenging by the fact that FortisOntario makes ongoing and appropriate levels of investment in its distribution plant and operates as a “full service utility” (i.e., owns and operates its own distribution substations) relative to other LDCs in Ontario. This difference in investment levels and operating philosophy impacts comparisons to other utilities and underscores the importance of the Company's continuing efforts to enhance operating efficiencies.

2016 will be the final year for incentive rate-setting for CNPI prior to rebasing in 2017. In addition, in 2016, CNPI will have completed rate harmonization in its three service territories.

4.3 SCORECARD

The OEB has developed a Scorecard with standards and measures that will link directly to the new performance outcomes including: customer focus, operational focus, public policy responsiveness, and financial performance. Using a Scorecard approach, distributors will be required to report annually on their key performance outcomes. The OEB is committed to ensuring that there is continuous improvement in the sector. The Scorecard will be used as a tool by the OEB for public reporting of the comparative performance of an LDC in a transparent manner. The Scorecard includes five years of data with trending signs. The distributor can submit a management discussion and analysis attachment to provide the reader with explanations of the outcomes.

The Scorecard will be used as a tool by the OEB for public reporting of the comparative performance of an LDC in a transparent manner. The 2014 Scorecard is posted on both the OEB's and Company's websites, and a copy is included in Appendix "D".

4.4 DISTRIBUTION RATES

REVENUE DECOUPLING

Under revenue decoupling, the OEB is pursuing a rate design methodology that will allow charges related to the distribution of electricity to be collected through a fixed monthly charge. Under existing rate design methodologies, distributors collect distribution charges through a combination of a fixed monthly charge and a variable charge. Under the new OEB policy, electricity distributors will structure residential rates so that all the costs for distribution service are collected through a fixed monthly charge. This change will take effect with the 2016 electricity distribution rates and will be phased in over a five year period provided that the annual increment in the fixed charge is not more than $4 and the total bill impact for a select low volume customer is not more than 10%. Otherwise, a rate mitigation proposal will be required from the distributor. FortisOntario has been represented on the OEB Working Group advising in this initiative.

CNPI will begin decoupling electricity distribution rates for residential customers with its 2016 incentive rate-setting application. CNPI anticipates that it will be able to fully implement decoupling in the timeframe proposed by the OEB. Management's initial assessment of this new rate design methodology is primarily favourable since it appears to insulate the Company's net margins from variations in sales, weather, energy efficiencies and conservation initiatives.

The OEB has begun a second rate decoupling initiative, which will address electricity distribution rates for commercial and industrial customers.

CNPI DISTRIBUTION RATES

CNPI's electricity distribution rates were rebased in 2013, with the OEB approving a revenue requirement of $19.0 million, a rate base of $73.5 million, a deemed 60/40 capital structure, and an 8.93% allowed return on equity. These rebased rates became effective January 1, 2013.

In August, 2015, CNPI will file an application with the OEB seeking approval to change distribution rates effective January 1, 2016, based on the 4th Generation Incentive Regulation Mechanism. This application introduces the decoupling of electricity distribution rates for the Residential customer class; complete decoupling is expected to take four consecutive years to fully implement.

CNPI is scheduled to rebase its electricity distribution rates in 2017. CNPI anticipates that its cost of service application will be filed with the OEB in April 2016.

SECTOR CONSOLIDATION

On March 26, 2015, the OEB released a report setting out policies relating to rate-making associated with electricity distribution consolidation. The policy changes are intended to encourage efficient and beneficial consolidation transactions within the electricity distribution sector. Consolidating entities can choose to defer rebasing for up to 10 years compared to five years under the current policy. An earnings sharing mechanism is required with earnings greater than 300 basis points above the allowed ROE being shared 50:50 with consumers.

REGULATORY CALENDAR

The following is a listing of current and prospective appearances before the OEB by CNPI:

- CNPI Distribution to file a 2016 4th Generation IR application in August 2015
- CNPI Distribution to file a 2017 Cost of Service application in April 2016

4.5 CONSERVATION AND DEMAND MANAGEMENT ("CDM")

Under the Ontario government's new conservation framework, which commenced on January 1, 2015, LDCs were mandated to submit a six-year CDM plan to the IESO by May 1, 2015. API and CNPI submitted a joint six-year CDM plan on April 27, 2015, which allows both companies to move their target and budget allocations between the API and CNPI service territories. API has been assigned a target of 7.51 GWh and CNPI has been assigned 28.48 GWh for the new six-year conservation framework. API and CNPI have been allocated a combined budget for the joint plan totaling $9.5 million. The final plan submitted as of June 25, 2015, requested a budget of $9.8 million and API and CNPI are awaiting final approval.

4.6 TRANSMISSION REVENUE REQUIREMENT

CNPI transmission rates are the Uniform Transmission Rates ("UTR") set annually, effective January 1. The UTRs are based on the pooled revenue requirements of the transmitters in the pool; each transmitter receives a portion of the pool funds collected by the IESO based on its proportion of the overall revenue requirement.

On November 17, 2014, CNPI transmission filed a two year revenue requirement application seeking approval for the $6.9 million rebuild of the International Power Line ("IPL"), the $3.2 million recovery of the expansion to Station 18, and the recovery of $1.2 million of Project Fortran costs. On May 14, 2015, the Board approved both the IPL and Station 18 projects but denied recovery of Project Fortran costs, which were subsequently written off by CNPI.

The approved revenue requirement for 2015 and 2016 was $4.2 million and $4.6 million, respectively. The approved rate base for 2015 was $20.8 million and 24.2 million, with a deemed 60/40 capital structure and a 9.30% allowed return on equity.

As part of the Board Decision, the Board stated its interest in conducting a consultation process to apply its Renewed Regulatory Framework to the Transmission Filing requirements. The OEB encouraged CNPI to participate in the process. The discussions began in late May and CNPI is a participant in these consultations moving forward.

5.0 OPERATIONAL PERFORMANCE

5.1 DISTRIBUTION SYSTEM PLAN ("DSP")

The OEB requires all LDCs to file a detailed DSP as a mandatory component of their evidence when filing cost of service rate applications. The contents and the format of a DSP are outlined in the Board's "Consolidated Distribution System Plan Filing Requirements". CNPI is currently developing a DSP for its 2017 rate application. As part of the DSP, the Distribution Asset Management Plans ("DAMP") are also being developed and updated. Under the OEB's requirements, capital projects will be approved according to the DSP.

5.2 SYSTEM INSPECTION AND MAINTENANCE

System inspection and maintenance programs are an important part of the DAMP. Various system inspection and maintenance programs are implemented at FortisOntario for major substation and line equipment. These programs were developed based on OEB Distribution System Code ("DSC") requirements, manufacturers' specifications, and good utility practice. The historical inspection records are analyzed and results are used to develop maintenance programs and capital projects.

5.3 TRANSMISSION & DISTRIBUTION ("T&D") CAPITAL INVESTMENTS

Over the period of this Business Plan, CNPI will invest over $50.8 million in the transmission and distribution systems. Highlights of these investments include rebuilding or replacing electrical substations, 4.8 kV to 8.3 kV voltage conversion in downtown Fort Erie, and keeping the current pace of distribution rebuilds to ensure the appropriate level of distribution line replacement continues over the planning period. The capital projects will be developed according to the DSP required by the OEB.

The major categories of investment in transmission and distribution for the 2016-2020 period are highlighted as follows:

TRANSMISSION

- Relocating a section of the 115 kV line crossing QEW Highway in Fort Erie to accommodate the road expansion (2016 investment of $400 thousand).
- 115 kV transmission line upgrade (2017 investment of $500 thousand).

SUBSTATIONS

The substation capital budget for each system consists of major substation expansion or addition and regular equipment upgrades. The following highlights the major capital spending during the next five years:

- Retirement of the existing 34.5 kV/4.8 kV Station 15 and construction of the new 34.5 kV/8.3 kV Gilmore Distribution Station (2016 investment of $2 million).
- Replacement of Jefferson Substation in Port Colborne (2018 investment of $1.3 million).
- Replacement of the 1956 44 kV/26.4 kV power transformer at EOP main substation (2017 investment of $800 thousand).

DISTRIBUTION

According to OEB's DSP requirements, distribution system assets related capital investments are justified under the following four categories:

- System Access: investments to connect customers.
- System Renew: investments to replace end-of-life assets.
- System Services: investments to improve system functionality and reliability.
- General Plant: investment to improve efficiency and productivity.

The following provides a summary of major capital projects during the next 5 years:

- Line replacement and Customer Extension (Average annual investment of $3.4 million).
- Delta to Wye Conversion in Ridgeway, Fort Erie (Average annual investment of $756 thousand).
- Delta to Wye Conversion in downtown Fort Erie (Average annual investment of $750 thousand).
- EOP North Line rebuild (Average annual investment of $250 thousand)
- Distribution Transformers (Average annual investment of $430 thousand).
- Distribution System Automation (Average annual investment of $263 thousand).

Over the next five years, CNPI will invest $419 thousand annually on transportation equipment.

5.4 OPERATIONAL EFFICIENCIES

To improve operational efficiencies, management is focusing on technology deployment and improving system automation. After implementing Geographic Information System (“GIS”) and Outage Management System (“OMS”) at FortisOntario, distribution asset databases, field engineering tools, and mobile computing applications will be developed over the next five years.

The distribution asset databases include construction, inspection and maintenance records, and detailed technical attributes for all major distribution equipment in the system and in inventory. The field engineering tools provide technicians and field workers with all system technical information and design capacity. These tools will reduce the number of field visits for project development. Mobile computing applications include up-to-date system maps, electronic forms for equipment inspection and maintenance records, and better tools to document standards, procedures, and other information. System outage maps will also be developed and these maps will provide real-time power outage information to improve customer communication.

CNPI continues to improve system automation through substation breaker upgrades, relay replacement, installation SCADA controlled reclosers and switches, SCADA upgrades, and communication upgrades. The objectives of system automation are to reduce the areas impacted by power outages through more accurately identifying power outages and reducing restoration time.

5.5 SYSTEM RELIABILITY

As one of the key indicators monitored by the OEB, CNPI continues to focus on system reliability. O&M programs such as equipment inspection and maintenance will effectively prevent power outages and provide valuable information for developing capital projects. Capital projects such as replacement of end-of-life assets, installation of redundant capacity, and upgrading of protection and control systems will effectively reduce outage frequency, areas impacted by outages, and outage restoration time.

5.6 CUSTOMER SERVICE

CUSTOMER SERVICE ANALYSIS

The introduction of Smart Meters and Time-of-Use ("TOU") rates provided an opportunity to centralize key processes including the billing function. The closing of the Port Colborne office prompted a departmental reorganization whereby all TOU billing is now completed in Niagara.

Technological automation continues to increase. Mass processing is scheduled in the evenings and manual intervention will be eliminated for many customer service functions. After hour collection calls are now performed through an auto dialer service, reducing the required manpower time to complete collection calls. Such analysis will continue in 2015, and the focus will remain on core skills and reducing non-value added tasks within the department.

COLLECTIONS

Credit and collection activities have increased at CNPI. The weakened economy and rising power cost coupled with restrictions imposed by Distribution System Code regulations have resulted in increased challenges in receivables for management.

A thorough review of the current credit and collection process is underway and will continue in 2015. Specifically, the responsiveness of customers to all dunning activities is being measured to gauge what is working most effectively to reduce the average days of receivables. The review will look at developing best practices for all dunning processes, which will be consistent at CNPI. A renewed training rollout for customer service representatives will also be initiated to ensure consistency.

A request for proposal for a first and second level collection agency was completed in 2014, to assist in collecting older bad debts. An analysis of the first year of utilizing both a first and second collection agency and the effect on receivables will be performed in 2015.

CUSTOMER ENGAGEMENT

The customer experience has been further enhanced with the introduction of Electronic Billing ("E-billing") along with MyHydroEye, a third party software that allows customers to view their TOU consumption in greater detail. Ongoing customer awareness will be generated through advertising campaigns and enrolment contests throughout the year. A successful campaign in 2014, resulted in the uptake for E-billing to grow from 5 per cent to 13 per cent. A similar enrolment contest for 2015 including MyHydroEye, pre-authorized payment and social media was successfully completed.

CNPI is using social media (Twitter and Facebook). While social media is currently used to disseminate Company related information to customers, the strategy includes integrating OMS technology to provide timely information to customers during power outages. Customer service representatives will be able to access real time information during power outages, which will assist in providing better information to customers. Operations will be able to identify the source due to the integration of SAP, Smart Meter technology and GIS within the OMS.

To date, customer feedback has focused primarily on the residential customers. Annual surveys are performed to assess overall satisfaction levels in the residential customer segment only. Avenues on how to best engage and interact with non-residential customers will become a priority for the department. The Company will undertake a review of the survey structure and service provider to ensure the results are gathered consistently with other LDCs in the Province.

6.0 HEALTH, SAFETY & ENVIRONMENTAL ("HSE")

6.1 MANAGEMENT SYSTEMS

CNPI's integrated health, safety and environmental management system ("HSEMS") remains consistent with OHSAS 18001 and ISO 14001.

A number of ongoing and future initiatives support the HSEMS framework that is built upon continual improvement. The following are CNPI's current year and 2016 objectives and targets, which are being supported through management programs:

DISTRIBUTION SYSTEM ARC FLASH ASSESSMENT PROGRAM

CNPI is in the process of completing the arc flash program for all of its distribution systems and implementing recommendations. CNPI is currently utilizing the new GIS system to calculate the arc flash rating of its distribution operation system. These arc flash ratings will be assessed and provide a detailed description of any risks associated and controls required with respect to arc flash beyond the boundaries of substations.

OPERATIONS ERGONOMICS PROGRAM

CNPI conducted a skilled trade ergonomic assessment at all worksites and is currently implementing recommendations. This assessment provided CNPI with a detailed description of any risks associated with skeletal muscular disorders and controls required to lower the risk of injuries of the operations employees with respect to working at heights and postures, working in hot and cold environments, tool selection, and general manual material handling.

APPRENTICESHIP AND TRADES MAINTENANCE PROGRAM

An apprenticeship and trades specific competency training program has been developed and will be implemented across the Company. The program is designed to provide training and validate the competency of skilled trade apprentices employed by the Company as an additional level of oversight and training to existing external schools and programs. The level of training and competency will be monitored throughout defined checkpoints during and upon completion of the apprenticeship.

DRIVE SAFE PROGRAM

The drive safe program encompasses key focus areas to improve CNPI's current driver awareness program. The program will increase employee awareness regarding vehicle and driving risks and controls associated with vehicle accident prevention. The program will teach employees that drive to think before they act and will provide experienced-based driver training that creates safer drivers by focusing on improving decision making and on such areas as circle checks and distracted driving awareness.

PUBLIC SAFETY AWARENESS – THIRD PARTY PROXIMITY PROGRAM

An increased amount of arboricultural work (tree trimming and tree removals) is occurring as a result of the emerald ash borer and other tree diseases. CNPI has seen an increased number of third party incidents associated with tree work in the proximity of our electrical equipment. This Public Safety Awareness program is focusing on reviewing our third party working in proximity procedure, updating any requirements associated with the Electrical Utility Safety Rules, utility arborist trade and third party work in proximity.

HABITAT STEWARDSHIP PROGRAM

CNPI has gathered information on significant natural areas ("SNA") (cultural/social/ecological/geological) associated with its activities, products and services. CNPI will develop habitat stewardship best practices and procedures to describe the required operational legislation and procedures to minimize threats to SNA by focusing on those activities, products and services, which create potential impact, and identify appropriate controls and work methods to mitigate, protect and enhance the ecosystem and communities affected by our activities. A key objective for 2015 is the mapping of SNA and ongoing management of this data in the GIS.

7.0 HUMAN RESOURCES ("HR")

7.1 LEADERSHIP DEVELOPMENT

The Company has 77 full-time equivalents ("FTEs") working throughout its service territories. It is projected that by the end of 2018, 32.5 per cent of employees will be reaching the age of 55. In response to this demographic, the Company remains committed to retaining and attracting skilled employees to meet ongoing business requirements. CNPI has initiated a practice of hiring co-op students or apprentices in technical areas to facilitate training and skills assessment in preparation for anticipated future vacancies due to retirement. This will also provide an opportunity to "retool" the business as required so that skill sets meet future business needs.

As part of CNPI's overall HR strategy, a mentoring program was fully implemented in 2014. The first round of mentees will run through 2015 and assessment of the program will be conducted to measure its effectiveness and modify as required.

The 360 benchmarks program, which has been in place since 2003, will continue to be utilized for supervisors and managers. Each year managers and/or supervisors are identified to participate in the program. Together the two programs will support the goal of ensuring the organization has the right people in the critical roles to meet the Company's strategic objectives.

7.2 SUCCESSION PLANNING

The Company has a succession plan in place for its Vice Presidents, Managers and key Supervisors. As part of the ongoing planning process, the Company enhanced this plan with more detailed supporting work history and biographic information for candidates and identification of gaps where there are no in-house candidates available to be groomed for succession opportunities.

7.3 LABOUR RELATIONS

Approximately 52 per cent of the CNPI's workforce is unionized. The Company's two collective agreements with the IBEW union expire in 2016. The Company and its unions continue to work together to maintain harmonious labour relations. The Company will continue to identify strategies for the upcoming bargaining sessions with an emphasis on improving overall efficiencies where possible, and labour agreements which are in line with the current economic climate. Research to identify trends in the areas of health care, pension and wage settlements across the Province is being conducted to provide the information necessary to align bargaining expectations.

The Human Resources team remains focused on the benefit administration process, streamlining where possible across CNPI and will continue to do so in 2016. An analysis of health plans will be undertaken to ensure that CNPI health and medical plans are structured to effectively manage anticipated costs increases due to industry trends.

7.4 EMPLOYEE COMMUNICATION

Human Resources continues to focus on improved employee communications to foster consistent messaging across all locations. A communications framework was rolled out to the Company's managers to set out these standards.

A 2015 initiative includes the implementation of digital billboards to provide timely information to all employees. Human Resources in conjunction with the Information Technology department will research and implement a digital bulletin board pilot in 2015 or early 2016. A cross-functional team will assist with content management so that all departments and locations can participate.

8.0 INFORMATION TECHNOLOGY

The following project list provides a summary of significant information technology initiatives intended to meet regulatory requirements, improve customer service and/or operational efficiency.

MAJOR IT PROJECTS

- **SAP HARDWARE LANDSCAPE REPLACEMENT (2016):** As part of the ongoing hardware lifecycle management, host servers responsible for managing the virtualized environment for development, quality assurance and production hardware will be at end of life (fifth year) and will require replacement. Additionally, the storage system housing SAP related data will be replaced.

ESTIMATED COST	SCHEDULE	BUSINESS/REGULATORY DRIVER
$350,000	March 2016 – May 2016	Business requirement to replace critical hardware at end of life.

- **CORPORATE INTRANET UPDATE (2016):** As a followup to the technical upgrade of the corporate intranet application (Microsoft SharePoint), this product provides an opportunity to take advantage of new functionality. Content management, collaboration and a variety of functions designed to improve business processes related to Company communication.

ESTIMATED COST	SCHEDULE	BUSINESS/REGULATORY DRIVER
$50,000	Feb. 2016 – July 2016	Business requirement to improve document management and communication related processes.

- **SAP INTEGRATION WITH GIS/OMS (2016):** An integration of Geographic Information System/Outage Management System ("GIS/OMS") with SAP, including Advanced Metering Infrastructure ("AMI") information as well as automations to distribution equipment.

ESTIMATED COST	SCHEDULE	BUSINESS/REGULATORY DRIVER
$50,000	Mar. 2016 – Sept. 2016	Business requirement to further align SAP with operational technology.

- **SAP FUNCTIONAL AREA IMPROVEMENTS (2016):** As part of the ongoing evolution of SAP, capital improvements to the ERP supports business initiatives specific to various functional areas. Enhancements and automations in the areas of billing and collections, financial reporting and metering further support the ongoing use of a centralized system of records.

ESTIMATED COST	SCHEDULE	BUSINESS/REGULATORY DRIVER
$300,000	Mar. 2016 – Dec. 2016	Business requirement to align SAP with operational technology.

- **FORT ERIE – FILE/MESSAGING STORAGE REPLACEMENT (2017):** As part of the ongoing hardware lifecycle management, the File/Messaging hardware will be at end of life (fifth year) and will require replacement including replacement of host servers responsible for managing the virtualized environment for the file and messaging (email) servers. Additionally, the storage system that houses respective data for the aforementioned servers will be replaced.

ESTIMATED COST	SCHEDULE	BUSINESS/REGULATORY DRIVER
$350,000	Mar. 2017 – Aug. 2017	Business requirement to replace critical hardware at end of life.

- **CORPORATE FIREWALLS (2019):** As part of the ongoing hardware lifecycle management, the firewall hardware will be at end of life (fifth year) and will require replacement. These appliance based systems are responsible for managing enforcement points within the organization and provide intrusion detection/prevention technology as part of the ongoing improvement to mitigating external threats.

ESTIMATED COST	SCHEDULE	BUSINESS/REGULATORY DRIVER
$150,000	Feb. 2019 – April 2019	Business requirement to replace critical hardware at end of life.

- **INTERACTIVE VOICE RECOGNITION ("IVR") (2019):** This application provides customers with an ability to retrieve billing and related information automatically through a "self-help" technology. In the event of a storm, there is considerable benefit by providing outage and related restoration information during high call volume periods.

ESTIMATED COST	SCHEDULE	BUSINESS/REGULATORY DRIVER
$100,000	May 2019 – Nov. 2019	Business driver to improve customer call-in experience and outage information.

- **CORPORATE COMMUNICATION SWITCHES (2020):** Replacement of corporate communication switches which are at end of life (fifth year).

FINAL COST	SCHEDULE	BUSINESS/REGULATORY DRIVER
$80,000	April 2018 – Oct. 2018	Business requirement to replace critical hardware at end of life.

IT RISK MANAGEMENT

Assessment of information technology risk is currently measured through internal disaster recovery simulations and vulnerability assessment of firewalls by external parties. Given the rapid evolution of cyber-attacks globally, CNPI is planning to expand its review of technology risks with a focus on cyber security in consultation with FortisOntario. Three critical characteristics of information that are at risk from cyber-attacks are confidentiality, integrity and availability. Known areas of liability relate to privacy breaches due to the release of confidential customer information, as well as financial and operational risk associated with critical infrastructure disruption. In this regard, the Company is proposing an assessment exercise over the forecast period to identify the most sensitive “at risk” information, and to develop a plan to prioritize and protect such information.

9.0 CORPORATE TARGETS

CNPI will use the following key corporate targets to measure performance against plan. This subjective approach promotes accountability while ensuring focus on key success factors and identifying areas where improvement is required.

CORPORATE TARGETS							
	2014 ACTUAL	2015 FORECAST	2016 TARGET	2017 TARGET	2018 TARGET	2019 TARGET	2020 TARGET
FINANCIAL							
NET EARNINGS ($' MILLIONS)	4.7	2.5	3.3	5.0	5.3	5.1	5.4
OPERATING EXPENSE ($' MILLIONS)	11.0	11.7	12.0	12.1	12.3	12.5	12.7
GROSS CAPITAL EXPENDITURES ($' MILLIONS)	11.1	15.7	11.1	9.7	10.6	9.8	9.6
SAFETY							
HIGH RISK LOST TIME INJURY	0	0	0	0	0	0	0
PLANNED WORK OBSERVATIONS & WORKPLACE INSPECTIONS (% OF PLAN)	110%	100%	100%	100%	100%	100%	100%
RELIABILITY							
AVERAGE HOURS OF SERVICE INTERRUPTION PER CUSTOMER (SAIDI)	1.95	2.22	2.4	2.4	2.4	2.4	2.4
AVERAGE INCIDENT PER CUSTOMER (SAIFI)	2.07	2.32	2.8	2.8	2.8	2.8	2.8
CUSTOMER SERVICE							
CUSTOMER SATISFACTION RATING (%) (2)	80	81	81	82	83	83	83
ACCOUNTS RECEIVABLE OVER 30 DAYS (%)	13.5	15	15	15	15	15	15
SERVICE LEVEL (% CALLS WITHIN 30 SEC.)	78	80	80	81	82	83	83
HUMAN RESOURCES							
ABSENTEEISM (DAYS/EMPLOYEE)	2.8	3	3	3	3	3	3
FTE (YEAR-END)	87	87	87	86	86	86	86

(1) ROE adjusted for goodwill impact.

(2) Rating negatively impacted by provincial energy policy, including cost of power increases. 2015 and 2016 are adjusted to be the same as 2014 due to expected rate increases in 2016 due to the removal of the OCEB credit and the rate rider to fund the OESP program both effective January, 2016.

10.0 FINANCIAL PERFORMANCE

10.1 CONSOLIDATED FINANCIAL FORECAST

	2014 ACTUAL	2015 FORECAST	2016 PLAN	2017 FORECAST	2018 FORECAST	2019 FORECAST	2020 FORECAST
Sales (GWh)	511	488	481	486	491	496	501
Revenue net of energy purchases	23,570	22,988	23,291	25,707	25,794	25,787	26,392
Operating expenses	11,034	11,651	11,953	12,132	12,314	12,499	12,686
Amortization	4,912	4,291	4,403	4,320	4,022	3,865	3,894
Operating income	7,624	7,045	6,935	9,256	9,459	9,424	9,812
Other income and expense	1,907	3,933	3,075	3,096	3,238	3,592	3,586
Income taxes	996	579	536	1,142	953	752	804
Net Income	4,721	2,533	3,324	5,018	5,268	5,080	5,422
Dividends paid	2,500				11,000		
Regulated ROE *	11.2%	5.9%	7.5%	10.3%	10.9%	10.6%	10.2%

* Adjusted for goodwill impact

The 2015 forecast earnings are expected to be approximately $0.5 million lower than the plan. The decrease in earnings is primarily a result of the write off of Project Fortran.

The 2016 plan earnings of $3.3 million are up $0.8 million from the 2015 earnings forecast primarily due to the 2015 write off of Project Fortran and increased margins.

The Business Plan assumes that CNPI distribution rebases in 2017. CNPI's distribution business last rebased in 2013, and the 2017 distribution rate base is anticipated to be $89.8 million, an increase of $16.3 million or 22.2 per cent over the 2013 rate base. In the non-rebasing years the Business Plan assumes that the base distribution margin increase is 1.75 per cent under the incentive regulation mechanism. CNPI's transmission business last rebased in 2015 and 2016, with rate bases of $20.8 million and $24.2 million, respectively.

Over the business planning period for goodwill analysis purposes, financial modeling assumes electricity distribution rates in non-rebasing years grow conservatively by 1.75 per cent (combination of incentive regulation and load growth) and operating expenses grow by 1.5 per cent. The financial modeling does not consider the potential positive impacts of the OEB's 2014 revenue decoupling initiatives.

Detailed financial statements for the forecast period have been attached (Appendix A), along with the forecast capital budget (Appendix B) and the major assumptions in the plan (Appendix C).

10.2 FINANCING

CNPI maintains a capital structure of approximately 60 per cent long-term debt and 40 per cent equity, similar to the OEB's deemed capital structure.

Financing requirements of the regulated operations will be supported by short-term borrowings from the non-regulated operations until the short-term debt is large enough to be replaced by financing from capital markets.

In 2018, the $30 million in 15 year senior unsecured notes mature at CNPI. The Business Plan assumes that maturing debts are reissued and an additional $32 million in debt is acquired.

10.3 SCENARIO ANALYSIS

CNPI filed a cost of service application in 2012 for rates effective January 1, 2013. The allowed ROE is 8.93 per cent. A one per cent change in the assumed allowed ROE will change CNPI earnings by $453 thousand (distribution $361 thousand and transmission of $92 thousand).

Canadian Niagara Power Inc.
Balance Sheet
As at December 31

	Actual 2014	Forcast 2015	Budget 2016	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020
Current assets							
Cash and temporary investments	$ 1,216	$ 1,268	$ 53	$ 1,383	$ 1,466	$ 1,183	$ 1,425
Accounts receivable	11,690	11,924	12,162	12,406	12,654	12,907	13,165
Due from affiliated companies		-	-	-	3,043	3,043	3,043
Inventory	143	80	80	82	83	85	87
Regulatory assets	260	-	245	250	255	260	265
Other current assets	469	500	500	510	520	531	541
	13,778	13,772	13,040	14,630	18,021	18,008	18,526
Utility plants							
Cost	158,480	171,665	181,538	190,173	199,742	208,489	217,076
Less: accumulated amortization	(60,117)	(64,102)	(68,799)	(73,425)	(77,767)	(81,965)	(86,206)
	98,363	107,563	112,739	116,748	121,976	126,524	130,870
Accrued pension benefit asset	3,698	4,834	5,497	5,607	5,719	5,833	5,950
Goodwill	7,232	7,232	7,232	7,232	7,232	7,232	7,232
Regulatory assets, non current	9,038	11,210	10,385	8,957	9,286	9,622	9,964
Intangible assets	8,783	9,068	9,191	9,156	9,121	9,087	9,054
Total assets	$ 140,892	$ 153,679	$ 158,085	$ 162,330	$ 171,355	$ 176,307	$ 181,596
Current liabilities							
Bank indebtedness	$ -	$ 8,000	$ 10,000	$ 10,000	$ -	$ -	$ -
Accounts payable and accrued liabilities	7,348	7,497	7,645	7,798	7,954	8,114	8,278
Regulatory liabilities	699	578	-	-	-	-	-
Customer deposits	606	600	600	600	600	600	600
Income taxes payable	31	200	-	-	-	-	-
Due to affiliates	10,344	7,139	7,139	7,139	-	-	-
	19,028	24,014	25,384	25,537	8,554	8,714	8,878
Affiliate long-term debt	20,000	20,000	20,000	20,000	20,000	20,000	20,000
Long-term debt	29,885	29,917	29,949	29,981	62,000	62,000	62,000
Future income taxes payable	4,318	4,563	5,050	5,151	5,254	5,359	5,467
Accrued post retirement benefit liability	6,652	7,241	7,386	7,534	7,684	7,838	7,995
Contributions	10,401	14,514	14,999	14,455	13,898	13,326	12,741
Regulatory liabilities, non current	3,012	3,302	1,864	1,202	1,226	1,251	1,276
Shareholder's equity							
Common stock	23,900	23,900	23,900	23,900	23,900	23,900	23,900
Retained earnings	23,696	26,228	29,551	34,570	28,838	33,918	39,340
Total shareholder's equity and liabilities	$ 140,892	$ 153,679	$ 158,085	$ 162,330	$ 171,355	$ 176,307	$ 181,596
Total debt	56%	56%	56%	53%	60%	58%	56%
Shareholder's equity	44%	44%	44%	47%	40%	42%	44%

Canadian Niagara Power Inc.
Statement of Cash Flows
For the Period Ending December 31

	Actual 2014	Forecast 2015	Budget 2016	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020
Operating activities							
Net earnings for the period	$ 4,721	$ 2,533	$ 3,324	$ 5,018	$ 5,268	$ 5,080	$ 5,422
Amortization of capital assets	4,912	4,677	4,788	4,705	4,407	4,250	4,279
Change in working capital	2,178	5,789	889	(107)	(20,291)	(111)	(113)
Deferred pension costs	(3,073)	(1,136)	(663)	(110)	(112)	(114)	(117)
Future income taxes	(1,373)	245	487	101	103	105	107
Regulatory assets, non-current	168	(1,882)	(613)	766	(305)	(311)	(317)
Deferred post retirement benefits	3,885	589	145	148	151	154	157
Cash from operations	11,419	10,815	8,356	10,521	(10,779)	9,053	9,417
Financing activities							
Dividend paid	(2,500)	-	-	-	(11,000)	-	-
Change in long-term debt	32	32	32	32	32,019	-	-
Contributions	1,390	4,925	1,466	450	450	450	450
Cash from (used in) financing activities	(1,078)	4,957	1,498	482	21,469	450	450
Investing activities							
Additions to utility plant	(10,371)	(14,434)	(9,873)	(8,635)	(9,569)	(8,747)	(8,587)
Change in intangibles	(59)	(1,284)	(1,196)	(1,038)	(1,038)	(1,039)	(1,039)
Change in other assets	-	-	-	-	-	-	-
Cash used in investing activities	(10,430)	(15,719)	(11,070)	(9,672)	(10,607)	(9,785)	(9,626)
Increase (decrease) in cash	(90)	52	(1,215)	1,331	82	(282)	241
Cash , beginning of period	1,306	1,216	1,268	53	1,383	1,466	1,183
Cash , end of period	$ 1,216	$ 1,268	$ 53	$ 1,383	$ 1,466	$ 1,183	$ 1,425

Canadian Niagara Power Inc.
Income Statement
For the Period December 31

	Actual 2014	Forecast 2015	Budget 2016	Forecasted 2017	Forecasted 2018	Forecasted 2019	Forecasted 2020
Revenue							
Electric revenue	$ 75,206	$ 75,115	$ 80,203	$ 83,804	$ 85,100	$ 86,326	$ 88,190
Transmission	4,854	4,246	4,647	4,694	4,741	4,788	4,836
less purchased power	(56,490)	(56,373)	(61,559)	(62,790)	(64,046)	(65,327)	(66,634)
	23,570	22,988	23,291	25,707	25,794	25,787	26,392
Operating expenses							
Transmission	714	886	919	933	947	961	975
Distribution	3,558	3,657	3,711	3,766	3,823	3,880	3,938
General	4,695	4,866	5,088	5,164	5,241	5,320	5,400
Customer Service	1,862	1,994	1,968	1,997	2,027	2,058	2,089
Municipal and other taxes	205	248	267	271	275	280	284
	11,034	11,651	11,953	12,132	12,314	12,499	12,686
Depreciation and amortization	4,912	4,291	4,403	4,320	4,022	3,865	3,894
Operating income	7,624	7,045	6,935	9,256	9,459	9,424	9,812
Other income							
Interest on Investments	30	29	-	-	-	-	-
Other interest	3	(1)	-	-	-	-	-
Services and miscellaneous revenue	1,161	334	329	334	339	344	350
Gain (loss) on disposals	75	16	-	-	-	-	-
Gain (loss) on foreign exchange	(12)	15	-	-	-	-	-
Other Income	1,257	393	329	334	339	344	350
Other income deductions							
Loan interest expense	2,230	2,322	2,444	2,469	2,617	2,976	2,976
Intercompany interest expense	934	1,086	960	960	960	960	960
Other income deductions	-	918	-	-	-	-	-
	3,164	4,326	3,404	3,430	3,577	3,936	3,936
Earnings before income taxes	5,717	3,112	3,860	6,160	6,221	5,832	6,226
Provision for income taxes	996	579	536	1,142	953	752	804
Net income	$ 4,721	$ 2,533	$ 3,324	$ 5,018	$ 5,268	$ 5,080	$ 5,422
Return on Equity	9.8%	5.1%	6.4%	9.0%	9.5%	9.2%	9.0%
ROE with the Goodwill impact	11.2%	5.9%	7.5%	10.3%	10.9%	10.6%	10.2%

FortisOntario
5 Year Capital Budget
(000's)

	2014 Actual	2015 Forecast	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
Canadian Niagara Power Inc.							
Transmission							
Station Projects	621	636	343	145	150	90	90
Line and Tower Projects	1,820	5,817	500	530	130	130	130
Total Transmission	**2,441**	**6,453**	**843**	**675**	**280**	**220**	**220**
Niagara							
Building Improvements-leasehold	79	97	50	53	55	58	61
Station Projects	838	943	2,124	502	1,672	431	401
Line Replacements and Customer Extensions	3,463	2,776	2,738	2,736	3,041	3,247	2,903
Communications and SCADA	119	290	35	60	62	63	65
Land Info. Mgmt System and Easements	2	21	20	26	26	27	27
Rebuilds, Pole Replacement and new transformers	1,340	1,486	1,345	1,935	1,973	2,013	2,053
Engineering Projects	-	61	85	80	80	80	80
DIstribution Automation	92	279	308	255	260	265	271
New Meters	166	199	291	122	125	127	130
Tools & Equipment Distribution	81	50	70	53	55	58	61
Transportation Equipment	365	135	327	175	350	100	375
Distribution Rebuilds Storms	34	91	25	82	83	85	87
Environmental PCB	-	44	-	-	-	-	-
Total Niagara Distribution	**6,579**	**6,472**	**7,418**	**6,077**	**7,782**	**6,553**	**6,512**
Information Technology							
Hardware	316	122	523	400	250	200	250
Applications	101	200	207	207	207	207	207
Projects	861	1,060	964	800	800	800	800
Total Information Technology	**1,278**	**1,382**	**1,694**	**1,407**	**1,257**	**1,207**	**1,257**
Gananoque							
Building Improvements	4	48	20	20	20	20	20
Substations	39	60	50	70	100	600	100
Line Replacements and Customer Extensions	649	853	693	835	850	865	880
Easements	-	4	5	5	5	5	5
Transformer	34	60	60	65	70	70	70
New Meters	5	38	64	25	25	25	27
New Tools & Equipment	10	23	22	18	18	20	20
New Transportation Equipment	30	25	40	310	35	35	350
Pole Replacement	-	300	161	165	165	165	165
Environmental PCB	8	-	-	-	-	-	-
Total Gananoque Distribution	**779**	**1,411**	**1,115**	**1,513**	**1,288**	**1,805**	**1,637**
Total Canadian Niagara Power	**11,077**	**15,718**	**11,070**	**9,672**	**10,607**	**9,785**	**9,626**

CANADIAN NIAGARA POWER INC.

2016-2020 PLAN AND FORECAST

ASSUMPTIONS

The following assumptions were made in developing the 2016 plan and 2017-2020 forecast:

DISTRIBUTION ENERGY SALES (GWH)

	2014A	2015F	2016P
RESIDENTIAL	203.0	209.3	203.6
COMMERCIAL	307.4	278.7	276.7
OTHER	0.8	0.7	0.6
TOTAL ENERGY SALES	511.2	488.7	480.9
% CHANGE FROM PRIOR YEAR		-4.4%	-1.5%

DISTRIBUTION – CONNECTED CUSTOMERS

	2014A	2015F	2016P
RESIDENTIAL	25,892	25,858	26,026
COMMERCIAL	2,861	2,781	2,875
TOTAL CUSTOMERS	28,721	28,639	28,901
% CHANGE FROM PRIOR YEAR		-0.4%	0.9%

T&D RATE INCREASES

T&D RATE INCREASES

	2015	2016	2017	2018	2019
CNPI – DISTRIBUTION (1)	1.75%	1.75%	Rebase	1.75%	1.75%
CNPI - TRANSMISSION (2)	Rebase	Rebase	1.0%	1.0%	1.0%

(1) In non-rebasing years, combination of IRM and load increase of the 1.75%.

(2) Transmission rebasing in 2015 and 2016. Growth of 1.0% per annum in 2017, 2018 and 2019.

	2015	2016	2017	2018	2019
DIVIDENDS ($'000)	-	-	2,500	12,000	3,000
CORPORATE INCOME TAX RATE	26.50%	26.50%	26.50%	26.50%	26.50%
COMBINED RATE BASE ($'M)	110	115	118	119	121
% CHANGE FROM PRIOR YEAR (%)	6.3%	5.2%	2.1%	1.5%	1.6%

EXPENSES

- General expenses rise at an average of 1.5% per annum beyond 2015.
- 2015 annual expense for pension and post- retirement benefits.

($ '000)	
DEFINED BENEFIT	535
DEFINED CONTRIBUTION	257
OMERS	158
POST RETIREMENT	485
	1,435

- Assumptions:

  Investment Rate: 6.00%
  Discount rate: 4.80%

- 2015 composite depreciation rate is 3.2%

Scorecard - Canadian Niagara Power Inc.

9/28/2015

Performance Outcomes	Performance Categories	Measures	2010	2011	2012	2013	2014	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time	94.70%	97.70%	95.70%	93.10%	96.00%		90.00%	
		Scheduled Appointments Met On Time	100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Telephone Calls Answered On Time	85.10%	83.40%	84.60%	82.60%	78.20%		65.00%	
	Customer Satisfaction	First Contact Resolution					99.9%			
		Billing Accuracy					99.92%		98.00%	
		Customer Satisfaction Survey Results				80.84%	79.59%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public awareness [measure to be determined]								
		Level of Compliance with Ontario Regulation 22/04	NI	C	C	C	C			C
		Serious Electrical Incident Index: Number of General Public Incidents	0	0	0	0	1			0
		Serious Electrical Incident Index: Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.978			0.137
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted	0.90	1.82	1.89	3.22	1.95			at least within 0.90 - 3.22
		Average Number of Times that Power to a Customer is Interrupted	1.27	1.63	2.21	2.72	2.07			at least within 1.27 - 2.72
	Asset Management	Distribution System Plan Implementation Progress					Completed			
	Cost Control	Efficiency Assessment			4	4	4			
		Total Cost per Customer [1]	$715	$727	$679	$726	$749			
		Total Cost per Km of Line [1]	$19,893	$20,204	$18,790	$20,275	$21,202			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Annual Peak Demand Savings (Percent of target achieved) [2]		8.06%	14.05%	37.28%	54.56%			4.07MW
		Net Cumulative Energy Savings (Percent of target achieved)		30.41%	46.13%	64.52%	82.55%			15.81GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time				0.00%				
		New Micro-embedded Generation Facilities Connected On Time				97.78%	95.65%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	0.77	0.65	0.33	0.34	0.33			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	2.68	2.97	2.53	2.30	2.02			
		Profitability: Regulatory Return on Equity: Deemed (included in rates)		8.01%	8.01%	8.93%	8.93%			
		Profitability: Regulatory Return on Equity: Achieved		7.21%	9.42%	6.71%	8.31%			

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 include any persisting peak demand savings from the previous years.

Legend: up down flat target met target not met

The link below provides a document titled “Scorecard - Performance Measure Descriptions” that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard’s measures in the 2014 Scorecard MD&A: **http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf**

Scorecard MD&A - General Overview

In 2014, CNPI met or exceeded 83% of all performance targets.

In 2015, CNPI expects to continue to improve its overall scorecard performance results as compared to previous years. These performance improvements are expected as a result of enhanced system reliability due to CNPI’s investment in its distribution system and continued responsiveness to customer feedback.

Service Quality

- **New Residential/Small Business Services Connected on Time**

In 2014, CNPI connected 96% of the 150 new eligible low-voltage residential and small business customers within the Ontario Energy Board’s prescribed five day timeline. Since 2010, CNPI has consistently met the Ontario Energy Board’s target and continues to trend upwards.

- **Scheduled Appointments Met On Time**

CNPI continues to exceed the Ontario Energy Board standard of meeting customers as requested within the prescribed timelines set out by the Ontario Energy Board.

- **Telephone Calls Answered On Time**

In 2014, customer service representatives answered 78.20% of its 42,361 calls within 30 seconds. This exceeds the Ontario Energy Board's mandated 65% target. 2014 results are slightly lower than previous years. CNPI continues to offer and promote self-serve options and utilizes social media to engage and inform customers in an effort to offer customers additional channels to interact with the Company.

Customer Satisfaction

- **First Contact Resolution**

CNPI measured First Contact Resolution by tracking the number of escalated calls as a percentage of total calls taken by the customer contact center from July 1, 2014 to December 31, 2014. For this period, less than one percent of calls were escalated.

- **Billing Accuracy**

For the period from October 1, 2014 – December 31, 2014, CNPI issued approximately than 87,000 invoices and 99.9% were accurate. This is above the industry standard of 98%.

- **Customer Satisfaction Survey Results**

CNPI utilizes a third party to conduct a telephone survey for its residential customers. The survey includes questions regarding the quality of service, safety, billing, customer communications and information on the industry. The results cited on the scorecard represent customers who indicated that they were 'completely' and 'mostly' satisfied with the overall quality of service. To date, CNPI has not included responses of being 'somewhat' satisfied in the scorecard result. 2014 results were slightly lower than 2013 which is consistent with lower 2014 industry results. This reduction may be attributable to well published events in the industry as a whole, such as the Ombudsman's report on electricity billing and the increasing cost of energy. However, within the survey, customers continue to rate CNPI very high for the safe and reliable delivery of service and providing timely and accurate bills at 90% and 91%, respectively.

The survey provides useful information to better meet the needs of CNPI's customers and is incorporated into the distribution system plan, capital planning and overall company objectives.

Safety

- **Public Safety**

  - **Component A – Public Awareness of Electrical Safety**

CNPI has a number of internal initiatives to communicate Public Awareness of Electrical Safety to our customers. Additionally, CNPI partners with ESA in promoting ESA provincial wide public safety campaigns.

  - **Component B – Compliance with Ontario Regulation 22/04**

This component includes the results of an Annual Audit, Declaration of Compliance, Due Diligence Inspections, Public Safety Concerns and Compliance Investigations. All the elements are evaluated as a whole and determine the status of compliance (Non-Compliant, Needs Improvement, or Compliant).

Results provided by ESA, CNPI's status for 2014 is Compliant.

  - **Component C – Serious Electrical Incident Index**

"Serious electrical incidents", as defined by Regulation 22/04, make up Component C. The metric details the number of and rate of "serious electrical incidents" occurring on a distributor's assets and is normalized per 10, 100 or 1,000 km of line (10km for total lines under 100km, 1000km for total lines over 1000km, and 100km for all the others).

Results provided by ESA, CNPI had one incident in 2014.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**

CNPI's customers experienced a decrease in the average duration of electrical service disruptions in 2014 over the previous year. CNPI continues to invest in grid modernization in order to gain visibility on the state of the distribution system and improve overall response and restoration times. Grid modernization initiatives include the deployment of automated devices and implementation of an outage management system. CNPI understands that reliability of electrical service is a high priority for its customers and continues to invest in replacement of end-of-life assets as well as vegetation management.

- **Average Number of Times that Power to a Customer is Interrupted**

CNPI's customers have experienced a reduction in the average number of electrical service disruptions in 2014 over the previous year. CNPI has deployed several initiatives aimed at reducing the number of electrical service interruptions such as the vegetation management program and cyclical asset preventative maintenance programs.

CNPI reviews outage statistics on a monthly basis to identify areas of poor distribution system performance. This process indicates any trends in poor performance and identifies opportunities to improve reliability. CNPI has also completed an asset condition assessment to identify assets that present a risk of impacting system reliability. CNPI uses reliability indicators and asset condition assessment data as key drivers into the system planning process.

Asset Management

- **Distribution System Plan Implementation Progress**

CNPI currently follows an internally developed five year capital planning process for expenditures on the distribution system. CNPI is in the process of aligning its internally developed process with the requirements outlined in the Chapter 5 Consolidated Distribution System Plan Filing guideline, including the Distribution System Plan. CNPI will be filing a formal Distribution System Plan in accordance with Chapter 5 in 2016 as part of evidence for its next cost of service application.

Cost Control

- **Efficiency Assessment**

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC on behalf of the Ontario Energy Board to produce a single efficiency ranking. The electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs. The model developed by Pacific Economics Group to predict a distributor's costs relies on a data set that includes all distributors in Ontario. For 2014, CNPI was placed in Group 4 indicating that actual costs are within +/- 25% of predicted costs.

However, CNPI uses industry-standard budgeting and accounting practices to predict and track its costs. The actual costs incurred each year by CNPI to deliver all of its programs generally compare favorably to the costs predicted by these practices. For 2014, these actual costs were within 5% of predicted (budgeted) costs. CNPI believes that this variance is minimal and indicative of sound performance from its distribution system planning process. CNPI's forward looking goal is that this efficiency performance will not decline in future years.

- **Total Cost per Customer**

Total cost is calculated as the sum of CNPI's OM&A costs, including depreciation and financing costs. This amount is then divided by the total number of customers that CNPI serves to determine Total Cost per Customer. The cost performance result for 2014 is $749 /customer which is a 3.2% increase over 2013. However, CNPI's Total Cost per Customer has increased on average by only 1.3% per annum over the period 2010 through 2014. This compares favorably with the Consumers Price Index (CPI) over the same period.

Historical cost measures are reflective of the fact that 80% of CNPI's service territory is located in rural areas, subject to more severe weather due to its location on the shore of Lake Erie (Lake Ontario for Eastern Ontario Power's service territory) with its prevailing winds and lake effect precipitation, and the operation and maintenance of several distribution substations. CNPI performs a comprehensive series of programs to meet all legal and regulatory requirements, with special emphasis on public safety, optimizing reliability, meeting customers' needs, and general cost control.

CNPI will continue to replace distribution assets proactively along a carefully managed timeframe in a manner that balances system risks and customer rate impacts. CNPI will continue to seek and implement productivity and system reliability improvement initiatives to help offset some of the costs associated with future system enhancements. Customer engagement initiatives will continue in order to ensure customers have an opportunity to share their viewpoint on CNPI's capital spending plans.

- **Total Cost per Km of Line**

This measure uses the same total cost that is used in the Cost per Customer calculation above. The total cost is divided by the total kilometers of line that CNPI operates to serve its customers. CNPI's 2014 rate is $21,202 per km of line, a 4.6% increase over 2013. However, CNPI's Total Cost per Customer has increased on average by only 1.8% per annum over the period 2010 through 2014. This compares favorably with the CPI over the same period.

As outlined on Total Cost per Customer above, historical cost measures are reflective of the fact that 80% of CNPI's service territory is located in rural areas, subject to more severe weather due to its location on the shore of Lake Erie (Lake Ontario for Eastern Ontario Power's service territory) with its prevailing winds and lake effect precipitation, and the operation and maintenance of several distribution substations. . CNPI performs a comprehensive series of programs to meet all legal and regulatory requirements, with special emphasis on public safety, optimizing reliability, meeting customers' needs, and general cost control.

As outlined on Total Cost per Customer above, CNPI will continue to replace distribution assets proactively along a carefully managed timeframe in a manner that balances system risks and customer rate impacts. CNPI will continue to seek and implement productivity and system reliability improvement initiatives to help offset some of the costs associated with future system enhancements. Customer engagement initiatives will continue in order to ensure customers have an opportunity to share their viewpoint on CNPI's capital spending plans.

Conservation & Demand Management

- **Net Annual Peak Demand Savings (Percent of target achieved)**

On the basis of the IESO's "2011 – 2014 Final Results Report" issued on September 1, 2015, CNPI achieved 54.6% of its Net Annual Peak Demand Savings. CNPI fully leveraged the suite of Independent Electricity System Operator ("IESO") province-wide demand management programs and placed emphasis on supporting the conservation efforts of large commercial, industrial and institutional customers.

CNPI had been challenged in its efforts to meet the assigned target due to a significant reduction in customer demand and energy consumption, in 2011, which has continued into 2014 with a decline in customer demand coupled with customer closures. This resulted in significant adverse economic impacts affecting the entire service territory. Due to these negative economic impacts, a lack of growth and decline in the larger customer base, the CNPI service territories have seen a dramatic overall decline in energy throughput and system

demand since 2008; the year that was used as the base year to set the mandated targets.

- **Net Cumulative Energy Savings (Percent of target achieved)**

On the basis of the IESO's "2011 – 2014 Final Results Report" issued on September 1, 2015, CNPI achieved 82.6% of its Net Energy Savings. CNPI fully leveraged the suite of Independent Electricity System Operator ("IESO") province-wide demand management programs and placed emphasis on supporting the conservation efforts of large commercial, industrial and institutional customers.

CNPI had been challenged in its efforts to meet the assigned target due to a significant reduction in customer demand and energy consumption, in 2011, which has continued into 2014 with a decline in customer demand coupled with customer closures. This resulted in significant adverse economic impacts affecting the entire service territory. Due to these negative economic impacts, a lack of growth and decline in the larger customer base, the CNPI service territories have seen a dramatic overall decline in energy throughput and system demand since 2008; the year that was used as the base year to set the mandated targets.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**

CNPI did not receive any requests for a renewable generation connections in 2014.

- **New Micro-embedded Generation Facilities Connected On Time**

In 2014, CNPI connected twenty-three (23) new micro-embedded generation facilities (microFIT projects of less than 10 kW). All but one facilities were connected within the prescribed time frame of five business days. Only one facility was connected on the sixth day. The minimum acceptable performance level for this measure is 90% of the time. CNPI works closely with its customers and their contractors to make the connection process as streamlined and transparent as possible.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

The Scorecard reports the current ratio for CNPI's segmented distribution business. On a consolidated basis, the 2014 liquidity current

ratio based on CNPI’s audited financial statements is 1.59 (2013 1.22). The liquidity ratio has remained relatively unchanged over the past several years and going forward it is expected to, at a minimum, be held relatively constant. CNPI has consistently shown a liquidity ratio greater than 1.0, which is an indication that CNPI is appropriately leveraged.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**

The Ontario Energy Board uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5.

The Scorecard reports the total debt to equity ratio for CNPI’s segmented distribution business. On a consolidated basis, the 2014 leverage debt to equity ratio based on CNPI’s audited financial statements is 1.27. The leverage ratio has remained relatively unchanged over the past several years and going forward it is expected to be held relatively constant.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**

CNPI's 2014 distribution rates were approved by the Ontario Energy Board as part of its last Cost of Service application for rates effective January 1, 2013 and this included an expected (deemed) regulatory return on equity of 8.93%. The Ontario Energy Board allows a distributor to earn within +/- 3% of the expected return on equity.

- **Profitability: Regulatory Return on Equity – Achieved**

CNPI’s return achieved in 2014 was 8.31%, which is within the +/- 3% range allowed by the Ontario Energy Board. CNPI achieved returns are higher in 2014 as compared to 2013 due to a higher adjusted regulated net income, as a result of decreased expenses offset by a decline in distribution revenue.

Note to Readers of 2014 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management’s best judgement on the reporting date of the performance scorecard, and could be markedly different in the future.

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REVENUE REQUIREMENT

The requested total revenue requirement for the 2017 Test Year is $22,294,747.

The requested 2017 total revenue requirement is an increase of $3,328,567 or 17.6% from the previously Board approved total revenue requirement of $18,966,181 for 2013.

The following table, reproduced from Exhibit 6, Tab 1, Schedule 2 shows the approved revenue requirement for 2013 and the requested revenue requirement for 2017 and provides the drivers of the change.

Table 1.2.1.1 Revenue Requirement Change from 2013 to 2017

Line No.	Particulars	Board Approved	Requested 2017	Change	%
1	OM&A Expenses	$ 9,719,261	$ 10,441,723	$ 722,462	7.4%
2	Amortization/Depreciation	$ 3,497,412	$ 4,766,329	$ 1,268,917	36.3%
3	Property Taxes	$ 116,700	$ 103,000	$ (13,700)	-11.7%
4	Capital Taxes	$ -	$ -	$ -	
5	Income Taxes (Grossed up)	$ 612,615	$ 526,758	$ (85,857)	-14.0%
6	Other Expenses	$ -	$ -	$ -	
7	Return				
	Deemed Interest Expense	$ 2,394,852	$ 3,151,314	$ 756,462	31.6%
	Return on Deemed Equity	$ 2,625,341	$ 3,305,624	$ 680,283	25.9%
8	Distribution Revenue Requirement before Revenues	$ 18,966,181	$ 22,294,747	$ 3,328,567	17.6%
9	Distribution revenue	$ 17,562,996	$ 19,870,302	$ 2,307,306	13.1%
10	Other revenue	$ 1,403,185	$ 2,424,445	$ 1,021,260	72.8%
11	**Total revenue requirement**	$ 18,966,181	$ 22,294,747	$ 3,328,567	17.6%

The primary driver for the increase in revenue requirement is an overall increase in rate base, as detailed in Exhibit 2, Tab 1, Schedule 1. The increase in rate base directly impacts the Amortization/Depreciation amounts, as well as Return on Capital (Deemed Interest Expense and Return on Deemed Equity), as detailed in Exhibit 5, Tab 1, Schedule 1.

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BUDGET ASSUMPTIONS

CNPI's service territories have seen relatively stagnant economic growth over the historic period detailed in this application. As discussed in Exhibit 3, Tab 1, Schedule 1, the Load and Revenue Forecast Overview, annual consumption has been declining across all customer classes. Based on this reality, CNPI has forecasted a decline in consumption and demand for the 2017 Test Year.

CNPI has projected labour costs to increase as discussed in Exhibit 4, Tab 4, Employee Compensation. Non-labour costs are generally projected to increase by an inflationary amount on an annual basis.

BUDGET PROCESS

When preparing its annual operations and administration budget, CNPI considers the operational needs and requirements of the organization for the upcoming year. To the extent possible, planned human resources, purchased services, materials and other costs are all identified and accounted for during the budgeting process. CNPI forecasts its budget based on a review of its historic costs, consideration of feedback obtained through customer engagement, and identified priorities for maintenance programs and capital projects based on asset condition information. Consideration is also given to the required and available resources, both internal and external. The 2017 Test Year budget was prepared and reviewed in the fourth quarter of 2015.

With respect to the maintenance budget, CNPI uses the information gathered through the processes identified in the Distribution Asset Management Plan, which is an Appendix to CNPI's Distribution System Plan ("DSP"), described at Exhibit 2, Tab 2, Schedule 1, Appendix A. Information is gathered from various sources, including inspections, testing and asset condition assessments. The information is reviewed in consideration of required and available resources, and is compared to historical spending patterns. The resulting maintenance budget assists CNPI in implementing an effective maintenance program that is expected to optimize the operational life of assets in service, and to enhance the safe and reliable supply of electricity to consumers in its service territories.

CNPI expects year-over-year changes to its total OM&A budget to generally be in line with inflationary increases. Following completion of the bottom-up approach identified above, the resulting OM&A budget is reviewed by the Executive from a top-down perspective. Where the bottom-up approach results in significant deviations from the inflationary target, any proposed new programs or any line items that are materially in excess of inflationary increases are analyzed in more detail. These items are then justified and/or adjusted prior to final budget approval.

In preparation of its capital budget, CNPI has been guided by the expectations set out by the Board, contained in the Chapter 5 Filing Requirements. This has resulted in the development of CNPI's first DSP, which describes CNPI's proposed capital programs and projects, both in the 2017 Test Year, and in the 2017-2021 horizon.

Management is responsible for preparing the budgets of the respective departments including using operating and capital budgets. Labour hours are charged to both capital and operating job orders. Non-labour costs are also taken into account.

The operating and capital budgets are reviewed prior to allocations for shared corporate services. The shared corporate services allocations are reviewed and approved separately by senior management. The finance department is responsible for managing the budgeting process.

The Executive reviews the operating and capital budgets with individual managers. The Board of Directors approves the operating and capital budgets annually.

The revenue requirement, and rate base were approved by the Board of Directors for this 2017 Cost of Service application.

LOAD FORECAST SUMMARY

CNPI's load forecast is based on a methodology that uses multifactor regression analysis in accordance with the Filing Requirements. CNPI has maintained its historical consumption and customer data and has utilized this data to develop a weather normal load forecast for 2016 – 2017. This is discussed in detail in Exhibit 3, Tab 1, Schedule 2.

The regions in which CNPI operates has seen very little growth or expansion in economic activity over the historical period. As a result, CNPI's proposed kWh and kW billing determinants for the 2017 Test Year are materially lower than 2013 OEB Approved values. Total kWh billing determinants for consumption-billed classes experience a 5.3% decrease from 2013 to 2017, while total kW billing determinants for demand-billed classes experience a 14.4% decrease.

The following table summarizes the customer and load forecast by customer class and provides a comparison with the 2013 Board Approved values. The 2017 Test Year include CDM adjustments. CDM is discussed in detail in Exhibit 3, Tab 2, Schedule 1.

Table 1.2.3.1 – Comparison of Load Forecast
2013 Approved and 2017 Test Year

	Customers/Connections			kWh		kW			Volumetric
Billing Determinants	2013 Approved	2017 Test	Difference	2013 Approved	2017 Test	2013 Approved	2017 Test	Volumetric Difference	% Difference
Residential	25,689	26,074	385	208,287,976	198,077,803			-10,210,173	-4.9%
GS Less Than 50 kW	2,521	2,489	-32	72,454,602	67,907,332			-4,547,270	-6.3%
GS 50 to 4,999 kW	228	217	-11			691,366	593,383	-97,983	-14.2%
USL	39	35	-4	1,527,929	1,462,761			-65,168	-4.3%
Sentinel Lighting	961	695	-266			2,334	1,916	-418	-17.9%
Street Lighting	5,696	5,713	17			11,789	8,591	-3,198	-27.1%
Total	**35,134**	**35,223**	**89**	**282,270,507**	**267,447,895**	**705,489**	**603,890**		

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SUMMARY OF RATE BASE AND CAPITAL PLAN

Rate Base

As set out at Exhibit 2, Tab 1, Schedule 2, CNPI's rate base from 2013 to 2017 can be summarized as follows:

Table: 1.2.4.1 - Rate Base Summary

	2013 Board Approved	2013 Actual	2014 Actual	2015 Actual	2016 Bridge Year	2017 Test Year
Average Net Book Value	65,400,087	64,425,120	67,272,605	70,020,520	77,253,204	84,465,451
Working Capital Allowance	8,097,701	8,162,120	8,570,264	8,759,330	9,521,595	5,459,030
Rate Base	73,497,788	72,587,240	75,842,870	78,779,850	86,774,799	89,924,481

Additional information on CNPI's rate base can be found in Exhibit 2.

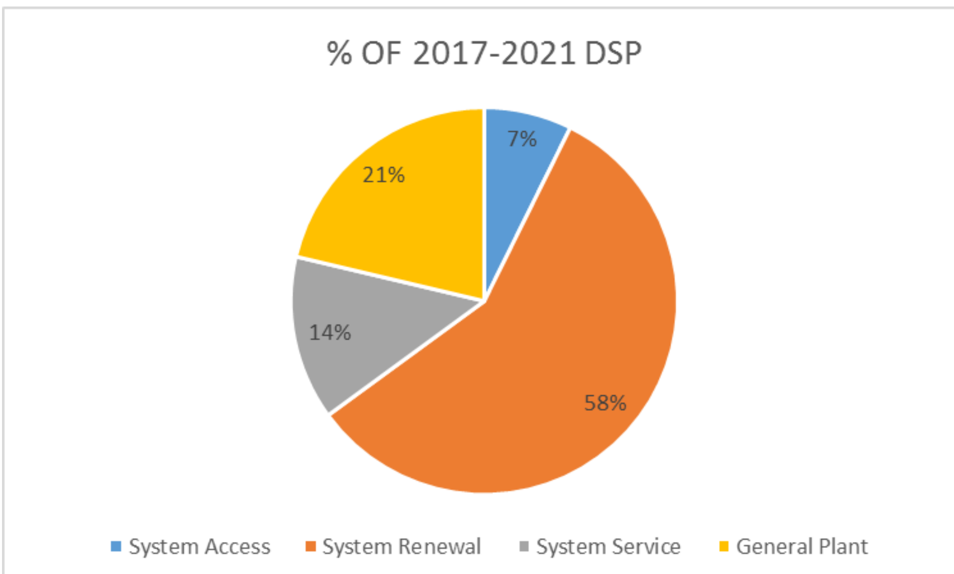
The following chart provides a summary of major contributors to the 2017 - 2021 five-year plan. The single largest driver of CNPI's Distribution System Plan ("DSP") is the proactive replacement of end of life assets with a high risk of failure, accounting for 58% of the total five-year plan. This is discussed in detail in Exhibit 2, Tab 3, Schedule 1, Appendix A.

CNPI is requesting a rate base of $89,924,481 for the 2017 Test Year, an increase of $16,426,693, or 22%, over the 2013 Board Approved amount of $73,497,788.

Capital Plan

Capital expenditures for the 2017 Test Year are $9,757,158, an increase of $2,395,857, or 33%, over 2013 Board Approved capital expenditures of $7,361,301 (Note that one-time costs related to capitalization of smart meter costs has been excluded from the 2013 Board Approved total).

The chart below illustrates the breakdown by investment category of the 5-year capital plan presented in CNPI's DSP. The single largest driver of CNPI's 5-year capital plan is investment in Delta to Wye voltage conversion, which is driven primarily by safety considerations and asset end-of-life. These investments are primarily within the System Renewal category as complete line rebuild and substation replacement projects. A portion of the System Service category also contains Delta to Wye conversion projects in situations where end-of-life lines have been recently rebuilt to a Delta standard, and minimal reconfiguration is required for the conversion to a Wye system in the area.



CNPI is not requesting any specific costs in relation to renewable energy connections/expansions or regional planning initiatives. CNPI has not requested any smart-grid specific costs, however continued investment in certain SCADA, and Distribution System Automation business system and reliability-driven projects are expected to serve as a foundation for future smart grid development.

OPERATIONS, MAINTENANCE AND ADMINISTRATIVE EXPENSE

Exhibit 4 (Operating Costs) sets out CNPI's operating costs forecasted for 2017 Test Year, including the following: operations, maintenance, and administration expenses ("OM&A expenses"), amortization expense, and income tax.

CNPI is proposing through distribution rates, the recovery of $10,544,723 in Operating, Maintenance and Administration (OM&A) costs for the 2017 Test Year, which represents an increase of $708,762 or 7.2% over the 2013 Board Approved OM&A expenditures of $9,835,961.

A summary of overall drivers and cost trends for CNPI's OM&A costs is provided in Table 1.2.5.1 below.

Table 1.2.5.1 Recoverable OM&A Cost Driver Table
Appendix 2-JB

OM&A	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Bridge Year	2017 Test Year
Reporting Basis = ASPE					
Opening Balance	$ 9,835,961	$ 8,864,063	$ 9,434,813	$ 9,518,933	$ 10,130,816
CDM Staffing	$ (85,000)	$ 56,000		$ 26,000	
Vehicle Depreciation Credit	$ (351,000)	$ 351,000			
Approved IFRS Costs	$ (85,000)	$ 85,000			
Port Colborne Service Center Closure	$ (35,000)	$ (20,000)			
Regulatory Staffing	$ (100,000)				
Customer Service Staffing and Charge-outs	$ (92,000)	$ (70,000)	$ (30,000)	$ 30,000	
Collections and Bad Debts	$ (8,000)	$ (99,000)	$ 29,000	$ 49,000	$ 38,000
Shared Service Allocation		$ 63,000		$ 45,000	$ (11,000)
ON1Call Initiative		$ 40,000			
Vacant IT Position			$ (40,000)	$ 40,000	
IT Billable Costs			$ (28,000)	$ 28,000	
Pole Testing Program				$ 150,000	
MIST O&M				$ 44,000	
EAB Program					$ 100,000
Load Dispatching					$ 65,000
Asset Management					$ 30,000
Miscellaneous	(215,898)	164,750	153,120	199,883	191,906
Closing Balance	$ 8,864,063	$ 9,434,813	$ 9,518,933	$ 10,130,816	$ 10,544,723

Summary of Overall Drivers and Costs Trends

The overall OM&A drivers can be grouped into three categories; New Program Scope and Outcomes, Payroll Factors and Other Material Variances to assist with the explanation of the cost increases.

New Program Scope and Outcomes

There are specific program variances that are due to the introduction of new scope and outcomes. Implementation of MIST Metering solutions, the Emerald Ash Borer Program and the enhancement of asset management through a comprehensive Pole Testing Program contribute approximately $300,000 or approximately 40% of the cost increases compared to 2013 Board Approved.

MIST Metering Solution

In accordance with amendments to the DSC in 2014, the recent installation of MIST meters across CNPI's service territories have resulted in an increase of operating expenses. The MIST metering program provides customers with greater choice, opportunity, ability, and incentive to better manage their electricity consumption and costs through load shifting, pricing options, and/or demand reduction. This program will bring these customers in line with the rest of the electricity customers in Ontario in terms of pricing. Potentially, this will lead to the deferral and mitigation of system investments, lowering overall system costs.

Emerald Ash Borer Program

The Emerald Ash Borer ("EAB") program has been designed to manage burdens resulting from an invasive species impacting the ash tree population within CNPI's service territories. This program is focused on sustaining service reliability by proactively eliminating risks associated with this infestation. Mitigation strategy includes but is not limited to the following:

- Completion of risk assessment
- Removal of infested tress on CNPI owned land
- Assisting stakeholders
    - Creation of electrically safe work zones

- Additional ash tree trimming in support of clearances for the purpose of removal

- Asset repairs as a result of ash tree failure

Pole Testing Program

CNPI's Pole Testing Program includes a six year pole testing cycle with alignment to existing distribution inspection area boundaries. The program will be aimed at investments in prioritized replacement of poles at end of life. This inspection program will commence in 2016. Additional operating expenses will be experienced as a result of this program as immediate repairs will be required to remediate deficiencies identified.

Payroll Factors

An increase in operating expenses can be attributed to cost of living and salary progression increases arising from collective bargaining agreements with the unions and percentage increases for management staff designed to reflect market compensation.

A summary of collective bargaining agreements has been provided in the table below:

Year	Niagara Service Territory Increase	Gananoque Service Territory Increase
2012	2.8%	2.8%
2013	2.9%	2.9%
2014	3%	3%
2015	3.1%	3.1%
2016	2.0%	To be negotiated.

Other Material Variances

The remaining OM&A increases between the 2017 Test Year and 2013 Board Approved is related to a variety of non-material operational adjustments and inflationary pressures.

These are detailed in Exhibit 4, Tab 3, Schedule 1- Program Delivery Costs with Variance Analysis.

Inflation rates used for OM&A forecasts

Where applicable, an inflation factor of 2% was considered and applied to 2016 Bridge Year and 2017 Test Year budgets, which is in line with the Bank of Canada's CPI inflation control target[1].

Total compensation

Total compensation increased an average of 2.7% year to year from 2013 Actual to 2017 Test Year. Total compensation increased by a total of $414,274 or 11% from 2013 Actual to 2017 Test Year. Increases are driven by negotiated collective agreements, economic and progression adjustments as well as changes in FTE allocations to the CNPI distribution business. Further detail on employee compensation can be found in Exhibit 4, Tab 4.

[1] http://www.bankofcanada.ca/rates/indicators/key-variables/inflation-control-target/

COST OF CAPITAL

CNPI has followed the Report of the Board on Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, in determining the cost of capital.

In calculating the cost of capital, CNPI has used the deemed capital structure of 56% long-term debt, 4% short-term debt, and 40% equity, and the Cost of Capital parameters in the OEB letter of October 15, 2015, for the allowed return on equity and deemed return on debt. CNPI has used its actual blended long-term debt rate of 6.14%, based on existing long-term debt instruments.

CNPI's return on capital for 2017 has been calculated as $6,456,937 based on a weighted average cost of capital of 7.18% as shown in Table 1.2.7.1 below:

Table: 1.2.7.1

Summary of Cost of Capital					
		2013 Board Approved		**2017 Test Year**	
	Deemed Capital Structure	Rate		Rate	
Short-Term Debt	4%	2.08%		1.65%	
Long-Term Debt	56%	5.85%		6.14%	
Equity	40%	8.93%		9.19%	
Total	100%		6.93%		7.18%

CNPI understands that the OEB will likely update the Cost of Capital Parameters for 2017 at a later date and commits to updating its Cost of Capital accordingly as new information is issued.

Further details on CNPI's Capital Structure and Cost of Capital can be found at Exhibit 5.

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COST ALLOCATION AND RATE DESIGN

CNPI has not deviated from the OEB's cost allocation and rate design methodologies.

The items listed below have resulted in significant impacts on CNPI's cost allocation and rate design processes since its 2013 cost of service application (EB-2012-0112):

- The full harmonization of monthly service charges and distribution volumetric charges as of January 1, 2016;
- The proposed harmonization of all rate riders effective January 1, 2017;
- The proposed establishment of a distinct Embedded Distributor rate class, as requested by Hydro One Networks Inc.;
- The Board's letter of June 12, 2015, outlining its new cost allocation policy for the Street Lighting rate class; and
- The Board's letter of July 16, 2015, describing the approach for the transition to a fully fixed monthly distribution service charge for residential customers.

Cost Allocation

A summary of the results of the 2017 fully harmonized cost allocation study, and the required adjustments to comply with the Board's policy range on revenue-to-cost (R/C) ratios is provided in the following table. These results include the establishment of a distinct Embedded Distributor rate class, and changes to cost allocation policy for the Street Lighting rate.

Table 1.2.7.1 – Summary of R/C ratios from Cost Allocation Study

Class	Previously Approved Ratios	Status Quo Ratios	Proposed Ratios	Policy Range
	Most Recent Year: 2016	(7C + 7E) / (7A)	(7D + 7E) / (7A)	
	%	%	%	%
Residential	91.42	94.62	95.37	85 - 115
GS < 50 kW	109.34	109.22	109.22	80 - 120
GS > 50 kW (or 50 kW < GS < xxx kW, if applicable)	119.94	106.96	106.96	80 - 120
GS > xxx kW, if applicable				80 - 120
Large User, if applicable				85 - 115
Street Lighting	96.28	162.22	120.00	80 - 120
Sentinel Lighting	91.42	105.08	105.08	80 - 120
Unmetered Scattered Load (USL)	120.00	72.95	95.37	80 - 120
Other class, if applicable				
Embedded distributor class		84.57	95.37	

The above results show that at Status Quo ratios (i.e. the ratios resulting from the Cost Allocation Study pre-adjustment), the Street Lighting class would have been recovering costs above the Board's policy range due to changes in Board policy for allocating costs to this class. CNPI made an adjustment to move the Street Lighting R/C ratio to the top of the Board's policy range (120%), and allocated the excess amount from the Street Lighting class to the three rate classes (Residential, USL, and Embedded Distributor) that were under-recovering at Status Quo ratios. Complete details of the Cost Allocation Study and R/C ratio adjustment can be found at Exhibit 7.

Rate Design

A complete description of CNPI's rate design process, along with a live Excel model is provided at Exhibit 8.

The following table provides the percentage change of the proposed fixed and variable distribution rates as compared to the most recent rates approved by the Board (EB-2015-0058) and effective January 1, 2016. Residential rates shown in the table are pre-mitigation. A summary of proposed mitigation is included in the following section.

Table 1.2.7.1 – Rate Comparison (Pre-Mitigation)

Comparison of Current Rates to Final Rate Design						
Customer Class	Existing Rates		Proposed Rates		Percent Change	
	Fixed Charge	Volumetric Charge	Fixed Charge	Volumetric Charge	Fixed Charge	Volumetric Charge
Residential	$ 23.44	$ 0.0152	$ 30.47	$ 0.0116	30.0%	-23.8%
GS Less Than 50 kW	$ 28.26	$ 0.0230	$ 32.02	$ 0.0261	13.3%	13.3%
GS 50 to 4,999 kW	$ 151.83	$ 6.6887	$ 172.04	$ 7.5344	13.3%	12.6%
Embedded Distributor	$ 151.83	$ 6.6887	$ 584.79	$ 8.3087	285.2%	24.2%
USL	$ 32.96	$ 0.0179	$ 50.53	$ 0.0274	53.3%	53.3%
Sentinel Lighting	$ 5.09	$ 5.9010	$ 5.77	$ 6.6867	13.3%	13.3%
Street Lighting	$ 4.96	$ 10.7965	$ 4.06	$ 8.8324	-18.2%	-18.2%

Residential Rate Mitigation

In certain cases (depending on combination of service territory and RPP vs Retailer supply), the total bill impacts for Residential customers at the 10^{th} percentile level of consumption exceed 10%. This is largely due to implementation of the transition to a fixed monthly service charge for the Residential class. As a result, CNPI has proposed a mitigation approach that involves a decrease to the amount of the fixed charge increment, and possible extension of the transition period by one additional year. Details of the proposed approach are provided at Exhibit 8, Tab 1, Schedule 12. The following table compares the resulting Residential rates (i.e. post-mitigation) to existing rates.

Table 1.2.7.2 – Rate Comparison (Post-Mitigation)

Customer Class	Existing Rates		Proposed Rates		Percent Change	
	Fixed Charge	Volumetric Charge	Fixed Charge	Volumetric Charge	Fixed Charge	Volumetric Charge
Residential	$ 23.44	$ 0.0152	$ 28.94	$ 0.0140	23.5%	-7.9%

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DEFERRAL AND VARIANCE ACCOUNTS

The total balance being requested for disposition by CNPI within this Application for Group 1 accounts is a credit $383,648, of which a credit of $1,566,699 relates to all customers, and a debit of $1,183,052 relates to non-RPP customers. Disposition is also being sought out for selected Group 2 and other DVA accounts including: a debit of $255,421 for OEB 1568, LRAM Variance Account, a credit of $38,857 for OEB 1508, Other Regulatory Assets, and a credit of $71,007 for OEB 1592, PILs and Tax Variance for 2006 and Subsequent Years.

A one year recovery period is being requested for all balances identified above. CNPI is also proposing harmonization across all of its service territories of an existing DVA rate rider related to 2016 balances that is in effect until December 31, 2017. Details of the proposed disposition of 2017 DVA amounts and the proposed harmonization of the 2016 rider that will remain in effect throughout 2017 are provided at Exhibit 9, Tab 5, Schedule 1. Details of the proposed disposition LRAMVA are provided at Exhibit 9, Tab 6, Schedule 1.

CNPI is also requesting the disposition of the OEB 1557 MIST Cost Deferral Account at Exhibit 9, Tab 3, Schedule 1 of this Application along with the recovery of stranded meter costs relating to MIST implementation within Exhibit 2, Tab 1, Schedule 8. CNPI is requesting that a new sub account of OEB 1557 be created to track the stranded costs and recovery requested within this Application.

CNPI is requesting the following new accounts:

- **OEB 1557 Sub-Account ($MIST_{STRANDED}$) for EB-2016-0061** – CNPI is requesting to create this Sub-Account upon approval within this Application, of the disposition of the meters stranded as a result of the implementation of MIST.
- **OEB 1595 Sub-Account (2017_{POWER}) for EB-2016-0061** – CNPI is requesting to create this Sub-Account upon approval within this Application, of the disposition of DVA balances as at December 31, 2015.
- **OEB 1595 Sub-Account (2017_{GA}) for EB-2016-0061** – CNPI is requesting to create this Sub-Account upon approval within this Application, of the disposition of DVA balances as at December 31, 2015.

- **OEB 1595 Sub-Account (2017$_{LRAM}$) for EB-2016-0061** – CNPI is requesting to create this Sub-Account upon approval within this Application, of the disposition of LRAM balances as at December 31, 2015.

BILL IMPACTS

Tables 1.2.9.1 to 1.2.9.3 below provide a summary of total bill impacts for all classes, as per Appendix 2-W. Each of CNPI's service territories (Fort Erie, EOP, and Port Colborne) are presented in separate tables since the non-harmonized rate riders currently in effect result in differences in 2016 total bill amounts. Bill impacts are addressed in detail in Exhibit 8, Tab 1, Schedule 11.

Table 1.2.9.1 - Bill Impacts - Fort Erie Service Territory

Class	kWh	kW	Energy Charge	Total Bill 2016 $	Total Bill 2017 $	Total Bill Difference $	Total Bill Difference %
Residential	100	-	RPP - TOU	$ 44.54	$ 51.37	$ 6.83	15.33%
Residential	210	-	RPP - TOU	$ 63.10	$ 68.89	$ 5.79	9.18%
Residential	250	-	RPP - TOU	$ 69.85	$ 75.26	$ 5.41	7.75%
Residential	500	-	RPP - TOU	$ 112.02	$ 115.08	$ 3.06	2.73%
Residential	750	-	RPP - TOU	$ 154.22	$ 154.90	$ 0.68	0.44%
Residential	1,000	-	RPP - TOU	$ 196.40	$ 194.72	-$ 1.68	-0.86%
Residential	1,500	-	RPP - TOU	$ 280.77	$ 274.37	-$ 6.40	-2.28%
Residential	2,000	-	RPP - TOU	$ 365.14	$ 354.01	-$ 11.13	-3.05%
Residential	100	-	Retailer	$ 51.53	$ 59.48	$ 7.95	15.43%
Residential	210	-	Retailer	$ 77.78	$ 85.85	$ 8.07	10.38%
Residential	250	-	Retailer	$ 87.32	$ 95.54	$ 8.22	9.41%
Residential	500	-	Retailer	$ 146.98	$ 155.47	$ 8.49	5.78%
Residential	750	-	Retailer	$ 206.64	$ 215.74	$ 9.10	4.40%
Residential	1,000	-	Retailer	$ 266.30	$ 275.51	$ 9.21	3.46%
Residential	1,500	-	Retailer	$ 385.62	$ 396.05	$ 10.43	2.70%
Residential	2,000	-	Retailer	$ 504.94	$ 515.58	$ 10.64	2.11%
GS Less Than 50 kW	1,000	-	RPP - TOU	$ 208.17	$ 212.01	$ 3.84	1.84%
GS Less Than 50 kW	2,000	-	RPP - TOU	$ 383.23	$ 386.66	$ 3.43	0.90%
GS Less Than 50 kW	5,000	-	RPP - TOU	$ 908.42	$ 910.60	$ 2.18	0.24%
GS Less Than 50 kW	10,000	-	RPP - TOU	$ 1,783.73	$ 1,783.84	$ 0.11	0.01%
GS Less Than 50 kW	15,000	-	RPP - TOU	$ 2,659.04	$ 2,657.09	-$ 1.95	-0.07%
GS Less Than 50 kW	1,000	-	Retailer	$ 278.07	$ 292.56	$ 14.49	5.21%
GS Less Than 50 kW	2,000	-	Retailer	$ 523.03	$ 547.77	$ 24.74	4.73%
GS Less Than 50 kW	5,000	-	Retailer	$ 1,257.92	$ 1,313.39	$ 55.47	4.41%
GS Less Than 50 kW	10,000	-	Retailer	$ 2,482.73	$ 2,589.42	$ 106.69	4.30%
GS Less Than 50 kW	15,000	-	Retailer	$ 3,707.54	$ 3,865.45	$ 157.91	4.26%
GS 50 to 4999 kW	20,000	60	Market	$ 3,582.55	$ 3,759.42	$ 176.87	4.94%
GS 50 to 4999 kW	40,000	100	Market	$ 6,720.24	$ 6,990.79	$ 270.55	4.03%
GS 50 to 4999 kW	200,000	500	Market	$ 32,913.80	$ 34,127.08	$ 1,213.28	3.69%
GS 50 to 4999 kW	400,000	1,000	Market	$ 65,655.75	$ 68,047.44	$ 2,391.69	3.64%
USL	3,500	-	RPP	$ 652.50	$ 688.27	$ 35.77	5.48%
Sentinel Lighting	75	0.25	RPP	$ 18.21	$ 18.77	$ 0.56	3.08%
Street Lighting	40	0.125	Market	$ 13.11	$ 11.55	-$ 1.56	-11.90%

Table 1.2.9.2 - Bill Impacts - Eastern Ontario Power Service Territory							
				Total Bill			
Class	kWh	kW	Energy Charge	2016 $	2017 $	Difference $	Difference %
Residential	100	-	RPP - TOU	$ 44.22	$ 51.37	$ 7.15	16.17%
Residential	210	-	RPP - TOU	$ 62.43	$ 68.89	$ 6.46	10.35%
Residential	250	-	RPP - TOU	$ 69.06	$ 75.26	$ 6.20	8.98%
Residential	500	-	RPP - TOU	$ 110.45	$ 115.08	$ 4.63	4.19%
Residential	750	-	RPP - TOU	$ 151.84	$ 154.90	$ 3.06	2.02%
Residential	1,000	-	RPP - TOU	$ 193.24	$ 194.72	$ 1.48	0.77%
Residential	1,500	-	RPP - TOU	$ 276.02	$ 274.37	-$ 1.65	-0.60%
Residential	2,000	-	RPP - TOU	$ 358.81	$ 354.01	-$ 4.80	-1.34%
Residential	100	-	Retailer	$ 53.11	$ 59.48	$ 6.37	11.99%
Residential	210	-	Retailer	$ 81.10	$ 85.85	$ 4.75	5.86%
Residential	250	-	Retailer	$ 91.28	$ 95.54	$ 4.26	4.67%
Residential	500	-	Retailer	$ 154.89	$ 155.47	$ 0.58	0.37%
Residential	750	-	Retailer	$ 218.51	$ 215.74	-$ 2.77	-1.27%
Residential	1,000	-	Retailer	$ 282.12	$ 275.51	-$ 6.61	-2.34%
Residential	1,500	-	Retailer	$ 409.35	$ 396.05	-$ 13.30	-3.25%
Residential	2,000	-	Retailer	$ 536.58	$ 515.58	-$ 21.00	-3.91%
GS Less Than 50 kW	1,000	-	RPP - TOU	$ 205.23	$ 212.01	$ 6.78	3.30%
GS Less Than 50 kW	2,000	-	RPP - TOU	$ 377.36	$ 386.66	$ 9.30	2.46%
GS Less Than 50 kW	5,000	-	RPP - TOU	$ 893.73	$ 910.60	$ 16.87	1.89%
GS Less Than 50 kW	10,000	-	RPP - TOU	$ 1,754.35	$ 1,783.84	$ 29.49	1.68%
GS Less Than 50 kW	15,000	-	RPP - TOU	$ 2,614.97	$ 2,657.09	$ 42.12	1.61%
GS Less Than 50 kW	1,000	-	Retailer	$ 294.12	$ 292.56	-$ 1.56	-0.53%
GS Less Than 50 kW	2,000	-	Retailer	$ 555.13	$ 547.77	-$ 7.36	-1.33%
GS Less Than 50 kW	5,000	-	Retailer	$ 1,338.15	$ 1,313.39	-$ 24.76	-1.85%
GS Less Than 50 kW	10,000	-	Retailer	$ 2,643.19	$ 2,589.42	-$ 53.77	-2.03%
GS Less Than 50 kW	15,000	-	Retailer	$ 3,948.23	$ 3,865.45	-$ 82.78	-2.10%
GS 50 to 4999 kW	20,000	60	Market	$ 3,920.29	$ 3,759.42	-$ 160.87	-4.10%
GS 50 to 4999 kW	40,000	100	Market	$ 7,283.14	$ 6,990.79	-$ 292.35	-4.01%
GS 50 to 4999 kW	200,000	500	Market	$ 35,728.29	$ 34,127.08	-$ 1,601.21	-4.48%
GS 50 to 4999 kW	400,000	1,000	Market	$ 71,284.73	$ 68,047.44	-$ 3,237.29	-4.54%
USL	3,500	-	RPP	$ 641.83	$ 688.27	$ 46.44	7.24%
Sentinel Lighting	75	0.25	RPP	$ 18.29	$ 18.77	$ 0.48	2.62%
Street Lighting	40	0.125	Market	$ 12.98	$ 11.55	-$ 1.43	-11.02%

Table 1.2.9.3 - Bill Impacts - Port Colborne Service Territory							
				Total Bill			
Class	kWh	kW	Energy Charge	2016 $	2017 $	Difference $	Difference %
Residential	100	-	RPP - TOU	$ 44.34	$ 51.37	$ 7.03	15.85%
Residential	210	-	RPP - TOU	$ 62.69	$ 68.89	$ 6.20	9.89%
Residential	250	-	RPP - TOU	$ 69.37	$ 75.26	$ 5.89	8.49%
Residential	500	-	RPP - TOU	$ 111.07	$ 115.08	$ 4.01	3.61%
Residential	750	-	RPP - TOU	$ 152.77	$ 154.90	$ 2.13	1.39%
Residential	1,000	-	RPP - TOU	$ 194.48	$ 194.72	$ 0.24	0.12%
Residential	1,500	-	RPP - TOU	$ 277.89	$ 274.37	-$ 3.52	-1.27%
Residential	2,000	-	RPP - TOU	$ 361.29	$ 354.01	-$ 7.28	-2.02%
Residential	100	-	Retailer	$ 51.15	$ 59.48	$ 8.33	16.29%
Residential	210	-	Retailer	$ 76.99	$ 85.85	$ 8.86	11.51%
Residential	250	-	Retailer	$ 86.39	$ 95.54	$ 9.15	10.59%
Residential	500	-	Retailer	$ 145.12	$ 155.47	$ 10.35	7.13%
Residential	750	-	Retailer	$ 203.84	$ 215.74	$ 11.90	5.84%
Residential	1,000	-	Retailer	$ 262.57	$ 275.51	$ 12.94	4.93%
Residential	1,500	-	Retailer	$ 380.03	$ 396.05	$ 16.02	4.22%
Residential	2,000	-	Retailer	$ 497.48	$ 515.58	$ 18.10	3.64%
GS Less Than 50 kW	1,000	-	RPP - TOU	$ 206.36	$ 212.01	$ 5.65	2.74%
GS Less Than 50 kW	2,000	-	RPP - TOU	$ 379.62	$ 386.66	$ 7.04	1.85%
GS Less Than 50 kW	5,000	-	RPP - TOU	$ 899.38	$ 910.60	$ 11.22	1.25%
GS Less Than 50 kW	10,000	-	RPP - TOU	$ 1,765.65	$ 1,783.84	$ 18.19	1.03%
GS Less Than 50 kW	15,000	-	RPP - TOU	$ 2,631.92	$ 2,657.09	$ 25.17	0.96%
GS Less Than 50 kW	1,000	-	Retailer	$ 274.46	$ 292.56	$ 18.10	6.59%
GS Less Than 50 kW	2,000	-	Retailer	$ 515.80	$ 547.77	$ 31.97	6.20%
GS Less Than 50 kW	5,000	-	Retailer	$ 1,239.84	$ 1,313.39	$ 73.55	5.93%
GS Less Than 50 kW	10,000	-	Retailer	$ 2,446.57	$ 2,589.42	$ 142.85	5.84%
GS Less Than 50 kW	15,000	-	Retailer	$ 3,653.30	$ 3,865.45	$ 212.15	5.81%
GS 50 to 4999 kW	20,000	60	Market	$ 3,510.99	$ 3,759.42	$ 248.43	7.08%
GS 50 to 4999 kW	40,000	100	Market	$ 6,600.98	$ 6,990.79	$ 389.81	5.91%
GS 50 to 4999 kW	200,000	500	Market	$ 32,317.50	$ 34,127.08	$ 1,809.58	5.60%
GS 50 to 4999 kW	400,000	1,000	Market	$ 64,463.14	$ 68,047.44	$ 3,584.30	5.56%
Embedded Distributor	427,454	1,143	Market	$ 69,802.20	$ 75,735.34	$ 5,933.14	8.50%
USL	3,500	-	RPP	$ 645.38	$ 688.27	$ 42.89	6.65%
Sentinel Lighting	75	0.25	RPP	$ 18.21	$ 18.77	$ 0.56	3.08%
Street Lighting	40	0.125	Market	$ 13.10	$ 11.55	-$ 1.55	-11.83%

CUSTOMER FOCUS

For over a decade the core values of CNPI have included a strong focus on delivering excellence in customer service and this remains the underlying premise of the Company's Customer Engagement Strategy:

> <u>*Customer Service*</u> *– Everyone has customers. Determine your customer's needs by listening. When you can meet these needs; do so. When you cannot, tell them that you cannot; or tell them who can. When in doubt about how to treat a customer, do what you believe is right. When serving customers, be pleasant, courteous and accurate; smile, act professionally and enjoy yourself. Attitudes are contagious.*

This Customer Engagement Strategy is divided into three categories and encompasses a number of initiatives and best practices; Customer Communications, Initiatives Specific to the Application and Future Initiatives. A comprehensive list of all Customer Engagement activities can be found in Appendix 2-AC.

(A) Customer Communications

Some of the ways CNPI communicates, seeks feedback and interacts with its customers are as listed below:

Monthly Calendar Billing
Monthly billing provides the opportunity to interact with customers on a frequent basis. Monthly invoices are either sent via mail or electronically and include bill inserts and semi-annual newsletter providing customers with current information related to the industry, the Company and their electricity bills. Furthermore, customers have told CNPI that comparing month over month electricity bills would be beneficial in assisting them in making decisions related to energy consumption. Therefore, in late 2012, CNPI made the decision to move to monthly calendar billing, aligning the bill period to a calendar month. This allows true monthly comparisons for CNPI's customers. While, resulting in a fundamental change to the billing schedule and internal business practices, the needs of the customers were the driving

factor in making this change. This billing period also reduces the complexity of the customer invoice during rate changes.

Website

CNPI's website is continuously updated to provide an enhanced customer experience with a goal of providing customers easy access to an abundance of information. As products and services are launched, for example e-Billing, MyHydroEye and social media, changes are made accordingly.

Social Media

In 2014, CNPI launched a social media campaign including Facebook and Twitter to further interact and communicate with its customers. The customer survey results indicated that 10 per cent of customers surveyed preferred to receive communications via social media channels and this number is expected to grow. CNPI's social media following has continually increased since the launch. Contests were held to promote the new communication channels. Currently, social media is currently not used during after business hours, but future initiatives involve after hours monitoring of social media by a third party to keep customers informed during all power outages. This will be implemented in June 2016.

Customer Surveys

CNPI has utilized residential customer surveys for the past ten years. Prior to 2014, the telephone survey was completed by Corporate Research Associates Inc. The survey was conducted by fully trained interviewers who asked a series of questions, with an average survey length of time of 8 minutes. The chart below outlines CNPI's results from 2011-2014.

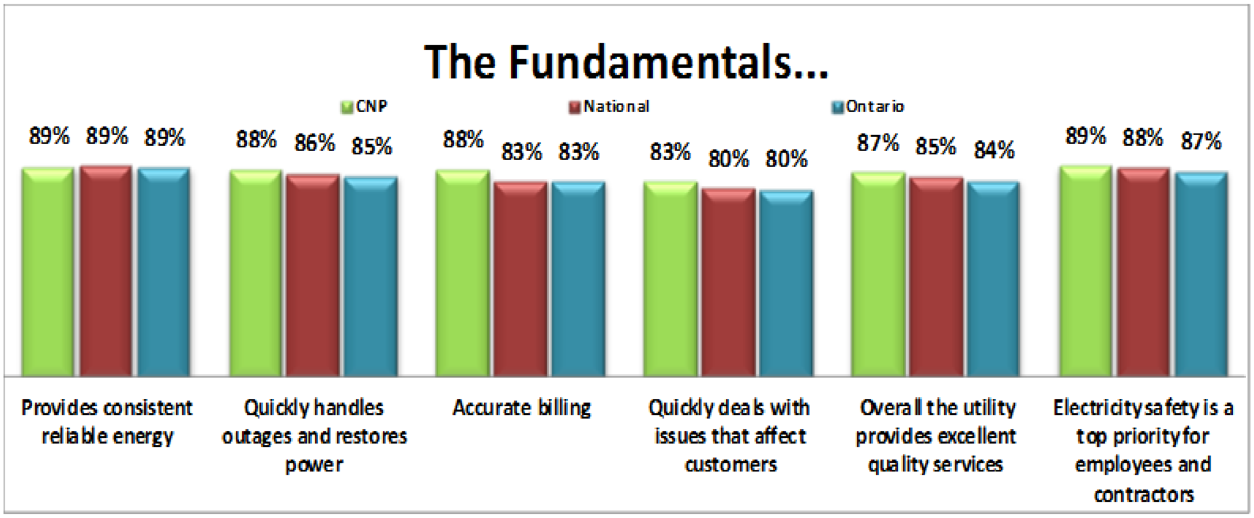
	2011	2012	2013	2014
Overall Satisfaction	80	89	81	80
Reliability and Safety	89	95	95	90
Quality of Service	85	91	91	87

The results indicate that year-over-year, CNPI's customers continue to highly regard their electricity service provider. CNPI's performance continues to be strong specifically in the provision of reliable and safe delivery of electricity.

In 2015, CNPI moved to a new survey provider, UtilityPULSE, to be more consistent with other LDCs in the province. The survey sample size was expanded and general service customers were included. UtilityPULSE completed 410 telephone interviews with residential and general service customers in the fall of 2015. The phone numbers were randomly selected and were stratified so that 85 per cent of the interviews were conducted with residential and 15 per cent with general service customers. The 2015 satisfaction score was significantly higher than both the national and Ontario averages. Satisfaction is defined as happening when utility core services meet or exceed customers' needs, wants or expectations. CNPI's results as compared to the both the national and Ontario scores are listed below.

CNPI's SATISFACTION SCORES – Electricity customers' satisfaction		
CNPI	**National**	**Ontario**
94%	89%	88%

This is further reinforced in the chart below where in the categories of providing consistently reliable energy, quickly handling and restoring power, accurate billing, quickly dealing with issues that affect customers, excellent quality services and the high priority of safety for employees and contractors. CNPI, again, rates higher than both the national and Ontario averages.



Overall, CNPI met or exceeded the national and Ontario results in all categories as outlined in the chart below.

CNPI's UtilityPULSE Report Card®				
Performance				
	CATEGORY	**CNP**	**National**	**Ontario**
1	**Customer Care**	**A**	**B+**	**B**
	Price and Value	B+	B	B
	Customer Service	A	B+	B+
2	**Company Image**	**A**	**A**	**B+**
	Company Leadership	A	B+	B+
	Corporate Stewardship	A	A	A
3	**Management Operations**	**A**	**A**	**A**
	Operational Effectiveness	A	A	A
	Power Quality and Reliability	A	A	A
	OVERALL	**A**	**A**	**A**

A comprehensive and complete summary of the 2015 survey is included in Appendix 4-B.

Departmental Strategy

Customers have continuously told CNPI that their preferred method of communication is via the telephone, specifically during a power outage. The chart below reiterates CNPI's customers overwhelming preference for speaking to representatives via the telephone:

	Telephone	Email	Utility Website	Social Media	Mail	In Person
Ontario LDCs	84%	5%	2%	1%	0%	0%
CNPI	89%	4%	2%	2%	0%	3%

In response to this, CNPI has maintains very personal service and ensures that all customers have access to speak to a live agent. The chart below outlines CNPI's call statistics from 2011-2015. With various changes to the electricity industry over the past several years, customer telephone inquiries have become increasingly complex. As such, customer service representatives ("CSR") require more time to assist customers with their concerns resulting in the longer call durations. This is a contributing factor to the decrease in the percentage of calls answered within thirty seconds, although call centre statistics have remained strong and CNPI continues to far exceed the OEB benchmark of 65 per cent of calls being answered within 30 seconds.

Telephone Accessibility	2011	2012	2013	2014	2015
Total general inquiry telephone calls	39,985	36,052	38,704	42,361	39,803
Total general inquiry telephone calls answered within 30 seconds	33,839	30,485	31,956	33,140	30,279
% of general inquiry telephone calls answered within min standards (65%)	85%	85%	83%	78%	76%

Longer call processing times directly align with First Contact Resolution. CNPI's 2015 result for First Contact Resolution on the OEB scorecard was 99 per cent. While calls may take longer to answer, the customer is able to resolve their issue or concern in one call the majority of times.

In response to customer satisfaction survey results, where customers identified proactive outage communications as the most important item, they were willing to pay more for this service each month and thus an important area where CNPI could improve overall service levels, CNPI has entered into a project to provide enhanced call answer services to its customers. Leveraging the services of UtilAssist (PowerAssist), customers will have more access to a live CSR through an increased number of after business hours inbound telephone lines. Current providers have a limited number of inbound telephone lines which can result in busy signals when customers are trying to contact CNPI. PowerAssist's CSRs have access to customer data to provide a higher level of customer interaction during the call. This service will be expanded in late 2016 for all inbound power outage calls.

Conservation and Demand Management Initiatives

The Conservation and Demand Management ("CDM") team are responsible for the delivery of energy efficient programs to residential and business customers. In addition to one-on-one customer interviews and visits, the CDM team has also undertaken customer specific or segmented focus groups throughout the year. As an example, CNPI engaged its larger industrial customers in a presentation by the IESO on the Global Adjustment. At this same presentation, the CDM team informed the customers about Demand Response programs, and how the customer can affect their Global Adjustment charge. The CDM group participates in numerous events throughout the year, promoting both the residential and commercial CDM programs. A detailed listing of events attended during the 2011 – 2015 timeframe is outlined in the table below.

Event/Promotion	Location	Customer Target	Event Date	Event Days	Outreach Potential	Program
CNPI						
Employee Awareness Day	Douglas Memorial Hospital-FE	Res, C&I, Ind	Sep 12 2012	0.5	50	All Programs
Social Agency meeting	County Office-Brockville	Res	Dec 3 2012	0.5	Gananoque	HAP
Social Agency meeting	Fort Erie - CNP offices	Res	Dec 6 2012	0.5	Fort Erie/Port Colborne	HAP
Kingston Home Show	Cataraqui Sports Complex	Res, C&I, Ind	Apr 5-7 2013	3	500	All Programs
Learn to Earn	Clarion Hotel - FE	Contractors	Apr 12 2013	0.5	30	All Business Programs
Learn to Save	Clarion Hotel - FE	C&I, Ind	Apr 12 2013	0.5	50	All Business Programs
FE Town Council	Fort Erie	Res	Jan 21 2013	0.5	Fort Erie	HAP Presentation
Conservation Showcase	Black Creek Retirement Community	Res	May 10 2013	0.5	75	All For Home Programs
Springfest	Stevensville Community Hall	Res	Jun 1 2013	1	100	All For Home Programs
Ribfest/Craft Fair	Gananoque Town Square	Res, C&I, Ind	Jun 28-30 2013	3	Gananoque	All Programs
United Way Golf Classic	Bridgewater Golf Club	C&I, Ind, Contractors	Aug 12 2013	1	150	All Business Programs
Business Trade Show	Fort Erie Chamber of Commerce	Res, C&I, Ind, Contractors	Sep 26 2013	0.5	500	All Programs
Niagara Region SOE Symposium	White Oaks Conference Resort-NOT	C&I, Ind, Contractors	Oct 24 2013	1		All Business Programs
Coupon Event	Cdn Tire - Gananoque	Res, C&I, Ind	May 16 2014	1	50	All Programs
Chalk The Walk	Gananoque Town Square	Res, C&I, Ind	May 17 2014	1	100	All Programs
Springfest	Stevensville Community Hall	Res	Jun 7 2014	1	100	All For Home Programs
United Way Golf Classic	Bridgewater Golf Club	C&I, Ind, Contractors	Jul 14 2014	1	150	All Business Programs
Business Trade Show	Fort Erie Chamber of Commerce	Res, C&I, Ind, Contractors	Sep 25 2014	0.5	500	All Programs
Business Trade Show	PC Chamber of Commerce	Res, C&I, Ind, Contractors	Nov 6 2014	0.5	150	All Programs
FE Santa Claus Parade	Fort Erie	Res	Nov 24 2014	0.5	Fort Erie	All For Home Programs
FE Lioness Monthly Meeting	Ridgeway	Res	Dec 4 2014	0.5	20	All For Home Programs
PC Santa Claus Parade	Port Colborne	Res	Dec 6 2014	0.5	Port Colborne	All For Home Programs
Abor Group - HAP	FE Native Center	Res-Aboriginal	Apr 7 2015	0.5	50	HAP
United Way Golf Classic	Bridgewater Golf Club	C&I, Ind, Contractors	Jul 13 2015	1	150	All Business Programs
Employee Energy Awareness Day	Durez - Fort Erie	Res	Aug 12 2015	0.5	80	All For Home Programs
Business Trade Show	Fort Erie Chamber of Commerce	Res, C&I, Ind, Contractors	Sep 17 2015	0.5	500	All Programs
Coupon Event	Cdn Tire - FE/PC	Res	Sep 26 2015	1	200	All For Home Programs
Lunch & Learn	FE Lions Senior Center	Res	Oct 20 2015	0.25	20	All For Home Programs
Business Trade Show	PC Chamber of Commerce	Res, C&I, Ind, Contractors	Nov 5 2015	0.5	150	All Programs
FE Santa Claus Parade	Fort Erie	Res	Nov 21 2015	0.5	Fort Erie	All For Home Programs
PC Santa Claus Parade	Port Colborne	Res	Dec 5 2015	0.5	Port Colborne	All For Home Programs

At a number of the events shown in the table above, the CDM team works in conjunction with the Customer Service department. It provides an excellent platform to communicate with customers directly regarding the promotion of service offerings such as e-Billing, MyHydroEye, power outage notifications etc. As a result of this, a further understanding is gained about the needs of our customers, which help decide on future offerings for program delivery.

As a result of feedback from residential customers, CNPI will be promoting an IESO sponsored pilot program for its residential customers starting in April 2016. This program will allow residential customers to receive up to $500 in free energy efficiency measures. The objective of the Direct Mail Pilot Program is to provide select residential (non-low income) customers with an opportunity to order a customized Energy Saving Kit, to help them reduce their energy consumption. Participants will visit a website and be asked a series of questions to help identify their eligibility and determine which rebates they qualify for. Once all questions are answered, the customer will proceed to a shopping cart. Depending on how they responded to questions asked, specific rebates will be applied to the shopping cart items, for the customer to select and checkout. The customer will not only have the option to select free items based on the questions answered, but also purchase additional measures at a regular or reduced price, to further enhance the efficiency of their home.

Engagement and consultation with stakeholders including the IESO, customers, trade allies and associations, and government organizations have occurred frequently and on an ongoing basis as part of engagement, promotion and delivery of CDM programs. CNPI continues to be involved with a number of provincial LDC's to identify and pursue opportunities for collaboration on design and implementation of programs that satisfy regional needs and requirements. CNPI will continue to participate in engagement and consultation as it is a key component for market research, program design and development, and implementation of individual and regional CDM programs.

Town Council Meeting Presentations

CNPI endeavors to meet annually with town counsel and town leaders to provide an overview of the previous years' capital and maintenance programs and will also provide an update on the coming years' initiatives.

Community Involvement

Interacting with the community has always been a focus of CNPI. CNPI has been awarded the highest recognition from the United Way of Niagara Falls and Greater Fort Erie for its dedication to the community. Dinners are served annually by employees at the local soup kitchens, participation in community parades and other community events throughout the year. Employees participate annually in the Big Bike Event for the Heart & Stroke Association. Employee news releases are included in Appendix 4-C outlining these events.

School awareness events have proven to be a very useful way to increase electrical safety awareness while promoting Energy Conservation at the primary level.

Annually, CNPI hosts Grade 9 students for the *Take Our Kids to Work*™ national program. The students learn about the utility industry, various career opportunities, as well complete the Passport to Safety Training. The program supports career development by helping students connect school, the world of work, and their own futures.

Public Safety

CNPI engages in a number of on-going initiatives with a focus on public safety. Regular messaging is sent out via social media in conjunction with Electrical Safety Authority ("ESA") campaigns. Semi-annual company newsletters include a safety message. The Company's website dedicates resources to electrical safety. School age children are made aware of the importance of electrical safety through presentations held at each school in the service territory, every four years.

Local Service Provider Information Night

CNPI hosts an annual information session for local service providers who work for customers and prospective customers in the CNPI service territories. Participants include local builders, electricians, realtors etc. The information session provides an opportunity to communicate with these parties on changes to connection requirements and service repairs. Parties also have the opportunity to provide feedback to CNPI on various processes.

Contractor Pre-Qualification Session

CNPI hosts a bi-annual contractor information session for contractors employed by CNPI. As well, representatives from the local office of the ESA are present. The event discusses public safety issues, customer service topics regarding interactions between CNPI and the contractor community as well any changes to CNPI's customer connection process. Refer to Appendix 4-E for the presentation.

Emergency Responder Information Night

CNPI hosts training on a three (3) year rotation for staff of local fire, police and paramedical services. A review of electrical fundamentals and an overview of electrical safety and processes related to emergency situations are reviewed. Refer to Appendix 4-F for the presentation.

Joint Use Partner Interaction

CNPI meets regularly with local representatives from Bell and other Joint Use customers to discuss each company's upcoming and ongoing capital and maintenance projects. The purpose of these meetings is to ensure all parties can coordinate resources for demand work initiated by a joint use request as well as to monitor the progress of work related to these joint use requests.

MNR Species at Risk Review

Throughout the calendar year, the location of each capital project undertaken by CNPI is sent to local Ministry of Natural Resources and Forestry ("MNRF") offices for a species at risk review. The MNRF provides guidance to CNPI regarding species at risk in the area, often proposing work windows to avoid harassment of species during critical breeding and/or nesting periods. For vegetation at risk, the MNRF provides at risk locations enabling CNPI to identify at risk vegetation in the field ensuring measures are taken to avoid damage or destruction of these specimens.

CNPI will continue its on-going efforts of engaging its customers through this multi-channeled model. By utilizing this model, customers can actively provide feedback and be aware of the Company's on-going activities while staying current with industry changes.

Overall, this approach presents many channels for customers to actively engage with CNPI, allowing CNPI to incorporate useful feedback into the operation of the distribution business. Initiatives such as launching social media, moving to calendar billing and improving the website are all examples of areas that were undertaken because CNPI's customers requested them.

(B) Initiatives Specific to this Application

In response to the Board's Filing Requirements to engage customers on the specific proposals contained in this application, in addition to the annual customer survey, in January 2016, CNPI retained UtilityPULSE to design, collect feedback and provide detailed information on customer preferences. In March 2016, residential focus group sessions were held in Niagara and Gananoque with a total of 32 participants, and general service focus group sessions were held in Niagara and Gananoque with a total of 25 participants. The goal of the focus group sessions was to engage customers in dialogue to gain a better understanding of the findings from the telephone interviews from the annual survey referred to in the section (A) and to capture their thoughts and ideas on the company's rate application process and Distribution System Plan ("DSP").

Each of the focus group sessions followed a prescribed format where a CNPI executive and the UtilityPULSE moderator welcomed attendees followed by the CNPI executive providing a 15-20 minute overview of the organization and the DSP (see Appendix 4-G for a copy of the executive presentation).

Focus group participants were provided an opportunity to ask questions of CNPI personnel, who then left the room. The moderator facilitated the session by sequencing the questions consistently in each session. In addition, every participant was given the opportunity to voluntarily complete a brief paper-based questionnaire and/or to provide written comments. Of the 57 people who attended the sessions, 51 provided responses. The results are incorporated in the sections below.

Capital Investments and OM&A Spending

(1) Investment in Aging Infrastructure

When focus group participants were asked about their willingness to support an increase to pay for various capital and operational items, support levels varied as highlighted in the table below.

Capital Expenditures

Which of the following items are you willing to pay more for per month…Capital items					
CNP	VS	SS	N	SU	NS
Replacing aging equipment to improve safety and reliability	27%	33%	19%	10%	12%
Upgrading equipment to accommodate future growth in the community	17%	42%	17%	12%	12%
Adding automation and technology to reduce outage time	25%	38%	17%	10%	10%

Base: Focus Group respondents, scale: VS- Very Supportive, SS- Somewhat Supportive, N- Neither, SU- Somewhat Unsupportive, NS- Not Supportive

Focus group participants were also asked for comments regarding the following statement: "Electric utilities typically follow one of two strategies or main practices for replacing equipment. Which one of these two statements comes closest to your beliefs?

1) "run-to-failure" when there are limited customers affected ensures full-value is received from the equipment or;

2) "pro-active replacement, even though it may cost more, should ensure reliable power."

General service customers were in favour of pro-active replacements. Comments from customers included:

> *"We don't operate our own business in run-to-failure mode, why would we expect CNPI to do so?"*

Comments about the need for the utility to be putting money away to replace equipment, just like a business, or just like a residential customer when they are going to replace something in their home were as follows:

> *"A well run business plans for replacement."*
>
> *"Pro-active makes sense. If you run everything in your house to run-to-failure, it would cost a lot more."*
>
> *"I work for the fire-department, and maintenance is really the key."*

Consistent with this customer feedback, CNPI's Distribution System Plan ("DSP") and Distribution Asset Management Plan ("DAMP") include ongoing maintenance and upkeep initiatives to ensure reliable delivery of electricity. An example of a project to improve reliability is the distribution automation program. The distribution automation program is a multi-year initiative aimed at improving service reliability and availability for CNPI's customers. The program introduces field based automated switching and protection devices to CNPI's overhead distribution system. Based on analysis of reliability statistics, CNPI targets sections of feeders with poor performance and implements automation to mitigate outage frequency and duration.

The installations typically consist of a motor operated switch or recloser coupled with a protective relay and control device. The resulting installation is capable of remote interrogation and operation via CNPI's SCADA system. This improves response time and overall outage restoration time during unplanned events. The protection elements incorporated into these intelligent field devices limits feeder exposure to faults, dramatically reducing the number of customers affected by an unplanned event.

In the focus group session, a customer commented:

> *"I notice a huge improvement on the number of outages in our area."*

CNPI invests considerable capital dollars to maintain and improve system reliability and it is evident from the focus group feedback this is of the utmost importance to customers.

(2) OM&A

When customers were asked about what services they are willing to pay for each month tree trimming was rated second as it is recognized it will improve system reliability. The DSP addresses this ongoing need and outlines plans to continue a three-year aggressive tree trimming program which also includes the removal of hundreds of ash trees affected by the Emerald Ash Borer.

(3) Customer Services

In 2014, SAP "dunning" enhancements streamlined the process by which customers are notified of overdue accounts. The replacement of mailed reminder notices with an automated telephone call has resulted in a savings of approximately $12,000. This allows customers to be notified in a more timely fashion of overdue amounts on their hydro accounts. Technological enhancements have reduced manual processing through automations with Canada Post Xpress post software to more efficiently issue final collection notices to customers. As well, regulatory requirements are tracked with the capability of the software to identify where the collection notice is in the delivery cycle.

In response to customer satisfaction survey results, 60 per cent of residential customers and 58 per cent of general service customers indicated a preference to receive information about outages via a recorded message. CNPI has developed a process to pro-actively identify customers affected by power interruptions resulting from system repairs/upgrades. Automated phone calls via OnecallNow.com are generated prior to the outage giving customers the opportunity to make any necessary arrangements for their electrical service.

Customers identified proactive outage communications as the most important item they were willing to pay more for each month and thus an important area where CNPI could improve overall service levels. CNPI has entered into a project to provide enhanced call answer services to its customers. Leveraging the services of UtilAssist (PowerAssist) customers will have more access to a live CSR through an increased number of after-business hours inbound telephone lines. Current providers have a limited number of inbound telephone lines which can result in busy signals when customers are trying to contact CNPI. PowerAssist CSR's have access to customer data to provide a higher level of customer interaction during the call. This service will be expanded in late 2016 for all inbound power outage calls.

Customers have indicated that they want access to their time-of-use ("TOU") and interval data to help them make informed decisions about their energy usage. As such, CNPI has provided all TOU customers with the MyHydroEye on-line resource which allows customers to review usage data. This allows customers to adjust their consumption patterns which influence electricity bill amounts. The product also provides forecast bill results in the event the customer has enrolled with a retailer. For large users, UtiliSmart Settlement Manager is available providing more detailed and individualized data around the composition of the customers' invoice as well as load information. In 2016, customers with MIST meters will also be able to access the Settlement Manager to review their usage data and assist them in managing their electricity costs.

(C) Future Initiatives

Many steps have been taken to ensure that the needs and wants of CNPI's customers are considered as the company prepares plans for capital and maintenance initiatives.

Survey results indicate that 73 per cent of customers feel that CNPI provides a good value for their money. This well exceeds the Ontario benchmark of 66 per cent and the national benchmark of 67 per cent. However, CNPI strives to continually improve the customer experience.

The future will include more self-service options for customers, improved outage communications, leveraging social media and websites to provide 24/7 customer updates during power outages, key account management and continue requesting feedback from its customers through on line surveys and in person dialogue.

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Appendix 4-A – CNPI Newsletter

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Canadian Niagara Power Inc. A FORTIS Ontario Company

Eastern Ontario Power A FORTIS Ontario Company

Algoma Power Inc. A FORTIS Ontario Company

making CONNECTIONS

fall/winter 2015 newsletter





24 Hour Emergency Service

To report a power outage or a fallen line call our 24 Hour Emergency Service:

Canadian Niagara Power
Fort Erie - 905.871.0330
Port Colborne - 905.835.0051

Eastern Ontario Power
613.382.2118

Algoma Power
705.256.3850 or 1.877.457.7378

Thank you to everyone who participated in our Customer Engagement Contest. Congratulations to our winners:

John & Elizabeth Anne Rae - Algoma Power
Nancy Cash - Canadian Niagara Power
Penny Patterson - Eastern Ontario Power

Electronic Customer Engagement Tools

1. E-Billing

Receive your bills in a "click"

In our fast paced world, why not simplify? To get your bills quicker than by mail, and to reduce paper, sign up for e-billing by going to **www.fortisontario.com** and choose your local utility from the list of "Our Companies."

2. Pre-Authorized Debit Plan

By having your bill payments automatically deducted from your bank account each due date with the pre-authorized debit plan, you save time and never have to worry about timely invoice payments or getting late payment charges.

3. MyHydroEye - "MHE"

Check out how you use electricity with MHE! You can use either the MHE website or your mobile phone to access the information and better understand how your electrical service is consuming electricity! This knowledge will provide insight and opportunities to lower or shift your consumption to off-peak or mid-peak periods. Shifting or changing your consumption patterns will have a direct impact on your bills. To register for MHE visit your Utility's website and use the activation code found on the left hand side of your invoice.

4. Twitter

Find your utility's Twitter handle on their website and follow along for industry information and conservation tips.

5. Facebook

Like your utility's Facebook page and start following along.

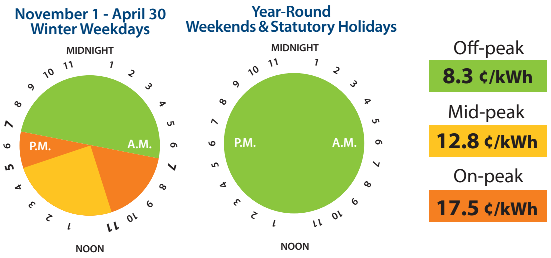
FortisOntario in Your Community

Canadian Niagara Power Inc. hosts Thanksgiving dinner at the Salvation Army

A team of CNP 'Helping Hands' hosted dinner for roughly 135 people on October 8, 2015 at the Salvation Army in Fort Erie. The community was very appreciative of the delicious meal and it was a rewarding experience for all.

Time-of-Use Winter Rates

Provincial winter Time-of-Use rates come into effect as of November 1, 2015.



Important Public Safety Messages

Did you know it is illegal to talk, text, dial or e-mail using hand-held phones and or hand-held communication and entertainment devices while driving? Do you know what can happen if you are found to be driving while distracted?

FortisOntario cares about the safety of our employees and our customers. Anyone who puts others at risk by driving while distracted, for whatever reason, may still be charged with Careless or Dangerous Driving. For more information on distracted driving and the rules of the road visit www.mto.gov.on.ca.

Electricity Market Updates:

New OEB Program Offers Electricity Bill Relief for Low-Income Households

The Ontario Energy Board (OEB) is helping make electricity more affordable for low-income households. The Ontario Electricity Support Program, or OESP, will provide ongoing assistance directly on the bills of eligible low-income electricity consumers.

Low-income households that apply and qualify will receive an OESP credit on electricity bills. The program, designed and implemented by the OEB, will come into effect on January 1, 2016. Consumers can apply online or with the assistance of local intake agency partners, including Low-Income Energy Assistance Program Emergency Financial Assistance intake agencies.

Visit OntarioElectricitySupport.ca for more information and to sign up to receive OESP updates by email.

Interest charges on overdue amounts are applicable the day after the due date.

www.fortisontario.com

www.cnpower.com www.easternontariopower.com www.algomapower.com

Be Energy Conscious at HOME and WORK

saveONenergy FOR HOME

saveONenergy℠

saveONenergy FOR BUSINESS

Northern Lights

Residents and Businesses in Wawa will certainly notice a crisp, bright look throughout the Municipality now that night is coming early. The new LED streetlighting project is almost complete and right in line with the Township's new Green Energy Plan.

The Municipality of Wawa applied to Algoma Power's **saveONenergy RETROFIT PROGRAM** to take advantage of great incentives to replace their aging 430 streetlights with new LED's. The estimated annual energy savings is equivalent to avoiding the CO2 emissions from 25 homes' electricity use for one year. These LED streetlights are estimated to last for over 20 years.

"We are pleased to be finalizing our LED Streetlight Project with our partners LAS, RealTerm and Algoma Power's **saveONenergy RETROFIT PROGRAM**. This will now allow us to cut our energy use for streetlights by about 65% while saving ratepayers' money and cutting GHG Emissions. This the latest in a number of initiatives that we have embarked on around the conservation of energy and the production of green energy," stated Chris Wray, CAO/Clerk-Treasurer, Municipality of Wawa."

Bright Lights, Big City

Have you noticed lately when driving through the City of Port Colborne a slick, clean look to the City? Can't quite put your finger on what the change is? It's the new LED streetlighting!

In December 2014, the City of Port Colborne took the bold initiative to continue reducing their overall energy consumption by applying to Canadian Niagara Power's **saveONenergy RETROFIT PROGRAM** and switching all 1,985 city-owned streetlights to new LED streetlights. When the project completes this fall, the estimated annual energy savings is equivalent to avoiding the CO2 emissions from 67.2 homes' electricity use for one year. These LED streetlights will reduce not only annual operating and maintenance costs, but estimated to last for over 20 years.

Flying High with Energy Savings

Imagine having what you thought was a fairly energy efficient compressor. Then imagine a company, knowledgeable in air compressors, come in to test yours only to find out it wasn't efficient at all, and was in fact wasting energy as well as money.

Imagine as well that not only did your local electric utility offer you a financial incentive through the **saveONenergy RETROFIT PROGRAM** to help you invest in a new energy efficient model, but the new compressor would perform the same and use 75% less energy. And the incentive you would receive from your utility covered half the purchase cost of the new one. Who wouldn't go for that deal?

Aero-safe Processing certainly did with Canadian Niagara Power's help! Based on the model Aero-safe chose with their air compressor consultant, this new compressor, with the savings on their energy bill and the **RETROFIT PROGRAM** incentive, will pay for itself in under one year.

The Facts on Ceiling Fans

(courtesy saveonenergy.ca)

Everybody knows air conditioners use more electricity than fans - but just how much more will blow you away.

A standard high efficiency central air conditioning system uses on average 3,500 watts of power while in use. A room air conditioner uses an average of 1,000 watts. But a ceiling fan turned on high uses approximately 50 watts.

IF YOU WANT TO SAVE MONEY, HERE'S WHAT YOU NEED TO KNOW ABOUT CEILING FANS:

They can help keep you warm – You can reverse the blade direction to clockwise in the winter to push rising warm air down to where you and your family are.

They keep room temperature constant – Air conditioners will kick in and out when thermostat settings give them the signal that temperature is too high or low. Fans are designed to circulate air to maintain room temperature at a consistent level at the hottest times of the day.

Size matters – Ceiling fans come in sizes ranging from 32-inches in diameter up to 52-inches. If the room you're trying to keep cool is more than 500 square feet, you'll probably need more than one 52-inch ceiling fan.

Play the angles – Blade angles can make a big difference in air circulation. Blades should be at a minimum of 12 degrees to be effective at cooling in comfort. Blades set at an angle above 16 degrees will keep you cool, but may also blow around loose objects like paper.

Look for ENERGY STAR® – Ceiling fans certified by ENERGY STAR® provide the most cooling efficiency for your buck.

And best of all? We offer an annual coupon for saving on ENERGY STAR® certified ceiling fans. Call us or visit saveonenergy.ca to download one today.

For more information on all programs available, please visit **saveonenergy.ca**

Contact our CDM Team
conservation@cnpower.com
conservation@algomapower.com
OR Call your local office and ask for Extension 3399

Appendix 4-B – Customer Satisfaction Survey

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Canadian Niagara Power Inc.

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

17th Annual Electric Utility Customer Satisfaction Survey

UtilityPULSE

The purpose of this report is to profile the connection between Canadian Niagara Power Inc. and its customers.

The primary objective of the Electric Utility Customer Satisfaction Survey supported by information received from Focus Groups is to: provide feedback, comment and data to support discussions about improving customer care at every level in the LDC and in making Capital & Operational expenditures.

The UtilityPULSE Report Card® and survey analysis contained in this report do not merely capture state of mind or perceptions about your customers' needs and wants - the information contained in this survey provides actionable and measurable feedback from your customers.

All comments and questions should be addressed to:

Sid Ridgley, UtilityPULSE division, Simul Corporation

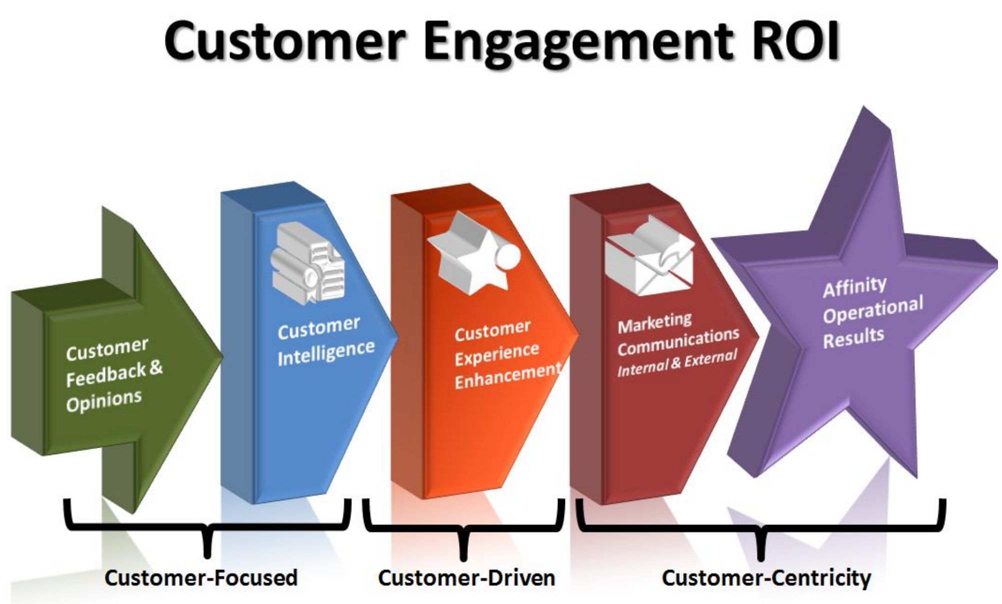
Toll free: 1-888-291-7892 or Local: 905-895-7900

Email: sidridgley@utilitypulse.com or sridgley@simulcorp.com

Survey Report

Customer engagement is a key driver for the success of energy efficiency, demand response, adoption of smart energy technologies and other programs the LDC manages. The key to effective engagement lies in understanding customers' attitudes, wants, needs, motivations, and in recognizing customers are smart people. Customer engagement is crucial for the longer term success of the LDC.

UtilityPULSE completed 410 telephone interviews with Residential and Commercial Customers in fall of 2015. This was followed up with 4 Focus Group sessions. There were 32 participants in the 2 Residential Focus Group sessions and 25 participants in the 2 Commercial Focus Group sessions.



By engaging customers in a comprehensive telephone survey the goal was to provide useable information CNP could use about items such as: customer satisfaction, customer service, company image, operations, billing, outages and outage management. The goal(s) of the Focus Group (FG) sessions was to engage customers in dialogue to gain a better understanding of the findings from the telephone survey and to capture their thoughts, ideas and recommendations to CNP when moving forward with their rate application to the OEB.

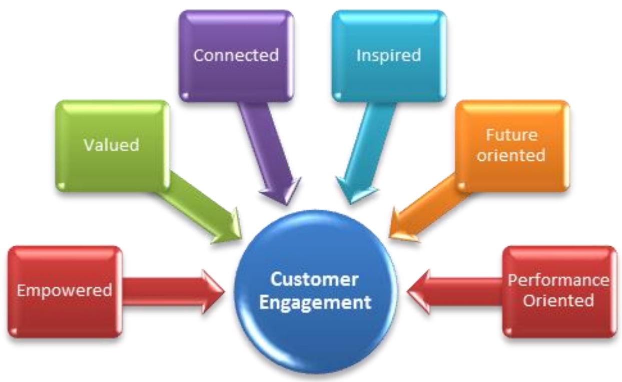
Comparability

This report contains data comparisons to:

- An Ontario-wide LDC benchmark
- A National LDC benchmark
- Ontario LDCs participating in the 17th Annual Customer Satisfaction survey
- UtilityPULSE database

Customer Centric Engagement Index (CCEI)

It is important to note there are 2 sides of engagement. One side is getting customer participation in various activities while the other is about getting higher levels of emotional connection (affinity). Conducting surveys (like this one), holding town hall meetings, focus groups, etc. are examples of engaging your customers that is, getting your customers to actively participate in something. This survey also provides you with an emotional look at engagement. The CCEI index is a gauge of the amount of goodwill that has been generated. High



numbers in CCEI suggest there is a high level of goodwill amongst your customers. Goodwill helps when things go awry for the utility and goodwill encourages active participation.

Utility Customer Centric Engagement Index (CCEI)			
	CNP	**National**	**Ontario**
CCEI	84%	80%	80%

Base: total respondents

Engagement is how customers think, feel and act towards the organization. Ensuring customers respond in a positive way requires being rationally satisfied with the services provided AND emotionally connected to the LDC and its brand. Connecting both rationally and emotionally strengthens and intensifies the degree to which the customer becomes engaged with the organization.

Why bother with making investments in Customer Engagement activities? (Partial list)

1. Better understanding of expectations
2. Clarify interests
3. Strategy alignment
4. Enhanced reputation/risk management
5. Improved efficiency of operations
6. Proof stakeholder input is valuable
7. Efficient use of resources
8. More effective communications
9. Improved issues management
10. Better openness in decision making
11. Increased accountability
12. Better information/intelligence

Customer engagement is not about making customers "happy" with the costs or the service being provided by their LDC. Nor is customer engagement about making the industry regulator "happy". The purpose of engaging customers is to gather usable information to help Canadian Niagara Power be more effective and efficient with higher levels of customer affinity.

Customer Focus - Customer Satisfaction - Satisfaction Survey Results

The Ontario Energy Board's consumer centric regulatory framework includes a customer satisfaction measure. Scoring well in this measure would indicate that many aspects of the LDC's operations are running well i.e., power reliability, restoring outages quickly, professional customer care, etc. Customer satisfaction is known as an effectiveness measure.

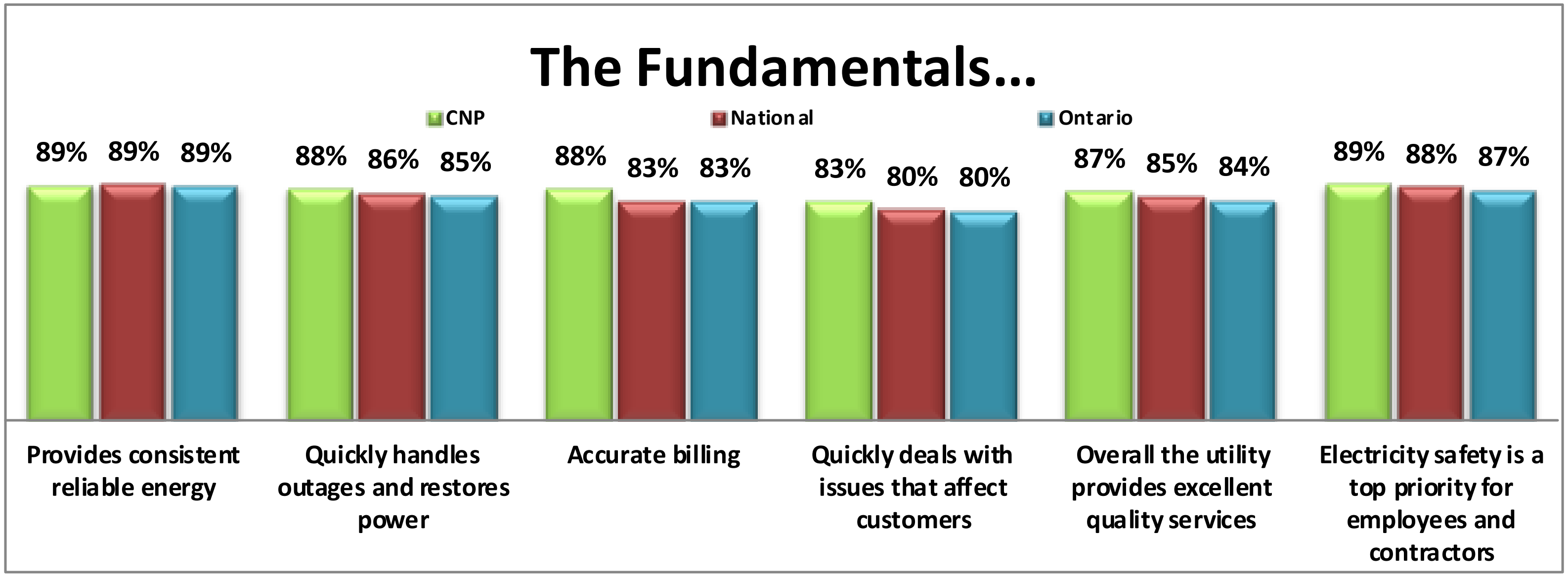
CNP's SATISFACTION SCORES – Electricity customers' satisfaction

Top 2 Boxes: 'very + fairly satisfied'	CNP	National	Ontario
PRE: Initial Satisfaction Scores	94%	89%	88%
POST: End of Interview	91%	88%	86%

Base: total respondents

- ***Satisfaction*** *happens when utility core services meet or exceed customer's needs, wants, or expectations.*
- ***Loyalty*** *(Affinity) occurs when a customer makes an emotional connection with their electric utility on a diverse range of expectations beyond core services.*

Customer satisfaction is a priority for LDCs. Rigorous measurement of this measure is an essential first step to ensuring services are delivered consistently at the expected time, money and quality levels customers desire. We remind readers, a satisfied customer is not necessarily a customer with a high affinity level i.e., emotional engagement. The satisfaction measure focuses attention on the product or service of the LDC. Customers have a more multi-faceted view about their LDC, something that is captured in the UtilityPULSE report card.



Base: total respondents

Customer Experience Performance rating (CEPr)

Some of the factors which contribute to the overall customer experience:

- Delivering accessible and consistent customer service (multi-channel)
- Understanding customer expectations

- Maintaining timely resolution timelines
- Providing effective communication(s) according to customer needs
- Demonstrating responsiveness
- Speeding up problem resolution
- Conducting problem analysis to prevent recurring issues
- Easy to do business with
- Seeking customer feedback and following through on recommendations

Customer Experience Performance rating (CEPr)			
	CNP	**National**	**Ontario**
CEPr: all respondents	86%	83%	82%

Base: total respondents

Focus Group participants were asked: *"Overall, how satisfied or dissatisfied are you with the communications you receive from CNP related specifically to your electricity service?"*

33% Very Satisfied
45% Fairly Satisfied
18% Neither
4% Fairly Dissatisfied
0% Very Dissatisfied

The CEPr rating suggests a very large majority of customers have a belief that they will have a good to excellent experience dealing with Canadian Niagara Power professionals.

Operational Effectiveness

With the exception of the Public Safety measure, performance measures would typically take the form of a monitoring and measuring (quantitative) rating. The realities are the hard numbers of actual (provable) performance may not correlate to actual customer perception.

Management Operations

Top 2 boxes, 'strongly + somewhat agree'	CNP	National	Ontario
Provides consistent, reliable electricity	89%	89%	89%
Quickly handles outages and restores power	88%	86%	85%
Makes electricity safety a top priority for employees and contractors	89%	88%	87%
Operates a cost effective electricity distribution system	76%	70%	68%
Overall the utility provides excellent quality services	87%	85%	84%

Base: total respondents with an opinion

Focus Group participants were asked: *"Based on what you've heard today about Capital & Operational Investments, as you look into the future 4-5 years from now, which of the following 3 statements comes closest to your view about the overall future performance of your utility…"*

60%	A-	Overall performance at the utility will improve over today's level
40%	B-	Overall performance will stay the same as it is, general no worse and no better
0%	C-	Overall performance will get worse over today's level.

Focus Groups – Help to understand

Each of the FG sessions followed a prescribed format where a CNP executive and the UtilityPULSE moderator welcomed attendees followed by the CNP executive providing about a 15-20 minute overview of the organization and the Distribution System Plan (DSP).

Focus Group participants were provided an opportunity to ask questions. CNP personnel left the room once questions (if any) were answered. The moderator facilitated each session by sequencing the questions consistently in each session. In addition, every participant was given the opportunity to voluntarily complete a brief paper-based questionnaire and/or to provide written comments. Of the 57 people who attended the FG sessions, 51 provided responses.

Statistically speaking, data and comments from 57 people is far too small a sample size to suggest the information applies to the whole customer base. However, data and comments from focus group participants can help in gaining a better picture of issues. Focus Groups are not about the quantitative side of research but the qualitative side. Information received in FGs is less about the rational but more about the emotional.

It was clear from the telephone survey and from FG participants, customers do not want to pay more money for electricity. We did note there were participants who were quite emotional about the *"cost of* *electricity, and they want something done about it.”* Unfortunately they were referring to billing items other than the CNP portion of the bill.

When FG participants were asked about their willingness to support an increase to pay for various Capital and Operational items, support levels ran the full gamut from Not Supportive to Very Supportive.

Capital Expenditures

Which of the following items are you willing to pay more for per month…Capital items					
CNP	**VS**	**SS**	**N**	**SU**	**NS**
Replacing aging equipment to improve safety and reliability	27%	33%	19%	10%	12%
Upgrading equipment to accommodate future growth in the community	17%	42%	17%	12%	12%
Adding automation and technology to reduce outage time	25%	38%	17%	10%	10%

Base: Focus Group respondents, scale: VS- Very Supportive, SS- Somewhat Supportive, N- Neither, SU- Somewhat Unsupportive, NS- Not Supportive

Focus Group participants were asked for comment regarding the following statement: “Electric utilities typically follow one of two strategies or main practices for replacing equipment. Which one of the these two statements comes closest to your beliefs? One, “run-to-failure” when there are limited customers affected ensures full-value is received from the equipment. Or Two, “pro-active replacement, even though it may cost more, should ensure reliable power.”

Customers from the Commercial Focus Groups were on the side of "pro-active", *"We don't operate our own business in run-to-failure mode, why would we expect CNP to do so?"*

In one Commercial and one Residential Focus Group, a comment about the need for the utility to be putting money away to replace equipment, just like a business, or just like a residential customer when they are going to replace something in their home. From a residential customer: *"A bit of smoke and mirrors here. A well run business plans for replacement."*

"Pro-active makes sense. If you run everything in your house to run-to-failure, it would cost a lot more."

"I work for the fire-department, and maintenance is really the key."

Diving deeper into the FG session information shows a marked difference between Residential and Commercial customers. Recognizing smaller sample sizes produce wider swings in data, it is interesting to note, 28% of the Residential participants were Somewhat Unsupportive or Not Supportive as compared to 9% of Commercial participants.

Of the 3 items listed above, whether we look at FG information or UtilityPULSE database information, *"Replacing aging equipment to improve safety and reliability"* garners the highest levels of support. However it still has to be noted, there are substantive numbers in the 'neither supportive' 'and 'unsupportive categories'.

Focus Group comments:

"I notice a huge improvement on the number of outages in our area."

"Upgrading equipment to accommodate future growth" has high variability in our database. The reason revolves around what economic activity is actually happening in the area. For example, in the EOP territory there are 3 large condos and 1 antique boat museum scheduled to be built. In this tiny part of CNP this is substantive economic activity. As such, Focus Group participants showed 59% support as compared to about 45% in the UP database.

CNP Residential Focus Group participants were stronger than their EOP counterparts that developers ought to pay more for access.

Focus Group comments:

"Developer should pay the whole amount."

"Maybe [CNP] haven't positioned the costs well about system access. What are the benefits?"

"Adding automation and technology to reduce outage time" generally attracts support based on the respondents assumptions about technology. That is, if the respondent is cynical about the value of technology (often learned through a previous bad experience) then there is less support to pay more for it.

Focus Group comments:

"Many people have a sour taste about technology. Smart meters and their costs."

"Skepticism is part of it, that is, technology not doing what it is supposed to do."

"[I think] Privacy is a concern."

Based on observations and comments from FG participants, investments in automation and technology have to be specific and be accompanied with the benefits of the items. When FG participants were given examples of items which would fall into the "automation and technology" category there was a positive change to support levels.

Operational Expenditures

Which of the following items are you willing to pay more for per month…Capital items					
CNP	**VS**	**SS**	**N**	**SU**	**NS**
A proactive outage management communication system	18%	44%	20%	6%	12%
Increased self-serve options on the website	10%	22%	25%	16%	27%
Extended office hours	4%	10%	27%	14%	45%
Increased tree-trimming to improve reliability	18%	35%	20%	18%	10%
Educating customers about energy conservations	10%	24%	35%	10%	22%
Educating customers and the public about electricity safety	10%	31%	27%	14%	18%

Base: Focus Group respondents, scale: VS- Very Supportive, SS- Somewhat Supportive, N- Neither, SU- Somewhat Unsupportive, NS- Not Supportive

Coincidently with the exception of *"educating customers about energy conservation"*, data from the FG participants as it relates to being supportive is in line with our UP findings from over 3,000+ telephone interviews of Ontarians. In both Residential FGs there were a number of comments, mostly from much older participants, that there isn't a need to spend money on *"educating customers about energy conservation"* because information is available on-line and there has been so much information given there isn't a need to do more. However, 50% of Commercial FG customers were supportive of promoting education.

Consistent with our findings from other Ontario LDCs, there is a majority support for *"a proactive outage management communication system"* – but not unanimous. Having a majority not supportive for *"extended office hours"* is also consistent with our findings.

Tree-trimming is a controversial subject and it was so when raised at the FG sessions. The need for tree-trimming is real as it speaks to the heart of reliability. Our data shows, in the communities affected by the December 2013 ice-storm, support for tree-trimming increased.

A review of the data for *"increased self-serve options on the website"* shows a bias towards the unsupportive. Three points worthy of note. The first is, the bias is typically age related. That is, older customers less supportive than younger customers. Second, in a world where customers want their problem solved when they want their problem solved, the need for 24/7 capability is real. If the LDC didn't invest in their website, in time, they could be seen as out-of-date. Like any other operational item, the key is to fully articulate what the investment is and the value it produces.

Focus Group comments:

About self-service options on the website*:*

“I want to talk to a real live person.”

“Canadian Niagara Power does a good job.”

Educating customers about energy conservation:

“I can’t reduce consumption much more so my support for these [operational] items is much lower.”

“Preach conservativism all you want, you’re going to raise rates anyways.”

“We’re not seeing any benefit from conserving, we’re doing what we can and we’re not seeing a return.”

“We have surplus power and we’re giving it away.”

“[You] Tell us to conserve and then put a push on buying an electric car, with an incentive.”

“The information is available on the web.”

“We’ve been bombarded for the last 3 years.”

Educating customers and the public about electricity safety:

“Some adults are about as bright as a 4 year old [and therefore should educate].”

“Children are trained in school, adults don’t need to be taught.”

The results show a range of 1 in 5 to 1 in 3 people rating the Capital or Operational items as neither supportive or unsupportive. We attribute the high numbers in this area to two things. First it is an indicator, the respondent needs to have more information before making a commitment. In short, there is a desire to make an informed choice. The second is, by being non-committal the LDC has to work harder at justifying an increase. In a somewhat perverse way, the belief is, if they say they are supportive then there really will be an increase.

The data clearly shows there is a range of views. The numbers fall into each area and, they are not small numbers that can or should be ignored. What we have noticed is, if a respondent is Somewhat Unsupportive (SU) or Not Supportive (NS) for 1 of the 3 Capital items, there is a high probability they will be SU or NS for all 3. The conclusion is simple, once a respondent (i.e., customer) is in the non-supportive camp, so-to-speak, they remain in that camp for other items which don't directly benefit them. In short, if a respondent is SU or NS for capital items then there is a very high probability they will be SU or NS for operational items. Conclusion, once there is a negative entrenched view that view is the lens by which the respondent makes decisions.

How much are customers willing to pay?

Much has been written and reported in regards to the cost of electricity. A goal of customer engagement, in addition to understanding wants & needs, is to reduce the worry customers have about the reliability and future costs of electricity. What readers may not know is, CNP has to focus on day-to-day operations while it builds, re-builds, re-furbishes and prepares the organization for a changed future. In addition, LDCs need to think in terms of decades, not just today, this week, this month, or this quarter. They need to do so in a regulated environment that is a 5 year planning environment. FG participants were asked "how much" more per month they would be willing to pay for Capital items and Operational items.

Data from our UtilityPULSE files shows lower income customers identify smaller amounts of increase for various Capital or Operational items than higher income customers. Our files also show, regardless of income, the amount a customer is willing to pay is not proportional to the number of items they support. For example, the amount a customer is willing to pay for 3 items is not 3 times the amount they would have paid for 1 item.

It is also important to note, data from all UtilityPULSE sources shows survey respondents do not have a sense of what things cost. Telling a customer an item/project costs $750,000 means little, but telling them it would increase their bill by $2.00 per month puts it in a context the customer can certainly understand and relate to. What matters most to customers is not the amount of the investment rather the personal impact of the investment.

Our database also shows about 1 in 4 customer respondents indicated they do not support any increase for any capital expense item or any operational expense item. This is a significant level of resistance. The amounts customers are willing to pay have significant variability based on income levels, personal interest in an item and/or personal benefit from an item.

Focus Group participants were asked: *"As it relates to increasing costs, what does CNP have to be mindful of?"* Here are some of the comments:

“They need to prove the benefits.”

“If it is going to cost us, what do we get?”

“Understand why rates [overall bill] are lower in other places. Quebec rates are so much lower than ours.”

“Every family is different. My costs are monthly, I would hope they would think about my household.”

“My pay has been frozen for 3 years.”

“Go after the other 82% on the bill.”

“Not a large salary increase.”

“My ability to pay is low, increases should not be above inflation.”

“An increase is coming, have you done the due diligence for the increase?”

While support for or against an item can be emotional, it is interesting to notice the difference in responses when FG participants were asked about how the LDC ought to approach the development of their DSP.

While statistically speaking the FG data collected may not be generalizable to the entire customer population, the results do however, demonstrate a person’s ability to make choices when the issue is not specific and not personal e.g., “tree-trimming”.

Could you tell us how important it is for CNP to pursue the following objectives?					
CNP	**VI**	**SI**	**N**	**SU**	**NI**
Construct, maintain and operate all assets in a safe manner	41%	37%	16%	4%	2%
Monitor and address asset condition issues in a timely manner to ensure continued reliability of supply of electricity	39%	43%	12%	6%	0%
Asset investment plans align with customer expectations of power reliability, quick restoration of power and customer service	45%	41%	12%	2%	0%
Asset investment planning is done in a way to mitigate rate impacts	37%	47%	10%	4%	2%
Ensure that environmental considerations are taken into account when designing and maintaining the overall electricity system	35%	45%	14%	6%	0%

Base: Focus Group respondents, scale: VI- Very Important, SI- Somewhat Important, N- Neither, SU- Somewhat Unimportant, NI- Not Important

Based on Focus Group data (pages 11 & 14), the data tells us that when CNP, or any other utility for that matter, is trying to "sell" an increase it will be met with some cynicism and resistance. This resistance is not unique to the LDC industry.

The above chart tells us, people will support doing things in the right way(s) for the right reason(s). Selling the cost increase of the DSP will cause resistance and for some, outrage and anger. Focus Group participants said a number of times there needs to be a cost-benefit analysis, there needs to be a benefit. Explaining "how" the DSP is done coupled with an explanation on "what" Capital and Operational expenditures are needed, will help people understand "why" there is an increase.

The Killer B's (Bills and Blackouts)

There will always be issues. To the customer the expectations from the physical world i.e., call-centre and the virtual world i.e., website, are the same: Solving the problem is the first priority. In terms of Billing Accuracy, Canadian Niagara Power rating was 88%, the Ontario benchmark was 83%.

Percentage of Respondents indicating that they had a Billing problem in the last 12 months

	CNP	National	Ontario
2015	14%	9%	15%
2014	-	16%	25%
2013	-	8%	10%
2012	-	12%	13%
2011	-	10%	16%

Base: total respondents/ (-) not a participant of the survey year

Customers understandably expect accurate bills and timely resolution of any billing issues. Billing is a frequent touch point with customers and presents an opportunity to create a positive experience and forge stronger relationships. Some the typical billing problems still encountered are:

- 78% : the amount owed was too high
- 9% : the bill arrived late
- 7% : too many extra charges
- 5% : the payment made was recorded incorrectly.
- 2% : the bill was difficult to understand

Outage Management

Outage management is a real customer concern. Expectations about the timelines of information and speed of restoration are increasing.

Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months			
	CNP	**National**	**Ontario**
2015	51%	52%	51%
2014	-	47%	49%
2013	-	41%	35%
2012	-	44%	46%
2011	-	43%	43%

Base: total respondents / (-) not a participant of the survey year

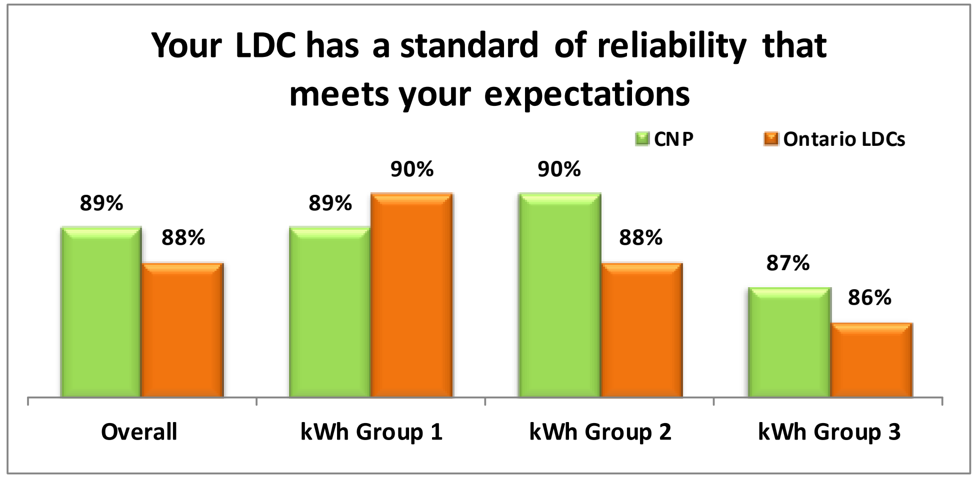
The perception of LDC competency and value are certainly linked to the frequency and duration of power outages. 88% of respondents with an opinion agree (top 2 boxes) Canadian Niagara Power "quickly handles outages and restores power."

Customers have increased their expectations as it relates to getting information about outages. What makes the dissemination of information challenging for the LDC is the need to provide the information via multiple media channels and in a timely manner whilst trying to get the power restored.

	Yes	No	Depends
Ontario LDCs	57%	35%	8%
CNP	54%	38%	8%

Base: An aggregate of respondents from the 2015 participating LDCs / total respondents from the local utility

Recognizing the importance of this topic to customers, a question about LDC reliability standards has been added to the core survey.



Base: An aggregate of respondents from the 2015 participating LDCs/total respondents from the local utility

Customers who responded to the survey offer a paradox. On the one hand, when asked about "your LDC has a standard of reliability that meets your expectations", scores are very high – no doubt somewhat comforting to the LDC. On the other hand, when asked "Should your LDC improve its reliability standards" the majority certainly said "yes".

Customers who responded to the survey offer a paradox. On the one hand, when asked about "your LDC has a standard of reliability that meets your expectations", scores are very high – no doubt somewhat comforting to the LDC. On the other hand, when asked "Should your LDC improve its reliability standards" the majority certainly said "yes". What we didn't do is tell the customer how much more money they would have to pay per month for higher standards.

An outage management system helps LDC employees to discover, locate and resolve power outages in a more informed, orderly, efficient and timely manner.

How many outages are acceptable over 12 months?		
	Ontario LDCs	**CNP**
None	23%	17%
One	15%	9%
Two	26%	28%
Three	13%	16%
Four	5%	7%
Five or more	7%	12%
Don't Know	9%	11%

Reasonable amount of time for an unplanned outage?		
	Ontario LDCs	**CNP**
Less than 15 minutes	14%	0%
16-30 minutes	15%	20%
31-60 minutes	13%	11%
1 to 2 hours	29%	36%
3 to 5 hours	13%	14%
6 to 12 hours	5%	5%
More than 12	3%	4%
Don't Know	8%	9%

Base: An aggregate of respondents from the 2015 participating LDCs / total respondents from the local utility

Focus Group participants were asked about the findings regarding 'how many outages are acceptable over 12 months'.

"Around here the season plays a role in number of outages."

"We have severe weather, blizzards and other major storms."

"Maybe if everything was underground we could get to zero."

"Long outages are killers, especially in the deep cold of winter or the high heat of summer."

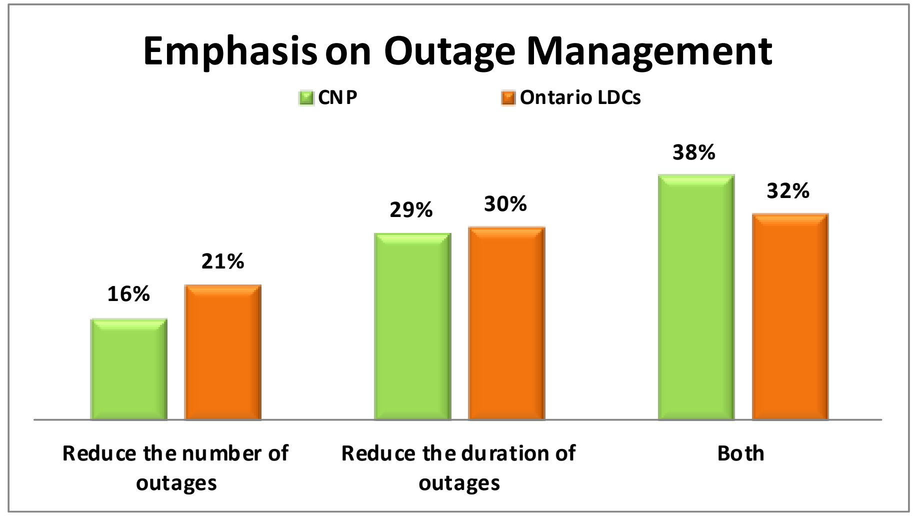
"Like to see some of the work for planned outages moved to a weekend." [Commercial customer]

"I'd like to see them look at a second (electricity) feed into our territory." [Commercial customer]

How many outages are acceptable over 12 months? Canadian Niagara Power respondents who said "none" was 17%; "one" was 9%. Clearly expectations are very high.

Respondents were asked about emphasis on outage management: reduce the number; reduce the duration; or both with an understanding a rate increase would be required.

Focus Group feedback tended towards 'reducing the duration' and 'both'.



Base: An aggregate of respondents from the 2015 participating LDCs / total respondents from the local utility

"[I think] They want both, until they get the bill."

"They're resigned that rates are going up, and if so, then do so for something that would be beneficial. [comment in support of both]

"It is the length of the outage that is a concern. In our municipality, we have to monitor our reservoir during an outage because we could run out of water."

"We run a retirement home and length of outage causes many people issues. When we know in advance we can plan, but even then we have to worry about the length of time. We have a generator but it only looks after the common room [for our residents]."

"Better equipment means better service."

LDC effectiveness responding to outages		
	Ontario LDCs	**CNP**
Responding to the power outage	85%	95%
Restoring power quickly	86%	88%
Using media channels for updates	54%	46%
Providing information about the outage	61%	61%

Base: An aggregate of respondents from the 2015 participating LDCs / total respondents from the local utility

Preferred methods for LDC to contact the customer		
	Ontario LDCs	**CNP**
Recorded telephone message	53%	57%
Email notice	29%	10%
Posted on utility's website	24%	6%
Social media - such as Twitter, facebook	17%	5%
Text message	28%	13%
Local radio	31%	6%
Local TV	23%	3%
Don't Know	3%	0%

Base: An aggregate of respondents from the 2015 participating LDCs / total respondents from the local utility

Being effective during an outage situation from the point of view of a customer requires:

- timely information on outages is provided
- utilities understand even a short outage in duration is impactful
- in large scale events, utilities should proactively provide tips on how to prepare for extended outages

- being kept informed about what is going on during an outage makes customers feel valued and that they matter.

Customer Focus – Customer Satisfaction – First Contact Resolution

Satisfaction with the contact experience

While employees can't control everything, they can control the quality of the experience. How a problem is handled can validate or invalidate a customer's perception about the utility's competency in providing excellent quality services. Customers, who contacted your LDC, rated their one-on-one transaction as follows:

Satisfaction with Customer Service			
Top 2 Boxes: 'very + fairly satisfied'	**CNP**	**National**	**Ontario**
The time it took to contact someone	80%	74%	70%
The time it took someone to deal with your problem	78%	72%	66%
The helpfulness of the staff who dealt with you	85%	72%	70%
The knowledge of the staff who dealt with you	78%	72%	70%
The level of courtesy of the staff who dealt with you	84%	79%	80%
The quality of information provided by the staff who dealt with you	79%	71%	69%

Base: total respondents who contacted the utility

Given today's technology, many customers use more than one service channel. This gives the LDC a great opportunity to connect to both digital and physical service, providing customers a true omni-channel experience.

Overall satisfaction with most recent experience			
	CNP	**National**	**Ontario**
Top 2 Boxes: 'very + fairly satisfied'	80%	76%	69%

Base: total respondents who contacted the utility

Problem solved rating

Respondents who said they contacted the utility were also asked "Do you consider the problem solved or not solved?" 73% of your LDC's respondents said the problem was solved. The Ontario benchmark rating is 69%.

Customer Focus – Service Quality

Current measures in the LDC scorecard are: New Residential Services Connected on Time; Scheduled Appointments Met on Time; and, Telephone Calls Answered on Time. These are good examples of efficiency measures as all are time based. Showing up on time may not create satisfaction; not showing up on time will cause dissatisfaction. Other dimensions of Service Quality that customers value include:

Customer Service Quality			
Top 2 boxes, 'strongly + somewhat agree'	**CNP**	**National**	**Ontario**
Deals professionally with customers' problems	86%	82%	82%
Pro-active in communicating changes and issues affecting Customers	81%	74%	77%
Quickly deals with issues that affect customers	83%	80%	80%
Customer-focused and treats customers as if they're valued	82%	74%	76%
Is a company that is 'easy to do business with'	87%	81%	81%
Cost of electricity is reasonable when compared to other utilities	62%	62%	58%
Provides good value for money	73%	67%	66%
Delivers on its service commitments to customers	88%	84%	84%

Base: total respondents with an opinion

CNP has superb ratings, 73% Provides good value for money, when compared to the Ontario benchmark and the UtilityPULSE database. None-the-less finding a way to increase the LDC's value proposition remains a challenge for every LDC.

FG participants were asked: *"Before this survey, how familiar were you with the percentage of your electricity bill that went to CNP?"*

12%	Very familiar	25%	Not very familiar
20%	Somewhat familiar	43%	Not familiar at all

Data collected in the FG shows Commercial customers are far and away more likely to say they are Very familiar or Somewhat Familiar, versus Residential customer.

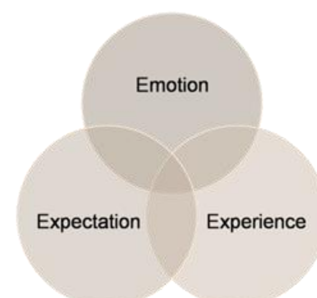
Customer Affinity

Customers continue to be more sophisticated, educated and demanding and with less money available. They expect value and quality services – not either/or but and/also. Recognizing that customers have a meaningful perspective can help the LDC drive out waste, reduce complaints, embrace new processes and new technologies leading to greater efficiency and effectiveness.

> "Whether a customer is loyal and/or satisfied will be determined by an alignment of the emotion, experience and expectation of both the customer and the LDC."

There are many reasons why LDCs should put a premium on satisfying customers. Such as: there is an obligation to satisfy people; it makes sense economically; the industry has to prove it is valuable to its customers and, increased customer satisfaction can influence employee morale and retention. A big reason is, higher levels of customer affinity (Loyalty). Loyalty, for private industry, is a behavioural metric. Loyalty, for natural monopolies (like LDCs) is an attitudinal metric.

Customer Loyalty Groups				
	Secure	**Favorable**	**Indifferent**	**At Risk**
CNP	31%	14%	55%	0%
National	18%	11%	61%	10%
Ontario	17%	11%	61%	11%



Base: total respondents

UtilityPULSE Report Card®

The purpose of the UtilityPULSE Report Card is to provide your utility with a snapshot of performance – it represents the sum total of respondents' ratings on 6 categories of attributes that research has shown are important to customers in influencing satisfaction and affinity levels with their utility.

CNP's UtilityPULSE Report Card®

Performance

	CATEGORY	CNP	National	Ontario
1	**Customer Care**	**A**	**B+**	**B**
	Price and Value	B+	B	B
	Customer Service	A	B+	B+
2	**Company Image**	**A**	**A**	**B+**
	Company Leadership	A	B+	B+
	Corporate Stewardship	A	A	A
3	**Management Operations**	**A**	**A**	**A**
	Operational Effectiveness	A	A	A
	Power Quality and Reliability	A	A	A
	OVERALL	**A**	**A**	**A**

Base: total respondents

Credibility and Trust

Higher levels of trust are the hallmarks of Secure customers and utilities benefit from a trusted relationship with their empowered customers. When people interact, either face-to-face, by telephone or on-line, if there is a lack of trust, the interaction is not going to be efficient. Trust improves the speed at which the interaction can be accomplished. The attributes which help an LDC to be seen as trusted and highly credible are: knowledge, integrity, involvement and trust. Trust is not a thing, it is a feeling. On demonstrating Credibility and Trust, Canadian Niagara Power has done well.

Credibility and Trust Index

	CNP	National	Ontario
Knowledge	86%	84%	84%
The LDC is seen as being knowledgeable about the services it provides, about what is happening in the industry, and how customers can reduce costs or manage consumption.			
Integrity	86%	82%	72%
The LDC is seen as an organization that will act in the best interests of its customers and can be counted on to provide services and resolve problems in a professional manner.			
Involvement	80%	75%	76%
The LDC is actively involved in the industry, in the community and in things that affect the customer.			
Trust	86%	81%	81%
The LDC is an organization that can be trusted and is worthy of respect.			
Overall	**85%**	**81%**	**81%**

Base: total respondents

Company Image

How customers think about their LDC has a direct influence on how customers act, react or engage with Canadian Niagara Power. For example, customers with a positive impression put less strain on the operations. In 2006, 10 years ago, our industry research showed Company Image had an 18% weighting as it relates to shaping perception about their LDC. Today, Company Image weighting for Canadian Niagara Power is 32%, Ontario is 33%, a significant change.

Attributes strongly linked to a hydro utility's image

	CNP	National	Ontario
Is a respected company in the community	88%	82%	82%
A leader in promoting energy conservation	82%	78%	77%
Keeps its promises to customers and the community	86%	79%	80%
Is a socially responsible company	85%	80%	80%
Is a trusted and trustworthy company	88%	81%	81%
Adapts well to changes in customer expectations	75%	71%	71%
Is 'easy to do business with'	87%	81%	81%
Provides good value for your money	73%	67%	66%
Overall the utility provides excellent quality services	87%	85%	84%
Operates a cost effective electricity distribution system	76%	70%	68%

Base: total respondents with an opinion

Marketing communications should capitalize on the strong image scores to reduce the worry customers have about reliability, future costs and other concerns. Technically performing the expected job well is one thing, but the LDC also has to be "seen" as performing well.

Focus Group participants were asked: “*What is it going to take for customers to see more value in the price of electricity [the CNP portion]?”*

“More incentive programs for commercial operations and market the incentives.”

“Put a face to the utility.”

“An education campaign on the 18%.”

“We take it [electricity service] for granted.”

“We’ve seen some real operational improvements.”

“Fortis has done some things right.”

“The transformer change was wonderfully handled, they (CNP) were pro-active.” [Commercial]

“Provide some comparisons with other jurisdictions.”

“I think you could ask the same question about water and gas.”

What do customers think about electricity costs?

For years electric utility customers have had a very real concern about high bills and the cost of electricity. We’ve constantly and consistently have told our clients “when a value proposition doesn’t exist or is unclear, then people will focus on price.” LDCs in Ontario certainly score low on “value for money.” When a customer struggles to pay their electricity bill they also struggle to see the LDC providing good value for money.

The good news is, LDCs have been doing more to engage customers about the utilities' plans to spend money to improve operations and/or make capital investments. While this is seen as an important process, especially by the Ontario Energy Board, it doesn't deal with the basic issue at hand – the customer's own struggle to pay the bill. Our first year of research, 1999, showed us there was a very high correlation between ability to pay and satisfaction – in 2015 the correlation is still high.

Is paying for electricity a worry or major problem …

	CNP	National	Ontario
Not really a worry	67%	67%	59%
Sometimes I worry	22%	22%	25%
Often it is a major problem	9%	8%	10%
Depends	1%	2%	2%

Base: total respondents

Additional Insights from the UtilityPULSE Database

As it relates to SMART Grid knowledge, customers polled in the Ontario survey show 37% *"have heard the term SMART Grid but know very little about it"* and 32% claimed they *"have not heard the term"*. This suggests customers will not automatically understand and accept SMART Grid technology.

The Ontario survey shows that interest in purchasing an electric vehicle remains at 34% - unchanged since 2012. 75% of those that are "interested in purchasing" claim they wouldn't be acting on their interest in purchasing for 24 months or more. The adoption rate of EVs is still in its infancy.

UtilityPULSE asked 1,269 Residential customers, located throughout Ontario and who pay the electricity bill questions pertaining to the solicitation of customer feedback and opinions on different electricity industry matters. These questions were asked with the intent of gauging the customer's perception of requesting feedback and the importance thereof. Percentage of respondents who said it was important to solicit feedback [Top 2 Boxes: 'very + somewhat important']:

- 89% on "overall satisfaction with the utility"
- 83% on "how much money is being spent on repairing equipment"
- 86% on "how much money is being spent on keeping the system reliable"
- 84% on "extending the system to help economic development in the community".

The data on the importance of "feedback" tells us customers want their voice heard. We believe this is completely in sync with, what experts call, customer centricity. However asking for feedback, but not acting on that feedback or not using the feedback in a constructive way could have some adverse consequences for the LDC i.e., lower levels of trust, credibility and customer affinity.

We've often been asked: "What does it take to be seen as having great customer service?" Our answer continues to be "have genuine empathy for customers." If you and your fellow employees don't have it, then your organization will not achieve the highest levels of customer engagement and affinity as may be possible. This requires Canadian Niagara Power to ensure it is truly embracing the strategic intent of being "customer centric" AND it requires the establishment of a corporate culture which supports both customer and employee engagement.

Focus Group participants were asked: *"What are some of the things CNP does well?"*

"Their customer service is excellent. I've never had to wait on a call. Live people."

"Office staff are extremely polite and cooperative."

"I think they do a really good job."

"We have less outages."

"They come across as professional with a good corporate image."

"They collect the money well."

"They support the community."

"Good community involvement proves they are a good corporate citizen."

"Local telephone number is great."

"Arborist was brought in when I had a tree-trimming issue. I was impressed that they did so."

"Good at advising people on planned outages."

"The linesmen are on the road right away when there is an outage. "

Customers do have a major concern over the cost of electricity – the whole bill. While it is true, customers with a high emotional attachment towards their electric utility tend to have less resistance the reality is the majority of customers do not have a high emotional connection. Justifying an increase, frankly any increase, will be negatively received. As such, we recommend highlighting the benefits or rationale for the increase. As stated earlier are you “selling” a price increase or what the increased investments are going to do for customers?

We recommend having meaningful two-way dialogue with employees (and others) to leverage the results from your 2015 customer satisfaction survey derived from speaking with 410 Canadian Niagara Power customers [October 8-22, 2015]. After-all, people cannot care about the things that they don’t know about.

UtilityPULSE
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March, 2016

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Satisfaction (pre & post)

In Ontario, the Ontario Energy Board (OEB) has made it clear Customer Satisfaction measurement will be part of an Electricity Distributor's reporting. Of the many reasons why every LDC should place a premium on satisfying customers, here are some of the important ones:

1- Every enterprise has an obligation to satisfy its customers
2- Economically, high levels of satisfaction lead to less customer complaints and less scrutiny (hence less cost)
3- As an effectiveness measure it prompts discussion about policies, procedures, planning, use of technology, and more
4- When things go wrong (and they do), customers with high levels of satisfaction handle the problem far better than customer with very low levels of satisfaction
5- For employees there is a morale boost when working in an organization with a high level of customer satisfaction
6- Customers (as well as others) have growing levels of expectations which means the things that satisfy customers today may not tomorrow.

A focus on satisfaction prompts an organization to continue to evolve in ways that make sense to those who pay the bills. A focus on satisfaction is a focus on effectiveness in the delivery of service to the customer. Satisfied customers who trust their LDC may be more likely to seek advice i.e. energy efficiency methods, and may be more receptive to important messages i.e. safety, new capital projects, etc.

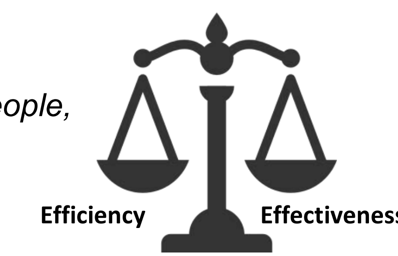
A word of caution to readers, please do not assume that great performance in an efficiency rating (such as answering the phone in 30 seconds) will lead to customer satisfaction. It will not. Answering the phone in 20 seconds but not solving the customer's problem is not going to ameliorate the customer's perception about the transaction.

Efficiency ratings won't lead to satisfaction but they can lead to dissatisfaction. Taking 90 seconds to answer the phone will create an agitated customer who, for the most part starts off being dissatisfied with the service – before you've even had a chance to deal with or solve their problem.

Customer expectations of their electricity LDC have evolved past the "provide electricity reliably, safely and billed both accurately with fair pricing". They do expect their LDC to be ethical, forward-thinking, competent and trustworthy.

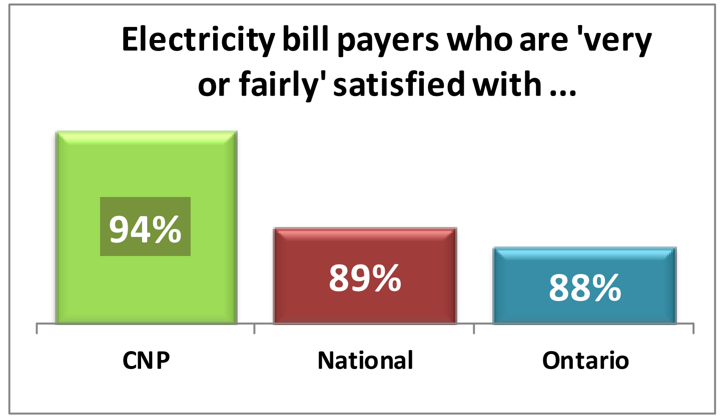
In a nutshell:

- Satisfaction is not a program, it is an outcome.
- ***Efficiency*** *is about achieving objectives with the minimum amount of people, time, money and other resources.*
- ***Effectiveness*** *ratings are measures that keep the organization and its people more future focused than efficiency ratings*
- Finding the right balance between efficiency and effectiveness measures is difficult.



- **Satisfaction** happens when utility core services meet or exceed customer's needs, wants, or expectations.

- **Loyalty** occurs when a customer makes an emotional connection with their electric utility on a diverse range of expectations beyond core services.



Base: total respondents

Satisfaction alone does not make a customer loyal; a willingness to commit and advocate for a company along with satisfaction identifies the three basic customer attitudes which underpin loyalty profiles. While satisfaction is an important component of loyalty, the loyalty definition needs to incorporate more attitudinal and emotive components.

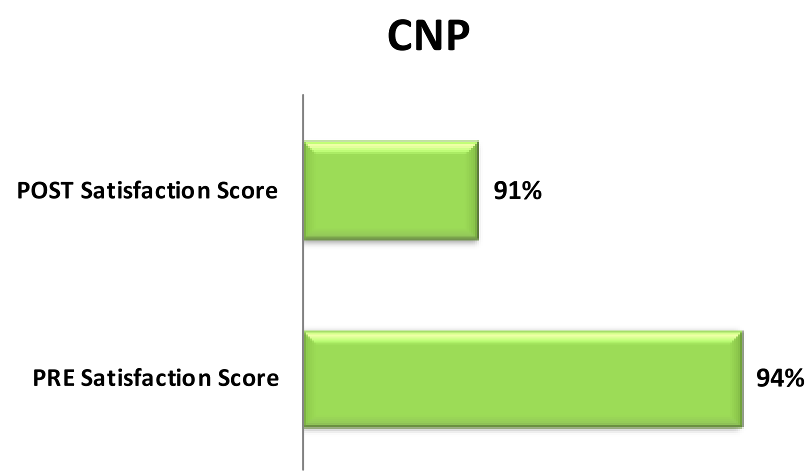
Electricity bill payers who are 'very or fairly' satisfied with…

	2015	2014	2013	2012	2011
CNP	94%	-	-	-	-
National	89%	89%	90%	88%	89%
Ontario	88%	83%	90%	86%	84%

Base: total respondents/ (-) not a participant of the survey year

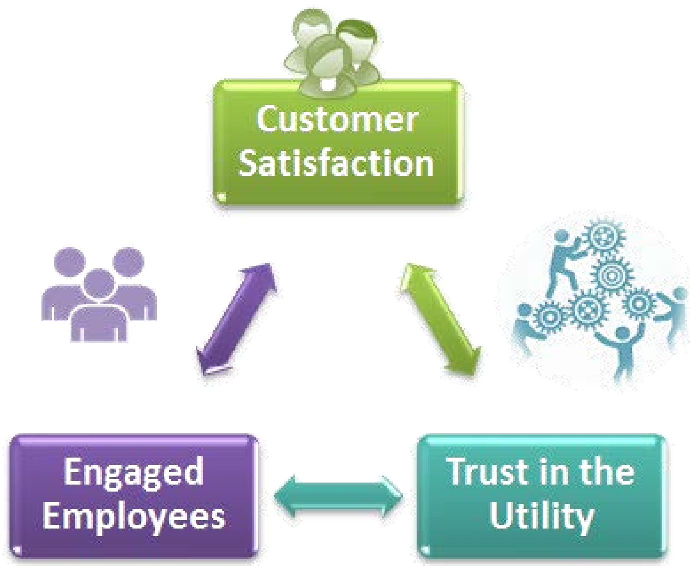
Every LDC we've worked with over the past 17 years conducting this survey can provide examples of employees who have certainly gone above and beyond the call of duty. Just listen to employees, at all levels, as they talk – with pride – about what their LDC is doing.

In the Simul/UtilityPULSE Customer Satisfaction survey, the overall satisfaction question is asked both at the beginning (PRE) and the end (POST). Asking the general satisfaction question at the start of the survey avoids bias and we obtain a spontaneous rating. This allows measurement of customers' overall impressions of the utility prior to prompting them to think of specific aspects of the relationship. After we have asked about specific aspects of the customer experience, we gain a more *considered* (or conditioned) response.



Base: total respondents

Satisfied and engaged employees who work in an organizational culture that promotes service excellence is key for completing the job both efficiently and effectively. After-all employees do more than deliver customer service – they personalize the relationship between customer and the utility



SATISFACTION SCORES – Electricity customers' satisfaction			
Top 2 Boxes: 'very + fairly satisfied'	**CNP**	**National**	**Ontario**
PRE: Initial Satisfaction Scores	94%	89%	88%
POST: End of Interview	91%	88%	86%

Base: total respondents

Customers, as human beings, are both rational and emotional. The rational side of the customer holds the LDC accountable for doing its job. The emotional side of the customer is about fulfilling expectations. Not meeting rational needs – creates dissatisfaction. Meeting emotional needs, can move a customer from neutral to higher levels of satisfaction.

Attributes strongly linked to a hydro utility’s image			
	CNP	**National**	**Ontario**
RATIONAL NEEDS			
Provides consistent, reliable electricity	89%	89%	89%
Quickly handles outages	88%	86%	85%
Accurate billing	88%	83%	83%
Provides good value for money	73%	67%	66%
Is ‘easy to do business’ with	87%	81%	81%
Operates a cost effective electricity distribution system	76%	70%	68%
EMOTIONAL NEEDS			
Deals professionally with customers’ problems	86%	82%	82%
Provides information to help customers reduce electricity costs	80%	76%	76%
Pro-active in communicating changes	81%	74%	77%
Quickly deals with issues that affect customers	83%	80%	80%
Adapts well to changes in customer expectations	75%	71%	71%
Overall the utility provides excellent quality services	87%	85%	84%

Base: total respondents with an opinion

Customer Service

There is no way the quality of customer service can exceed the quality of the people delivering it. LDCs can have all the elements of customer service in place, but if customers are disappointed with the way their transaction was handled or its results, they will not be satisfied. There are lots of things the LDC and its people cannot control, but employees can control the quality of the experience.

Having well-trained employees is foundational. The keys to good customer service is listening to understand with real empathy and then responding in a professional, knowledgeable, and timely manner. After-all it is the customer who decides whether the interaction was worthwhile and/or valued.

Respondents, who contacted their utility via the telephone or in-person about a problem, were asked about six aspects of their most recent experience with a representative from Canadian Niagara Power.

- Information – quality of information provided
- Staff attitude – level of courtesy
- Professionalism – the knowledge of staff
- Delivery – helpfulness of staff
- Timeliness – the length of time it took to get what they needed
- Accessibility – how easy it was to contact someone

"What do our **customers** want?"

1. *Their problem solved quickly*
2. *To have personal interaction with a customer care representative*
3. *To speak with a knowledgeable and courteous customer care representative*

Base: total respondents who contacted the utility

Satisfaction with Customer Service			
Top 2 Boxes: 'very + fairly satisfied'	**CNP**	**National**	**Ontario**
The time it took to contact someone	80%	74%	70%
The time it took someone to deal with your problem	78%	72%	66%
The helpfulness of the staff who dealt with you	85%	72%	70%
The knowledge of the staff who dealt with you	78%	72%	70%
The level of courtesy of the staff who dealt with you	84%	79%	80%
The quality of information provided by the staff who dealt with you	79%	71%	69%

Base: total respondents who contacted the utility

Respondents, who contacted their utility via an electronic means, e.g., email, website, social media, were asked about four aspects of their most recent experience with a representative.

Satisfaction with Customer Service via electronic means	
Top 2 Boxes: 'very + fairly satisfied'	**Overall**
The timeliness of response	60%
The quality of information provided	66%
The helpfulness of the information	66%
The level of professionalism	65%

Base: total respondents from the full 2015 database

Overall satisfaction with most recent experience			
	CNP	**National**	**Ontario**
Top 2 Boxes: 'very + fairly satisfied'	80%	76%	69%

Base: total respondents who contacted the utility

The difference between overall service quality and service encounter quality (most recent experience), viewing the service encounter as a discrete event occurring over a defined period/moment of time (such as a call about their "September billing"). Customers hold expectations of the quality of each service encounter, just as they hold expectations about the overall service quality of an LDC. When the expectations are about individual service encounters, they are likely to be more specific and concrete (such as the number of minutes one waited for a CSR) than the expectations about overall service quality (like prompt service).

Interestingly when customers do have a problem, contact their LDC, and get the problem solved their satisfaction ratings are very similar to the overall level of satisfaction that exists. It is important that LDCs have an obsession with "first call resolution" as it is very beneficial and is more than a "nice idea".

SATISFACTION SCORES – Electricity customers' satisfaction			
	Overall	**Problems Solved**	**Problems Not Solved**
Top 2 Boxes: 'very + fairly satisfied'	89%	88%	60%
Bottom 2 Boxes: 'fairly + very dissatisfied'	7%	8%	37%

Base: total respondents from the full 2015 database

Satisfaction with Customer Service			
Top 2 Boxes: 'very + fairly satisfied'	**Overall**	**Paying for electricity:**	
		No worries	**Often worry**
The time it took to contact someone	74%	75%	64%
The time it took someone to deal with your problem	71%	72%	58%
The helpfulness of the staff who dealt with you	75%	78%	59%
The knowledge of the staff who dealt with you	75%	76%	65%
The level of courtesy of the staff who dealt with you	83%	83%	73%
The quality of information provided by the staff who dealt with you	73%	75%	62%

Base: total respondents from the full 2015 database

While there is more information about customer loyalty in this report, the following chart shows the difference in customer service ratings given by customers who are "secure" versus customers who are "at risk". In addition, "at risk" customers seem to have more problems than other customers and are much more likely to contact their LDC to do something about it.

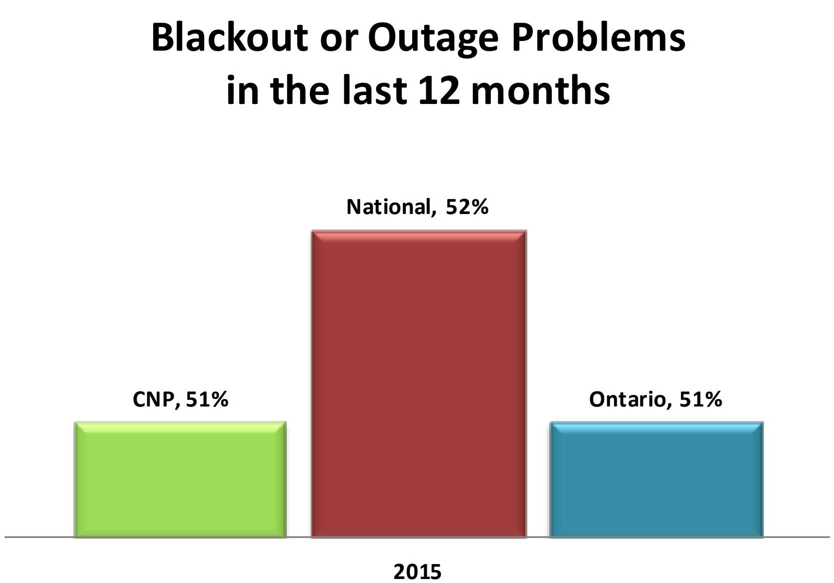
Base: total respondents from the full 2015 database

Important attributes which shape perceptions about service quality			
	CNP	**National**	**Ontario**
Deals professionally with customers' problems	86%	82%	82%
Is pro-active in communicating changes and issues which may affect customers	81%	74%	77%
Quickly deals with issues that affect customers	83%	80%	80%
Customer-focused and treats customers as if they're valued	82%	74%	76%
Is a company that is 'easy to do business with'	87%	81%	81%
Cost of electricity is reasonable when compared to other utilities	62%	62%	58%
Provides good value for money	73%	67%	66%
Delivers on its service commitments to customers	88%	84%	84%
Trusted and trustworthy company	88%	81%	81%
Respected company in the community	88%	82%	82%
Provides information and tools to help manage electricity consumption	82%	77%	77%
Adapts well to changes in customer expectations	75%	71%	71%

Base: total respondents with an opinion

Bill payers’ recent problems and problem resolution

Outages and billing problems, we call them the “Killer B’s”, the two issues most likely to cause grief to utility customers. Ensuring power reliability has and will continue to be the key operational priority for electric utilities.



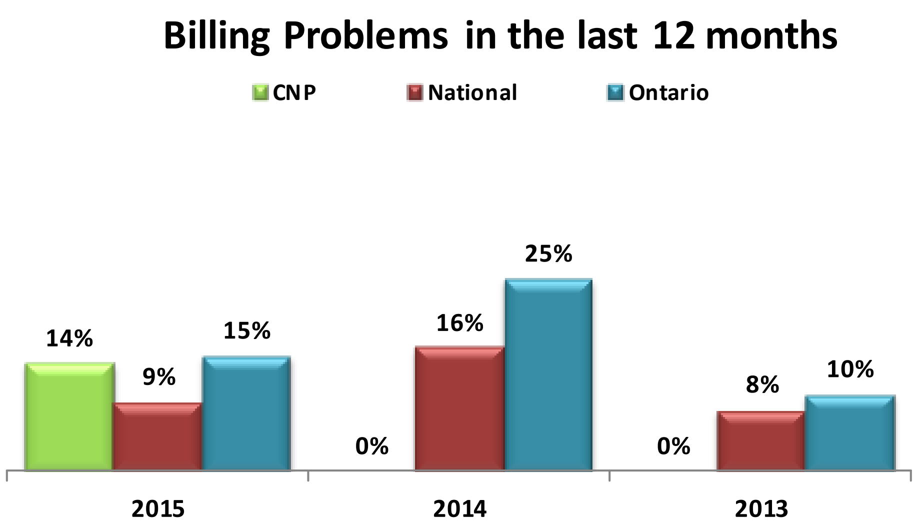
The perception of competency and value are certainly linked to the frequency and duration of power outages. 88% of respondents with an opinion agree (top 2 boxes) Canadian Niagara Power “quickly handles outages and restores power” and 89% agreed (top 2 boxes) that this LDC has a standard of reliability meeting expectations.

Base: total respondents

Like it or not, there will be times when the power goes off – and for reasons beyond the control of the LDC.

Percentage of Respondents indicating they had a Blackout or Outage problem in the last 12 months			
	CNP	National	Ontario
2015	51%	52%	51%
2014	-	47%	49%
2013	-	41%	35%
2012	-	44%	46%
2011	-	43%	43%

Base: total respondents / (-) not a participant of the survey year



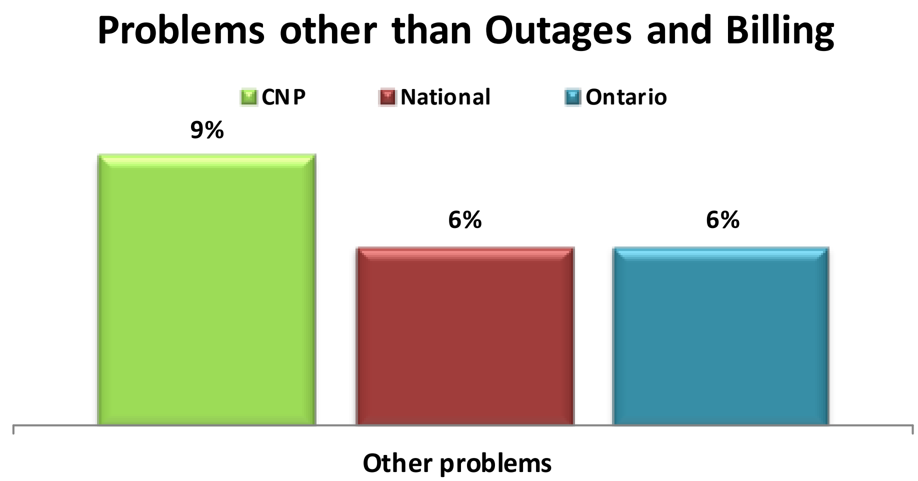
Percentage of Respondents indicating they had a Billing problem in the last 12 months			
	CNP	**National**	**Ontario**
2015	14%	9%	15%
2014	-	16%	25%
2013	-	8%	10%
2012	-	12%	13%
2011	-	10%	16%

Base: total respondents / (-) not a participant of the survey year

Types of Billing Problems	
	CNP
The amount owed was too high	78%
The bill arrived late	9%
Too many extra charges	7%
Payment incorrectly recorded	5%
The bill was difficult to understand	2%

Base: total respondents with billing problems

As it relates to problems, the Killer B's – Bills and Blackouts still occupy top ranking – while moving/setting up a new account, maintenance repairs, high bills, information on pricing, ways to save energy, incentives on energy conservation are issues which also **contribute to customer contact levels through a circa-centre or electronic media.**



Base: total respondents

Survey respondents were asked about how they contacted their utility when there was a problem. For utilities, customers continue to favour the telephone.

What method did you use to contact your electric utility when you had a problem?

Base: total respondents

Problems aggravate customers. It could be said some problems can actually anger customers. As a minimum, a problem is an inconvenience to the customer – and they want it solved/resolved. When the problem is solved with the first interaction (often called first call resolution) overall customer satisfaction improves. When customer satisfaction improves the utility benefits.

Percentage of Respondents who contacted their utility and had their problem solved in the last 12 months

	CNP	National	Ontario
Yes	73%	78%	69%
No	21%	20%	27%

Base: total respondents

Attributes describing operational effectiveness

	Overall Score	Problem Solved	Problem Not Solved
Provides consistent, reliable electricity	90%	88%	77%
Delivers on its service commitments to customers	86%	85%	68%
Accurate billing	86%	84%	64%
Quickly handles outages and restores power	87%	85%	73%
Makes electricity safety a top priority	88%	90%	79%
Has a standard of reliability that meets expectations	88%	87%	72%
Is efficient at managing the electricity system	82%	81%	63%
Is a company that is 'easy to do business with'	84%	82%	59%
Overall the utility provides excellent quality services	85%	84%	66%

Base: total respondents from the full 2015 database with an opinion

While an LDC is a natural monopoly i.e., customers can't go elsewhere and an LDC can't "fire" a customer, we recommend LDCs continue to build and strengthen their relationship with customers. UtilityPULSE categorizes respondents into 3 customer groups. Interestingly when the customer relationship is strong i.e., customers are Secure, they recall less outages and billing problems than customers who are At Risk.

Bill payers recalling a power failure or outage

	Secure	Favorable	Indifferent	At Risk
Yes	31%	40%	46%	58%
No	68%	60%	53%	42%

Base: total respondents from the full 2015 database

Bill payers recalling a billing problem

	Secure	Favorable	Indifferent	At Risk
Yes	3%	5%	10%	38%
No	97%	94%	89%	61%

Base: total respondents from the full 2015 database

Bill payers who said their problem was solved

	Secure	Favorable	Indifferent	At Risk
Yes	94%	84%	73%	37%
No	5%	15%	23%	61%

Base: total respondents from the full 2015 database

Customer Experience Performance rating (CEPr)

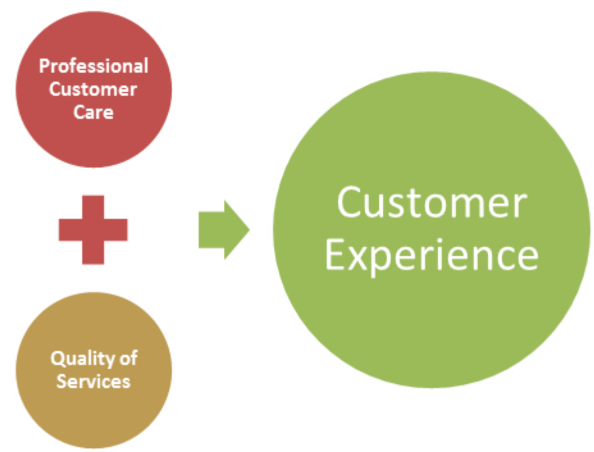
The CEPr score is an effectiveness rating and is affected by many dimensions of service. Every touch point with customers on the phone, website or in-person influences what customers think and feel about the organization. While an excellent transaction today creates a positive experience today, the perception created is that future transactions will be excellent too. Of course a negative transaction creates the perception future transactions will be negative.

When the customer experience is strong, the opportunity to build loyalty is great. When the experience is a negative one, customers often conclude the organization doesn't care. When a customer believes the organization doesn't care, outrage and anger are a very real possibility.

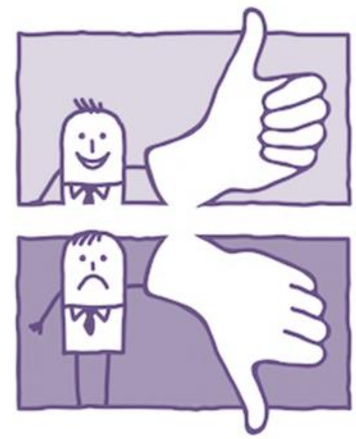
Understanding your customer's expectations for service is the first step in providing an amazing customer experience. It is essential customer care call centers develop a comprehensive understanding of what

At the heart of the CEPr are 4 central questions:

1. *Are interactions with the organization professional and productive?*
2. *Is the organization 'easy to deal with'?*
3. *Does the organization effectively meet your needs?*
4. *Does the organization provide high quality services?*



customers expect from them, whether or not their needs are being met and how they can improve their service to meet their expectations.



Some of the factors which contribute to the overall customer experience:

- Delivering accessible and consistent customer service (multi-channel)
- Understanding customer expectations
- Maintaining timely resolution timelines
- Providing effective communication(s) according to customer needs
- Demonstrating responsiveness
- Speeding up problem resolution
- Conducting problem analysis to prevent recurring issues
- Easy to do business with
- Seeking customer feedback and following through on recommendations

Customer Experience Performance rating (CEPr)

	CNP	National	Ontario
CEPr: all respondents	86%	83%	82%

Base: total respondents

The CEPr for Canadian Niagara Power is 86%. This rating would suggest a very large majority of customers have a belief they will have a good to excellent experience dealing with Canadian Niagara Power professionals.

Customer Centric Engagement Index (CCEI)

Customer engagement is often thought of as a series of activities involving the customer such as conducting a survey, holding town hall type meetings, focus groups, etc. One could call these types of activities as the behaviour side of engagement. However there is an emotional side to engagement.

This survey also provides you with an emotional look at engagement. The UtilityPULSE CCEI is a gauge of the amount of goodwill that has been generated. High numbers in CCEI suggest there is a high level of goodwill amongst your customers – this is important for two reasons. First when something goes awry for the utility, goodwill helps the utility to be resilient. Second, goodwill encourages active participation in requests to participate in engagement activities or program offerings from the utility.

The CCEI is a metric designed to get a more in-depth look at the attachment a customer has with your LDC and its brand. High levels of customer engagement (emotional) correlate strongly to high levels of Secure and Favourable customer numbers.

Engagement is how customers think, feel and act towards the organization. As such, ensuring that customers respond in a positive way requires that they are rationally satisfied with the services provided AND emotionally connected to your LDC and its brand. The more frequently and consistently an organization's products and services can connect with a customer, especially on an emotional level, the stronger and deeper the customer becomes engaged with the organization.

UtilityPULSE has identified the six key dimensions of what defines customer engagement. They are: empowered, valued, connected, inspired, future oriented and performance oriented.

Utility Customer Centric Engagement Index (CCEI)

	CNP	National	Ontario
CCEI	84%	80%	80%

Base: total respondents

Customer centric engagement is a measure of "goodwill" towards the utility. Customers who are less engaged, as measured by the CCEI are more likely to let costs and/or price impact their perceptions of their LDC. Customers who are highly engaged are more inclined to look past costs and money issues and use a rational approach to make values-based decisions. Highly engaged customers have a stronger emotional connection to your utility. It's this emotional connection that will drive commitment, loyalty and advocacy.

UtilityPULSE Report Card®

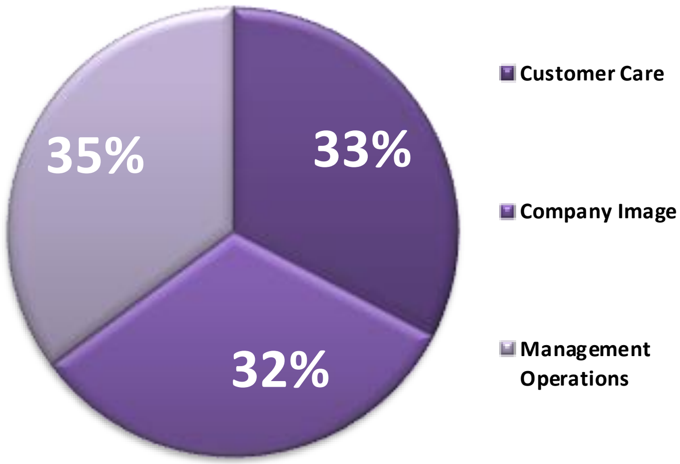
Simul's UtilityPULSE Report Card® is based on tens of thousands of customer interviews gathered over seventeen years. The purpose of the UtilityPULSE Report Card® is to provide electric utilities with a snapshot of performance – on the things that customers deem to be important. Research has identified over 20 attributes, sorted into six topic categories (we call these drivers), that customers have used to describe their utility when they have been satisfied or very satisfied with their utility. These attributes form the nucleus, or base, from which "scores" are assigned. Customer satisfaction and loyalty also play a major role in the calculations.

There are two main dimensions of the UtilityPULSE Report Card® the first is customer psyche and the other is customer perceptions about how the utility executes its business.

The Psyche of Customers

Every utility has virtually the same responsibility – provide safe and reliable electricity – yet not all customers are the same. The following chart shows the weight or significance of each category to the customer when forming their overall impression of the utility. Three major themes, each with two major categories make up the UtilityPULSE Report Card®. In effect the Report Card provides feedback about your customers' perception on the importance of each category and driver – as it relates to the benchmark.

UtilityPULSE Report Card® for Canadian Niagara Power



The UtilityPULSE Report Card is a zero sum game. As customer interest/concern in one area goes up, the others go down.

Base: total respondents

The UtilityPULSE Report Card® also provides customer perceptions about how your utility executes or performs its responsibilities. This is different, very different, from what a customer might say about a major concern or worry that they have about electricity. As our survey has shown since its inception the primary suggestion for improvement is "reduce prices", which is also a major concern which your customers have about municipal taxes, gas for the vehicle, and other utilities.

Readers of this report should note that the categories and drivers are interdependent. Which means that, for example, failure to provide high levels of power quality and reliability will have a negative impact on customer perceptions as it relates to customer service. Customer care, when it doesn't meet customer expectations has a negative impact on Company Image, etc.

Defining the categories and major drivers:

Category: Customer Care

Drivers: Price and Value; Customer Service

Just because everyone likes good customer care, that in and by itself, is not a reason to provide it – though it may be important to do so. In highly competitive industries good customer service may be a differentiating factor. The case for electric utilities is simple, high levels of customer care result in less work (hence cost) of responding to customer inquiries and higher levels of acceptance of the utility's actions.

Price and Value:

Customers have to purchase electricity because life and lifestyle depend on it. This driver measures customer perceptions as to whether the total costs of electricity represent good value and whether the utility is seen as working in the best interests of its customers as it relates to keeping costs affordable.

Customer Service:

Customers do have needs and every now and again have to interface with their utility. How the utility handles various customers' requests and concerns is what this driver is all about. Promptly answering inquiries, providing sound information, keeping customers informed and doing so in a professional manner are the major components of this driver.

Category: Company Image

Drivers: Company Leadership; Corporate Stewardship

Utilities have an image even if they do not undertake any activities to try to build it. A company's image is both a simple and complex concept. It is simple because companies do create images that are easily described and recognized by their target customers. It is complex because it takes many discrete elements to create an image which includes, but is not limited to: advertising, marketing communications, publicity, service offering and pricing.

An electric utility trying to manage its image has one more challenge to deal with, and that is the electric industry itself. There are so many players that residential customers (in particular) don't know who does what or who is responsible for what. So when there are political or regulatory announcements, the local utility is often swept up into the collective reaction of the population.

Company Leadership

This driver is comprised of customer perceptions as it relates to industry leadership, keeping promises and being a respected company in the community.

Corporate Stewardship

Customers rely on electricity and want to know that their utility is both a trusted and credible organization that is well managed, is accountable, is socially responsible and has its financial house in order.

Category: Management Operations

Drivers: Operational Effectiveness; Power Quality and Reliability

Electrical power is the primary product which utilities provide their customers and, they have very high expectations that the power will be there when they need it. Customers have little tolerance for outages. The reality is, every utility has to get this part right…no excuses. It is the utility's core business. This category and its drivers are clearly the most important for fulfilling the rational needs of a utility's customers.

Operational Effectiveness

This driver measures customers' perceptions as they relate to ensuring that their utility runs smoothly. Attributes such as: accurate billing and meter reading, completing service work in a professional and timely manner and maintaining equipment in good repair are deemed as important to customers.

Power Quality and Reliability

Power outages are a fact of life – and, customers know it. They expect their utility to provide consistent, reliable electricity, handle outages and restore power quickly and make using electricity safely an important priority.

CNP's UtilityPULSE Report Card®

Performance

	CATEGORY	CNP	National	Ontario
1	**Customer Care**	**A**	**B+**	**B**
	Price and Value	B+	B	B
	Customer Service	A	B+	B+
2	**Company Image**	**A**	**A**	**B+**
	Company Leadership	A	B+	B+
	Corporate Stewardship	A	A	A
3	**Management Operations**	**A**	**A**	**A**
	Operational Effectiveness	A	A	A
	Power Quality and Reliability	A	A	A
	OVERALL	**A**	**A**	**A**

Base: total respondents

As the UtilityPULSE Report Card® shows, the total customer experience with an electric utility is defined as more than “keeping the lights on”. Customers deal with your utility every day for a variety of reasons, most likely because they need someone to help them solve a problem, answer a question or take their order for service. All your employees, from customer service representatives to linemen, leave a lasting impression on the customers they interact with. In effect there are many moments of truth. Moments of truth are every customer touch point a utility has with their customers. Therefore, managing these moments of truth creates higher levels of Secure customers while reducing the number of At Risk customers that exist.

It's the small things done consistently that matter: Things like greeting every customer, whether on the phone or in person, in a friendly and helpful manner. Things like listening to the customer's needs, providing solutions to their problems and showing appreciation to the customer for their business.

Utilities now recognize customer communications as a valuable aspect of their business. The better a utility communicates with customers in a manner that speaks to them, the more satisfied they are with their overall service. “Sending out information” is not the same as having a “conversation” with a customer. We believe it is increasingly important to channel your communications to the various customer segments which exist.

Obviously employees – in every area – play a critical role in customer service success. Consequently how they feel about their job responsibilities and role in the company will be communicated indirectly through the level of

service which they actually provide customers with whom they interact. The reality is engaged employees are the key to excellent customer care.
Our survey work with employees shows there are many elements of an organizational culture to support the people model needed to achieve high levels of engagement.

Our research has identified 6 main drivers that promote and support people giving their best:

People Model

- **Empowered**
- **Valued**
- **Connected**
- **Inspired**
- **Growing**
- **Performance oriented**

There are 12 key processes from “attracting employees” to “saying goodbye to employees” are part of your people model to get the best performance from every employee.

We believe taking the time to understand the difference between employee satisfaction and organizational culture is worthwhile from a resourcing perspective and from a people development perspective. Every organization has a culture – we believe it is a leadership imperative to install and maintain a culture that ensures you attain the achievements and successes of your utility’s many investments in people, technology and equipment. It is true, organization culture affects everyone and everyone affects organization culture.

The Loyalty Factor

Hierarchy of Loyalty

© UtilityPULSE

If a customer is satisfied, it doesn't necessarily mean he or she is loyal. Satisfaction is about fulfilling promises/expectations; loyalty goes way beyond that by creating exceptional experiences and long-lasting relationships. There is a reason why marketing campaigns strive to build brand loyalty, not brand satisfaction. Measuring customer loyalty in an industry where many customers don't have a choice of providers doesn't make sense. Or does it?

The answer depends on how you define "customer loyalty."

Private industry often equates customer loyalty with basic customer retention. If a customer continues to do business with a company, the customer is, by definition, considered to be loyal. If this definition were applied to many companies in the utility industry, all customers would automatically be considered loyal. As such, measuring customer loyalty would appear to be unnecessary.

Natural monopolies (like LDCs) are not really different in what they should measure except that trying to determine which customers are "loyal" or "at risk" is not about their future behaviour but more about their "attitudinal" loyalty (are they advocates?).

Whether a customer is loyal and/or satisfied will be determined by an alignment of the emotion, experience and expectation of both the customer and the LDC.

Perhaps a better or more relevant way for utilities to approach the definition of customer loyalty is to further expand how they think about loyalty. Consider the following definition: Customer loyalty is an emotional disposition on the part of the customer affecting the way(s) in which the customer (consistently) interacts, responds or reacts towards the company – its products & services and its brand.

So what does it mean to respond favourably to a company? At a basic level, this can mean choosing to remain a customer. As previously mentioned however, this is essentially a non-issue for many utility companies. It then becomes necessary to think beyond just customer retention. One needs to consider other ways in which customers can respond favourably toward a company.

Some Tips to build loyalty:

- ✓ **Solve problems quickly**
- ✓ **Treat customers right**
- ✓ **Listen to complaints**
- ✓ **Be personal; create a great experience**
- ✓ **Friendly customer service**
- ✓ **Accessible information or help**
- ✓ **Good reputation**
- ✓ **Demonstrate you care**

Other favourable responses or behaviours can be classified into one of three categories reflecting the concept of customer loyalty:

- Participation
- Compliance or Influence
- Advocacy

Specific examples of potential participatory behaviour in the electric utility industry include:

- Signing up for programs that help the customer reduce or manage their energy consumption
- Using the utility as a consultant when selecting energy products and services from a third party
- Participating in pilot programs or research studies.

Specific examples of potential compliance or influence behaviours that utility customers might exhibit include:

- Seeking the utility's advice or expertise on an energy-related issue
- Voluntarily cutting back on electricity usage if the utility advised the customer to do so
- Accepting the utility's energy advice or referrals to energy contractors or equipment
- Being influenced by the utility's opinion regarding energy- management advice, equipment, or technologies
- Providing personal information that enables the utility to better serve the customer
- Paying bills online.

Creating customer advocates can be especially important for a company in a regulated industry. In the absence of customer advocates, or worse, in a situation where customers speak unfavourably about a company or actively work to support issues that are counter to those the company supports, companies can suffer a variety of negative consequences like increased business costs, lawsuits, fines and construction delays. For an electric utility, specific examples of potential advocacy behaviour include:

- Supporting the utility's positions or actions on energy-related public issues, including the environment
- Supporting the utility's position on the location and construction of facilities
- Providing testimonials about positive experiences with the utility.

In sum, loyal behaviour in the utility industry may not be as evident as it is in a more competitive environment. Measuring customer loyalty in a generally non-competitive industry requires one to think about loyalty in non-traditional ways. Customer loyalty is an intangible asset that has positive consequences or outcomes associated with it no matter what the industry. Properly measuring loyalty among utility customers requires thoughtful probing to thoroughly identify the range of participation, compliance, and advocacy behaviours that will ultimately benefit the company in meaningful ways, and foster happier and more loyal customers.

The UtilityPULSE Customer Loyalty Performance Score segments customers into four groups: **Secure** – the most loyal - **Still Favorable**, **Indifferent**, and **At risk**.

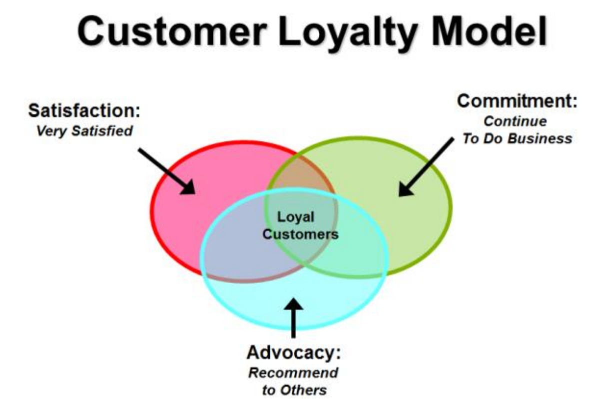
Secure customers are "very satisfied" overall with their local electricity utility. They have a very high emotional connection with their utility and definitely would recommend their local utility.

Still favorable customers are "very satisfied" overall, "definitely" or "probably" would recommend their local utility and not switch if they could.

Indifferent customers are less satisfied overall than secure and still-favorable customers and less inclined to recommend their local utility or say they would not switch.

At risk customers, who are "very dissatisfied" with their electricity utility, "definitely" would switch and "definitely" would not recommend it.

Loyalty is driven primarily by a company's interaction with its customers and how well it delivers on their wants and needs.

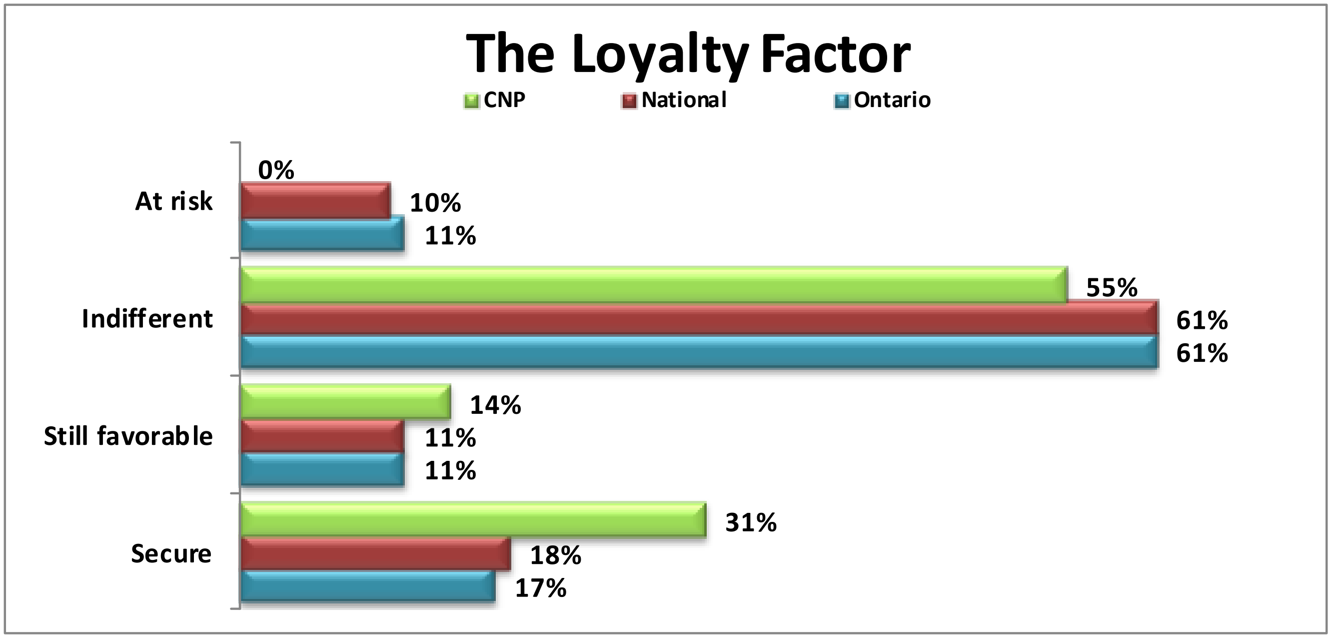


Loyalty is based on likelihood to:

- ***Satisfaction: overall satisfaction***
- ***Commitment: continue as a customer***
- ***Advocacy: willingness to recommend***

Customer Loyalty Groups				
	Secure	Favorable	Indifferent	At Risk
2015	31%	14%	55%	0%

Base: total respondents

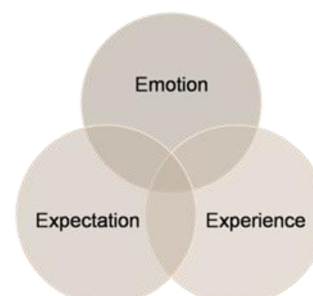


Base: total respondents

Customer Loyalty Groups				
	Secure	**Favorable**	**Indifferent**	**At Risk**
		Ontario		
2015	17%	11%	61%	11%
2014	17%	10%	57%	17%
2013	24%	15%	51%	11%
2012	20%	13%	53%	14%
2011	17%	13%	54%	16%
		National		
2015	18%	11%	61%	10%
2014	20%	11%	56%	13%
2013	26%	17%	47%	10%
2012	30%	13%	46%	11%
2011	28%	14%	46%	12%

Base: total respondents

"Whether a customer is loyal and/or satisfied will be determined by an alignment of the emotion, experience and expectation of both the customer and the LDC."



Secure customers' experiences and perceptions are distinct from those of Indifferent customers. There is yet an even greater gap between those identified as Secure versus At Risk.

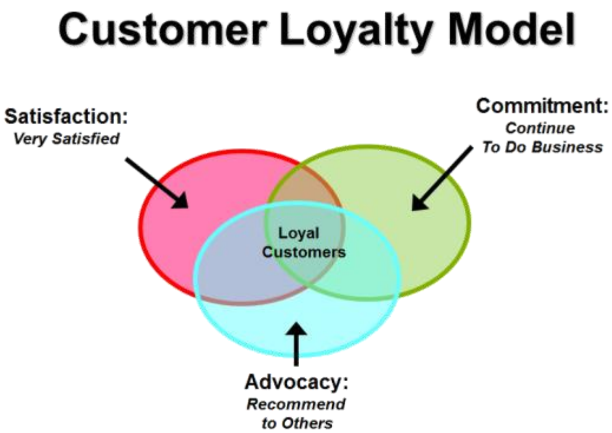
- Problems are experienced and remain unresolved far more often by the Indifferent or At Risk segments in comparison to others. This is not an unusual finding.
- Other areas of interaction also revealed considerable differences among the segments. Consistently, Secure customers' perceptions are most positive.

Important attributes which shape perceptions about customer affinity

	Overall	Secure	At Risk
Customer focused and treats customers as if they're valued	79%	94%	49%
Is pro-active in communicating changes and issues which may affect customers	79%	92%	5%
Deals professionally with customers' problems	85%	96%	60%
Provides information to help customers reduce their electricity costs	78%	91%	53%
Quickly deals with issues that affect customers	82%	96%	56%
Delivers on its service commitments to customers	86%	98%	65%
Provides information and tools to help manage electricity consumption	79%	92%	53%
Is 'easy to do business with'	84%	97%	55%
Adapts well to changes in customer expectations	75%	90%	45%
The cost of electricity is reasonable when compared to other utilities	60%	79%	34%
Provides good value for your money	69%	88%	36%
Provides consistent reliable electricity	90%	99%	76%
Operates a cost effective electricity distribution system	72%	91%	40%
Overall the utility provides excellent quality services	85%	98%	61%

Base:data from the full 2015 database from those respondents with an opinion

Customer commitment



Customer loyalty is a term used to embrace a range of customer attitudes and behaviours. One of the metrics used to gauge loyalty is the measure of **retention,** or intention to buy again; this loyalty attitude is termed **commitment.** For LDCs commitment is not about behaviour it is about attitude i.e., do they want to remain your customer.

Customer commitment is a very important driver of customer loyalty in the electricity service industry. In a similar way to trust, commitment is considered an important ingredient in successful relationships. In simpler terms, commitment refers to the motivation to continue to do business with and maintain a relationship with a business partner i.e. the local utility.

For electric utilities, this measurement is about identifying the number of customers who feel they "want to" vs "have to" do business with you. Potential benefits of commitment may include word of mouth communications - an important aspect of attitudinal loyalty. Committed customers have been known to demonstrate a number of beneficial behaviours, for example committed customers tend to:

- Come to you. One of the key benefits of establishing a good level of customer loyalty is, customers will come to you when they need a product or service

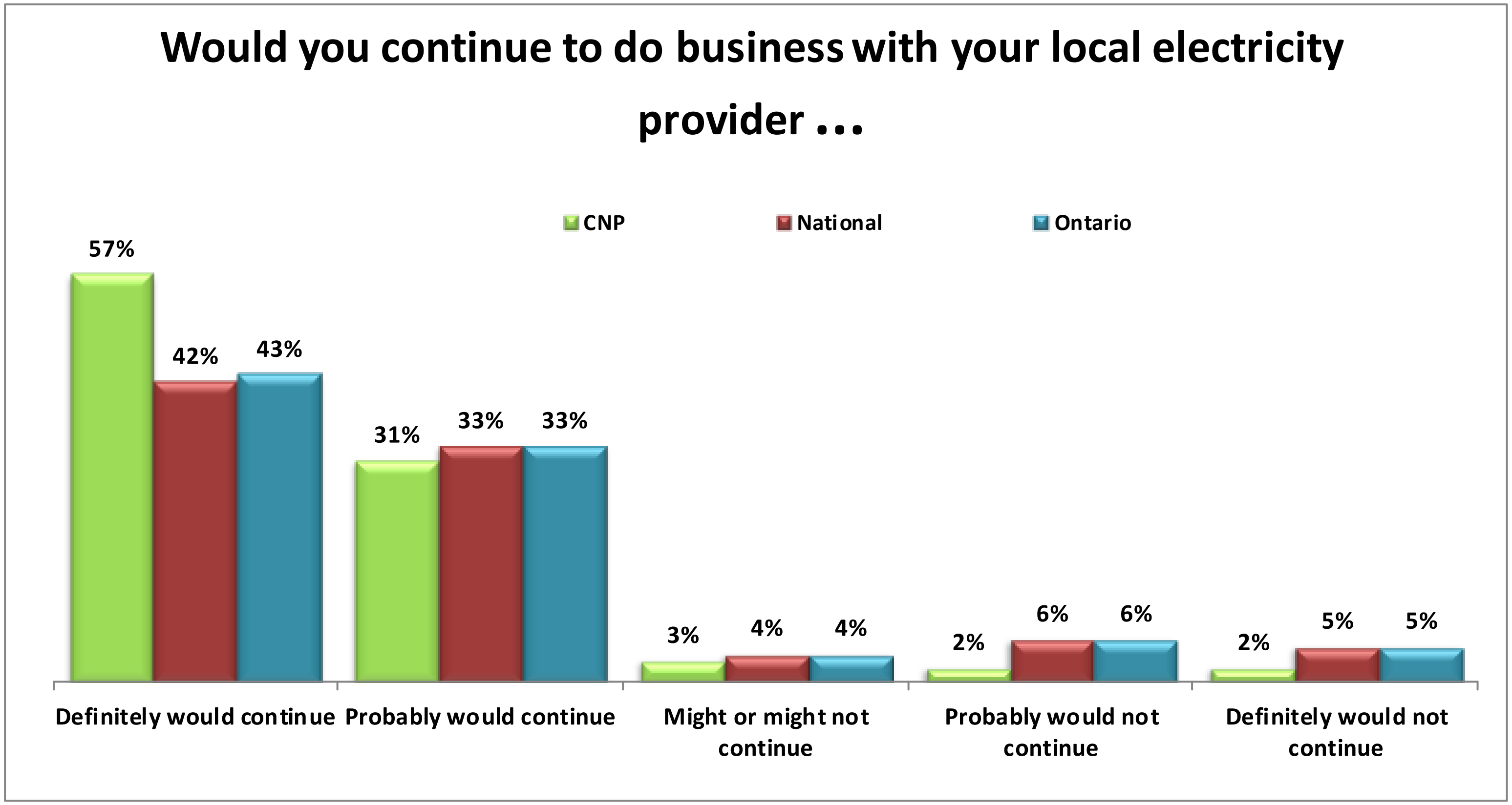
- Validate information received from 3rd parties with information and expertise that you have
- Try new products/initiatives
- Perhaps they will even trust you when recommendations are made
- Be more price tolerant
- More receptivity of utility viewpoints on various issues
- More tolerance of errors or issues which inevitably take a swipe at the utility
- Stronger levels of perception regarding how the utility is managed.

Though customers can not physically leave you, they can emotionally leave you and when they do, it becomes an extreme challenge to garner their participation or support for utility initiatives.

Electricity customers' loyalty – … Is a company that you would like to continue to do business with

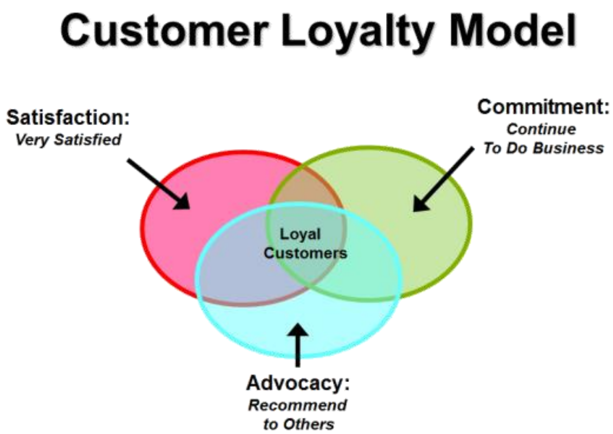
	CNP	National	Ontario
Top 2 Boxes: 'Definitely + Probably' would continue	88%	75%	77%
Definitely would continue	57%	42%	43%
Probably would continue	31%	33%	33%
Might or might not continue	3%	4%	4%
Probably would not continue	2%	6%	6%
Definitely would not continue	2%	5%	5%

Base: total respondents



Base: total respondents

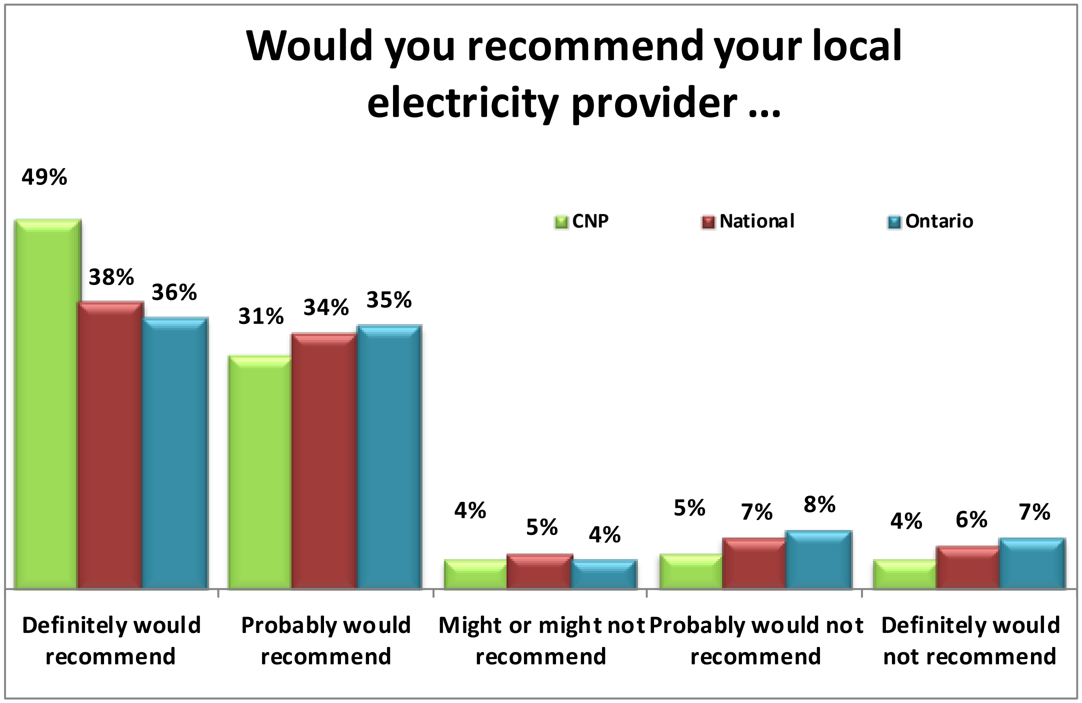
Word of mouth



Advocacy is one of the metrics measured in determining customer loyalty. Essentially, companies believe a loyal customer is one that is spreading the value of the business to others, leading new people to the business and helping the company grow. Customer referrals, endorsements and spreading the word are extremely important forms of customer behaviour. For LDCs this is about generating positive referants about the LDC as a relevant and valuable enterprise.

When customers are loyal to a company, product or service, they not only are more likely to purchase from the company again, but they are more likely to recommend it to others – to openly share their positive feelings and experiences with others. In today's world, thanks to the Internet, they can tell and influence millions of people. That equates to new customers and revenue. The same holds true, if not more, when customers are disloyal. Disgruntled customers could share their negative experiences with an ever-widening audience, jeopardizing a company's reputation and resulting in fewer engaged customers and/or customers who are Favourable or Secure. Secure customers, typically are advocates and they are deeply connected and brand-involved.

Would you tell me if you agree or disagree with the following statement? Canadian Niagara Power is a company that you would recommend to a friend or colleague …



Base: total respondents

Word of mouth communication is a very powerful form of communication and influence. When customers are speaking to other customers (or their peers) it is more credible, goes through less perceptual filters and can enhance the view of services or products better than marketing communication.

There are two forms of word of mouth which utilities need to understand. The first is Experience-based word of mouth which is the most common and most powerful form. It results from a customer's direct experience with the utility or the re-statement of a direct experience from a trusted source.

The second is Relay-based word of mouth. This is when customers pass along important messages to others based on what they have learned through the more traditional forms of communications. For example, if the utility was communicating an offer for "free LED lights" chances are high that the offer will be "relayed" to others through word of mouth.

For an electric utility, specific examples of potential positive advocacy behaviour include:

- *Recommending that other customers specifically locate in the geographic area that is serviced by that utility*
- *Supporting the utility's positions or actions on energy-related public issues, including the environment*
- *Supporting the utility's position on the location and construction of facilities*
- *Providing testimonials about positive experiences with the utility*

Electricity customers' loyalty – … is a company that you would recommend to a friend or colleague			
	CNP	National	Ontario
Top 2 boxes: 'Definitely + Probably' would recommend	79%	72%	71%
Definitely would recommend	49%	38%	35%
Probably would recommend	31%	34%	35%
Might or might not recommend	4%	5%	4%
Probably would not recommend	5%	7%	8%
Definitely would not recommend	4%	6%	7%

Base: total respondents

Our survey research as well as theory backs up the fact that if your customers are willing to endorse you and put their reputation on the line to recommend you, they also trust you and are satisfied with the service you are providing. As stated earlier, loyalty is not about behaviour in the LDC world, but one of attitude.

Corporate image

Twenty years ago many LDCs didn't put too much effort into managing their corporate brand/image. One could argue customers cared less about image and more about operational items such as reliability, restoring power quickly and billing accuracy. In fact, our research from 2006 shows Company Image represented about an 18% weight in affecting the customer's perception about their utility.

But times and customer expectations have changed a lot since then. Customers expect their utility to do the core job exceptionally well AND be much more to customers and the community. They expect you'll be socially responsible, have information they can use to reduce energy costs, be available to answer questions about the industry, etc. In 2015, Company Image represents about a 33% weight in affecting the customer's perception.

In a world where most customers feel time pressed and bombarded with information, a utility should put some real energy behind communicating its brand. The brand of a company is really its reputation. Just like a personal reputation, a brand reputation is formed based on the behaviors and actions of the company (or person), and how those behaviors and actions are perceived. After-all a positive brand image supports a positive perception of the organization. There will always be a brand/image, an LDC should actively manage its reputation, image and brand in order to have the brand/image it desires.

Every LDC has a brand and a brand image, while an image can be affected by events in the industry beyond the control of the LDC, the reality is there is a cost benefit to improving the customer experience, generating higher levels of customer engagement and growing the numbers of Favourable and Secure customers. Customers expect your utility will conduct its business professionally ***AND*** be a proactive enterprise. How would they know, if you don't communicate with them?

Marketing – Communications			
	CNP	**National**	**Ontario**
Topics that require more pro-active communication			
Cost of electricity is reasonable when compared to other utilities	62%	62%	58%
Adapts well to changes in customer expectations	75%	71%	71%
Provides good value for money	73%	67%	66%
Spends money prudently to keep the system reliable and up-to-date	79%	73%	73%
Operates a cost effective electricity distribution system	76%	70%	68%
Topics that your utility scores very well on			
Is a respected company in the community	88%	82%	82%
A company to "continue to do business with'	85%	82%	82%
Overall the utility provides excellent quality services	87%	85%	84%
Standard of reliability delivering electricity that meets expectations	89%	87%	87%
Provides consistent, reliable energy	89%	89%	89%

Base: total respondents with an opinion

Corporate Credibility & Trust

So, you have taken the time to listen to your customers and stakeholders. What next? Everyone will be looking at you to follow through on this feedback. You need to start establishing your credibility. You have to demonstrate that you can be trusted to get the job done and deliver on your promises. And, you need to do this in a way which builds your credibility and improves trust.

Creating credibility is a process, which advances only through honest, continuous communication between the utility, its regulators, and the public at large. Pro-active and credible communications from an LDC should do three things for its customers: 1- demonstrate competency 2- build confidence and 3- show a future orientation.

Attributes strongly linked to Credibility & Trust

	CNP	National	Ontario
Overall the utility provides excellent quality services	87%	85%	84%
Keeps its promises to customers and the community	86%	79%	80%
Customer-focused and treats customers as if they're valued	82%	74%	76%
Is a trusted and trustworthy company	88%	81%	81%

Base: total respondents with an opinion

Trust and credibility are indicators of the degree of confidence stakeholders have in your organization's ability to deliver on its commitments. Trust and credibility are outcomes based on what your utility actually does, not what it might be doing.

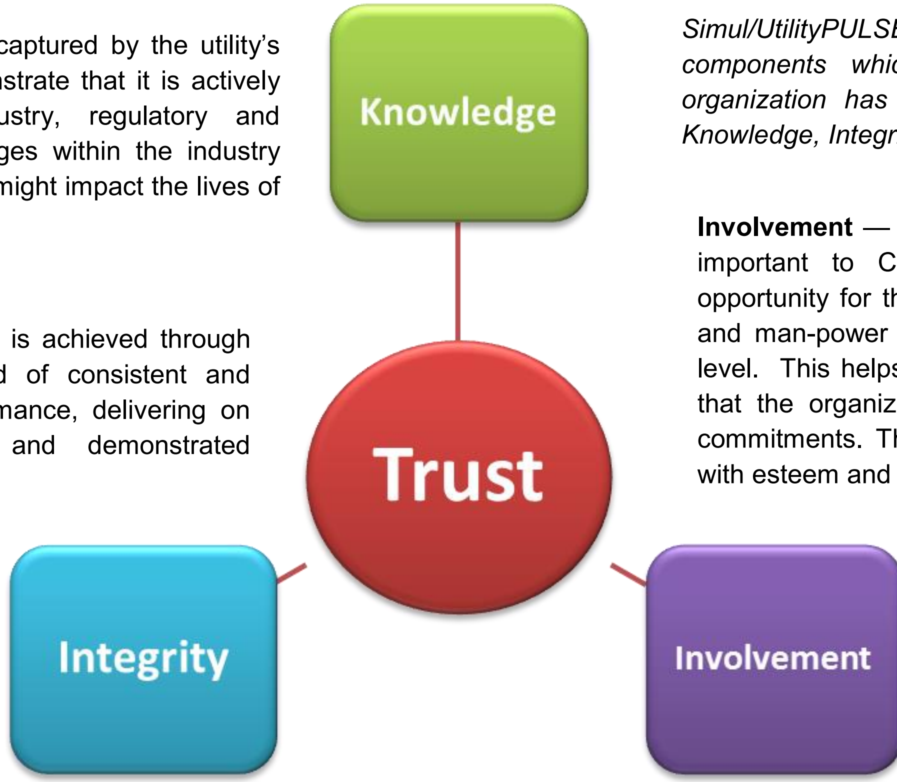
Simul/UtilityPULSE research shows the under-pinning components which lead customers to believe an organization has credibility and can be trusted are: Knowledge, Integrity, Involvement and Trust.

Knowledge is captured by the utility's ability to demonstrate that it is actively aware of industry, regulatory and economic changes within the industry and how these might impact the lives of customers.

Trust — Trust is achieved through a track record of consistent and reliable performance, delivering on commitments and demonstrated accountability.

Involvement — Corporate Involvement is increasingly important to Canadian communities as it is an opportunity for their local utility to use their resources and man-power to benefit people at the community level. This helps to build credibility as customers see that the organization is acting and delivering on its commitments. This helps customers regard the utility with esteem and respect.

Integrity is established by demonstrating adherence to a code of conduct. It requires consistently acting in accordance with the values and goals that have been communicated to customers.



Credibility and Trust Index
Canadian Niagara Power 85%
Ontario 81%
National 81%

How can service to customers be improved?

Every business, even natural monopolies, need to keep a focus on its customers, its standards of operations and in being responsive to problems. Insights into what isn't working or what can be done to improve often come from customers. Continuous improvement is the new normal.

Customers are more informed, more aware, more conscious of what's going on around them and in this age of internet and social media, they are better equipped to influence service quality and outcomes. They have learned to compare products and services, to document and monitor customer service and satisfaction, and to request or demand higher quality. And, when things go wrong, customers also know they are "one click" away from the world knowing about it.

As a further way to identify pressure points and areas of concern, respondents were asked to give their top one or two priorities for improvement to their local utility's service.

For 2015 there is heightened awareness for the need to maintain equipment, keep things up to date, improve reliability, and communicate effectively, but true to historical form the number one suggestion remains "better prices/lower rates".

And we are interested in knowing what you think are the one or two most important things Canadian Niagara Power could do to improve service to their customers?

One or two most important things 'your local utility' could do to improve service	
CNP	**% of all suggestions**
Better prices/lower rates	55%
Improve reliability of power	19%
Better communication with customers	7%
Improve/simplify/clarify billing	6%
Extend service hours/availability of hydro representative	6%
Be more efficient	4%
Better maintenance	4%
Eliminate SMART meters	2%
Information & incentives on energy conservation	1%
Better online presence	1%
Staff related concerns	1%

Base: total respondents with suggestions

What do customers think about electricity costs?

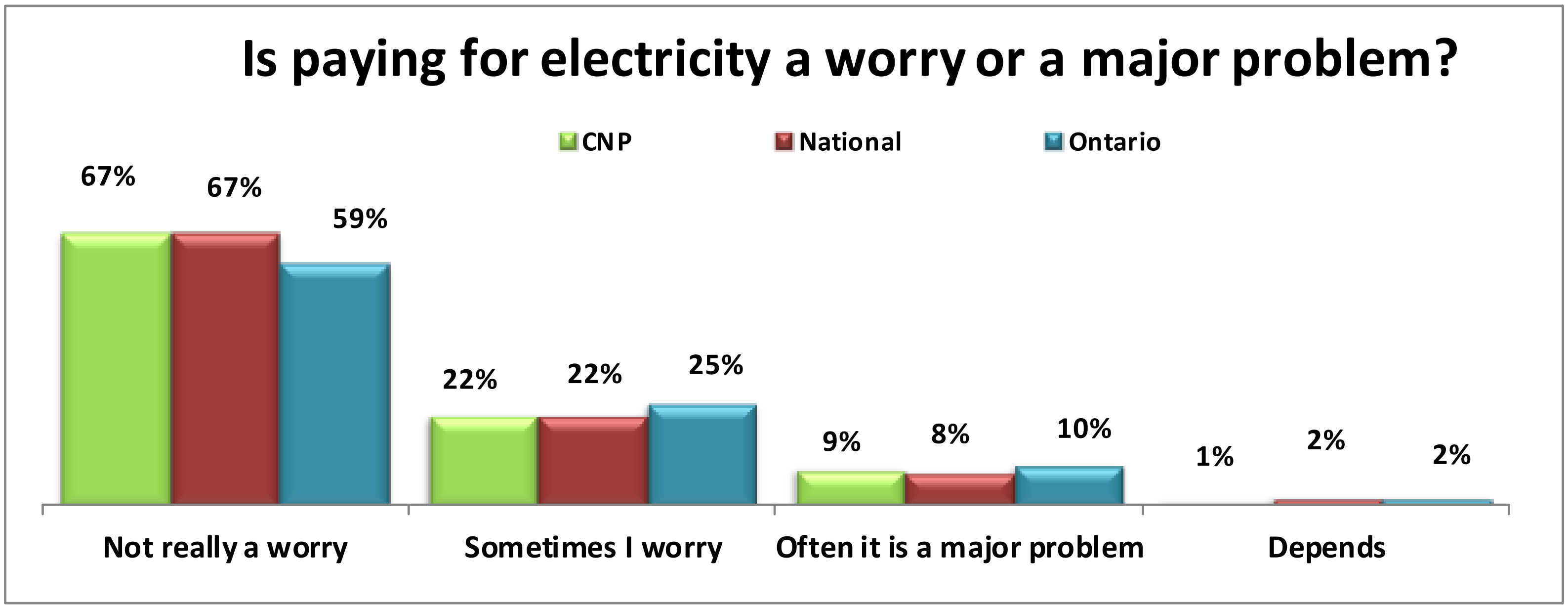
For years electric utility customers have had a very real concern about high bills and the cost of electricity. We've constantly and consistently have told our clients "when a value proposition doesn't exist or is unclear, then people will focus on price". LDCs in Ontario certainly score low on "value for money". The reality is, when a customer struggles to pay their electricity bill they struggle to see the LDC providing good value for money.

The good news is LDCs have been doing more to engage customers about the utilities' plans to spend money to improve operations and/or make capital investments. While this is seen as an important process, especially by the Ontario Energy Board, it doesn't deal with the basic issue at hand – the customer's own struggle to pay the bill. Our first year of research, 1999, showed us there was a very high correlation between ability to pay and satisfaction – in 2015 the correlation is still very high.

Next I am going to read a number of statements people might use about paying for their electricity. Which one comes closest to your own feelings, even if none is exactly right? Paying for electricity is not really a worry, Sometimes I worry about finding the money to pay for electricity, or Paying for electricity is often a major problem?

Is paying for electricity a worry or a major problem?				
	Not a worry	**Sometimes**	**Often**	**Depends**
CNP	67%	22%	9%	1%
National	67%	22%	8%	2%
Ontario	59%	25%	10%	2%

Base: total respondents



Base: total respondents

Is paying for electricity a worry or a major problem?				
	Not a worry	**Sometimes**	**Often**	**Depends**
CNP				
<$40,000	60%	32%	8%	0%
$40<$70,000	67%	18%	11%	1%
$70,000+	78%	12%	10%	0%

Base: total respondents

For 2015, UtilityPULSE segmented respondents into 3 "average kWh groups". Group 1 represents 25% of the customer base derived from segmenting the customer data file into the first quartile of kWh usage. Group 2 represents the middle 50% of the customer base; and Group 3 represents the top quartile of kWh customers. Group 1 uses the least amount of electricity on average, while Group 3 uses the most.

Is paying for electricity a worry or a major problem?			
	kWh Group 1	**kWh Group 2**	**kWh Group 3**
Not really a worry	71%	66%	66%
Sometimes I worry	19%	21%	24%
Often it is a major problem	7%	10%	10%
Depends	1%	1%	0%

Base: total respondents

Is paying for electricity a worry or a major problem?				
	Not a worry	**Sometimes**	**Often**	**Depends**
Ontario				
2015	59%	25%	10%	2%
2014	59%	26%	11%	2%
2013	66%	21%	11%	1%
2012	59%	27%	11%	2%
2011	52%	31%	13%	3%
National				
2015	67%	22%	8%	2%
2014	69%	20%	7%	3%
2013	70%	18%	8%	2%
2012	67%	22%	8%	2%
2011	63%	25%	8%	2%

Base: 2015 Ontario and National benchmark surveys

What do small commercial customers think?

Small commercial customers represent a significant amount of any LDC's customer base yet the amount of customer intelligence a LDC has on this customer segment is extremely low. Beyond having a contact telephone number, name of company and address there often isn't much more information.

In an time when "targeted" communication is important, knowing the type of category of small commercial account would assist LDCs in delivering meaning messages in an effective way. This could be particularly important in the area of energy conservation i.e., pulling together messages and programs for specific types of businesses. After all, a small restaurant is different from a small accounting office.

Small commercial customers have, in many ways, very similar concerns with Residential customers but there are some differences. For example, small business customers are 1.5X more likely to contact their LDC when there is an outage or billing issue.

Small Commercial Customer (General Service < 50kW Demand)

A small commercial customer is defined by the OEB as a non-residential customer in a less than 50 kW demand rate class. These customers are similar to the residential customer in that their bill does not have a demand component to it and their charges are based upon KWH of consumption. Most of these customers would occupy small storefront locations or offices

Deposit requirements, monthly energy bills (and, therefore, energy usage), power quality, and reliability all directly impact a small business's financial situation. Unlike residential customers who tend to describe the cost of power interruptions in terms of a "inconvenience", commercial (and industrial) customers associate power interruptions with the cost of lost business, i.e., a loss in production is a loss in profits.

Likewise, based on the requirement of electricity to sustain business operations, there exists a difference in actual levels of demand response. For instance, small business and commercial users are unlikely to choose to decrease their electricity consumption if it is incompatible with efficient management of their business processes or threatens contracted deliveries to their primary product markets. In some cases, electricity consumption is a relatively small proportion of total input and operating costs, which substantially reduces the financial incentive for shutting down production during off peak pricing.

The tables associated with this report will contain Ontario LDC specific information as it relates to residential and commercial customers. Recognizing smaller data samples are susceptible to greater data swings, for most LDCs there would be 60 or 90 responses from small commercial customers. We have compiled the following based on a group composite of all of our 2015 discussions with small commercial and residential customers.

Satisfaction: Pre & Post		
Satisfaction (Top 2 Boxes: 'very + somewhat satisfied')	**Residential**	**Commercial**
Initially	89%	90%
End of Interview	89%	90%

Base: total respondents from the full 2015 database

As it relates to the six attributes associated with customer service:

Very or fairly satisfied with…	Residential	Commercial
The time it took to contact someone	73%	78%
The time it took someone to deal with your problem	70%	75%
The helpfulness of the staff who dealt with your problem	74%	80%
The knowledge of the staff who dealt with your problem	73%	82%
The level of courtesy of the staff who dealt with your problem	81%	88%
The quality of information provided by the staff member	72%	76%

Base: total respondents from the full 2015 database

Residential respondents had lower satisfaction levels with customer service versus Commercial respondents.

Overall satisfaction with most recent experience		
	Residential	**Commercial**
Top 2 Boxes: 'very + somewhat satisfied'	72%	77%
Bottom 2 Boxes: 'somewhat + very dissatisfied'	26%	22%

Base: total respondents from the full 2015 database

Comparisons between Residential and Commercial		
Loyalty Groups	**Residential**	**Commercial**
Secure	23%	25%
Still Favourable	10%	10%
Indifferent	59%	57%
At risk	8%	8%

Base: total respondents from the full 2015 database

Loyalty Model Factors	Residential	Commercial
Very/somewhat satisfied	89%	90%
Definitely/probably would continue	81%	81%
Definitely/probably would recommend	75%	78%

Base: total respondents from the full 2015 database

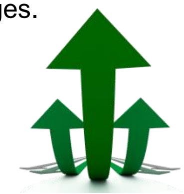
Outages & Bill problems	Residential	Commercial
Respondents with outage problems	44%	37%
Respondents with billing problems	10%	12%

Base: total respondents from the full 2015 database

Attempts to contact local utility…	Residential	Commercial
Respondents with outage problems	19%	30%
Respondents with billing problems	39%	63%

Base: total respondents from the full 2015 database

Residential respondents reported a considerably higher incidence of outages.



Commercial respondents were more likely to call in about billing and outage problems.

Important attributes which describe operational effectiveness		
	Residential	**Commercial**
Provides consistent, reliable electricity	90%	90%
Delivers on its service commitments to customers	86%	87%
Accurate billing	86%	85%
Quickly handles outages and restores power	87%	87%
Makes electrical safety a top priority	88%	90%
Uses responsible environmental practices when completing work	88%	89%
Is efficient at managing the electricity distribution system	82%	82%
Is a company that is 'easy to do business with'	84%	84%
Operates a cost effective electricity distribution system	72%	72%

Base: total respondents with an opinion from the full 2015 database

Important attributes which shape perceptions about corporate image		
	Residential	Commercial
Is a respected company in the community	85%	86%
A leader in promoting energy conservation	80%	81%
Keeps its promises to customers and the community	82%	83%
Is a socially responsible company	83%	84%
Is a trusted and trustworthy company	84%	85%
Adapts well to changes in customer expectations	74%	76%
Overall the utility provides excellent quality services	85%	86%

Base: total respondents with an opinion from the full 2015 database

Important attributes which shape perceptions about service quality and value		
	Residential	Commercial
Is pro-active in communicating changes and issues which may affect customers	79%	80%
Provides good value for money	68%	69%
Customer-focused and treats customers as if they're valued	79%	80%
Deals professionally with customers' problems	84%	87%
Spends money prudently	77%	77%
Quickly deals with issues that affect customers	82%	82%
Provides information and tools to help manage electricity consumption	79%	77%
Provides information to help customers reduce their electricity costs	78%	77%
The cost of electricity is reasonable when compared to other utilities	60%	59%

Base: total respondents with an opinion from the full 2015 database

Is paying for electricity a worry or a major problem?		
	Residential	**Commercial**
Not really a worry	63%	61%
Sometimes I worry	24%	27%
Often it is a major problem	8%	9%
Depends	3%	1%

Base: total respondents from the full 2015 database

When there is an outage, which of the following methods would you want your utility to use to give you information about the outage?

Preferred methods to give you information about the outage from your utility…		
	Residential	**Commercial**
Recorded telephone message	60%	58%
E-mail	32%	40%
Post on utility's website	25%	28%
Social media - Twitter	19%	20%
Text message	32%	35%
Local radio	41%	43%
Local TV	30%	30%

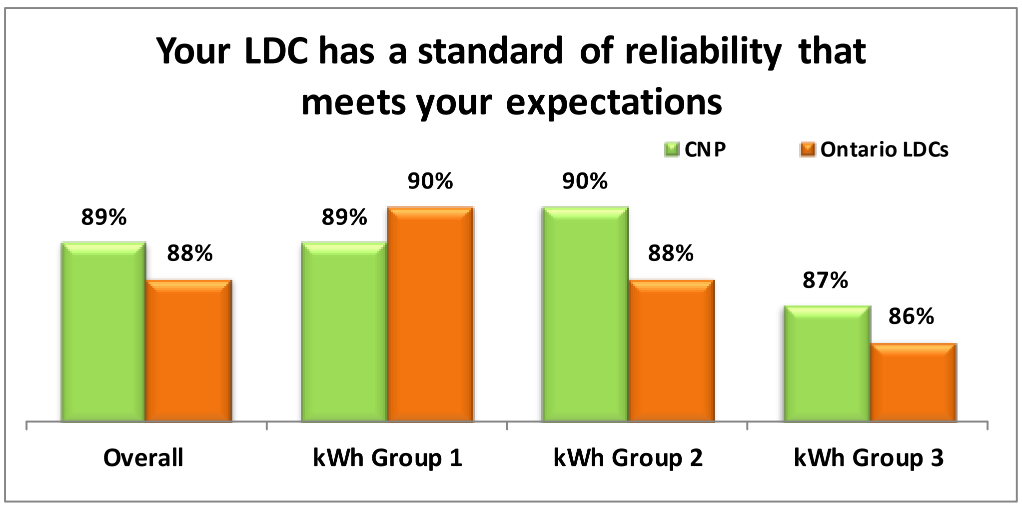
Base: total respondents from the full 2015 database

SUPPLEMENTAL QUESTIONS

Outage Management

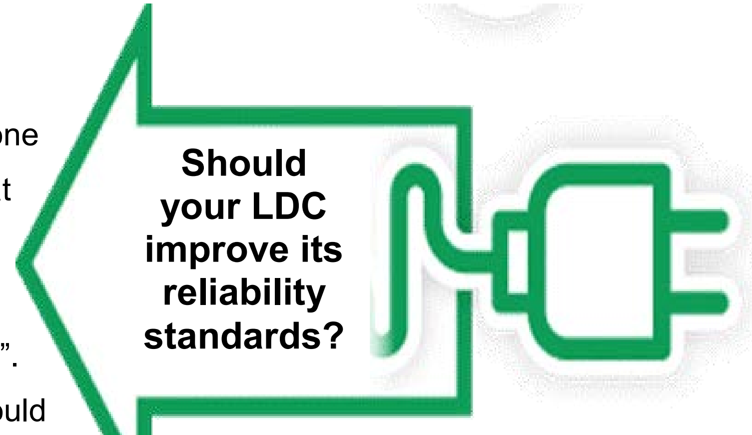
The ice-storm of December 2013 put more emphasis on how LDCs should be communicating with customers when there is an outage – both planned and unplanned outages. Since then much has been written about outage management thereby heightening customers' awareness about the issue. None-the-less every LDC has made changes and/or enhancements to their outage management practices.

Recognizing the importance of this topic to customers, a question about LDC reliability standards has been added to the core survey.



Base: An aggregate of respondents from the 2015 participating LDCs / total respondents from the local utility

Customers who responded to the survey offer a paradox. On the one hand, when asked about "your LDC has a standard of reliability that meets your expectations", scores are very high – no doubt somewhat comforting to the LDC. On the other hand, when asked "Should your LDC improve its reliability standards" the majority certainly said "yes". What we didn't do is tell the customer how much more money they would have to pay per month for higher standards.



Base: An aggregate of respondents from the 2015 participating LDCs / total respondents from the local utility

	Yes	No	Depends
Ontario LDCs	57%	35%	8%
CNP	54%	38%	8%

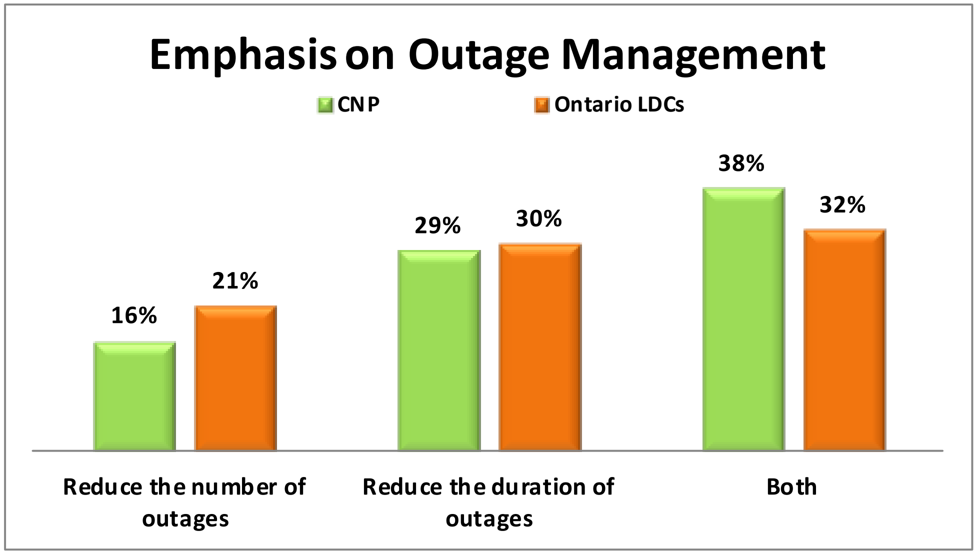
An outage management system helps LDC employees to discover, locate and resolve power outages in a more informed, orderly, efficient and timely manner.

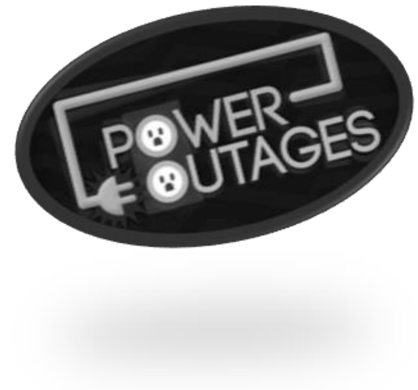
How many outages are acceptable over 12 months?		
	Ontario LDCs	**CNP**
None	23%	17%
One	15%	9%
Two	26%	28%
Three	13%	16%
Four	5%	7%
Five or more	7%	12%
Don't Know	9%	11%

Reasonable amount of time for an unplanned outage?		
	Ontario LDCs	**CNP**
Less than 15 minutes	14%	0%
16-30 minutes	15%	20%
31-60 minutes	13%	11%
1 to 2 hours	29%	36%
3 to 5 hours	13%	14%
6 to 12 hours	5%	5%
More than 12	3%	4%
Don't Know	8%	9%

Base: An aggregate of respondents from the 2015 participating LDCs / total respondents from the local utility

If the utility were to improve reliability should they put more emphasis on reducing the number of or unplanned outages or reducing the duration of the unplanned outage? Or both which requires an increase.





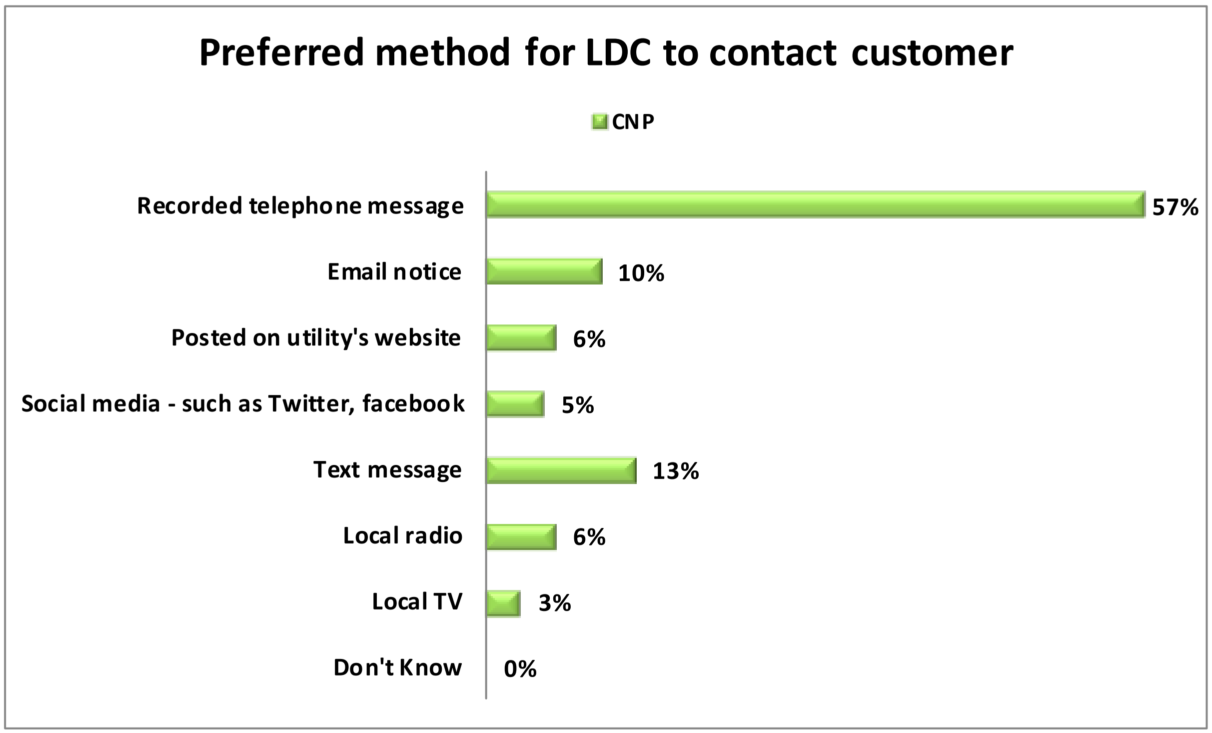
Base: An aggregate of respondents from the 2015 participating LDCs / total respondents from the local utility

Which communication channel do customers prefer to use? The telephone is the most used and preferred method to contact the LDC to communicate with customer care representatives.

	Telephone	Email	Utility Website	Social Media	Mail	In Person
Ontario LDCs	84%	5%	2%	1%	0%	0%
CNP	89%	4%	2%	2%	0%	3%

Base: An aggregate of respondents from the 2015 participating LDCs / total respondents from the local utility

While the telephone is still the communication channel most would prefer to use to communicate with or to be communicated to, customers do have an expectation for the LDC to use varied methods to contact them. Communication channels other than the telephone received higher preference scores when asked about the utility contacting the customer versus the customer's use of such channels to contact the utility. This indicates the onus is on the utility to find a way to contact a customer when necessary and that it should use various means to ensure the message is communicated. Proactive communication channels which include recorded calls, emails and SMS (text messaging) are increasingly being used by utilities to reach customers affected by outages.



Base: total respondents

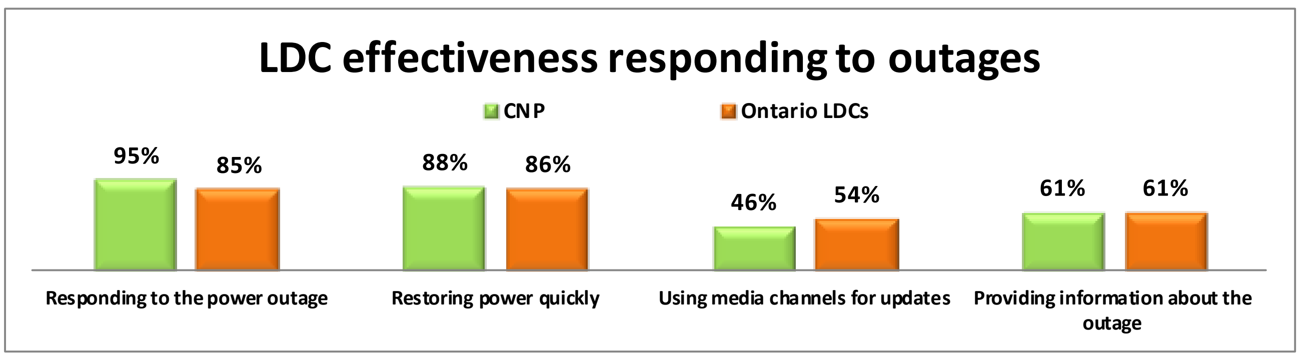
Responding to outages and making sure power is restored quickly is a priority item with customers as well as communications during outage events. Being effective during an outage situation from the point of view of a customer requires:

- timely information on outages is provided
- utilities understand that even a short outage in duration is impactful
- in large scale events, utilities should proactively provide tips on how to prepare for extended outages
- being kept informed about what is going on during an outage makes customers feel valued.

LDC effectiveness responding to outages

	Ontario LDCs	CNP
Responding to the power outage	85%	95%
Restoring power quickly	86%	88%
Using media channels for updates	54%	46%
Providing information about the outage	61%	61%

Base: An aggregate of respondents from the 2015 participating LDCs / total respondents from the local utility



Base: An aggregate of respondents from the 2015 participating LDCs / total respondents from the local utility

The types of information customers require during an outage include:

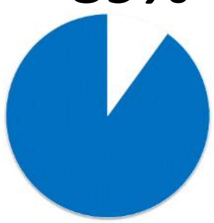
- *When will their power be restored?*
- *What areas are affected?*
- *How many customers are impacted?*
- *Have work crews been dispatched to the affected area and is the utility working to restore power?*
- *What was the cause of the power outage?*
- *What can customers do to cope during the outage?*

Soliciting Feedback

The Ontario Energy Board, in its publication: *"EB-2010-0379 Report of the Board Performance Measurement for Electricity Distributors: A Scorecard approach",* referenced staff recommendations that distributors would be required to survey customer satisfaction among other items in an effort to continually seek ways in which to improve performance and productivity while better understanding and engaging with their customers.

UtilityPULSE asked 1,269 Residential customers, located throughout Ontario and who pay the electricity bill questions pertaining to the solicitation of customer feedback and opinions on different electricity industry matters. These questions were asked with intent of gauging the customer's perception of requesting feedback and the importance thereof.

89%

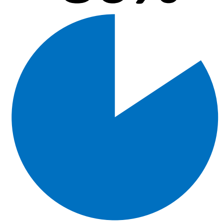


89% of Ontario respondents feel it is 'very + somewhat' important for their LDC to solicit customer feedback on customers' overall satisfaction with the utility.

83%

83% of Ontario respondents feel it is 'very + somewhat' important for their LDC to solicit customer feedback on how much money is being spent on repairing equipment.

86%



86% of Ontario respondents feel it is 'very + somewhat' important for their LDC to solicit customer feedback on how much money is being spent on keeping the system reliable.

84%

84% of Ontario respondents feel it is 'very + somewhat' important for their LDC to solicit customer feedback on the utility's plans to spend money on extending the system to help economic development in the community.

Importance of soliciting customer opinions and feedback on ….				
	Top 2 boxes: 'very + somewhat' important	Bottom 2 boxes: 'somewhat + very' unimportant	Neither	Don't know
… customers' overall satisfaction with the utility …	89%	8%	1%	3%
… how much money is being spent on repairing equipment …	83%	9%	1%	6%
… how much money is being spent on keeping the system reliable …	86%	6%	2%	6%
… the utility's plans to spend money on extending the system to help economic development in the community …	84%	10%	2%	4%

Base: 1,269 Residential respondents from the 2015 Ontario Benchmark survey

The data reveals customers do believe the LDC should be seeking their opinions on certain operational matters as well as their overall satisfaction. It could be the customer's view that by having their input counted especially where spending is concerned, they might play a part in controlling costs and stop any unnecessary spending.

SMART Grid

A number of functions will be available to electricity system stakeholders due to the advance of SMART Grid technologies. Providing tools to address peak demand, to improve system reliability, to manage distribution and energy storage are tools available to LDCs and system operators, SMART Grid technologies offer consumers possibilities as well. For the electricity customer, SMART grid technologies can provide the opportunity to manage electricity use, to control bills, and to sell power back the grid. How much of this is the average consumer aware of or “in the know”? While many industry insiders talk about the SMART Grid, i.e., its benefits and its challenges, the reality is, the average person is not very knowledgeable about it.

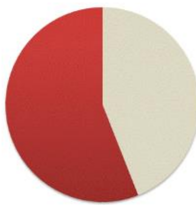
Level of knowledge about the SMART Grid

	Ontario 2015	Ontario 2014
I have a fairly good understanding of what it is and how it might benefit homes and businesses	9%	9%
I have a basic understanding of what it is and how it might work	21%	25%
I’ve heard of the term, but don’t know much about it	37%	36%
I have not heard of the term	32%	29%
Don’t know	1%	1%

Base: total respondents from the 2015/2014 Ontario Benchmark survey

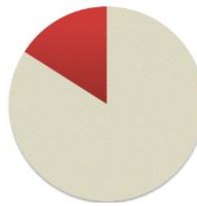
Once again, this year's survey probed around the concept of SMART Grid. While another year has passed, it is evident that the SMART Grid is still not a much talked about concept, only 30% [34%;2014] have a basic or good understanding of what it is, 69% have either not heard of the term or if they did, do not know much about it.

56%



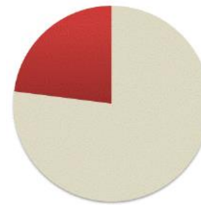
56% of Ontario respondents feel it is 'very + somewhat' important to pursue the implementation of SMART Grid technologies

16%



16% of Ontario respondents feel it is 'very + somewhat' unimportant to pursue the implementation of SMART Grid technologies

23%



23%, one in four Ontarians simply admitted they "do not know" if SMART grid technologies should be pursued.

Base: total respondents from the 2015 Ontario Benchmark survey

Support towards working with neighbouring utilities on SMART Grid initiatives

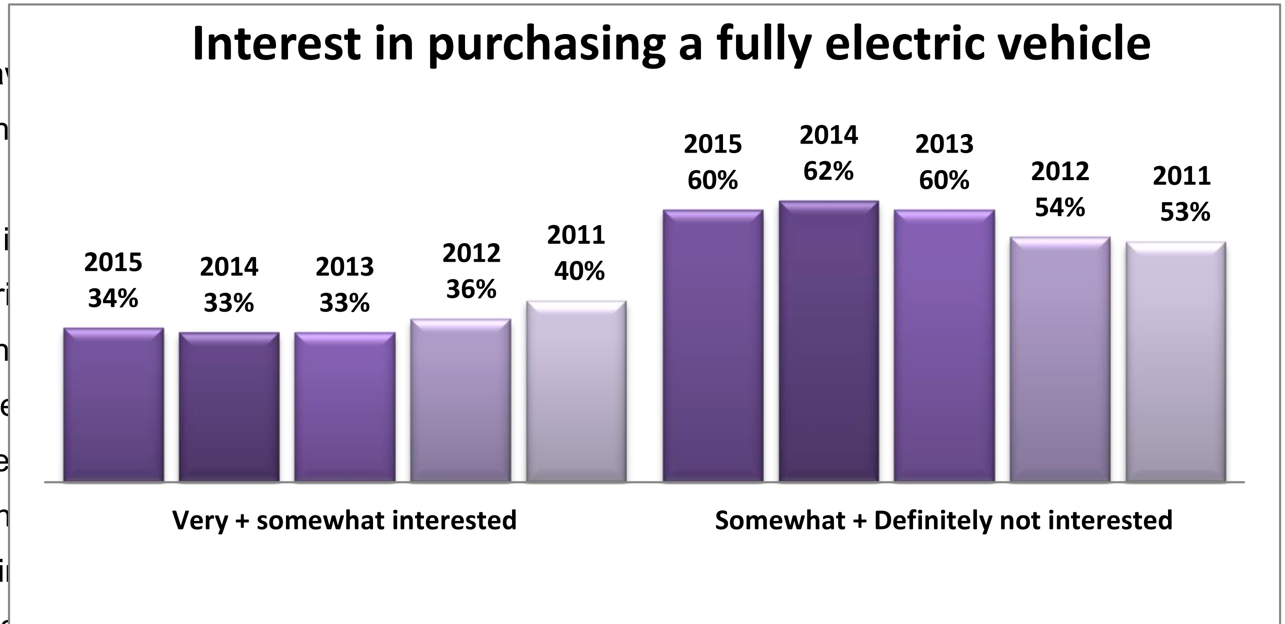
	Ontario 2015	Ontario 2014
Very supportive	40%	41%
Somewhat supportive	39%	37%
Neither supportive or unsupportive	2%	4%
Somewhat unsupportive	5%	4%
Unsupportive	6%	4%
Don't know	8%	10%

Base: total respondents from the 2015/2014 Ontario Benchmark survey

With inconsistencies between Ontario LDCs' about the definition of SMART Grid coupled with different levels of technical maturity --- collaboration amongst LDCs is very difficult.

Purchasing an Electric Vehicle

For 5 years UtilityPULSE has been collecting information and tracking electricity customers interest in purchasing an electric vehicle. In fact, we've asked the same questions in the same way for 5 years.



While the actual ra
numbers are interestin
e.g., 34% are very
somewhat interested i
purchasing an electri
vehicle, the 5 year tren
is also interesting. Othe
than the first year whe
various manufacturers h
the airwaves about thei
EVs the interest level has remained in the 34% area. We can conclude that "interest" in purchasing doesn't actually translate to a customer acting on that interest and buying an electric vehicle. Perhaps it is because the EV industry has not done a good job in allaying fears about distances that can be travelled between charges, or time to charge from empty, or the higher depreciation costs associated with most EVs.

From a demographics perspective respondents in the 35-54 age group had the highest level of interest at 45% (39% in 2014). Data from the survey also tells us there is very little variance in interest to purchase based on the respondents ability to pay for their electricity bills. Customers who said they have “No worries” or said they “Often worry” about paying their electricity bills were statistically equal in their level of interest.

Interest in purchasing a fully electric vehicle

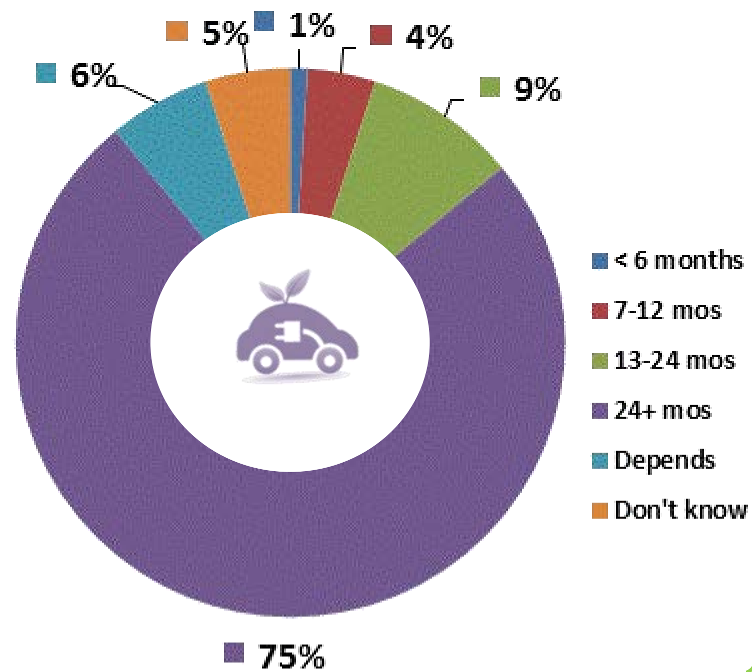
	Income <$40K	Income $40K<$70K	Income $70K +	Age 18-34	Age 35-54	Age 55+
Top 2 Boxes: 2015 ‘very + somewhat interested’	30%	28%	41%	29%	45%	29%
Top 2 Boxes: 2014 ‘very + somewhat interested’	30%	28%	42%	27%	39%	28%

Base: total respondents from the 2015 Ontario Benchmark survey

Length of time before purchasing a fully electric vehicle

	Ontario 2015	Ontario 2014
Immediately to next 6 months	6%	2%
7 to 12 months	4%	2%
13 to 24 months	9%	9%
Over 24 months	75%	79%
Depends	6%	5%
Don’t know	5%	3%

Base: total respondents from the 2015/2014 Ontario Benchmark survey



Method

The findings in this report are based on telephone interviews conducted for Simul Corp. / UtilityPULSE by Greenwich Associates between October 8-22, 2015, with 410 respondents who pay or look after the electricity bills from a list of residential and small and medium-sized business customers supplied by CNP.

The sample of phone numbers chosen was drawn randomly to insure that each business or residential phone number on the list had an equal chance of being included in the poll.

The sample was stratified so that 85% of the interviews were conducted with residential customers and 15% with commercial customers.

In sampling theory, in 19 cases out of 20 (95% of polls in other words), the results based on a random sample of 410 residential and commercial customers will differ by no more than ±4.84 percentage points where opinion is evenly split.

This means you can be 95% certain that the survey results do not vary by more than 4.84 percentage points in either direction from results that would have been obtained by interviewing all CNP residential and small and medium-sized commercial customers if the ratio of residential to commercial customers is 85%:15%.

The margin of error for the sub samples is larger. To see the error margin for subgroups use the calculator at http://www.surveysystem.com/sscalc.htm.

Interviewers reached 1,483 households and businesses from the customer list supplied by CNP. The 410 who completed the interview represent a 28% response rate.

The findings for the Simul/UtilityPULSE National Benchmark of Electric Utility Customers are based on telephone interviews conducted with adults throughout the country who are responsible for paying electric utility bills. The ratio of 85% residential customers and 15% small and medium-sized business customers in the National study reflects the ratios used in the local community surveys. The margin of error in the National poll is ±2.7 percentage points at the 95% confidence level.

For the National study, the sample of phone numbers chosen was drawn by recognized probability sampling methods to insure that each region of the country was represented in proportion to its population and by a method that gave all residential telephone numbers, both listed and unlisted, an equal chance of being included in the poll.

The data were weighted in each region of the country to match the regional shares of the population.

The margin of error refers only to sampling error; other non-random forms of error may be present. Even in true random samples, precision can be compromised by other factors, such as the wording of questions or the order in which questions were asked.

Random samples of any size have some degree of precision. A larger sample is not always better than a smaller sample. The important rule in sampling is not how many respondents are selected but how they are selected. A reliable sample selects poll respondents randomly or in a manner that insures that everyone in the population being surveyed has an equal chance of being selected.

How can a sample of only several hundred truly reflect the opinions of thousands or millions of electricity customers within a few percentage points?

Measures of sample reliability are derived from the science of statistics. At the root of statistical reliability is probability, the odds of obtaining a particular outcome by chance alone. For example, the chances of having a coin come up heads in a single toss are 50%. A head is one of only two possible outcomes.

The chance of getting two heads in two coin tosses is less because two heads are only one of four possible outcomes: a head/head, head/tail, tail/head and tail/tail.

But as the number of coin tosses increases, it becomes increasingly more likely to get outcomes that are either close to or exactly half heads and half tails because there are more ways to get such outcomes. Sample survey reliability works the same way but on a much larger scale.

As in coin tosses, the most likely sample outcome is the true percentage of whatever we are measuring across the total customer base or population surveyed. Next most likely are outcomes very close to this true percentage. A statement of potential margin of error or sample precision reflects this.

Some pages in the computer tables also show the standard deviation (S.D.) and the standard error of the estimate (S.E.) for the findings. The standard deviation embraces the range where 68% (or approximately two-thirds) of the respondents would fall if the distribution of answers were a normal bell-shaped curve. The spread of responses is a way of showing how much the result deviates from the "standard mean" or average. In the CNP data on corporate image, Simul converted the answers to a point scale with 4 meaning agree strongly, 3 meaning agree somewhat and so on (see in the computer tables).

For example, the mean score is 3.56 for providing consistent, reliable electricity. The average is 3.18 for providing information to help customers reduce their energy costs.

For reliable electricity the standard deviation is 0.69. For affordable energy the S.D. is 0.92. These findings mean there is a wider range of opinion – meaning less consensus – about whether CNP provides information to help customers to reduce their energy costs than about whether CNP energy supplies are reliable.

Beneath the S.D. in the tables is the standard error of the estimate. The S.E. is a measure of confidence or reliability, roughly equivalent to the error margin cited for sample sizes. The S.E. measures how far off the sample's results are from the standard deviation. The smaller the S.E., the greater the reliability of the data.

In other words, a low S.E. indicates that the answers given by respondents in a certain group (such as residential bill payers or women) do not differ much from the probable spread of the answers "predicted" in sampling and probability theory.

Certain questions pertaining to conservation and conservation efforts used an aggregate data approach whereby similar data sets were accumulated to form a larger sample size establishing a higher confidence interval, forecasting value and modeling data.

In certain instances, all of the sub-datasets from the entire UtilityPULSE database for 2015 were concatenated in order to use the average of all the control samples for comparison. The cumulated population base for these questions was in excess of 9,000.

At a 95% confidence level the margin of error is ±1.03 and at a 99% confidence level the margin of error would be ±1.36. So the aggregate strategy has given a very good population sample size which better, or more accurately, reflects the true feelings and beliefs of the population as a whole.

Good things happen when work places work. You'll receive both strategic and pragmatic guidance about how to improve Customer satisfaction & Employee engagement with leaders that lead and a front-line that is inspired. We provide: training, consulting, surveys, diagnostic tools and keynotes. The electric utility industry is a market segment that we specialize in. Both large and small utilities have received actionable insights. For seventeen years we have been talking to 1000's of utility customers in Ontario and across Canada and we have expertise that is beneficial to every utility.

Culture, Leadership & Performance – Organizational Development	Focus Groups, Surveys, Polls, Diagnostics	Customer Service Excellence
Leadership development	Diagnostics ie. Change Readiness, Leadership Effectiveness, Managerial Competencies	Service Excellence Leadership
Strategic Planning	Surveys & Polls	Telephone Skills
Teambuilding	Customer Satisfaction and Loyalty Benchmarking Surveys	Customer Care
Organizational Culture Transformation	Organization Culture Surveys	Dealing with Difficult Customers

Benefit from our expertise in Customer Satisfaction, Leadership development, Strategy development or review, and Front-line & Top-line driven-change. We're experts in helping you assess and then transform your organization's culture to one where achieving goals while creating higher levels of customer satisfaction is important. Anyone can present data, or design programs – we believe having an understanding of the industry before doing so is cruicial. Call us when creating an organization where more employees satisfy more customers more often, is important.

Your personal contact is:

Sid Ridgley, CSP

Phone: (905) 895-7900 Fax: (905) 895-7970 E-mail: sidridgley@utilitypulse.com or sridgley@simulcorp.com

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Appendix 4-C – Employee News Release for Community Involvement

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CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

EMPLOYEE INFORMATION RELEASE

CANADIAN NIAGARA POWER INC. PARTICIPATES IN FORT ERIE ANNUAL SANTA CLAUS PARADE


On Saturday, November 21, 2015, Canadian Niagara Power Inc. participated in the Fort Erie Annual Santa Claus Parade. This event was sponsored by the Conservation and Energy Efficiency Department to encourage residents to 'saveONenergy.' Thanks to all those employees and their families who helped make this event a success.

November 21, 2015
Human Resources Department

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Employee Information Release

CANADIAN NIAGARA POWER INC. PARTICIPATES IN
TAKE OUR KIDS TO WORK DAY

On Wednesday, November 4, 2015, Canadian Niagara Power Inc. hosted six (6) Grade 9 students. The students learned about the utility industry, the tools and equipment that we use and also completed our Passport To Safety Training. Both students and staff enjoyed the day.

Take Our Kids to Work™ is an annual national program in which Grade 9 students are hosted by parents, friends, relatives and volunteers at workplaces across the country every November. The program supports career development by helping students connect school, the world of work, and their own futures.

November 13, 2015
Human Resources Department

CANADIAN NIAGARA POWER INC. PARTICIPATES IN BIG BIKE EVENT FOR HEART & STROKE FOUNDATION

A team of CNP 'Heart' Cyclists took to the road on May 28, in support of the Heart and Stroke's Big Bike for Heart. The team raised over $1,400 for the charity and had a great time riding the Big Bike which was driven by our retiree, Jim Nigh.

Many thanks to Maria McKinnon and Chris Johnsen for organizing the successful event.

June 1, 2015

NOTICE TO ALL EMPLOYEES OF FORTISONTARIO

CANADIAN NIAGARA POWER INC. HOSTS DINNER AT PORT CARES

A team of CNP 'Helping Hands' hosted and served approximately 100 dinners on June 4, 2015 at Port Cares to local residents. The community was very appreciative of the delicious meal and it was an enjoyable event for the CNP volunteers.

Many thanks to the team and to Heather Fazekas for organizing the successful event.

June 16, 2015

FORTIS ONTARIO

NOTICE TO ALL EMPLOYEES OF FORTISONTARIO

CANADIAN NIAGARA POWER INC. HOSTS THANKSGIVING DINNER AT THE SALVATION ARMY

A team of CNP 'Helping Hands' hosted dinner for roughly 135 people on October 8, 2015 at the Salvation Army. The community was very appreciative of the delicious meal and it was a rewarding experience for all.

Many thanks to the team and to Heather Fazekas for organizing the successful event.

FORTIS ONTARIO

NOTICE TO ALL EMPLOYEES OF FORTISONTARIO

CNPI IS AWARDED THE EMPLOYEE GOLD AWARD BY THE UNITED WAY OF NIAGARA FALLS AND GREATER FORT ERIE

CNPI was presented with an Employee Gold Award by the United Way of Niagara Falls and Greater Fort Erie at the Annual General Meeting. CNPI was also recognized for its Top Ten Workplace Campaign and as a Corporate Partner.

Many thanks to all employees for their dedication to the United Way.

June 3, 2015

Appendix 4-D– Local Service Provider Information Presentation

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Connecting New or Upgrading Services

Process and Timeline

Types of Projects

- Subdivisions
- Primary Service
  - Overhead
  - Underground
- Secondary Service
  - Overhead
  - Underground

- CNPI schedules ALL projects on a '**First-Commit, First-Done**' basis

Note: Some projects WILL require upgrades to the CNPI system, which could mean higher connection costs and longer lead times!

Types of Projects

- Subdivisions
- Primary Service
  - Overhead
  - Underground
- Secondary Service
  - Overhead
  - Underground

Note: Some projects WILL require upgrades to the CNPI system, which could mean higher connection costs and longer lead times!

CNPI - SUBDIVISION Construction Timeline (Revised on 2015-11-26)

1) Project Developer contacts CNPI

2) CNPI waits for Developer to pay Design Fee *
- Currently $10,000
- Any unused portion credited to CIAC

3) Project Placed in CNPI Design Queue
- Currently about 3 weeks

4) Developer provides required information
- Subdivision layout / R-Plan
- Load Forecast
  - House Build SCHEDULE and types

5) CNPI creates electrical design for subdivision
- Typically about 3 weeks
- Requires prompt developer feedback to avoid delays

6) CNPI provides design and cost information
- Discount-Cash-Flow evaluation
- CIAC and Deposit determined to complete project by CNPI

7) CNPI waits for Developer to pay CIAC and Deposit *
- Developer may provide CNPI civil works as 'payment in kind' for portion of CIAC
- Material Orders wait as well

8) Project placed in CNPI Construction Queue
- Currently about 8-10 weeks
- May also be waiting for padmount transformer delivery (currently 18-20 weeks)

9) CNPI constructs subdivision
- Typically 4 weeks, assuming no project delays
- CNPI requires sole access to site at times of construction (per OHSA)

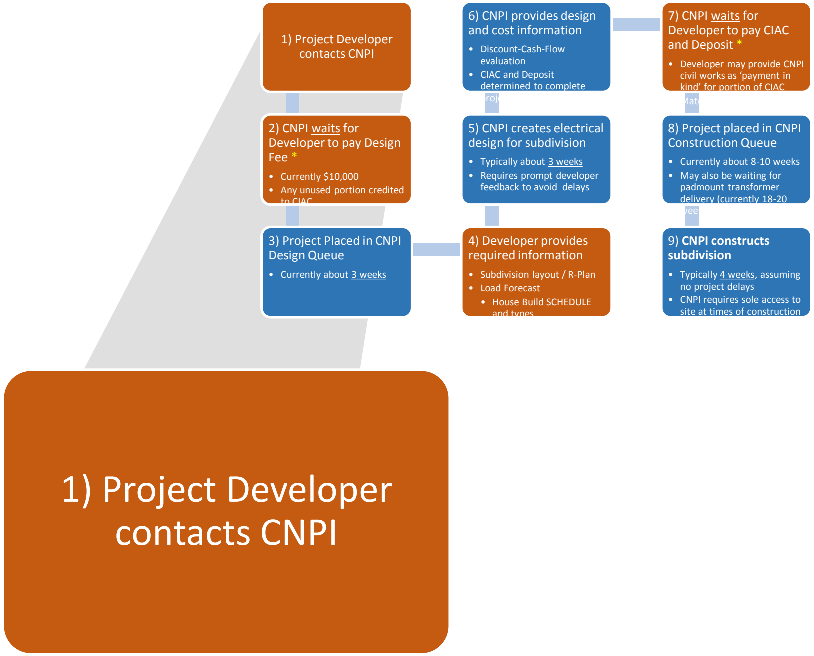
* Developer can prepay for padmount transformers to reduce transformer delivery delays

TOTAL Project Time = 30 weeks + any Developer delays. Can be reduced to 22-24 weeks if transformers are prepaid.

Step 1: Developer contacts CNPI

- Developer contacts CNPI and shares preliminary information:
  - Where is it?
  - How big is it?
  - When do they ***want*** it ready?
  - Contacts for consultants, builders, etc

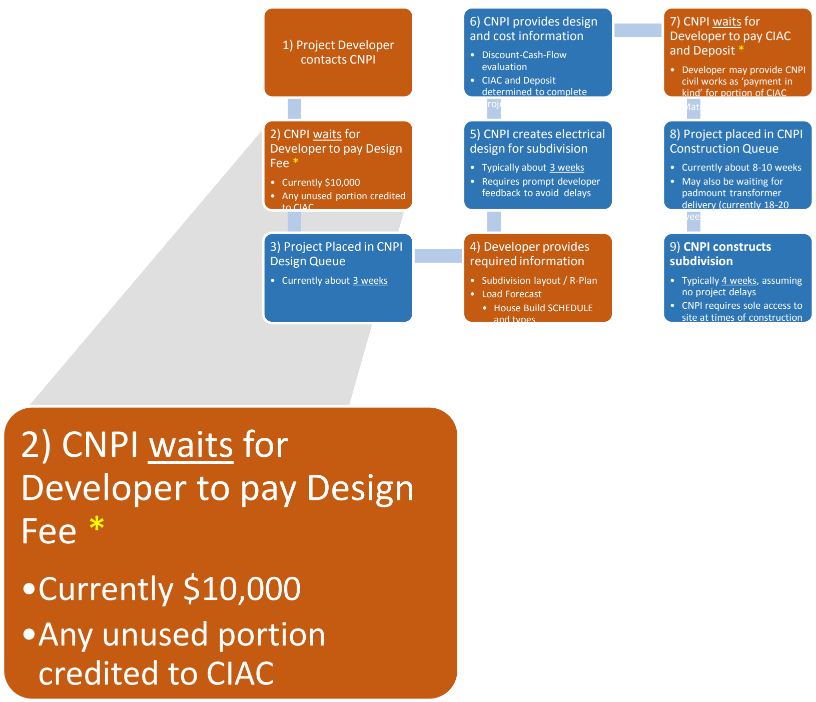
- CNPI will take no significant action until design fee is paid!



Step 2: CNPI waits for Developer Commitment

- CNPI waits for Developer <u>commitment</u> to proceed.
  - Design Fee: currently $10k unless job is very large or has special challenges
  - Any unused amounts are applied to construction costs or refunded if project does not proceed
- Developer may want to prepay a transformer deposit
  - CNPI will then order subdivision's distribution transformers
  - Recent delivery lead times are 18-20 weeks, on average

- CNPI will take no significant action until design fee is paid!

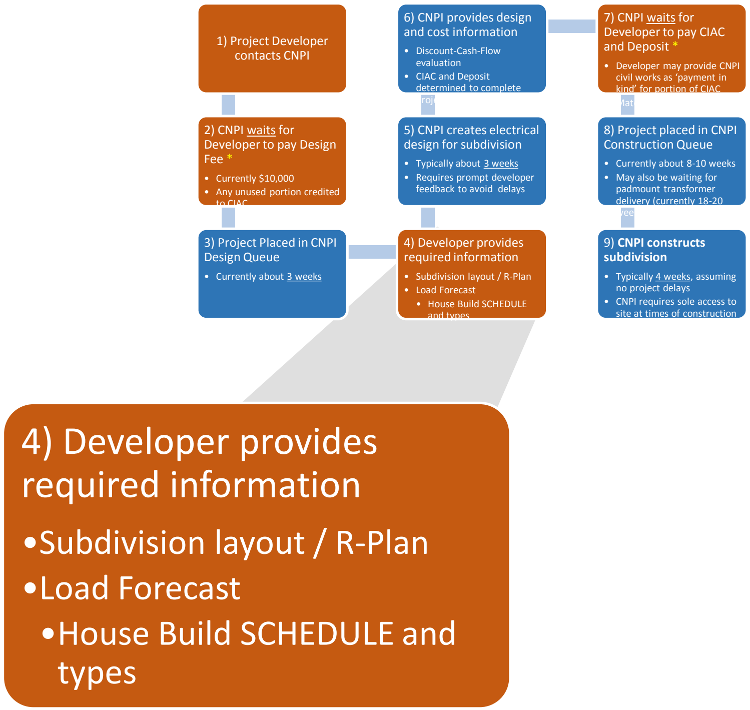


Step 3: CNPI puts project in Design Queue

- Once committed, the project is scheduled by CNPI for detailed design
- Assigned to next available Planner
  - Wait time for design to start can depend on volume of other projects that are already committed
  - Typical waiting period is 3 weeks

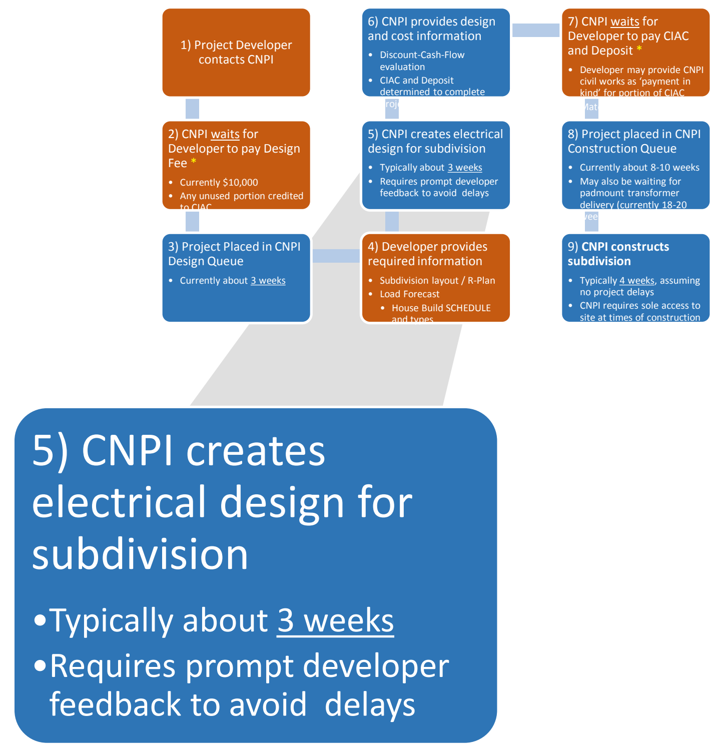
Step 4: Developer provides detailed project information

- Developer must provide project information to CNPI
  - This can (and should) be done during Design Queue waiting period
- Information includes:
  - R-Plan
  - Housing Types and Quantities
  - 5-year Load Forecast
  - Layout details:
    - street lighting



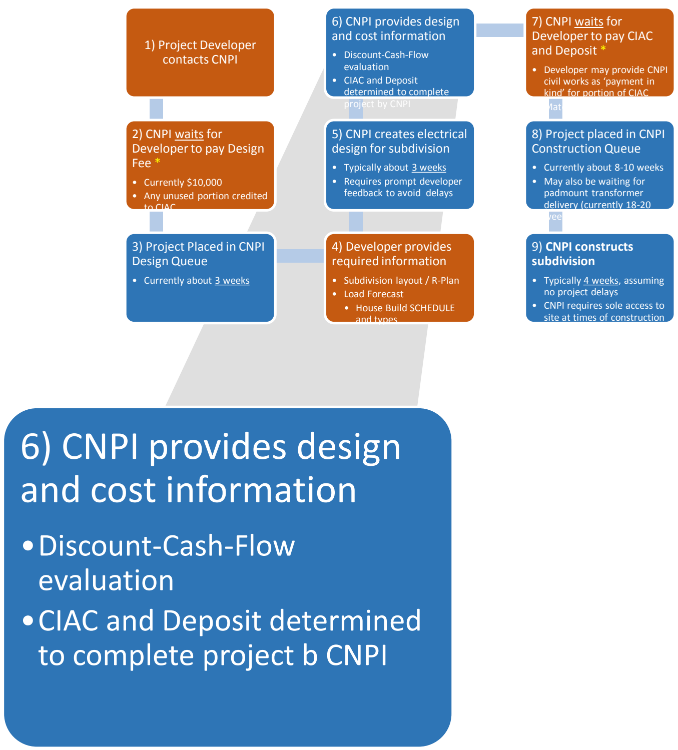
Step 5: CNPI creates electrical design

- CNPI creates electrical design
- This often involves discussion with developer
    - Prompt feedback ensures no unnecessary delays
- Typical design requires <u>3 weeks</u> to complete
- More complicated designs may require more time
    - E.g.: Location of proposed subdivision requires expansion of CNPI system



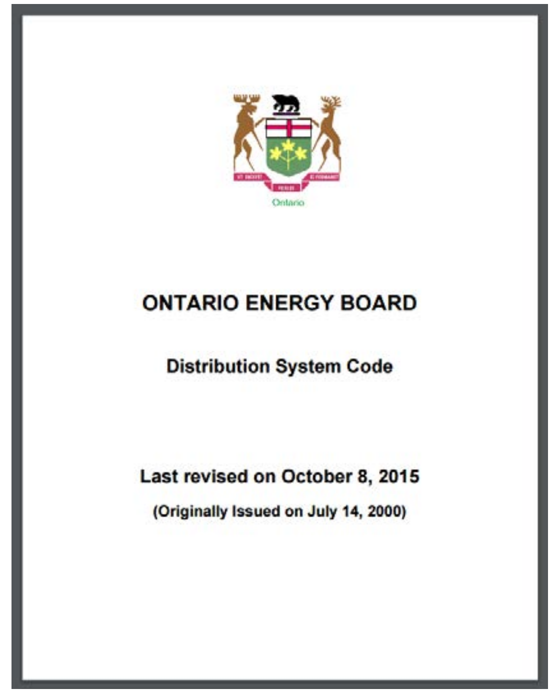
Step 6: CNPI provides design and cost information

- CNPI submits design to developer
- CNPI also provides cost information:
  - Contribution In Aid of Construction (CIAC)
    - ‘up-front’ Payment to CNPI
    - Represents the total project cost of CNPI *<u>less a credit</u>* for future net revenues
      - Credit based on Net-Present-Value of Discount Cash Flow evaluation
  - Surety (guarantee) for the CNPI future revenue credit:
    - “What if promised load doesn’t appear?”
    - Usually in the form of a Letter-of-Credit
    - Held for 5 years, but reviewed annually.



Discount-Cash-Flow? Net-Present-Value?
CIAC? What does all THAT mean !?

- CNPI follows process defined in our main Regulatory document:
  - OEB Distribution System Code
- Goal:
  - Over the Planning Horizon (e.g. 25 years), all of the 'legacy' Ratepayers of CNPI are to be 'held whole'
  - CNPI calculates the Contribution In Aid of Construction (CIAC) that it must collect from each new project that results in exactly ZERO net revenue to CNPI
  - CIAC <u>CAN be zero</u> if a project provides enough revenue !



Ontario

ONTARIO ENERGY BOARD

Distribution System Code

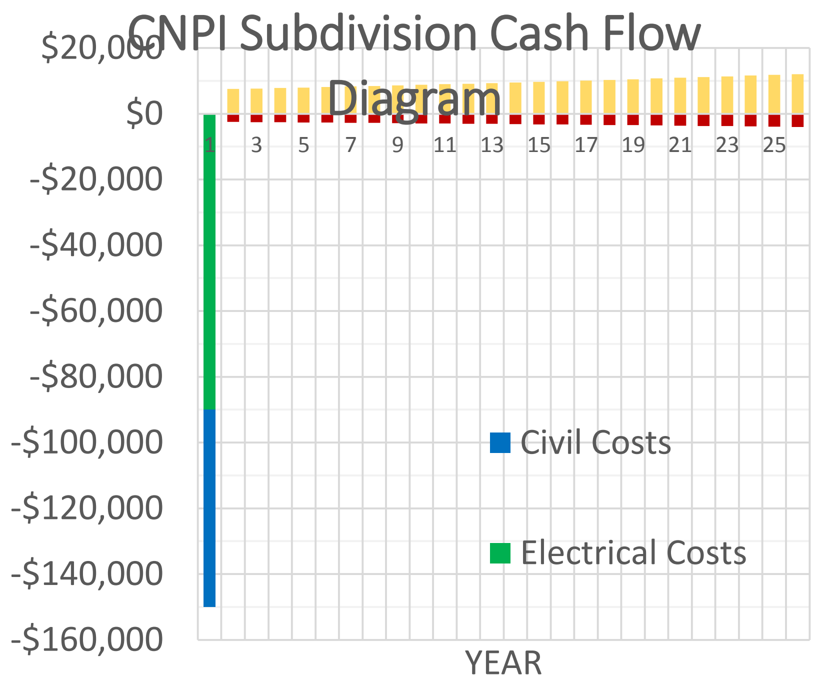
Last revised on October 8, 2015

(Originally Issued on July 14, 2000)

Discount-Cash-Flow? Net-Present-Value?
CIAC? What does all THAT mean !?

...continued

- CNPI uses estimates for:
  - Cost of Civil Works
    - trenching, conduit, transformer pads, etc
  - Cost of Electrical Works
    - poles, primary cables, distribution transformers, labor and expenses, etc
  - Future Operating Costs
    - Every new addition to CNPI system must be Operated and Maintained
  - Future Revenues to CNPI
    - Based on Developer's Forecast!
    - Every new load provides ongoing revenue to CNPI



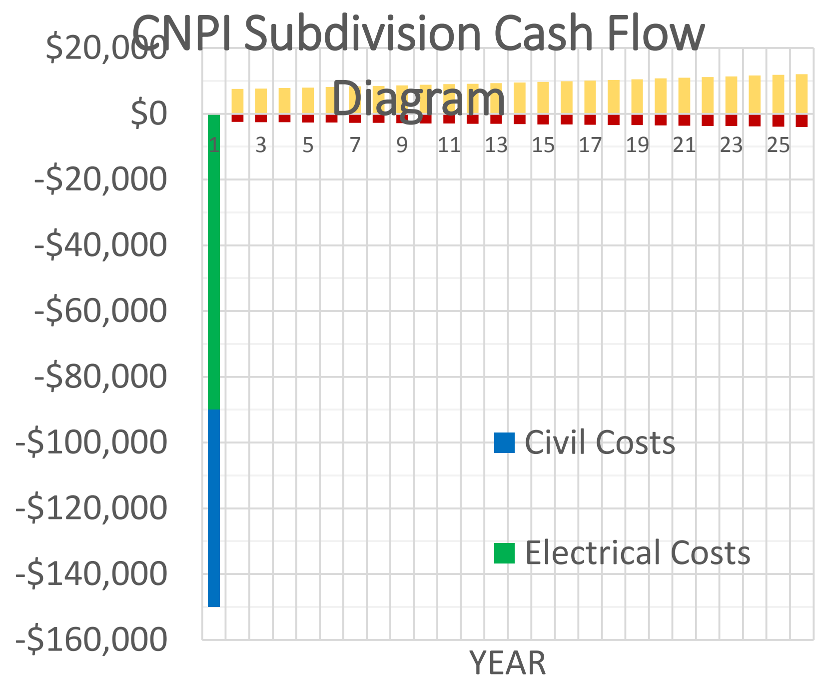
Example Calculation (Simplified):

- Up-front Costs to CNPI:
  - Civil Costs: $60,000
  - Electrical Costs: $90,000

- Ongoing:

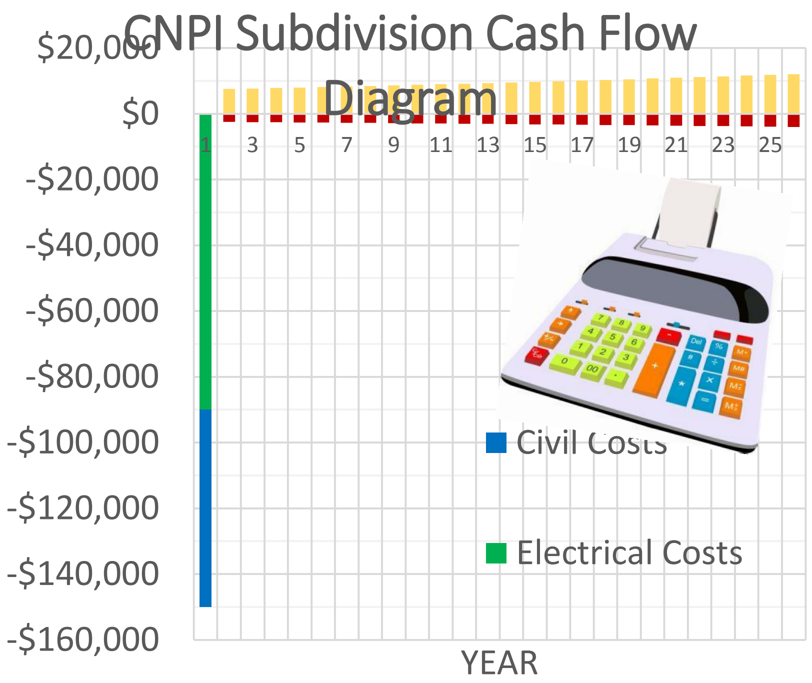
  (amounts shown for year 2, increasing over time, due to inflation)
  - Annual Sales Revenue: $7,500
  - Annual new O&M Cost: $2,500

  - Net Revenue: $5,000



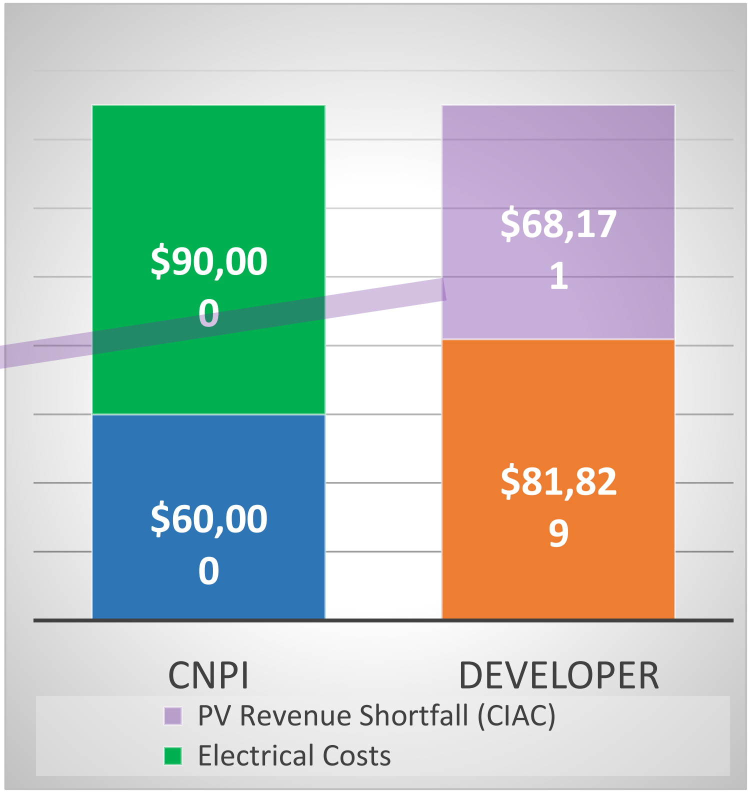
Example NPV Calculation (Simplified)

- Each FUTURE cash flow is converted to equivalent Present-Value cash flow, and then added up:
  - Result is Net-Present-Value equivalent of all cash flows
  - Calculations include allowances for:
    - Inflation and expected Rate Increases
    - Cost of interest on investments
    - Depreciation
    - CCA and Income Tax



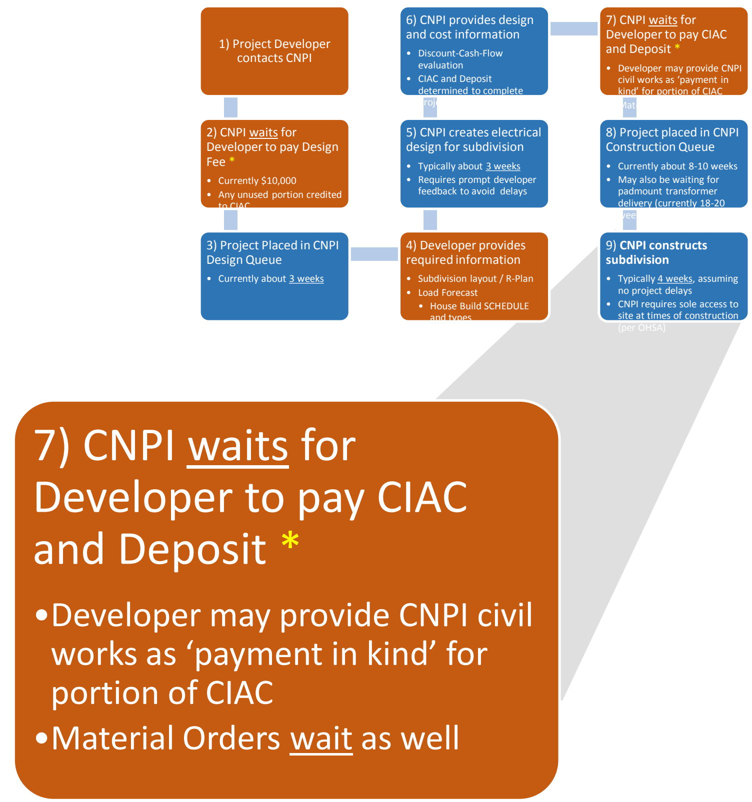
Example NPV Calculation (Simplified)

- Results:
  - Initial Construction Cost:
    - **$150,000**
    - The $60,000 Civil portion is often provided by Developer → CNPI pays for it!
  - Net-Present-Value (NPV) of Future Net Revenues:
    - **$81,829**
    - Includes O&M costs as well as electricity sales by CNPI
  - Shortfall in NPV:
    - **$68,171**
    - THIS is the **CIAC** needed by CNPI in order to 'break even' on the project over 25 years
  - CNPI also needs a guarantee for the forecasted future revenues
    - What if the homes never get built? Or built smaller than promised? Or later?
    - Letter Of Credit provides guarantee for first 5 years (per the DSC)



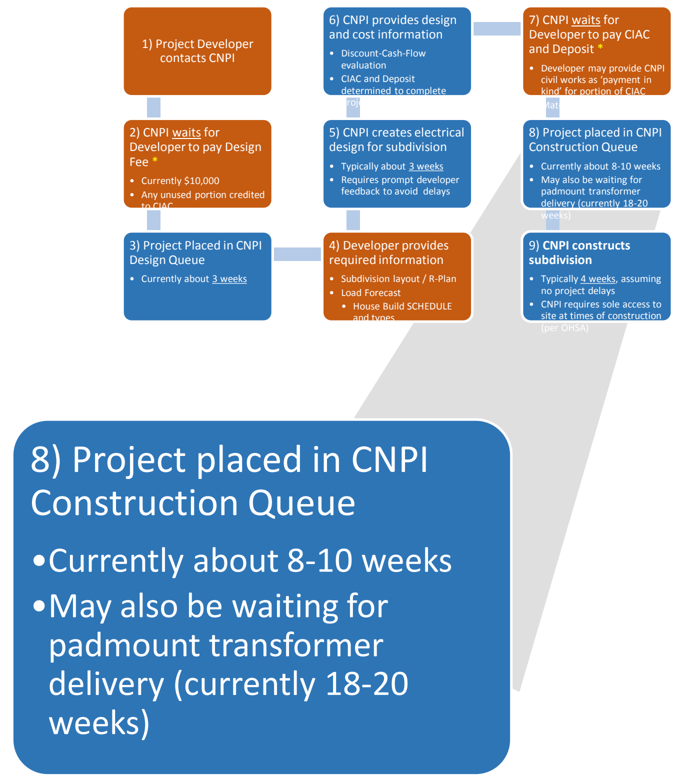
Step 7: CNPI waits for Developer to pay CIAC and Deposit

- CNPI plans out its construction schedule many weeks in advance.
  - CNPI will **NOT** reserve a spot in this schedule (or order materials) UNLESS the project is committed via payment!
  - **Typically, this construction 'queue' is 8 to 10 weeks.**
  - Delay for delivery of distribution transformers is usually 18-20 weeks
  - CNPI may also require commitment from Developer for Easements
- **Every day of delay** in committing any project will likely result in a **day of delay for energization**!
  - Also run the risk of getting 'behind' one or more other large projects



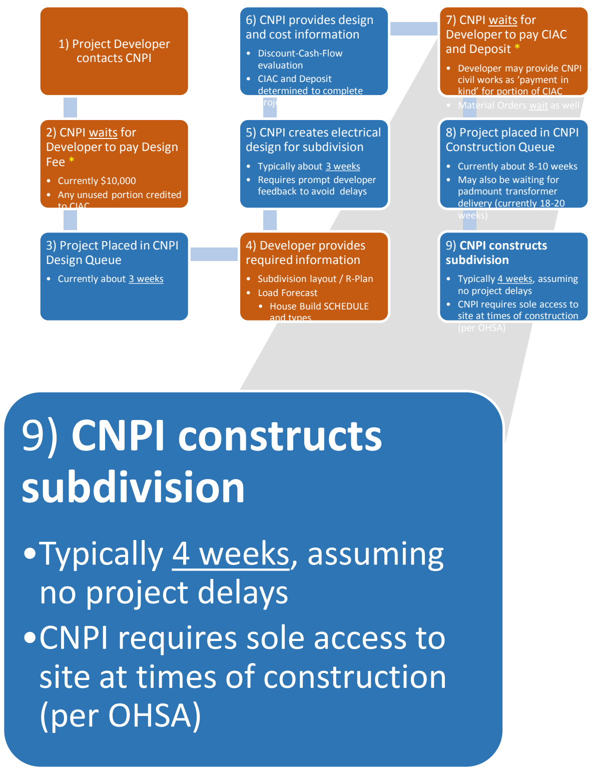
Step 8: Project placed in Construction Queue

- Once all issues are settled and payments made, project goes into CNPI 'Construction Queue'
- Typically 8-10 weeks
  - Can be longer if volume of committed projects grows
  - If distribution transformers were NOT pre-ordered earlier in project process, then this delay will generally be 18-20 weeks !



Step 9: CNPI constructs subdivision works

- Usually takes 4 weeks, after end of Construction Queue period
- If site is NOT ready for CNPI on day of construction start:
  - **CNPI will NOT make others wait because YOU were not ready!**
  - CNPI will reschedule to next window of opportunity
    - You will pay CNPI for any incremental costs!
- During CNPI work, OHSA must be followed:
  - Separation of time and/or space between 'constructors'



CNPI - SUBDIVISION Construction Timeline (Revised on 2015-11-26)

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- Requires prompt developer feedback to avoid delays

6) CNPI provides design and cost information
- Discount-Cash-Flow evaluation
- CIAC and Deposit determined to complete project by CNPI

7) CNPI waits for Developer to pay CIAC and Deposit *
- Developer may provide CNPI civil works as 'payment in kind' for portion of CIAC
- Material Orders wait as well

8) Project placed in CNPI Construction Queue
- Currently about 8-10 weeks
- May also be waiting for padmount transformer delivery (currently 18-20 weeks)

9) **CNPI constructs subdivision**
- Typically 4 weeks, assuming no project delays
- CNPI requires sole access to site at times of construction (per OHSA)

* Developer can prepay for padmount transformers to reduce transformer delivery delays

TOTAL Project Time = 30 weeks + any Developer delays. Can be reduced to 22-24 weeks if transformers are prepaid.

CNPI – PRIMARY SERVICE Construction Timeline (Revised on 2015-11-26)

1) Project Developer contacts CNPI

2) CNPI <u>waits</u> for Developer to pay Design Fee
- Currently $5,000
- Any unused portion credited to CIAC

3) Project Placed in CNPI Design Queue
- Currently about <u>3 weeks</u>

4) Customer provides required information
- Site Plan
- New/Upgraded Service Needs
- Load Forecast
- <u>Desired</u> In-Service Date

5) CNPI creates electrical <u>Design</u> for Primary Service
- Typically about <u>2 weeks</u>
  - *More time if CNPI needs system upgrades*
- Requires prompt developer feedback

6) CNPI provides Design and Cost information
- Discount-Cash-Flow evaluation
- CIAC and Deposit determined to complete project by CNPI
- CNPI Max Size transformer is 1000kVA

7) CNPI <u>waits</u> for Developer to pay CIAC and Deposit
- Material Orders <u>wait</u> as well

8) Project placed in CNPI Construction Queue
- Currently about 8-10 weeks

9) CNPI constructs subdivision
- Typically <u>4 weeks</u>, assuming no project delays
- CNPI requires sole access to site at times of construction (per OHSA)

TOTAL Project Time = 26 weeks + <u>any Developer delays</u>.

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

CONTRACTOR INFORMATION SESSION

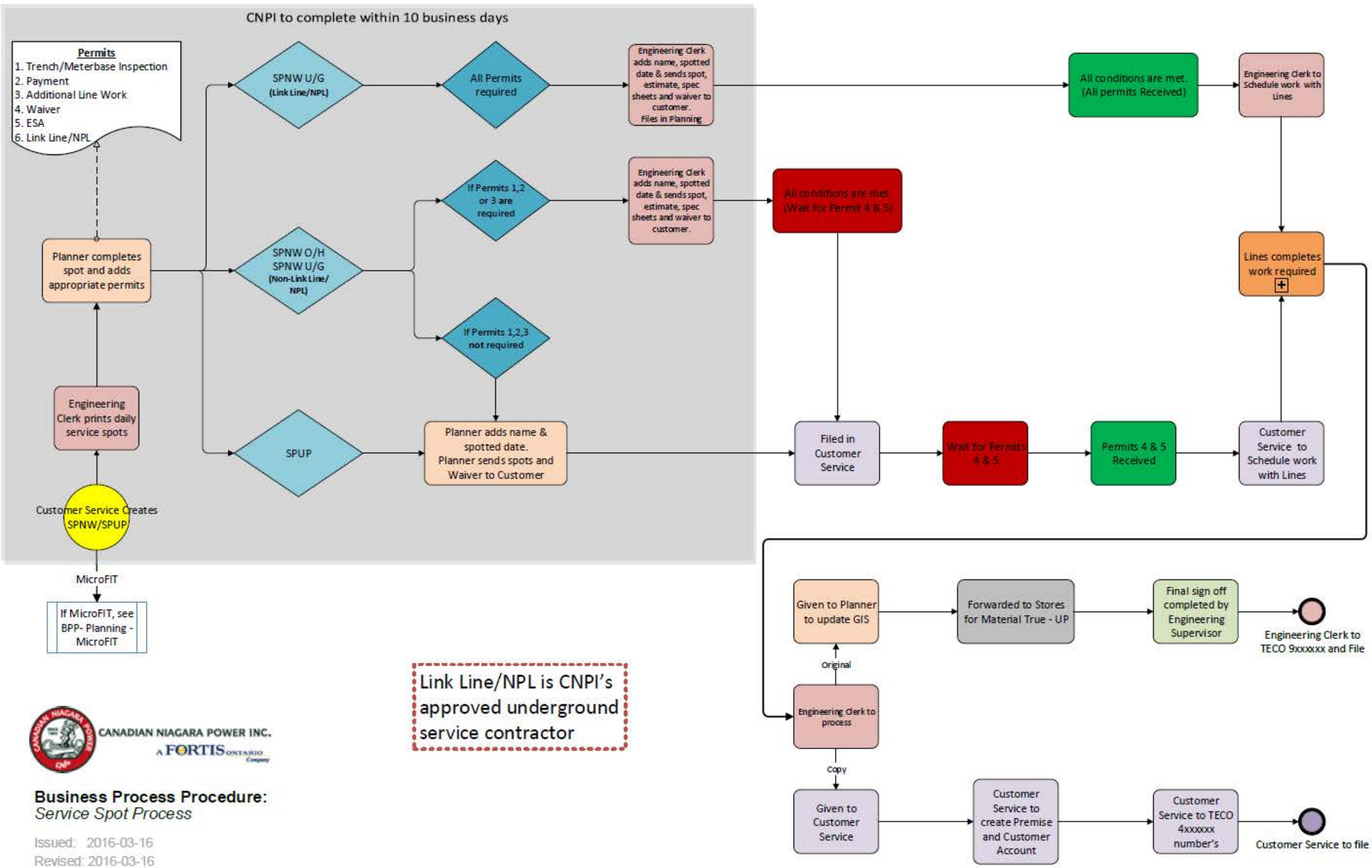
Wednesday, March 16th, 2016

Welcome and Introduction

Information presented by:

- Jeff Hoover – Planning Supervisor
- Pat Futino – Operations Supervisor
- Courtney Bonito – Customer Service Supervisor

Process for CNPI Service Spots



Link Line/NPL is CNPI's approved underground service contractor

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Business Process Procedure:
Service Spot Process

Issued: 2016-03-16
Revised: 2016-03-16

Review Service Spot Package
(Sent out to Electricians/Builders)

- Sample Service Spot

- Underground Service Spot
  - Electrician (Spot/Spec Sheets/Waiver)
  - Builder (Spot/Invoice/Contractor Sheet/Waiver)
  - If Link Line/NPL (Spot/Contractor Acknowledgment)

- Overhead Service Spot
  - Electrician and or Builder (Spot/Waiver)

2016.02.04 Printed by: HECKMANP Original Page 1

Service Spot-New Order: 4652716

9014282

Order type SPNW
Description Service Spot New-[redacted]
Start date 2016.02.03 *End date*
Priority
Entered by LAMBERTA
Status REL NMAT PRC PLNG 2000

COPY

Service Spot New-[redacted]
LOCATION PREFERRED: SPOT ALL POSSIBLES
ADDRESS/PLOT-PLAN: [redacted]
AMPS/VOLTS: 200
SINGLE/3-PHASE: SINGLE
OH/UG: U/G
ELECTRICIAN [redacted]
PHONE: 9C[redacted] FAX : 905-[redacted]
EMAIL:
OTHER/COMMENTS
ESA RECEIVED YES___ DAY OF____ NOTIFICATION#__________
WAIVER RECEIVED YES___
DISC/REC___ DISC ONLY____ CONNECT ONLY_____
VERIFIED BY:____

SCANNED

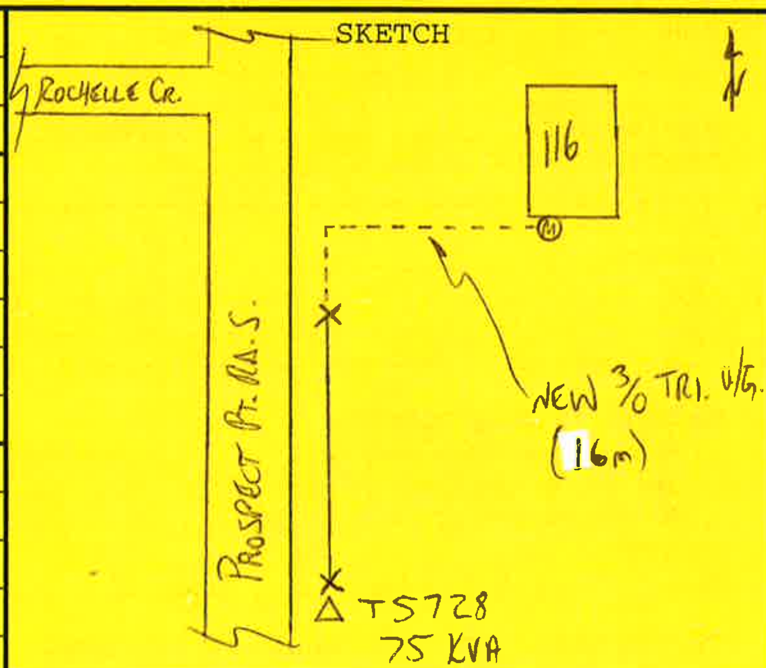
2016-02-08

Partner 1071911 SP
Address RIDGEWAY ESTATES
RIDGEWOOD CRES L2J 3H1

[X] **Joint Trenching Required**
Notification to Gas Comp Name: ____________
CNP Rep. Name: ____________ Date: ____________

NAME	RIDGEWAY ESTATES
ADDRESS	116 PROSPECT PT. RD. S.
ELECTRICIAN	[redacted]
REQUEST	NEW U/G SERVICE
AMPS MAIN SWITCH 200A	VOLTAGE 120/240V · PHASE 1Ø
2 (3) 4 WIRE	SERVICE WIRE SIZE 3/0 TRI. U/G
METER CABINET SIZE IF REQUIRED	M02 SERIES OR EQUIV.
REMARKS	- METER BASE 5'6" ABOVE GRADE
	- METER BASE, DUCTS, TRENCH AS PER CNP
	SPECS + INSPECTION.
[X] U/G CREW	[ ] O/H CREW

SKETCH



REPORT e MAILED TO [X] GIVEN TO [ ]
179 2016.02.09. Ridgeway

CNP REPRESENTATIVE K. WATSON
DATE SERVICE LOCATION 2016-02-05

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

1130 Bertie Street, P.O. Box 1218
Fort Erie, Ontario, Canada L2A 5Y2
Phone: (905) 871-0330 Fax: (905) 871-8818

Sold-to address:

Estimate

Estimate Number/Date
20007268 / 02/05/2016
Purchase Order Number/Date
FE9014282
Delivery date
Day02/05/2016
Customer No.
1909
Validity Period
02/05/2016 until 05/05/2016

We deliver according to the following terms and conditions: Currency CAD
The 'Final amount' must be paid as a downpayment before we can proceed with this work. This document, or a copy thereof, must accompany your payment. Upon completion of the work, you will be billed any extra costs or refunded any overpayment.

Material	Qty	Description	Price	Price unit	Value
12061		FO - CAPITAL CONTRIBUTION			
	Estimate				2,150.08
	Discount on Estimate				430.00-

NEW 200 AMP U/G SERVICE
METER BASE 5'6" ABOVE GRADE.
TRENCH, DUCTS, & METER BASE AS PER CNPI SPECS AND INSPECTION.
ESA INSPECTION REQ'D.
$500 JOINT TRENCH FEE INCLUDED.

Items total				1,720.08
HST	13.000	%	1,720.08	223.61
Final amount				1,943.69

COPY

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

SAP Number

Location

* To book a trench and/or meter base inspection call the office at 905-871-0330 ext: 3236.
CNPI requires a minimum 48 hours notice for these inspections.

*Entire trench must be open for inspection if the service is customer installed.

*CNPI meter base requirement is "MO2 Series" or equivalent.

*Half yard of sand must be located within a meter of the **frost loop**, CNPI will backfill this area before energizing the service.

**Meter base inspection must be scheduled prior to Link Line installing the underground service.

*If using CNPI Contractor Link Line, entire trench line must be free and clear of all obstructions.

***If customer installed, both trench & meter base must be ready for inspection when booking an appointment.

Acknowledged by:

_______________________ _______________________

print name *dated*

____

Signature

****PLEASE SIGN AND RETURN THIS FORM to patty.heckman@cnpower.com****

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

FAX: 905.871.8772

EMAIL: customer.service@cnpower.com

Technical Connection Waiver

This form must be completed and returned to Canadian Niagara Power Inc. "CNPI" prior to scheduling any work with CNPI. CNPI assumes no responsibility for incomplete work if all conditions of job (Including waiver, ESA & Payment) are not met.

Service Address: ______________________________

This is to confirm that I, ____________________________ give permission to CNPI to connect the electrical service at the above address without my presence. I confirm that I have the authority to grant this request.

Name (Please Print):______________________________

Phone Number: ______________________________

Email Address: ______________________________

ESA Permit Number: ______________________________

Date:______________________________

Authorized Signature: ____________________________

If a connection is not requested by 2:00 p.m. on the same day as disconnection applicable after hour charges may apply, otherwise connection will occur on the next available business day.

ACP (Authorized Contractor Program) Contractors: ESA Inspection Notification must be received in our office one day prior to the scheduled work. **Non ACP Electrical Contractors**: Please ensure that your booking for ESA is scheduled for same day of scheduled work.

****It is the responsibility of the person signing this wavier to call CNPI to schedule the Disconnection and/or Connection****

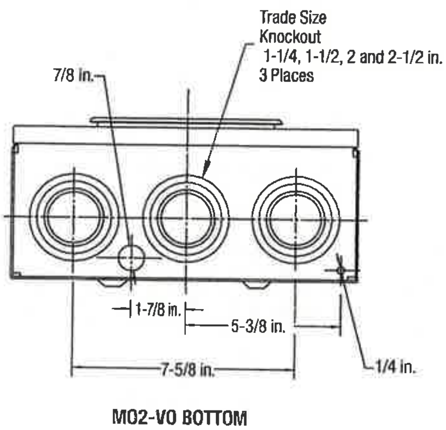
MO2 Series

200 A 600 V; Underground Only

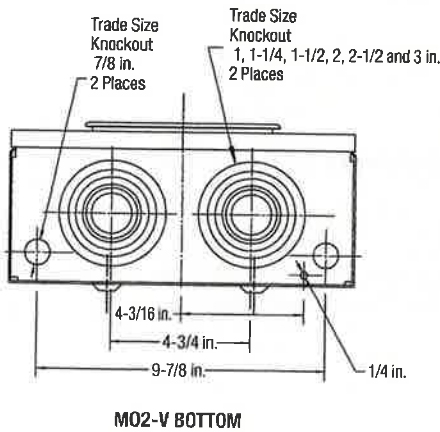
Product Specifications

- Conductor Range: Line: Single 1/2 in. studs to accommodate compression lugs 350 kcmil max. (supplied by utility), Load: 6 AWG-250 kcmil
- For underground service only
- Aluminum tunnel type connectors for load side, 1/2 in. studs on line side
- Supplied with screw type ring
- Weatherproof Type 3R enclosure
- Primarily used in: Sask., Man., Ont., Que.

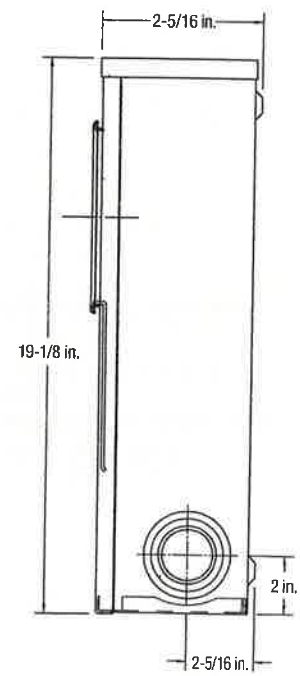
(M02-V)



M02-VO BOTTOM



M02-V BOTTOM



Approved for copper or aluminum

Cat. No.	Description	Dimensions (in.) H	W	D	Weight Each lb.	kg
4 JAW						
M02-V	Underground 1/2 in. studs					
M02-VO	Underground 1/2 in. studs for Ontario	19-1/8	12	5-9/16	18	8.1
M02MB-V	Underground 4/0 for Manitoba					
FACTORY-INSTALLED ACCESSORIES						
Include: -W	Water heater lugs					
-M	2/0 AWG subfeed on load side					

Please call 905-871-0330, ext. 3236, to set up your trench inspection. CNPI requires a minimum of 48 hours notice.

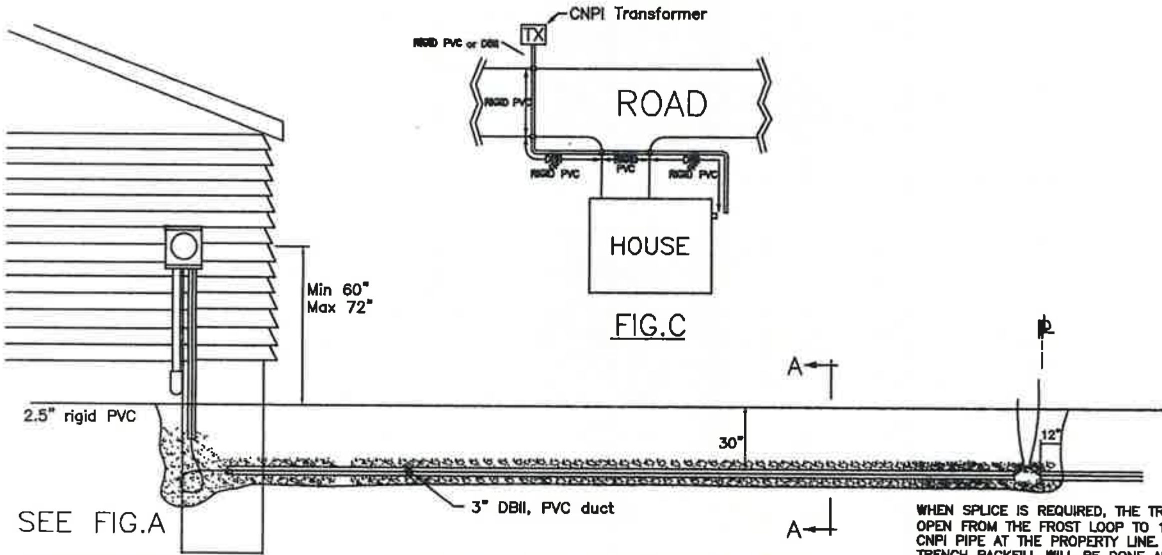


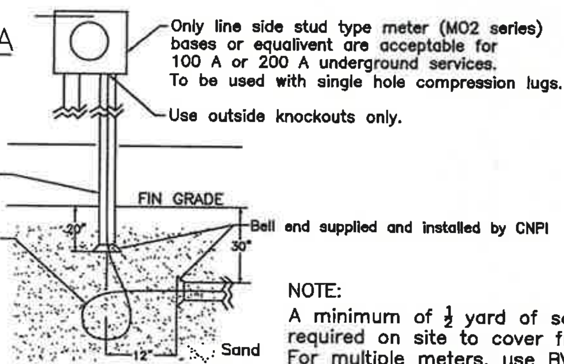
FIG.C

SEE FIG.A

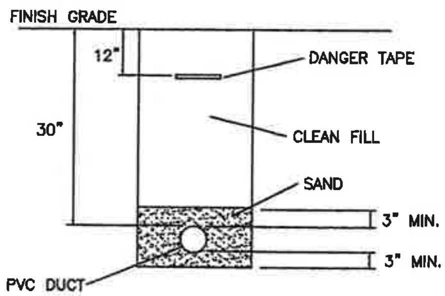
LOCATION OF METER AS SPOTTED BY CNPI PLANNING DEPT.

CNPI NOT RESPONSIBLE FOR TRENCH OPENING.

FIG. A



NOTE:
A minimum of ½ yard of sand is required on site to cover frost loop. For multiple meters, use BV series 2/3/4 bases or equivalent



SECT. A–A

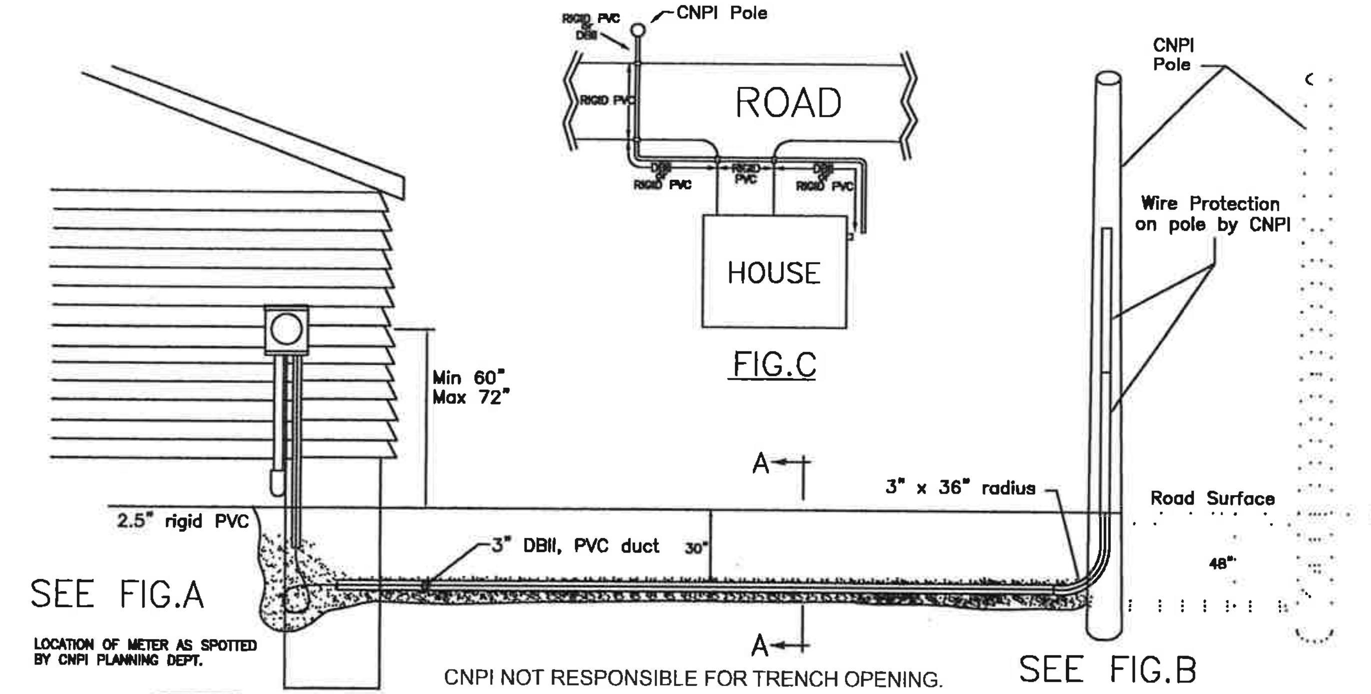
NOTES (General)

1. CNPI will own and maintain U/G service only if the design & construction is approved by CNPI.
2. Use 3" PVC (rigid conduit) under all road and driveway crossings. (See FIG.C)
3. CNPI will supply, and install cable at the customer's expense.
4. Meter to be located as per CNPI service spot sheet.
5. CNPI to do connections at line side of meter base, at pole, and in the trench.
6. CNPI to supply U/G danger tape (which customer will install at the time of backfilling to a depth of 12" below grade).

NOTES (Customer)

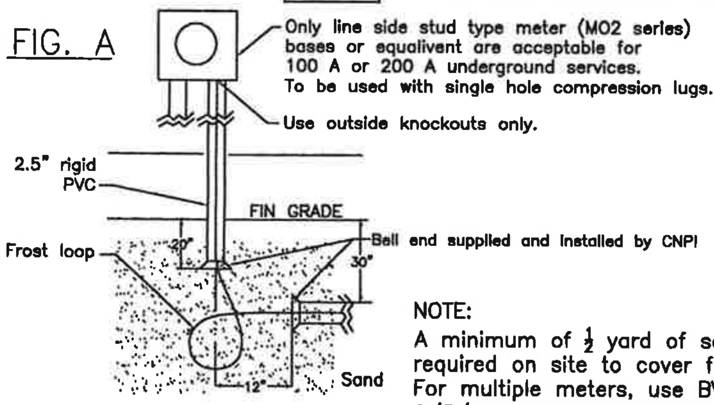
1. Customer is responsible for digging trench, installation of duct, fish rope (1/8" poly), and backfilling trench with rock free soil except for sand envelope per section A–A.
2. Duct, fittings, and fish rope are to be supplied by the customer.
3. No service will be connected without proper lot number and municipal address attached to the dwelling, ESA inspection approval and payment.
4. The trench and protection shall be inspected by CNPI prior to backfilling.
5. Inspection of the underground trench will be performed between the hours of 9:00a.m. – 2:00p.m. Monday to Friday.
6. Leave trench open from pole to meter base.

Please note the first inspection of the underground trench will be free of charge. If a customer calls for a CNPI crew to perform an underground service installation, but has not met all the above criteria, the crew will not install the service and the customer will be invoiced for a minimum call out. The minimum fee charged will be $170.00 plus applicable mark ups and taxes.

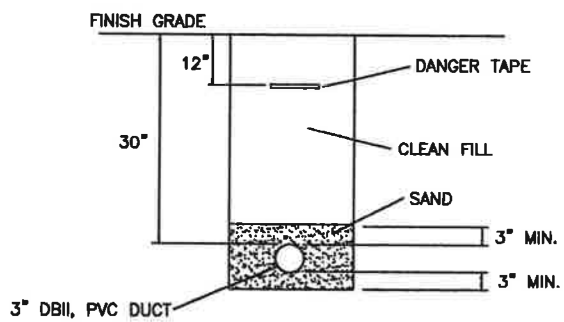


Please call 905-871-0330, ext. 3236, to set up your trench inspection. CNPI requires a minimum of 48 hours notice.

FIG. A



NOTE:
A minimum of ½ yard of sand is required on site to cover frost loop. For multiple meters, use BV series 2/3/4 bases or equivalent



SECT. A–A

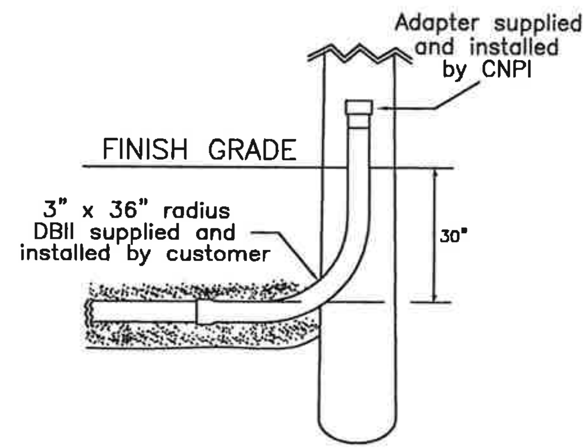


FIG.B

NOTES (General)

1. CNPI will own and maintain U/G service only if the design & construction is approved by CNPI.
2. Use 3" PVC (rigid conduit) under all road and driveway crossings. (See FIG.C)
3. CNPI will supply, and install cable at the customer's expense.
4. Meter to be located as per CNPI service spot sheet.
5. CNPI to do connections at line side of meter base, at pole, and in the trench.
6. CNPI to supply U/G danger tape (which customer will install at the time of backfilling to a depth of 12" below grade).

NOTES (Customer)

1. Customer is responsible for digging trench, installation of duct, fish rope (1/8" poly), and backfilling trench with rock free soil except for sand envelope per section A–A.
2. Duct, fittings, and fish rope are to be supplied by the customer.
3. No service will be connected without proper lot number and municipal address attached to the dwelling, ESA inspection approval and payment.
4. The trench and protection shall be inspected by CNPI prior to backfilling.
5. Inspection of the underground trench will be performed between the hours of 9:00a.m. – 2:00p.m. Monday to Friday.
6. Leave trench open from pole to meter base.

Please note the first inspection of the underground trench will be free of charge. If a customer calls for a CNPI crew to perform an underground service installation, but has not met all the above criteria, the crew will not install the service and the customer will be invoiced for a minimum call out. The minimum fee charged will be $170.00 plus applicable mark ups and taxes.

Inspections Underground Services

- Inspection Check List
- **With out** Link Line/NPL
  - Appointment must be made for Meter Base and Trench inspections
- **With** Link Line/NPL
  - Appointments must be made for Meter Base inspection.
  - Please notify CNPI as soon as meter base has been installed.

CNPI TRENCH & METER BASE INSPECTION

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

DATE: ____________________ **SAP NUMBER:** ____________________

LOCATION: ____________________

CONTRACTOR: ____________________

WIRE INSTALLED BY LINK LINE **YES / NO** **DATE INSTALLED** ____________________

COMPLETE	INCOMPLETE	
☐	☐	TRENCH OPEN
☐	☐	TRENCH SAND
☐	☐	FROST LOOP PIT (1m OPENING)
☐	☐	LONG RADIUS ELBOWS (36" SWEEP)
☐	☐	2.5" PIPE LINE SIDE OF METER BASE
☐	☐	DIRECTIONAL BORE (BOTH ENDS EXPOSED)
☐	☐	CAUTION TAPE ON SITE

COMPLETE	INCOMPLETE	
☐	☐	FISH ROPE
☐	☐	M02 SERIES METER BASE
☐	☐	DEPTH TRENCH 30" MIN.
☐	☐	METER IN CORRECT LOCATION

NUMBER OF 90 DEG ELBOWS ________

PICTURES ☐

☐ **PASS** ☐ **FAIL**

INSPECTORS NOTES:

CUSTOMER TO RESCHEDULE INSPECTION IF TRENCH OR METER BASE FAILS
*****A FEE OF $170.00 WILL APPLY IF EXTRA INSPECTIONS ARE REQUIRED*****

CUSTOMER: ____________________ **DATE:** ____________________

CNPI INSPECTOR: ____________________ **DATE:** ____________________

White • Customer Copy | BLUE • CNPI Copy

Overhead / Underground residential Service Truck Scheduling

- Calendar Bookings
  - Fort Erie - Tuesday, Wednesday, and Friday (ESA Inspection Day Wednesday).
  - Port Colborne - Monday and Thursday (ESA Inspection Day Thursday).
  - Maximum 4 scheduled appointments per day.
  - We will not schedule an appointment until all requirements are met.
  - Bookings are subject to change, due to circumstances beyond our control. (ESA, Weather)

Waivers Electrical

- [Electrical Waiver]

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

FAX: 905.871.8772

EMAIL: customer.service@cnpower.com

Technical Connection Waiver

This form must be completed and returned to Canadian Niagara Power Inc. "CNPI" prior to scheduling any work with CNPI. CNPI assumes no responsibility for incomplete work if all conditions of job (Including waiver, ESA & Payment) are not met.

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

FAX: 905.871.8772

EMAIL: customer.service@cnpower.com

Technical Connection Waiver

This form must be completed and returned to Canadian Niagara Power Inc. "CNPI" prior to scheduling any work with CNPI. CNPI assumes no responsibility for incomplete work if all conditions of job (Including waiver, ESA & Payment) are not met.

Service Address: ______________________________

This is to confirm that I, ____________________________ give permission to CNPI to connect the electrical service at the above address without my presence. I confirm that I have the authority to grant this request.

Name (Please Print):______________________________

Phone Number: ______________________________

Email Address: ______________________________

ESA Permit Number: ______________________________

Date:______________________________

Authorized Signature: ____________________________

If a connection is not requested by 2:00 p.m. on the same day as disconnection applicable after hour charges may apply, otherwise connection will occur on the next available business day.

ACP (Authorized Contractor Program) Contractors: ESA Inspection Notification must be received in our office one day prior to the scheduled work. **Non ACP Electrical Contractors**: Please ensure that your booking for ESA is scheduled for same day of scheduled work.

****It is the responsibility of the person signing this wavier to call CNPI to schedule the Disconnection and/or Connection****

1130 BERTIE STREET • P. O. BOX 1218 • FORT ERIE, ON L2A 5Y2

TEL: 905-871-0330/905-835-0051 • FAX: 905-871-8772 • www.cnpower.com

COPY

ESA Approval to Connect

- To ensure ESA is booked CNPI requires the ESA notification number prior to scheduling.
- **ACP (Authorized Contractor Program)** – ESA Inspection Notification must be received in our office one day prior to the scheduled work.
- **Non ACP Electrical Contractors** – Please ensure that your booking for ESA is scheduled for the same day as scheduled work.
- Day of ESA approval does not apply to new services. ESA approval must be received prior to connecting the new service.

CNPI Service Special Considerations

- If any additional line work is required ($), 6-8 weeks are required for line scheduling.
- If rock is encountered additional time is required.
- Permits:
  - Trench/Meter base inspection
  - Payment
  - Additional Line work
  - Waiver
  - ESA
  - Link Line/NPL

  Do you feel that a permit check list is beneficial to a Service Spot Package?
- OEB regulations state once all CNPI conditions are met CNPI has 5 business days to connect. This is reported to OEB on a monthly basis.
- Link Line Coordination of subdivision services from CNPI secondary pedestal. CNPI and Link Line will coordinate one visit to install service and energize.
- Loading sheets are required for services forecasted to have a demand over or near 50kW.

  2015_Load Summary for New Service form

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

LOAD SUMMARY for NEW or UPGRADED SERVICES:

Submit to: ***CNP Engineering Dept.*** ***Fax***: *(905)871-4458* ***Telephone***: *(905)871-0330*
Address: *P.O. Box 1218, 1130 Bertie Street, Fort Eire, Ontario*

Note: *Each separate service from CNP requires the submission of a separate form.*

1. General Information:

(a) Street Address: ______________________________ Building Name: _________________________

(b) Building Use: Apts: ☐ Condominium: ☐ Office: ☐ Other: __________________________

(c) Total GROSS enclosed floor area: ________________ ft^2 -or- _________________ m^2

(d) Portion of "c" which is to be used for parking: ________________ ft^2 -or- _________________ m^2

(e) Portion of "c" which is to be air-conditioned: ________________ ft^2 -or- _________________ m^2

(f) For Apt. Bldgs: Number of Apts: _____________ No. of Apts: with AC units: _____________

(g) Recreation centre total connected loads: _____________ Area for common use: ________________

2. Load Details:

	Estimated Load (kW)	Hour, First Use	Hour, Last Use
(a) Total **lighting load** (public lighting only, if Apt. Bldg):			
(b) Estimated **receptacle load**:			
(c) Total connected **space heating**:			
(d) Total connected **hot water heating**:			
(e) Total connected **duct heaters, parking garage**:			
(f) Total connected **duct heaters, rest of building**:			
(g) Total connected **heating cable**:			
(h) Total HP of **Air Conditioning (AC) equipment**:			
(i) Total HP of **Ventilation motors**:			
(j) **Kitchen equipment** (Do NOT fill in for Apt. Bldgs):			
(k) Total HP of **boilers and heating pumps:**			
(l) Total HP of **motors for elevators:**			
(m) Total HP of **motors, process or manufacturing**:			
(n) Total HP of **all other miscellaneous motors:**			
(o) **Total Connected load** (Do not fill in for Apt. Bldgs):			
(p) Number of **parking spaces with electric outlets**:			
(q) Number and size of **electric dryers**:			
(r) Number and size of **electric ranges**:			
(s) **Other** loads not listed above: ____________________			
(t) Total Apt or other multi-family Res. Demand, **Code**:			
(u) **Total Apt. Bldg. Demand:** (item "t" plus all other)			

3. Desired Service Voltage:

- ☐ Primary (3Ø, kV_{L-L})
- ☐ Primary (1Ø, kV_{L-G})
- ☐ 347 / 600 V (3Ø, 4-wire)
- ☐ 120 / 208 V (3Ø, 4-wire)
- ☐ 120 / 240 V (1Ø, 3-wire)

4. Size of Main Switch or Breaker (Amps):

- ☐ 200
- ☐ 400
- ☐ 600
- ☐ 800
- ☐ 1000
- ☐ other _______________

5. Date when permanent service is required:

____

6. Date when temporary service is required:

____

7. Peak load controller used: No: ☐ Yes:☐

If yes, load to be controlled:

____

____

8. Prepared by:

Business: ____________________________________ Telephone: (____) ____________

Address: ____ Fax: (____) ____________

Form Revision Date: 2016/03/15

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

9. Project Contacts:

Owner / representative:_______________________________ Phone:__________________________

Electrical / Mechanical Consultant:______________________ Phone:__________________________

General Contractor:__________________________________ Phone:__________________________

Architect:____ Phone:__________________________

Electrical Contractor:_________________________________ Phone:__________________________

10. Construction Schedule:

Start of Construction:____

Temporary Service Required by:____________________________________

Permanente Service Required by:__________________________________

11. Owner/Billing Customer:

Business/Name: _____________________________ Telephone: (____) ___________________

Address: __________________________________ Fax: (____) _________________________

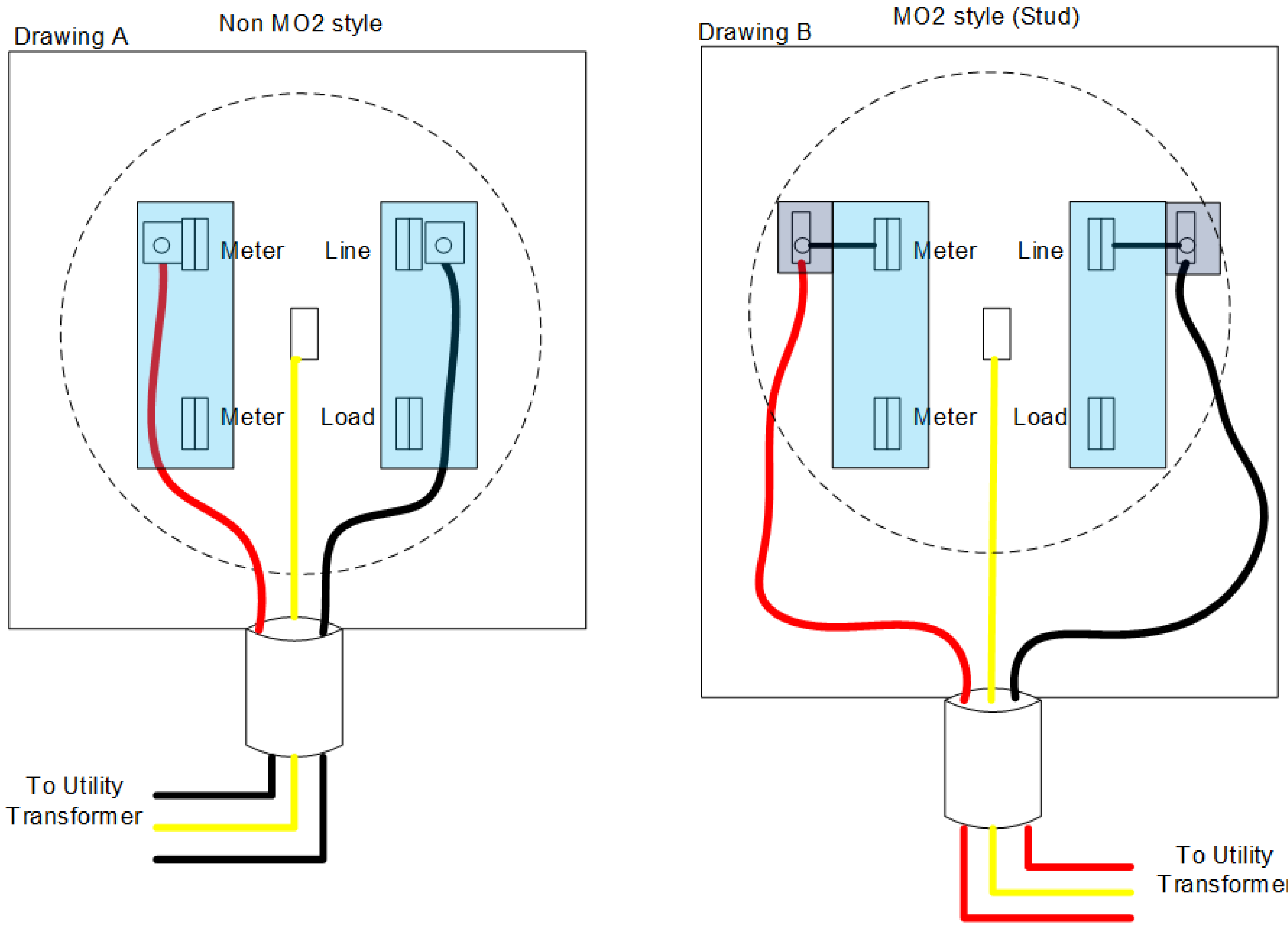
Date: ______________________ Signature: ____

Large Commercial and Industrial Customers (1 MVA and above)

12. Guaranteed Electrical Demand (KVA)

- Year 1
  Jan____Feb____Mar____Apr____May____Jun____Jul____Aug____Sep____Oct____Nov___Dec____
- Year 2
  Jan____Feb____Mar____Apr____May____Jun____Jul____Aug____Sep____Oct____Nov___Dec____
- Year 3
  Jan____Feb____Mar____Apr____May____Jun____Jul____Aug____Sep____Oct____Nov___Dec____
- Year 4
  Jan____Feb____Mar____Apr____May____Jun____Jul____Aug____Sep____Oct____Nov___Dec____
- Year 5
  Jan____Feb____Mar____Apr____May____Jun____Jul____Aug____Sep____Oct____Nov___Dec____

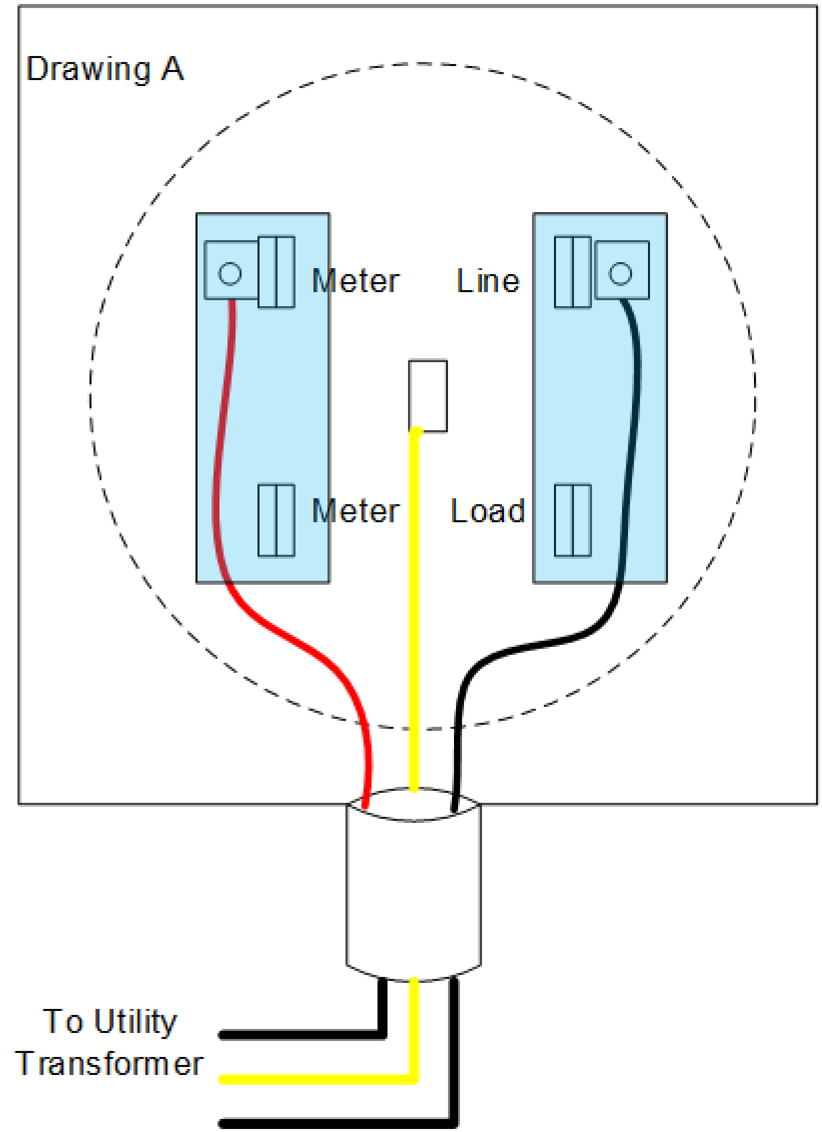
MO2 Meter Bases use for Underground services



MO2 Meter Bases use for Underground services

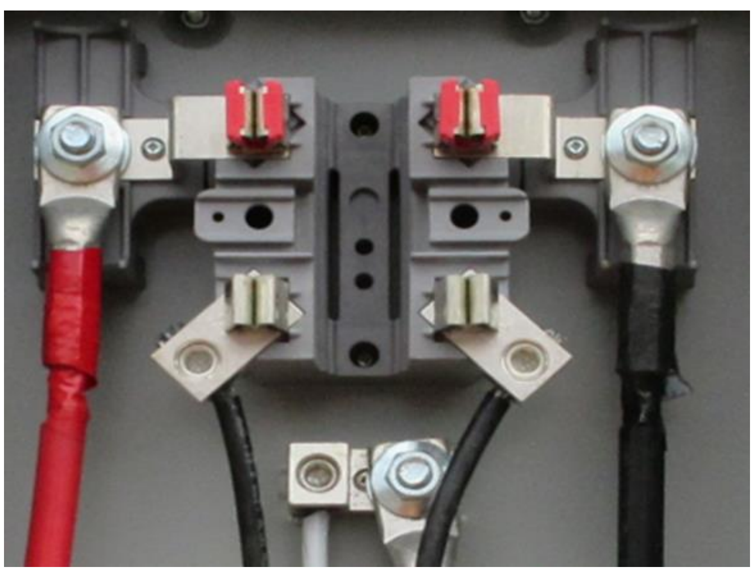
- As per Drawing A (Non MO2 stud style or equivalent) any downward force on the underground cable causes direct tension on the lug which tends to crack the polymer/ceramic base. These in turn can have the meter jaw connected freely to the meter. Once the meter is pulled the lose jaw can make contact with the meter base causing a flash.

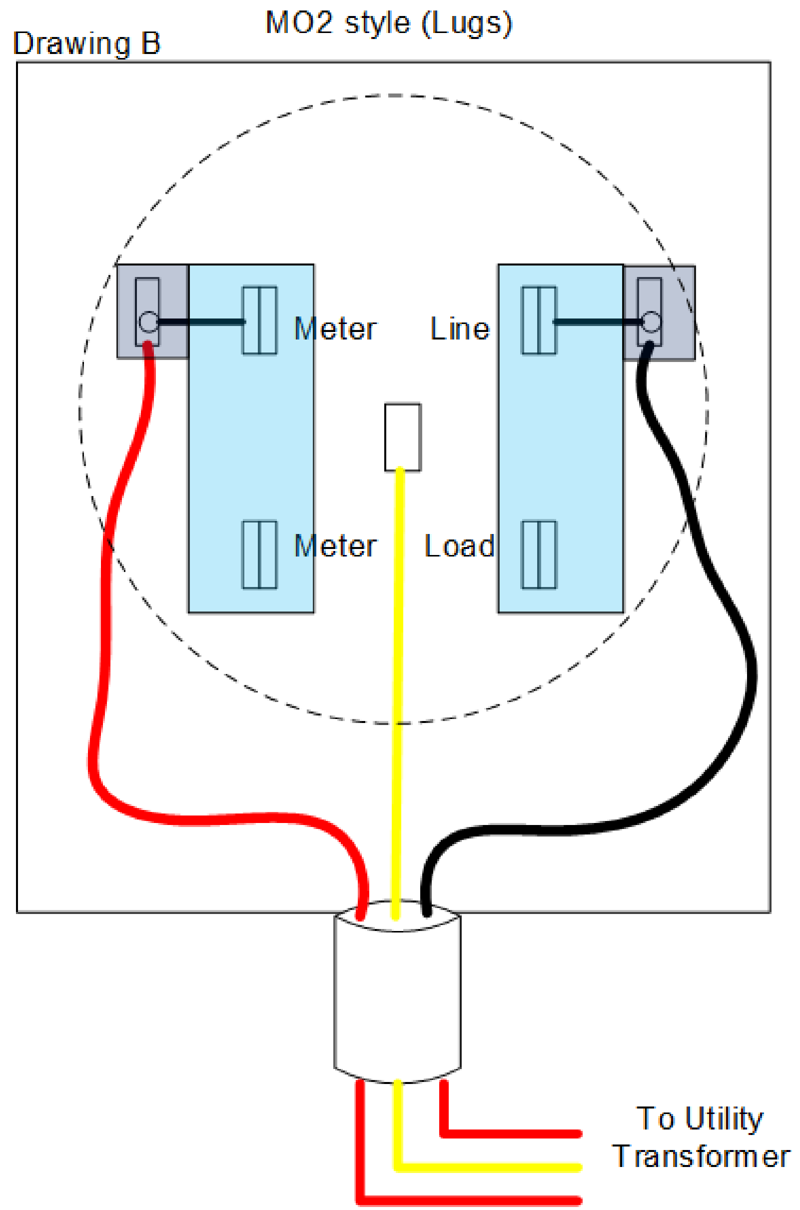
Non MO2 style



MO2 Meter Bases use for Underground services

- As per Drawing B (MO2 stud style or equivalent) any downward force on the underground cable does not causes direct tension on the lug which tends to crack the polymer/ceramic base. The downward force is on a separate polymer/ceramic base reliving direct strain from the meter lugs.





CANADIAN NIAGARA POWER INC.

A FORTIS ONTARIO Company

Questions?

CANADIAN NIAGARA POWER INC.

A FORTIS ONTARIO Company

thank you!

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Appendix 4-E– Local Contractor Prequalification Presentation

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Contractor Orientation

2016

Purpose of the Orientation:

To ensure that issues regarding,

- ❖ Health
- ❖ Safety
- ❖ Environment and
- ❖ Reliability

have been reviewed with contract personnel performing work for FortisOntario and Eastern Ontario Power

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- An introduction to our Health, Safety, Environmental (HSE) philosophy & system
- What experience has taught us about safety
- Not intended to be “training”

Intent of Session

Start by completing the **Bottom** portion of the form.

Sections 1 - 24 will be covered in the orientation.

A initial is required for each section indicating;

- ✓ Clearly understood
- ✓ Requires more info
- ✓ Not applicable.

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Health Safety & Environmental Contractor Orientation

Safety Concerns And Expectations	Clearly Understood	Require More Info	N/A
Health and Safety & Environmental Policy & Philosophy			
OHSA/MOL			
IRS System Employer/ Supervisor/Worker/JH&SC Roles			
Registration And Notice Of Project			
Risk Assessment/Job Planning			
The Environment			
Emergency Procedures			
Rescue Equipment, Fire Extinguisher, First Aid			
Incident Reporting			
Reporting Hazards			
Reliability			
Electrical Utility Safety Rules/M.O.T Book "7"			
Work Protection Code			
PPE			
Safety Rules, ,Security			
WHIMIS			
Proof Of Training			
Vehicle And Equipment Inspection(CVOR)			
Vehicle Documentation/Logs (Aerial And Hoisting)			
Use Of Hoisting Equipment(Chains, Ropes Slings)			
Working From Heights/ Ladder Requirements			
Excavation Requirements/Locates			
Job Site Visit Form			
Public Safety			
Discipline Policy/Termination Of Contract			

Orientation Conducted By:	Date/Month/Year	Start Time Finish Time
Employee Name(Print)	Employee Signature	Contractor Company Name
Contractor Reporting To:	FortisOntario. Representative:	

Orientation Type:

Utility/Electrical ☐ Civil/Underground ☐ Tree Trimming ☐ Facility ☐

Business Unit:

Algoma Power ☐ Canadian Niagara Power ☐ Cornwall Electric ☐

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FORTIS ONTARIO

HEALTH & SAFETY POLICY

FortisOntario Inc. (the "Company") and its operating subsidiaries strive to achieve health and safety excellence in providing electrical power and electrical utility services to its customers. Through the implementation of its Health, Safety & Environmental Management System, the Company maintains its focus on the continual improvement of its health and safety responsibilities and performance. The following policy sets the Company's health and safety commitments.

We will endeavour to:

- Encourage and enable the Company to have an effective health and safety management system that is appropriate to the nature, scale and risks of its business, and is committed to continual improvement and prevention of injury and ill health.
- Comply with all applicable health and safety legislation, regulations, and other requirements and require the Company's contractors to comply with the same standards.
- Integrate health and safety factors into the Company's planning, decision making, and business practices.
- Manage the system through documentation, implementation and maintenance.
- Set health and safety objectives and targets to enable the responsible management of the Company's health and safety risks.
- Make available to all employees of the Company appropriate training to ensure that their work is conducted in a healthy and safe manner.
- Ensure that the Company's health and safety policy is communicated to the Company's employees and available to the public, shareholders, and other interested parties.

Date: January 19, 2015

Approved By: W. J. Daley

President and Chief Executive Officer

Version 13

FORTIS ONTARIO

ENVIRONMENTAL POLICY

FortisOntario Inc. (the "Company") and its operating subsidiaries strive to achieve environmental excellence in providing electrical power and electrical utility services to its customers. Through the implementation of its Health, Safety & Environmental Management System, the Company maintains its focus on the continual improvement of its environmental responsibilities and performance. The following policy sets the Company's environmental commitments.

We will endeavour to:

- Encourage and enable the Company to have an effective environmental management system that is appropriate to the nature, scale and impacts of its business, and is committed to the continual improvement and prevention of pollution.
- Comply with all applicable environmental legislation, regulations, and other requirements and require the Company's contractors to comply with the same standards.
- Integrate environmental factors into the Company's planning, decision making, and business practices.
- Manage the system through documentation, implementation and maintenance.
- Set environmental objectives and targets to enable the responsible management of the Company's environmental aspects.
- Make available to all employees of the Company appropriate training to ensure that their work is conducted in an environmentally responsible manner.
- Ensure that the Company's environmental policy is communicated to the Company's employees and is made available to the public, shareholders, and other interested parties.

Date: January 22, 2016

Approved By: Bill Daley

President and Chief Executive Officer

Version 14

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“H,S & E Philosophy”

Say What You Do

Do What You Say

And Have the ability to Prove It

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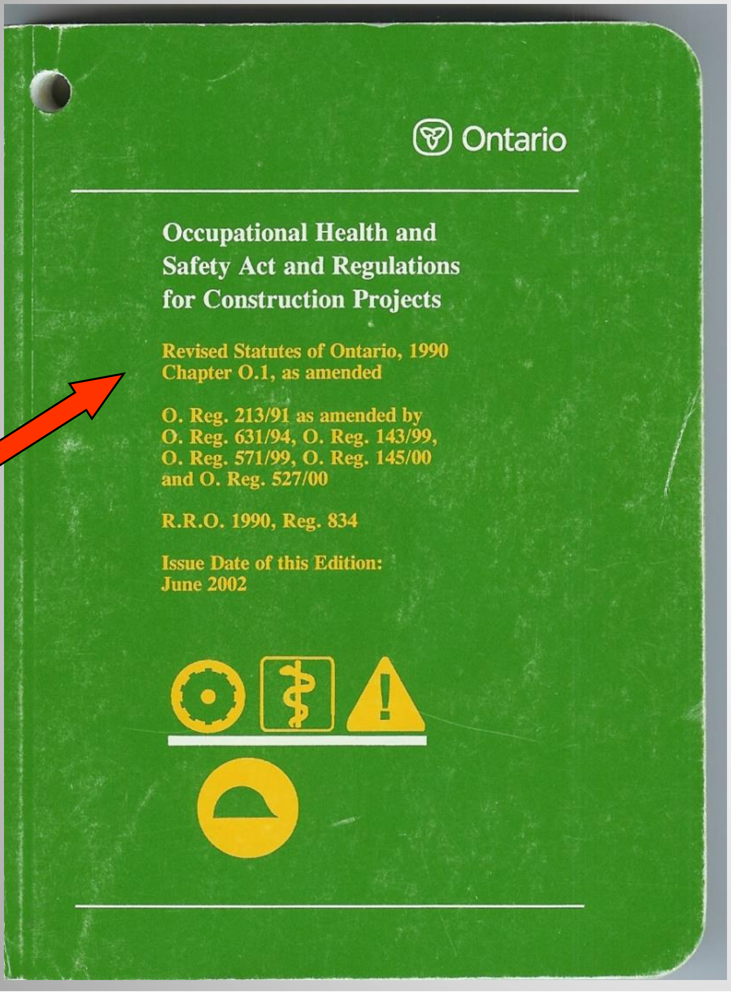
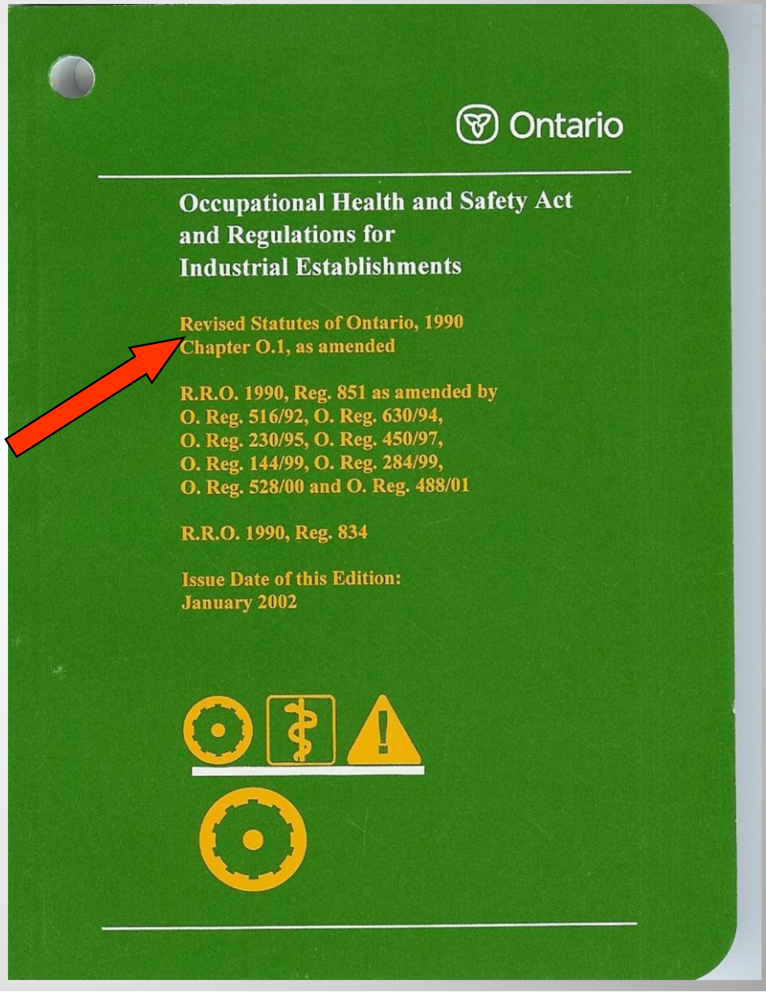
Act and Regulations





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Occupational Health & Safety Legislation

OH&S ACT:

SETS LEGAL AUTHORITY

- General Principles
- Rights
- Responsibilities

REGULATIONS:

SETS LEGAL RULES

- Safety requirements
- Exposure limits

OH&S Law is Based on.....

Internal Responsibility System

- Employer and employee are jointly responsible
- Employer <u>accountable</u> for non-compliance.

"Ignorance is not a defense"

Internal Responsibility System

Consists of:

The Employer
The Supervisor
The Worker
JH&SC/Rep

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General Duties of Employers,

Include But Are Not Limited To:

•Provide and maintain in good condition any prescribed equipment, materials and protective devices

•Ensure that the above are used in accordance with the regulations

•Carry out any measures and procedures that are prescribed for the workplace

•Appoint competent persons as supervisors, "*Competent person*" has a very specific meaning under the Act. He or she must:

1. be qualified–through knowledge, training and experience–to organize the work and its performance;
2. be familiar with the Act and the regulations that apply to the work being performed in the workplace;
3. know about any actual or potential danger to health and safety in the workplace;

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General Duties of a Supervisor

- Ensure that a worker complies with the Act and regulations.
- Ensure that any equipment, protective device or clothing required by the employer is used or worn by the worker.
- Advise a worker of any potential or actual health or safety dangers known by the supervisor *.*
- If prescribed, provide a worker with written instructions about the measures and procedures to be taken for the worker's protection
- Take every precaution reasonable in the circumstances for the protection of workers

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General Duties of a Worker

Include But Are Not Limited To

•Work in compliance with the Act and regulations.

•Use or wear any equipment, protective devices or clothing required by the employer *.*

•Report to the employer or supervisor any known missing or defective equipment or protective device that may be dangerous *.*

•report any known workplace hazard to the employer or supervisor.

•report any known contravention of the Act or regulations to the employer or supervisor.

Work within the guidelines set out by that of the employer

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The Powers of the JH&SC / Rep

- Identify Workplace Hazards
- Obtain Information from the Employer
- Make Recommendations to the Employer
- Investigate Work Refusals
- Investigate Serious Injuries
- Obtain Information from the Workplace Safety and Insurance Board

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Notice of Project

A constructor has to notify the Ministry of Labour before starting a project costing $50,000 or more. The Ministry will give you a Notice of Project form to complete and return to the nearest office. The white copy of the Notice of Project has to be posted at the construction site.

In Most Cases Algoma Power Inc, Canadian Niagara Power Inc, Cornwall Electric or Eastern Ontario Power will be responsible for obtaining the N.O.P

Ministry Of Labour

Anytime there is a site visit conducted by the Ministry of Labour at any project where Fortis Ontario is acting as either Owner or Constructor, the person in charge of the project will communicate the findings and any orders issued to the project manager acting on behalf of FortisOntario

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Risk Assessment
&
Job Planning

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Risk

RISK = PROBABILITY x CONSEQUENCE

The likelihood of something happening

The impact or result of something happening

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Risk

Risk Rating = Probability (F) X Consequence (S + L)

Frequency or Duration of Exposure to Risk (F)	
1 (L)	Less than annually
2 (L)	Quarterly to Semi-Annually
3 (M)	Monthly
4 (H)	Weekly
5 (H)	Daily

X

Severity of Incident (S)	
1 (L)	Hazard could result in a no treatment Injury or first aid treatment
2 (M)	Hazard could result in a medical aid
3 (M)	Hazard could result in non-critical lost time injury non
4 (H)	Hazard could result in a critical injury (Serious injury e.g. major broken bone; amputation; unconsciousness)>
5 (H)	Hazard could result in a fatality or permanent disability

+

Legal Exposure (L)	
1 (L)	Not regulated by a governed authority
3 (M)	May become regulated in the future (i.e. pending legislation)
5 (H)	Regulated an may result in an order or fine (municipal, provincial, or federal)
7 (H)	Regulated and may result in prosecution or civil action

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Risk

Classify the Risk (before control) as per the guidelines specified below.

Probability												
	5	10	15	20	25	30	35	40	45	50	55	60
	4	8	12	16	20	24	28	32	36	40	44	48
	3	6	12	16	15	18	21	24	27	30	33	36
	2	4	6	8	10	12	14	16	18	20	22	24
	1	2	3	4	5	6	7	8	9	10	11	12
		2	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
	Consequence											

Negligible (1 to 3)	Risk reduction not required. Risk is acceptable.
Low (4 to 13)	Implement risk reduction if practical and resources allow. Risk is acceptable.
Medium (14 to 34)was 94	Implement risk reduction actions to reduce risk to *As Low As Reasonably Achievable*. Risks in this category will be considered acceptable only if risk reduction is impractical or if its cost is grossly disproportionate to the improvement gained.
High (35 to 60)	The risk is unacceptable and cannot be justified on any grounds. The activity must be stopped immediately until effective control measures are put in place to reduce the risk.

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Risk

Level of Control	Description of Control Measure(s) *	Risk Reduction %
ZERO	• No controls or ineffective controls.	0
LOW	• Control is achieved by means of low level barriers such as personal protective equipment (PPE). • PPE/barriers are inventoried, tested, and/or calibrated, and results are recorded. • Establish and maintain competency levels	25
MEDIUM	• Hazards enclosed or guarded at the source to protect workers (e.g. guards, guard rails). • Hazard exposure periodically monitored (e.g. air quality testing). • Operating limits are known, or documented in procedures (e.g. Limits of Approach). • Procedures exist (OCP's)/training • Document job plan	50
HIGH	• Hazard potential is minimized by substituting with less hazardous material/process. • High level barriers such as structural barriers are in place (e.g. floor covering over hole or water). • Hazard exposure is continuously monitored. • Barriers are covered by a thorough maintenance/inspection program with accountabilities, schedules, and recording of completion. • Practices in place include redundant mechanisms such as the verification of tasks or status confirmation by others. • Key design conventions (e.g. directional "up" = "on", "down" = "off") are in place to minimize the chance of human error, or error-prone situations.	75
TOTAL	• Engineering controls which cannot be altered. • Hazard pertaining to product, workplace, job, or facility is eliminated at the source through design or engineering or substitution.	100

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Risk

				Risk Assessment											
				No Controls				After Controls							
ID #	Activity / Task	Hazard	Hazard Category	Frequency of Exposure	Severity of Incident	Legal Consequence	Initial Risk (Before Controls)	Risk Reduction	Residual Risk	Residual Risk Tolerable	Incident History	Incident History Tolerable	Assessment of Controls Required	Are Controls Met	Control Initiated
40	working with energized equipment or apparatus (300-750 volts) metering	electrical contacts	electrical	5	5	7	60	50%	30	YES	1	YES	NO	YES	*Electrical Utility Safety Rules (EUSR) and IHSA Safe Practice Guide Volume 1 & 2 :Reference OCP procedures section 600 & 700 Implemented use of meter puller & Arc flash Face Shield

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Risk

All high risk activities must be given the attention that they deserve and command

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Multi Barrier System

The probability of unwanted energy flow resulting in injury is dependant on:

- Effectiveness of each barrier in place
- Effectiveness of the multiple barrier system

The effectiveness of the multiple barrier system is improved when they are strategically located along the unwanted energy path.

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Multi Barrier System

- At the Source

  Remove and prevent the energy at the source

- Along the Energy Path

  To prevent contact between the unwanted energy flow and the target

- On the Target

  To minimize the injury or damage from contact with the target

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Multi Barrier System

Target Is The Worker

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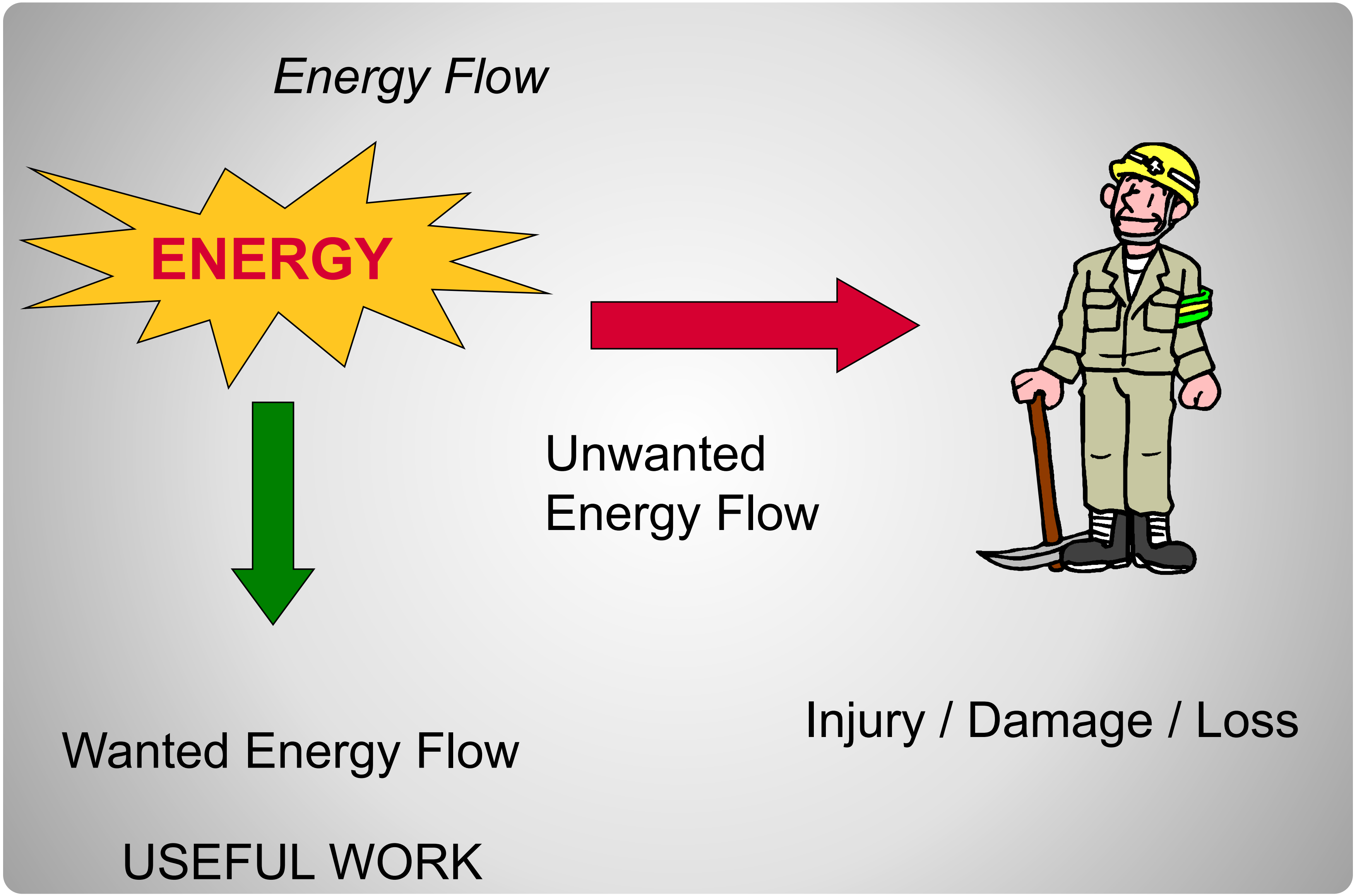

Energy Flow
ENERGY
Unwanted
Energy Flow
Injury / Damage / Loss
Wanted Energy Flow
USEFUL WORK

Multiple Barriers

Target NOT in Energy Flow!

Multiple Barriers

Barrier Effectiveness

The probability of unwanted energy flow resulting in injury is dependant on:

- Effectiveness of each barrier in place
- Effectiveness of the multiple barrier system

Unwanted Energy Flow

Pre Job Meeting

A pre job planning meeting must be completed and all associated risks and the controls that are to be used to minimize those risks have been reviewed and established in accordance with the OH&S Act and Regulations

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Pre Job Meeting

FORTIS ONTARIO HSE-R- 304	Health, Safety, & Environmental Pre-Job Meeting Minutes	Project:
		FO Project Manager:
		Date:

Contractor Information

Organization Name:	Telephone
Address :	Fax.
	Cell

Site Supervisor required for crews of 5 or more :Contractor will act as site supervisor on behalf of FortisOntario ☐ Applicable

Signature________________ Date ________________ ☐ Not Applicable

Meeting Attendees

Nature Of Work

Specific Job Notes -Comments

Hazards Identified & Controls

Hazards	Controls

FORTIS ONTARIO HSE-R- 304	Health, Safety, & Environmental Pre-Job Meeting Minutes	Project:
		FO Project Manager:
		Date: ____________

Emergency Response

Fortis Ontario Procedures	Contactors Emergency Response Procedures

Emergency Response Special Considerations –Notes	Closest Hospital or Urgent Care
	☐
	☐
	☐
	☐

Operational Control Procedures - Health Safety & Environmental Procedures

It is the expectation that all contractors working for or on behalf of FortisOntario subsidiaries must abide by the Policies, Operational Control Procedures and Health Safety and Environmental Procedures developed by FortisOntario. Copies of all applicable procedures have been provided, in an electronic format, for your review. It is the responsibility of each contractor to ensure that the specific requirements found in these procedures have been satisfied and are being adhered to. Compliance to these procedures will be monitored by FortisOntario through workplace inspection, work observation, safety meetings and document review.

Certain contractors may currently have operating procedures in place, should a discrepancy between procedures exist that task may not be performed until a mutually agreed upon resolution take place.

☐ Additional information or review' is required — Date:

☐ All FortisOntario documentation has been reviewed and ____________ (company name) is compliant with these operating procedures. — Name:______ Signature:______ Date:______

Contractor Representative	Name (Print):			
	Signature:		Date:	
FortisOntario Representative	Name (Print):			
	Signature:		Date:	

Project Planning

FortisOntario is committed to maintaining a high level of project planning. Ensure that through the pre job meeting that these developed procedures and expectations are reviewed and understood at this time.

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Job Planning

"5 Essentials" of Job Planning

1. Advance Preparation
2. Job Sequence Definition
3. Hazard and Control Identification
4. Communication
5. Supervision and Follow-up

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Tailboard Conference Plans

FORTIS ONTARIO OC-R-FO-NIAG-402 Line & Electrical Tailboard Conference Plan

Tailboard Conference Plan

Revised 09/29/15

Prepare, discuss, and review the Job Plan with the crew daily and whenever a change is introduced to the job.

Person in Charge:	Date:
Work Location:	
Job Being Performed:	
Working with Crew ☐ Working Alone ☐	☐ GPS Unit ☐ Cell Comm. ☐ S.C.C. notified of work location

Emergency Plan

Closest Hospital or Urgent Care

Call 911

- ☐ Welland General
- ☐ Fort Erie U.C
- ☐ Niagara Falls General
- ☐ Port Colborne U.C

Emergency Response Procedures

- ☐ ER-P-NIAG-202 Mayday
- ☐ ER-P-NIAG-212 Spill Oil
- ☐ ER-P-NIAG-224 Rescue Techniques
- ☐ ER-P-FO-201 Notification Of Emergencies

Notes or Considerations:

WORK PROTECTION ☐ A ☐ N/A

☐ Hold-Off	Feeder#:	Time On	Time Off	Work Permit #:	☐ Issued Work Permit	☐ Self-Adm. Work Permit
	Feeder#:	Time On	Time Off			
	Feeder#:	Time On	Time Off			

HAZARD IDENTIFICATION LIST

Gravity	Electricity	Mechanical	Kinetic/Vehicular	Other
☐ Falling from heights ☐ Falling objects / structures ☐ Dangerous trees ☐ Climbing obstructions	☐ Live apparatus ☐ Induction / Backfeed ☐ Static charge ☐ Ground gradients ☐ Flash potential ☐ Underground utilities	☐ Equipment failure ☐ Tension loads / springs ☐ Moving parts ☐ Sharp objects ☐ Deterioration of structure / apparatus	☐ Traffic conditions ☐ Driving conditions ☐ Moving / Shifting loads ☐ Vehicle stability ☐ Vertical Work ☐ Traffic Plan ☐ Applicable ☐ Non Applicable	☐ Confined space ☐ Flammable or explosives ☐ Chemicals ☐ Asbestos ☐ Extreme heat / cold ☐ Pressurized fluids/ gases

WE HAVE CONSIDERED

People	Procedures	Hardware/Equipment	Environment
☐ Worker qualifications ☐ Worker fatigue ☐ Lifting and twisting strains ☐ Outside influence / distractions ☐ PPE ☐ Other work groups ☐ Other utilities ☐ Public safety ☐ Pedestrian Control ☐ Communications	☐ De-energized apparatus ☐ Check for potential ☐ Adequate grounding ☐ Work Protection ☐ Limits of approach ☐ Vehicle grounds ☐ Work methods ☐ Operational Control Procedures List:__________	☐ Condition of structures ☐ Inspection of equipment / tools / vehicle ☐ Safe loads for rigging ☐ Temporary support ☐ Adequate cover-up ☐ Adjacent structures ☐ Booms inspected& cleaned ☐ Inspect rubber cover up ☐ Non-standard construction ☐ Contamination Readings / Monitoring______ (Barehand)	☐ Weather conditions ☐ Lighting conditions ☐ Terrain ☐ Locates ☐ Water bodies ☐ Spills/leaks ☐ Waste disposal ☐ Significant Natural Areas ☐ Permits: MOE MTO MNR Coast Guard Notice of Project ☐ Other potential environmental impacts

FORTIS ONTARIO OC-R-FO-NIAG-402 Line & Electrical Tailboard Conference Plan

Barrier Effectiveness Rating

Control Barriers	Safety Barriers	Support Barriers
Eliminate the Hazard Minimize Energy to a Safe Level Install Physical Barriers	Wear Protective Equipment Install Warning Devices Minimize Chance for Error	Work Procedures Identify Hazards Only Provide Training Provide Supervision

Job Steps Plan

Step	Hazards	Control	Safety	Support

Discuss/review job plan with crew daily and when changes occur. Ensure tasks are clearly defined, understood and assigned to qualified/trained crew members.

Identify D - initial & where applicable insert:

SS – Site Supervisor SP - Signal Person EW - Energized Work SW - Switching OP - Operator

TCP - Traffic Control Person DO - Dedicated Observer WA - Work Aloft UG – Underground JHS-JHS Worker Rep (6 Workers)

Crew Members	Date	Duties/Init	Record of Change (All crew members' initial changes)

Operational Control Procedures

FORTIS ONTARIO		OPERATIONAL CONTROL PROCEDURES
Fall Protection Inspection Program	Document No.:	OC-P-FO-406
	Page:	1 of 7
	Issued:	May 11, 2009
	Issue No.:	1.1

•You have been provided Fortis Ontario O.C.P's. Ensure that you review the applicable to your area of work - you must review and understand them.

•Ensure that your internal procedures meet or exceed FortisOntario requirements, that they are being utilized and staff clearly understand there intent.

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Risk Assessment & Job Planning

The degree of your Job Planning should be based on the Hazards of the job and the associated Risks. The quality of the job plan should remain consistent for every job executed.

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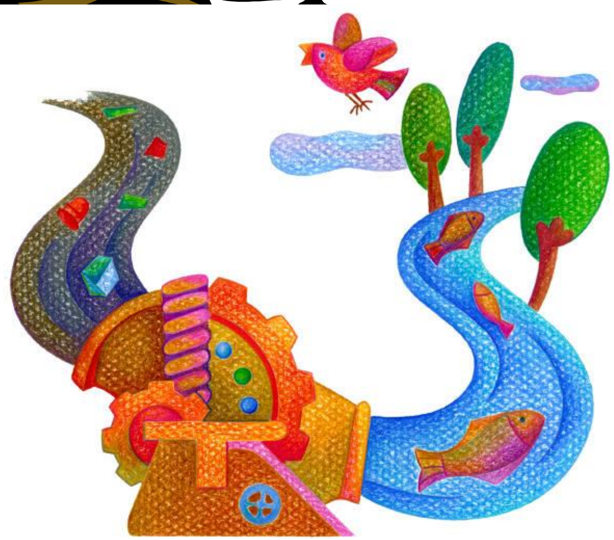
Environmental Concerns



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Environmental Philosophy

We promote a partnership approach for the development of responsible and realistic solutions.

We understand, minimize and manage the impacts and risks associated with our operations and we plan for all emergency situations.

We integrate environmental, public and socio-economic considerations into our business processes.

We ensure the efficiency of our operations and activities in the use of natural resources.

We exercise leadership by encouraging and training our employees at all levels to ensure environmental aspects have been evaluated and controls initiated.

We have developed and maintain an integrated Health Safety & Environmental Management System that support our policies and ensures continual improvement.

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Environmental Concerns

Would Include But Are Not Limited to

- Oil Spills From Transformers
- Work In Sensitive Areas (Significant Natural Areas)
- Use of Pesticides
- Work Near Waterways
- Work That May Affect Endangered Species

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Environmental Concerns

All Environmental Concerns Must be Taken into consideration when developing a job plan for all projects

All Spills Must be Reported to Eastern Ontario Power /Cornwall Electric

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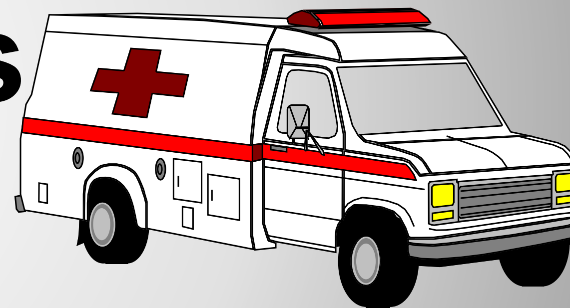
Emergency Procedures And Preparedness



This would include:

- Personal Injury
- Environmental Damage
- Equipment Damage -

Or anything that requires immediate attention.

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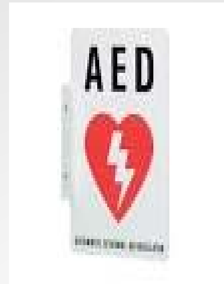
Components of Emergency Preparedness



Plan!

O.Reg.213/91

- 17. (1) A constructor shall establish for a project written procedures to be followed in the event of an emergency and shall ensure that the procedures are followed at the project. O. Reg. 145/00, s. 11.

- (2) The constructor shall review the emergency procedures with the joint health and safety committee or the health and safety representative for the project, if any. O. Reg. 145/00, s. 11.

- (3) The constructor shall ensure that the emergency procedures are posted in a conspicuous place at the project. O. Reg. 145/00, s. 11.

Reporting

Notification of Incidents

All incidents must be reported immediately or as soon possible or practicable

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Notification of Incidents

Upon discovering an accident, incident or emergency situation, which may include vehicle accident, property damage, fire, spill, injury, critical injury, fatality, or other emergency, immediately notify your Supervisor. If your supervisor cannot be contacted, immediately notify the Manager.

If the emergency requires the prompt assistance of police, fire, or ambulance, immediately activate the Regions ERP Emergency Communications.

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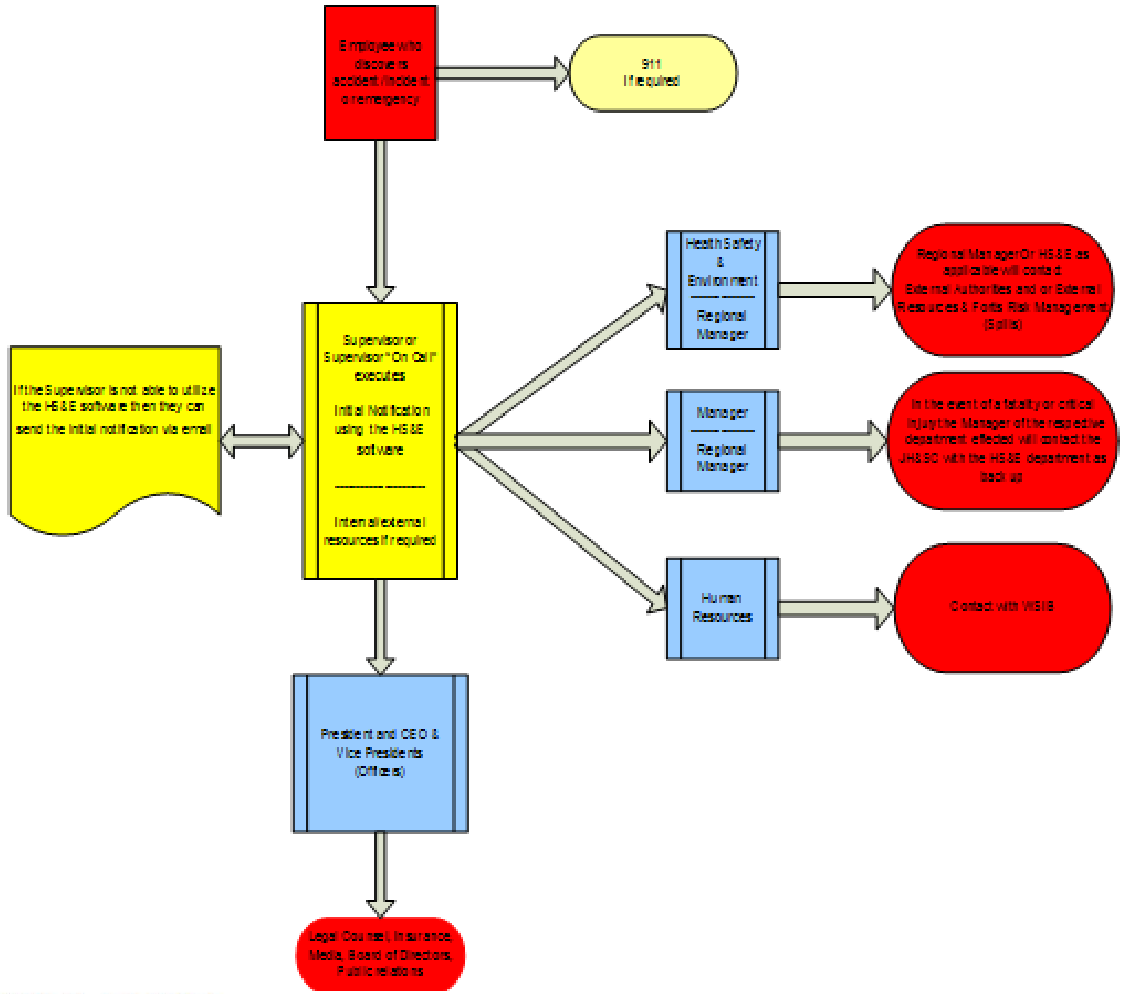
Notification of Incidents

(CONT.)



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Notification of Incidents

Minor Incidents (Low Risk)

The following types of incidents shall be investigated by the Supervisor of the department in which the accident/incident occurred, in consultation with the employee(s) who were involved in the accident:

•First Aid, Medical Aid or non-critical Lost-time injury,
•accident resulting in less than $5000 of property or equipment damage, or
•spill of up to 100L of any contaminant other than PCB oil

The Health, Safety, and Environment department may also be consulted to assist in the investigation, particularly if the accident results in a Lost-time injury. The Incident Investigation Report form shall be reviewed and signed by the supervisor and the department manager and submitted within 2 business days of the accident/incident to the Health, Safety, and Environment department.

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Notification of Incidents

Major Incidents (Medium & High Risk)

An Incident Investigation Team, led by appropriate front line management may conduct an investigation of the following types of incidents:

serious near-miss incident,
potential critical injury or fatality,
property or equipment damage in excess of $5000, or
spill of any amount of PCB oil or more than 100L of any other contaminant.

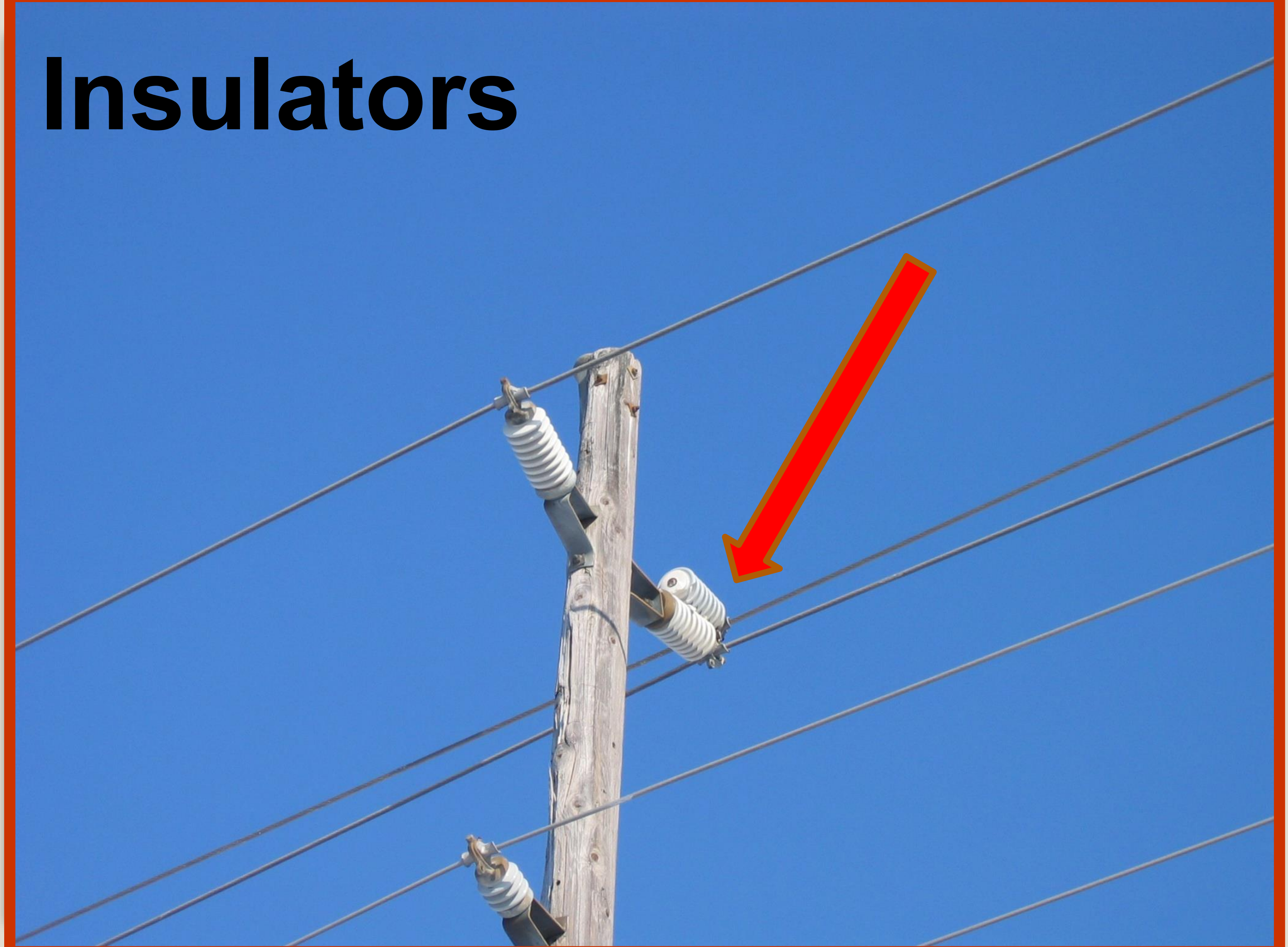
The Manager of the department in which the accident/incident occurred shall act in the capacity of Investigation Co-ordinator, with the supervisor of the department, the Health, Safety, and Environment department and the JHSC member(s) providing assistance and support as required. Other personnel that may be considered as team members include but are not limited to,

Reporting Hazards:

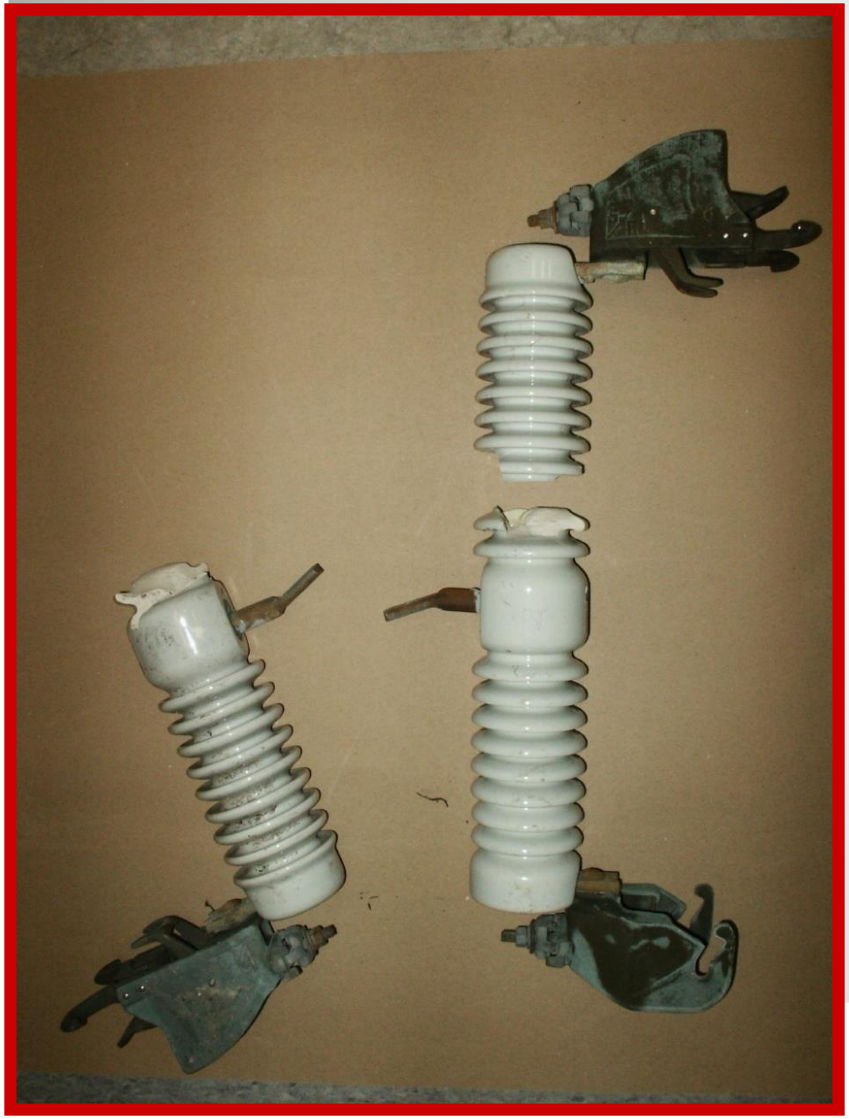
This would include;
- faulty or defective equipment,
- substandard acts & conditions
- unsafe work practices
- substandard clearances
- potential hazards
- suspicious behavior

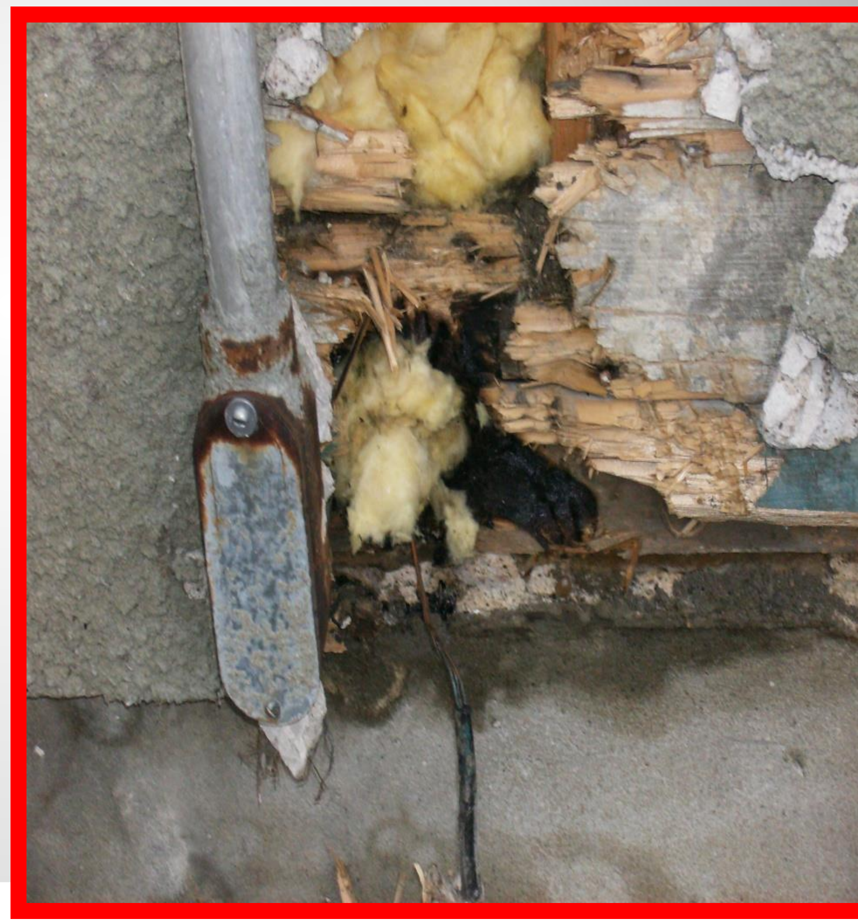
This ties in directly with our Reliability and in the prevention of loss.

Insulators

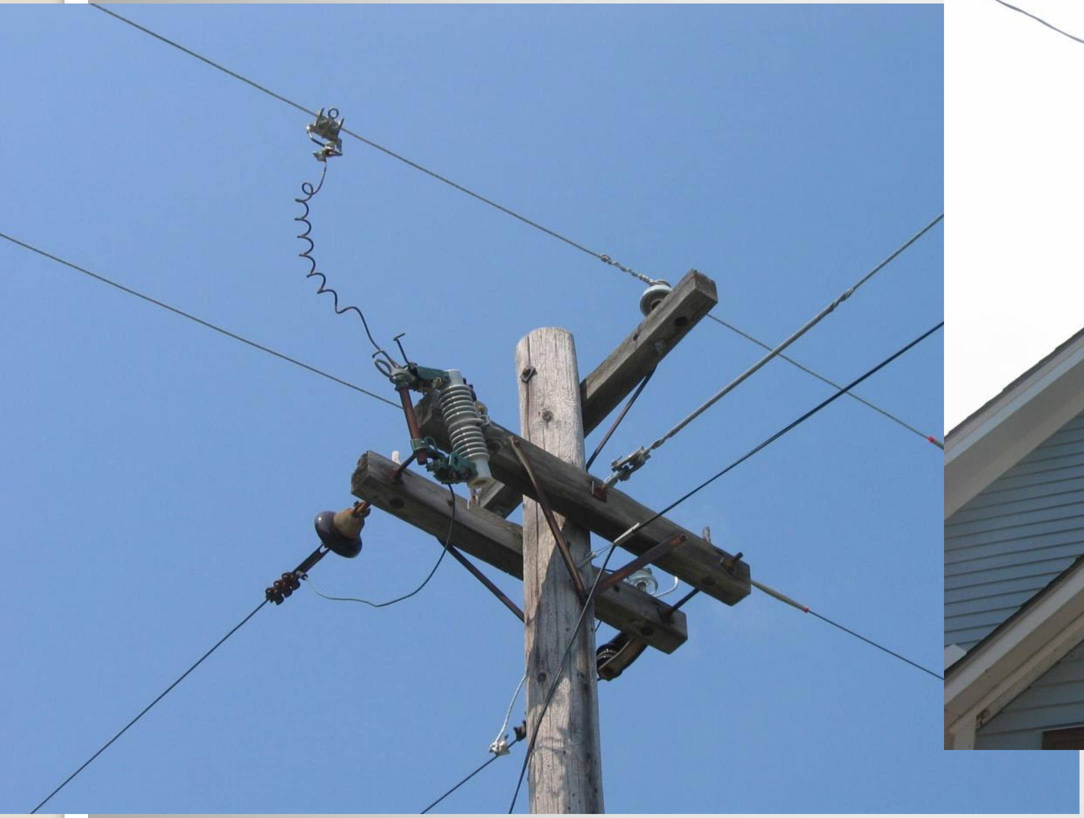


Other Hazards

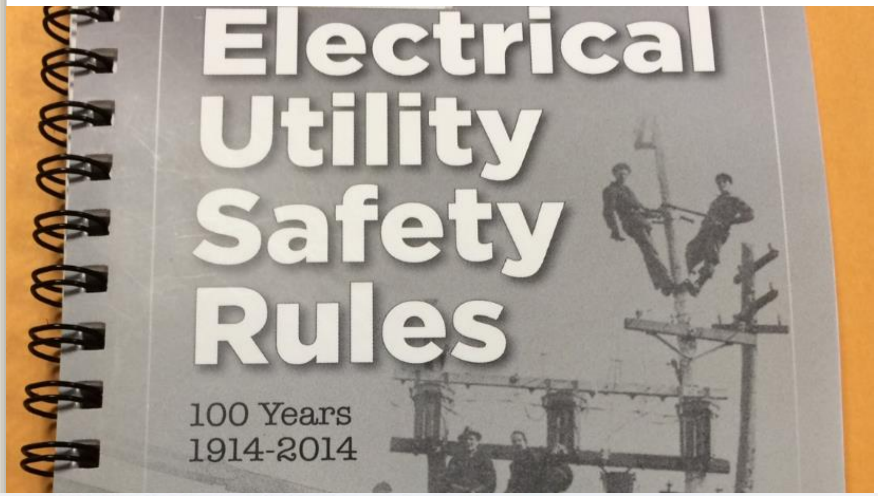




Unsafe Work Method



Unacceptable Clearances



LIMITS OF APPROACH

Maintain Maximum Clearances and Install Barriers Where Practical

EUSA Serving since 1915

Voltages	Personnel Zones*			Mobile Work Equipment*		
	O.H.S.A. Minimum	Authorized Worker	Restricted Zone	O.H.S.A.	Non-Insulated Booms	Certified Insulated A.D.
750 V to 15 kV	> 3 m	>.9 m (3 ft)	.9 m to .3 m (3 ft to 1 ft)	> 3 m	>.9 m (3 ft)	>.3 m (1 ft)
>15 kV to 35 kV			.9 m to .45 m (3 ft to 1.5 ft)			> .45 m (1.5 ft)
>35 kV to 50 kV		>1.2 m (4 ft)	1.2 m to .6 m (4 ft to 2 ft)		> 1.2 m (4 ft)	
>50 kV to 150 kV		>1.5 m (5 ft)	1.5 m to .9 m (5 ft to 3 ft)		> 2.4 m (8 ft)	> .9 m (3 ft)
>150 kV to 250 kV	> 4.5 m	>2.1 m (7 ft)	2.1 m to 1.2 m (7 ft to 4 ft)	> 4.5 m	> 3 m (10 ft)	> 1.2 m (4 ft)
>250 kV to 550 kV	> 6 m	>3.7 m (12 ft)	3.7 m to 2.75 m (12 ft to 9 ft)	> 6 m	> 4.6 m (15 ft)	> 2.75 m (9 ft)
* For detailed information relating to Limits of Approach Conditions and Restrictions refer to Electrical Utility Safety Rule # 129 and …n.				Cranes Power Shovels Back Hoes Mechanical Brush Cutter	RBD, Aerial Ladder, Work Platform, Uncertified Aerial Device	Certified and Tested by Certified Laboratory

Limits of Approach

Maintain Maximum Clearances and Install Barriers Where Practical

Voltages	Personnel Zones			Mobile Work Equipment		
	OHSA Minimum	Authorized Worker	Restricted Zone	OHSA	Non-Insulated Boom	Certified Insulated Aerial Devic
750 V to 15 kV	> 3.0 m (10 ft.)	> 0.9 m (3 ft.)	0.9 m to 0.3 m (3 ft. to 1 ft.)	> 3.0 m (10 ft.)	> 0.9 m (3 ft.)	> 0.3 m (1 ft.)
> 15 kV to 35 kV			0.9 m to 0.45 m (3 ft. to 1.5 ft.)			> 0.45 m (1.5 ft.)
> 35 kV to 50 kV		> 1.2 m (4 ft.)	1.2 m to 0.6 m (4 ft. to 2 ft.)		> 1.2 m (4 ft.)	
> 50 kV to 150 kV		> 1.5 m (5 ft.)	1.5 m to 0.9 m (5 ft. to 3 ft.)		> 2.4 m (8 ft.)	> 0.9 m (3 ft.)
> 150 kV to 250 kV	> 4.5 m (15 ft.)	> 2.1 m (7 ft.)	2.1 m to 1.2 m (7 ft. to 4 ft.)	> 4.5 m (15 ft.)	> 3.0 m (10 ft.)	> 1.2 m (4 ft.)

ECTRICAL
UTILITY
SAFETY
RULES

Traffic Control

Regulations 67 (2) (3) (4) (5) (6)

Ontario Traffic Control Manual Book 7 Temporary Conditions

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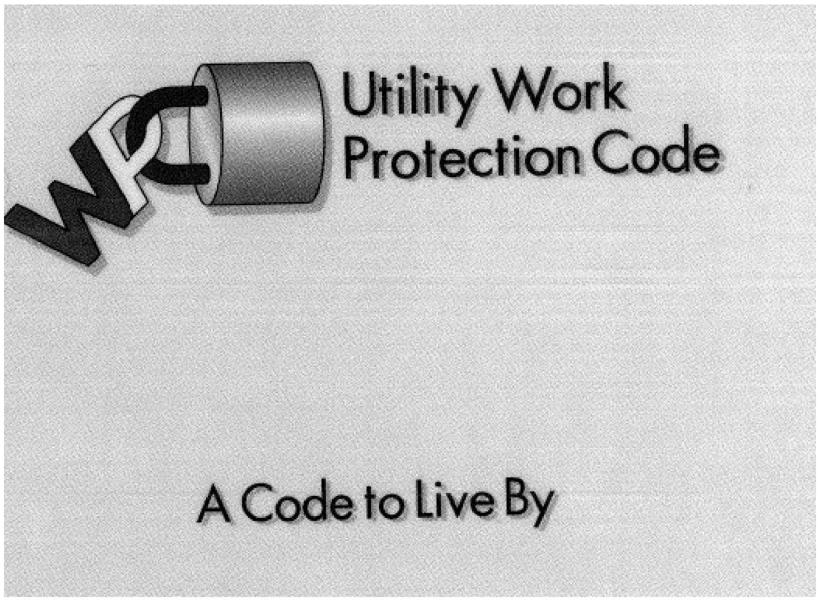
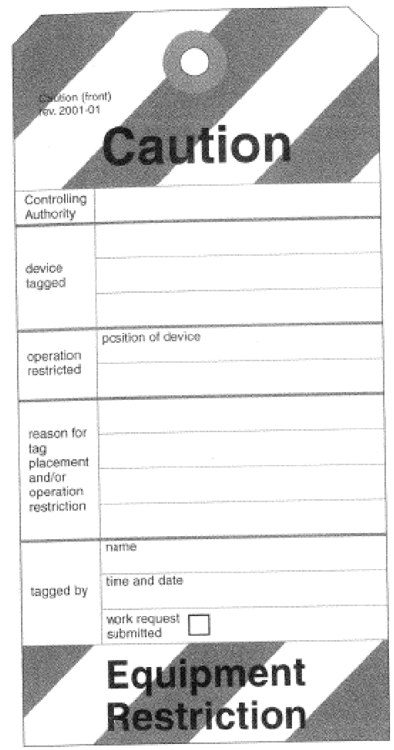
Utility Work Protection Code





Caution Tag (front)

Caution Tag (back)

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Safety Rules, Personal Protective Equipment

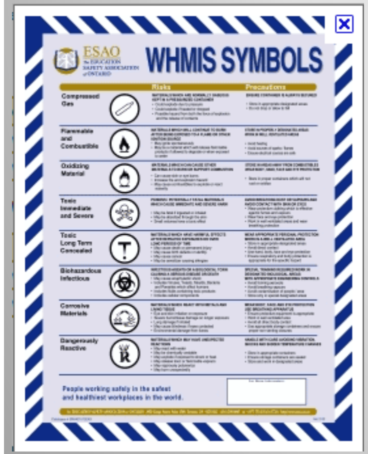
PPE Must Meet or Exceed FortisOntario Requirements

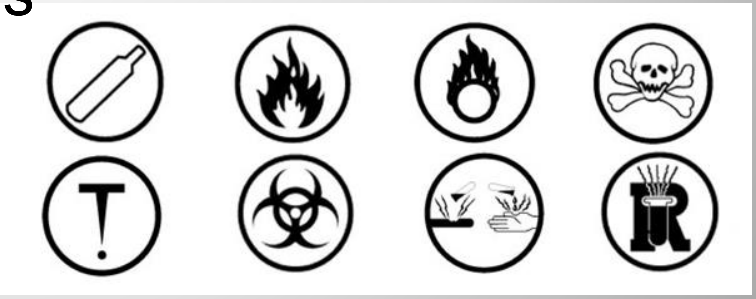
What are Your KEY Rules?
Have you communicated them to us?

Expect them to be measured

Global Harmonization System (WHMIS)

- Anything that comes with you onto a FortisOntario Project must be appropriately identified
- When you leave so does the product or empty containers





WHMIS

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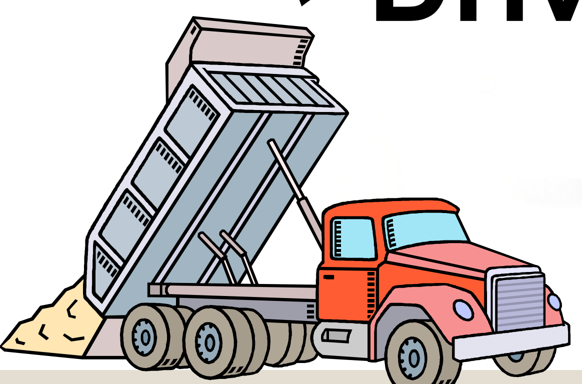
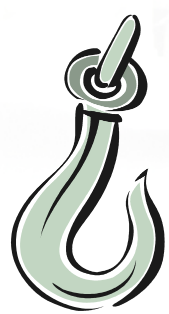
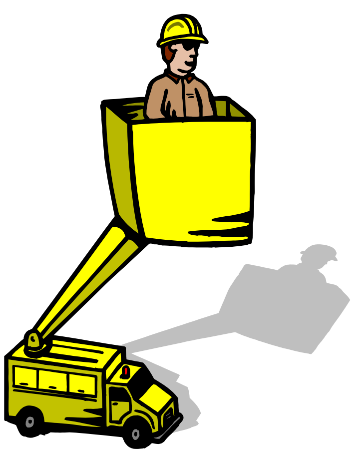
- **Vehicles ,**
- **Equipment Inspections and Documentation**

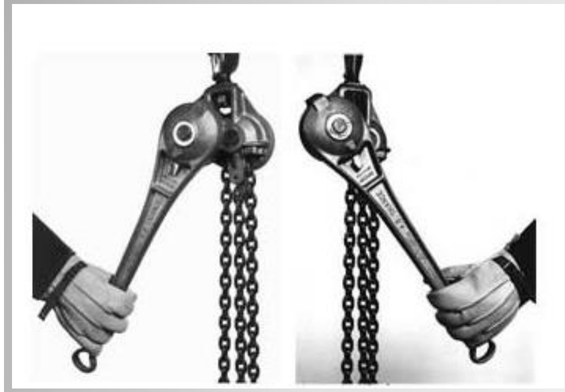
- ✓ **CVOR component**
- ✓ **Aerial Inspection Log**
- ✓ **Hoisting Log**
- ✓ **Drivers Log Books**







Hoisting Equipment



Ensure all hoisting equipment is in proper working order and is in test

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Regulation Reference: Construction Regulation 26.

Fall Protection is required where a worker is exposed to:

- **Falling more than 3 metres;or**
- **Falling into or onto a hazardous substance or object**

At FortisOntario workers will be protected by one of the following:

- **A Guardrail System**
- **A Travel Restraint System**
- **A Fall Restricting System**
- **A Fall Arrest System**
- **A Safety Net.**

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Proof of Training

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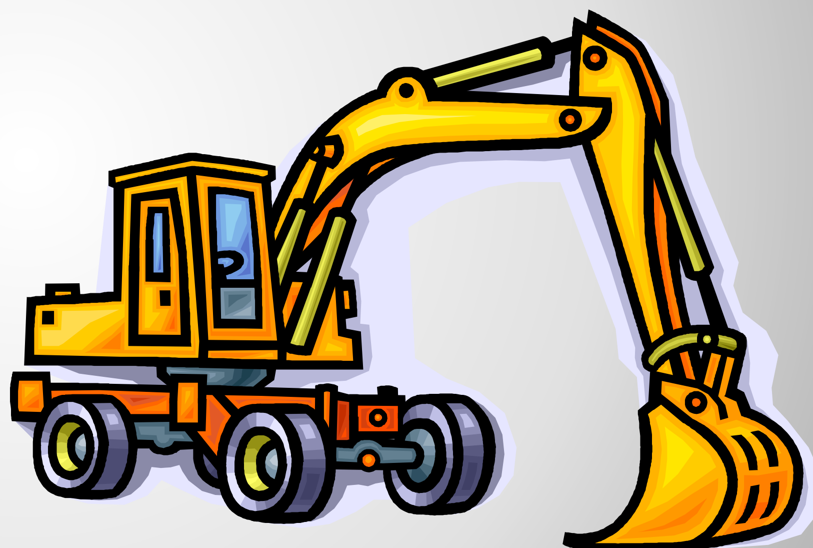
Excavation



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Locates

Regulation 228 – (1)(2)(3)(4)
Before an excavation is begun,

Cut primary cable

Ground Gradient mats are required when working on or near energized plant.

CONSEQUENCE:

- Health
- Safety
- Environment
- Reliability

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Work Observations

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Page 1 of 2

HSE-R-305 PLANNED WORK OBSERVATION REPORT

Supervisor's Observer Report

Supervisor/Observer:	Department: Lines Date:
Crew Leader:	Crew Members & Vehicles:
Contractor Company:	
Location of Job:	Description of Job:

Vehicle Inspection Report Complete: Yes ☐ No ☐ | Written/Drawn Traffic Plan: Yes ☐ No ☐ TL #

Job Plan Written: Yes ☐ No ☐ | Job Plan Communicated: Yes ☐ No ☐ | Written Emergency Plan:Yes ☐ No ☐

Hazards:

☐ Electrical	☐ Underground Utilities	☐ Moving parts
☐ Falling Hazards	☐ Hoisting	☐ Chemicals/Herbicide
☐ Traffic	☐ Vehicle Stability	☐ Flammable gas
☐ Flying particles	☐ Extreme heat/cold	☐ Pressurized gases
☐ Cave-ins	☐ Sharp objects	☐ Deterioration of apparatus
☐ Noise	☐ Confined Space	☐ Water
	☐ Body position/Action	☐ Other:

Other Observation Forms Attached ☐ Pesticide Application

List hazards identified above and indicate barriers used to Eliminate or Control the hazards.

List Personal Protective Equipment worn or used.

Additional Barriers or Controls

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Page 2 of 2

ON-SITE DISCUSSION WITH CREW MEMBERS

Supervisor's Comments:

Worker / Crew Comments:

Recommended safety meeting topic (indicate department):

Recommended training (if any):

Additional Follow-up Action:

Action Item	Responsibility	Target Completion Date	Completed

Crew Leader Signature: ____________ Date:

Observer Signature: ____________ Date:

Manager Signature: ____________ Date:

Forward to Health, Safety & Environment Department 06/01/10

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Security

This would include:

- ✓ Main Office
- ✓ Substations
- ✓ Equipment
- ✓ Switch Gear
- ✓ Transformers

Public Safety Requirements/Security

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Health and Safety Myth

If you create enough rules, policies and procedures, people won't get hurt!

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Reality

Rules and procedures may encourage safe actions, but they are only as effective as the consequences they predict.

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Discipline Policy/Termination of Contract

Discipline: This will be a combination of your Policies/Rules and our Daily Workplace Inspection Program and observations.

Termination will be for a:

- **Flagrant or Repeat Safety Violation**
- **Theft**
- **Unacceptable Behaviour.**

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What is new in 2016!

- Changes to Contractor Pre-Qualification Process
- Updated HSE Procedures and OCPs (CDs available)
- Bi-Annual Contractor Orientation
- Mandatory Health and Safety Awareness Training

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New Pre-Qualification Process

- Pre- Qualification Questionnaire completed once if,
  - Maintain continuation of similar work year over year
  - Maintain FO satisfactory HSE records and work reviews from previous year

- Annual update information required only

Annual Update Information:

- WSIB Workplace injury Summary Report
- Proof of WSIB Insurance & General Liability Insurance
- Updated Training records i.e. Electrical Awareness, Fall protection, certificates for operating equipment, WHMIS, First Aid
- Proof of meeting new applicable legislation introduced
- Emergency Response procedures updates (depending on work locations)

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Mandatory health and safety awareness training for Workers and Supervisors

History

Metron case Christmas Eve 2009

- Six workers fell from a suspended work platform; four died, one seriously injured, one survived
- Ontario government announced a comprehensive review of the Ontario OHS system
- 45 recommendations for change to Ontario's health and safety system

Recommendations

- The recommendations are targeted at such issues as the internal responsibility system
- New prevention organization (Safe Workplace Associations, MOL WSIB)
- Mandatory health and safety awareness training for Workers and Supervisors
- Mandatory training for health and safety representatives (JHSC and Basic Certification Training)
- Mandatory Working at Heights Training

Expert Advisory Panel Recommendations

Score Card

	In progress	Nearing completion	Completed
Creation of the Prevention Office			✓
Chief Prevention Officer			✓
Prevention Council			✓
Mandatory awareness poster			✓
New reprisal complaints process			✓
support for those involved in reprisal complaints			✓
Establish vulnerable workers committee			✓
Establish small businesses committee			✓
Mandatory awareness training for supervisors			✓
Mandatory awareness training for workers			✓
Mandatory training of health and safety representatives	✓		
Mandatory entry-level training for construction workers	✓		
Mandatory fall protection training for workers	✓		
Integrated Occupational Health and Safety Strategy for Ontario			✓

Health and Safety Awareness Training for Workers and Supervisors

- Duties of Employer, Supervisor, Worker and Rights of a Worker
- Worker Training - Hazard Identification and Barriers
- Working together for Safety
- External Resources within Ontario for Safety

Comes into force July 1st, 2014

Thank You for participating we look forward to WORKING SAFELY together with you

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Appendix 4-F– Emergency Responder Information Night Presentation

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First Responder Safety

Don Gilbert

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Agenda

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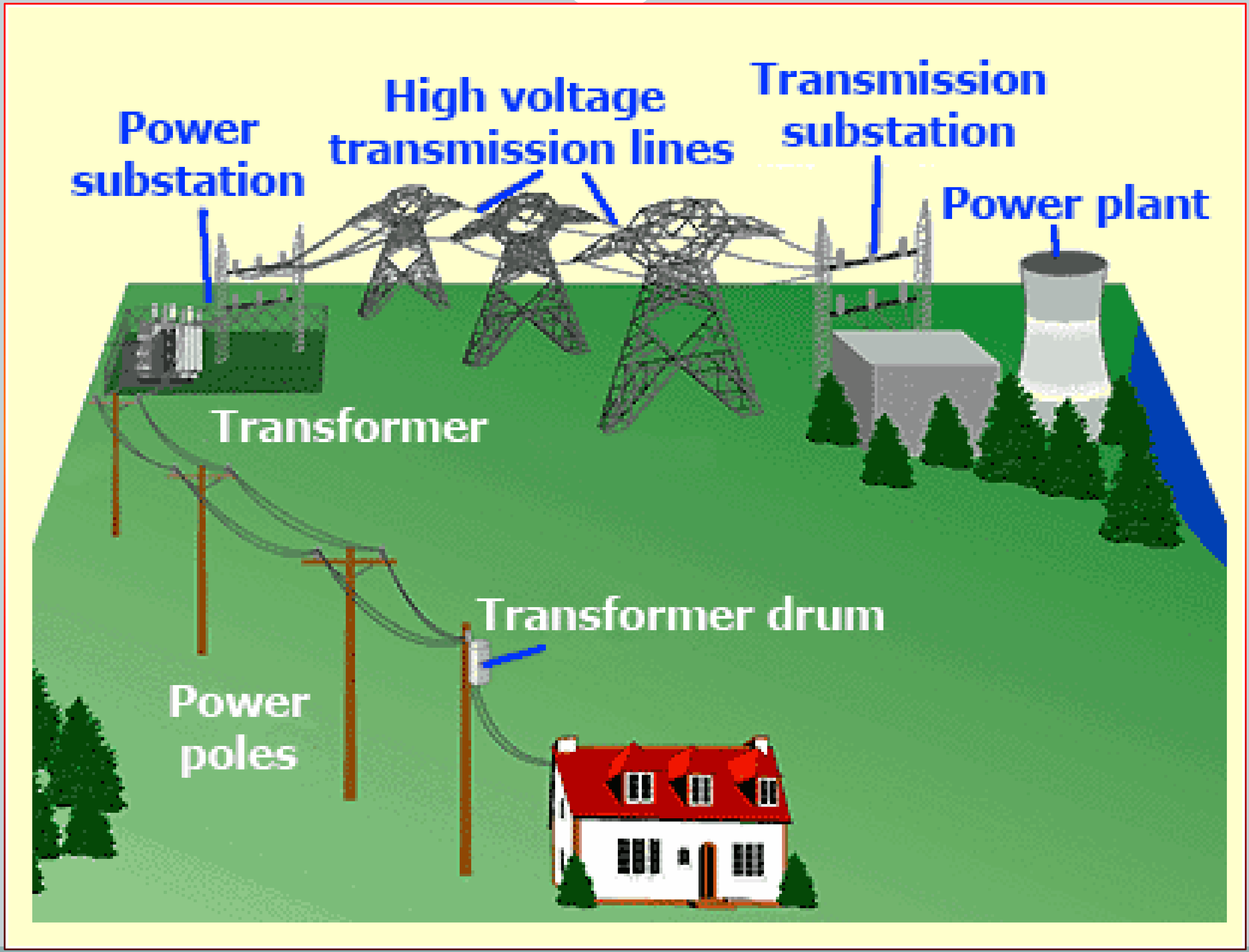
- Electricity Basics
- Characteristics of Electricity
- Unwanted Energy Flows
- Electricity and the Body
- Step and Touch Potentials
- Electrical Hazards Scene Survey

Electricity Basics



Characteristics of Electricity

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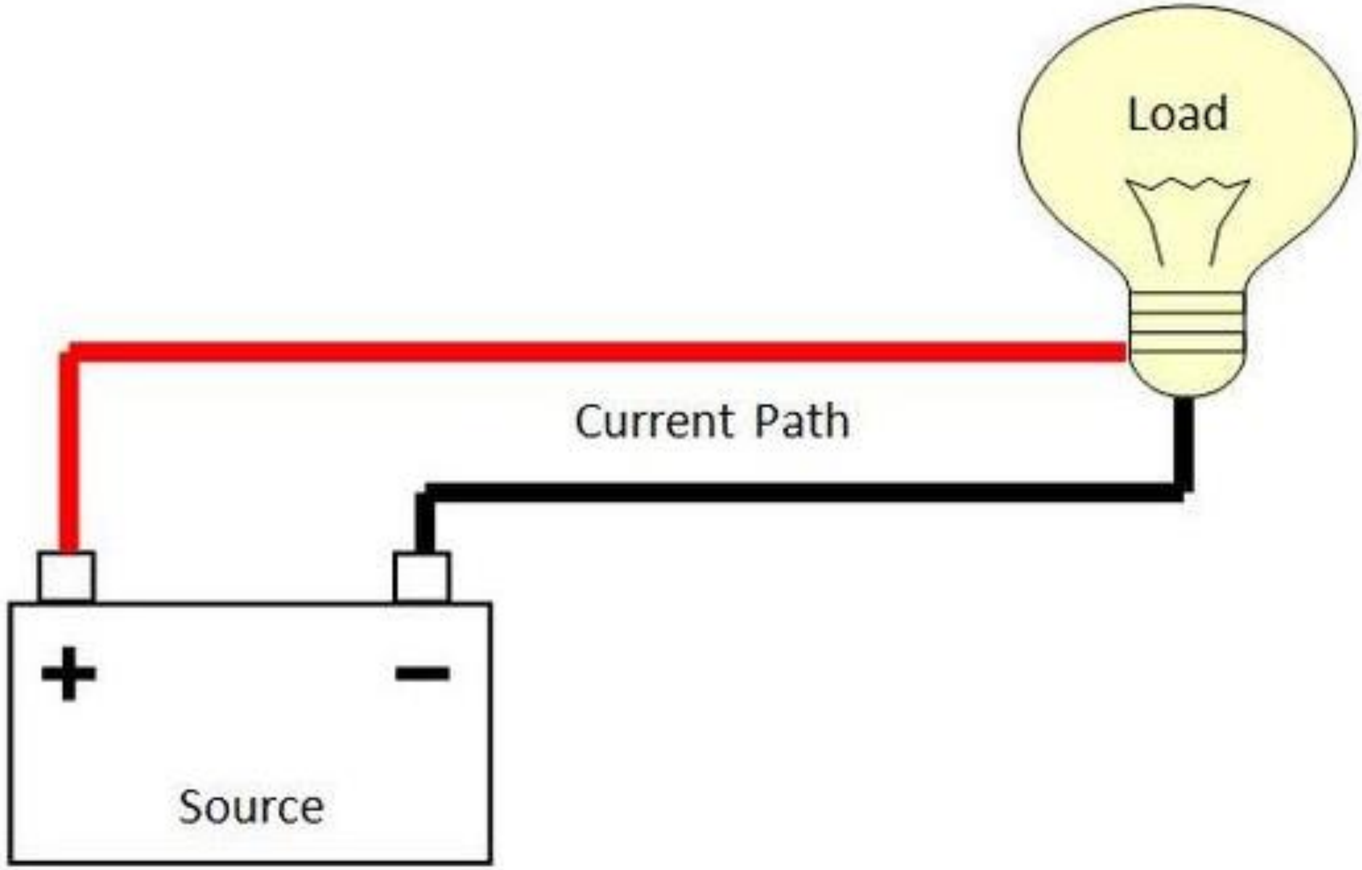
- Electricity always seeks the easiest path to ground
- Barriers such as porcelain, fiberglass or epoxy insulators assist in directing the voltage
- For electricity to function as an energy source it has to eventually reach ground

Characteristics of Electricity



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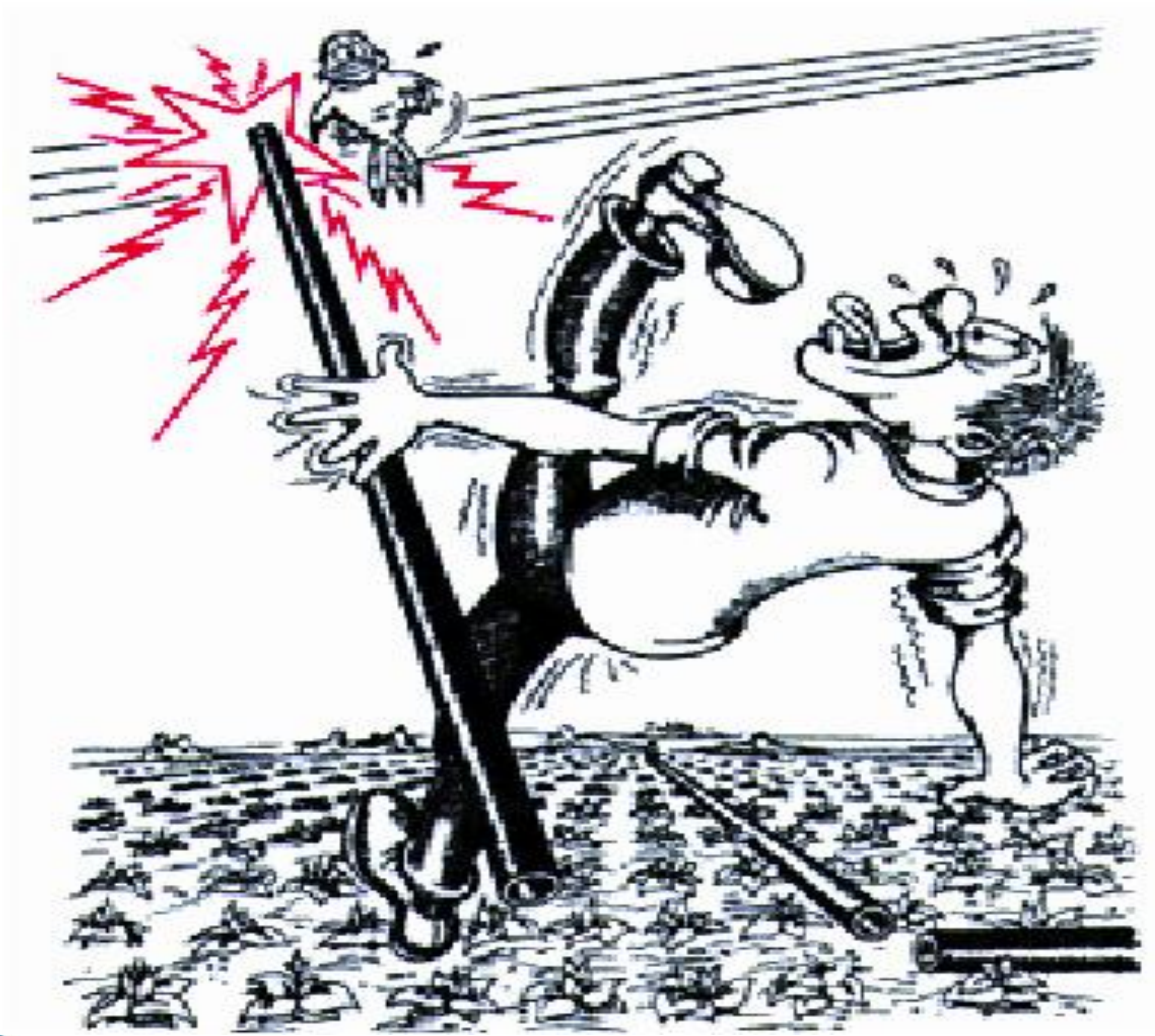
Unwanted Energy Flow



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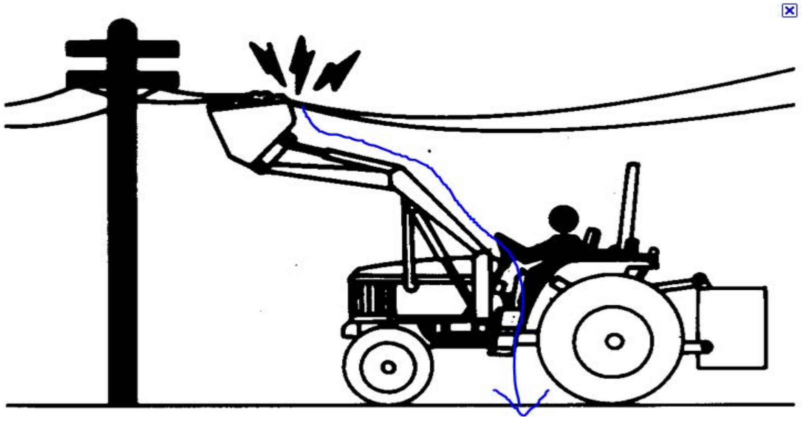
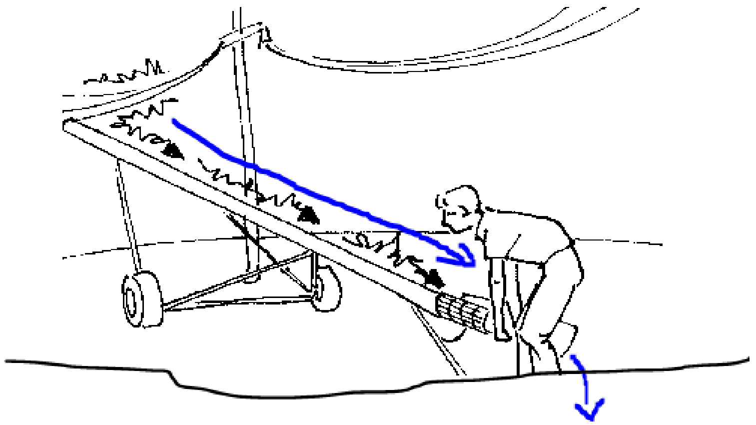
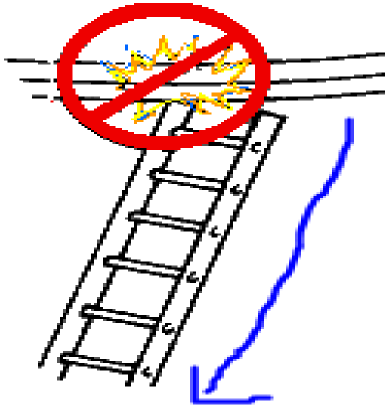
Unwanted Energy Flow

Electrical energy flowing in a direction that it is not intended to go







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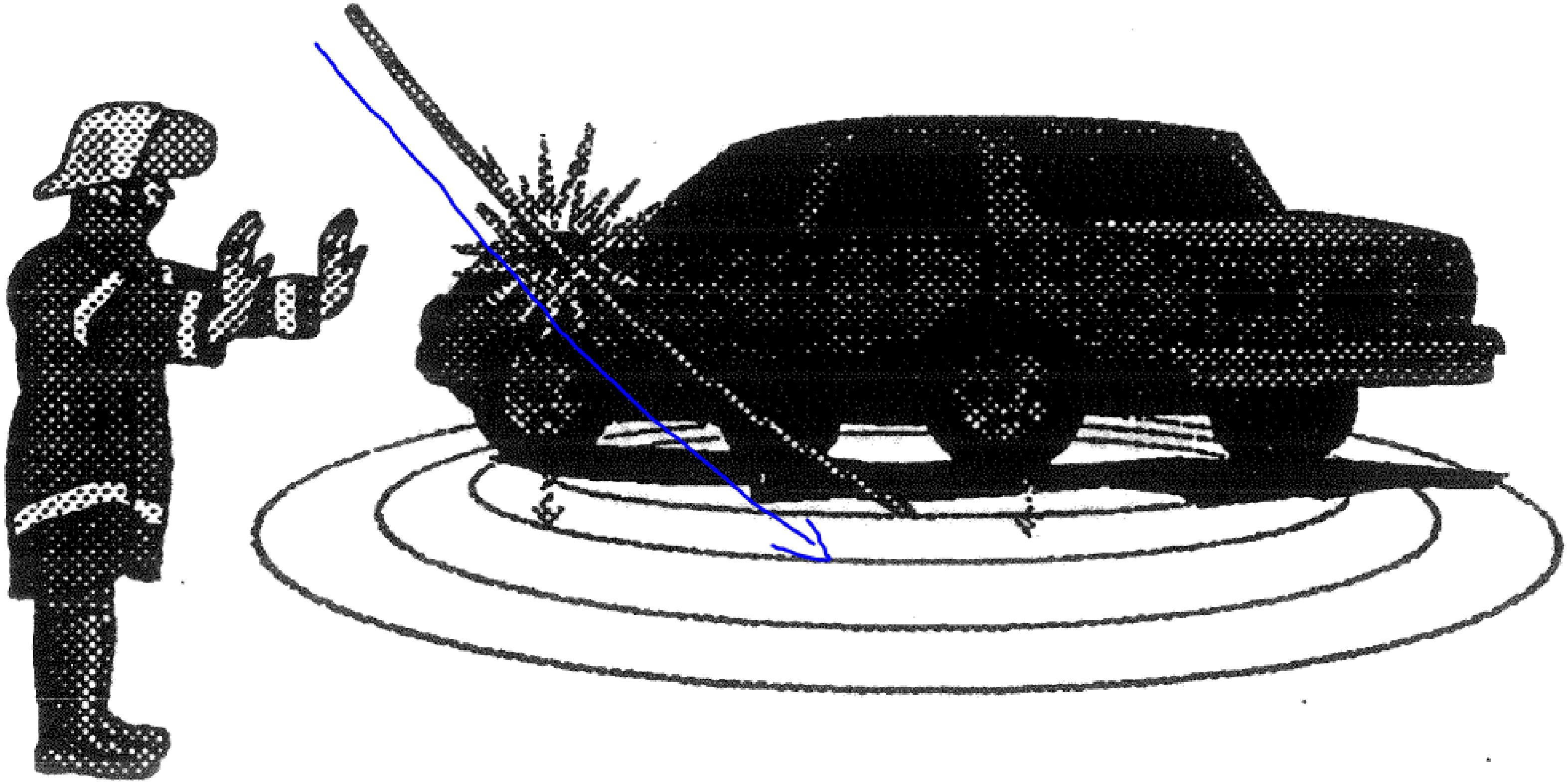
Unwanted Energy Flow



Effects of Electricity on the Body

EFFECTS OF ELECTRICAL CURRENT IN THE HUMAN BODY	
Current	**Reaction**
Below 1 Milliampere	Generally not perceptible
1 Milliampere	Faint Tingle
5 Milliampere	Slight shock felt. Not painful but disturbing. Average individual can let go. Strong involuntary reactions can lead to other injuries.
6 to 25 Milliampere (women)	Painful shocks. Loss of muscle control.
9 to 30 Milliampere (men)	The freezing current or "let go" range. If extensor muscles are excited by shock, the person may be thrown away from the power source. Individuals cannot let go. Strong involuntary reactions can lead to other injuries.
50 to 150 Milliamperes	Extreme pain, respiratory arrest, severe muscle reactions. Death is possible.
1.0 to 4.3 Amperes	Rhythmic pumping action of the heart ceases. Muscular contraction and nerve damage occur; death is likely.
10 Amperes	Cardiac arrest, severe burns, death is probable.

Effects of Electricity on the Body

Involuntary Movement –Loss of Muscle control

A factor that makes a large difference in the injury sustained in low-voltage shocks is the inability to let go. The amount of current in the arm that will cause the hand to involuntarily grip strongly is referred to as the let-go current. If a person's fingers are wrapped around a large cable or energized vacuum cleaner handle, for example, most adults will be able to let go with a current of less than 6 mA. At 22 mA, more than 99% of adults will not be able to let go. The pain associated with the let-go current is so severe that young, motivated volunteers could tolerate it for only a few seconds.

Effects of Electricity on the Body

External Burns

The temperature of an electrical arc can reach between 2500' C and 5000' C Burns can range from 1st to 3rd degree depending upon exposure and proximity

Internal Burns

While some electrical burns look minor, there still may be serious internal damage, especially to the heart, muscles, or brain.

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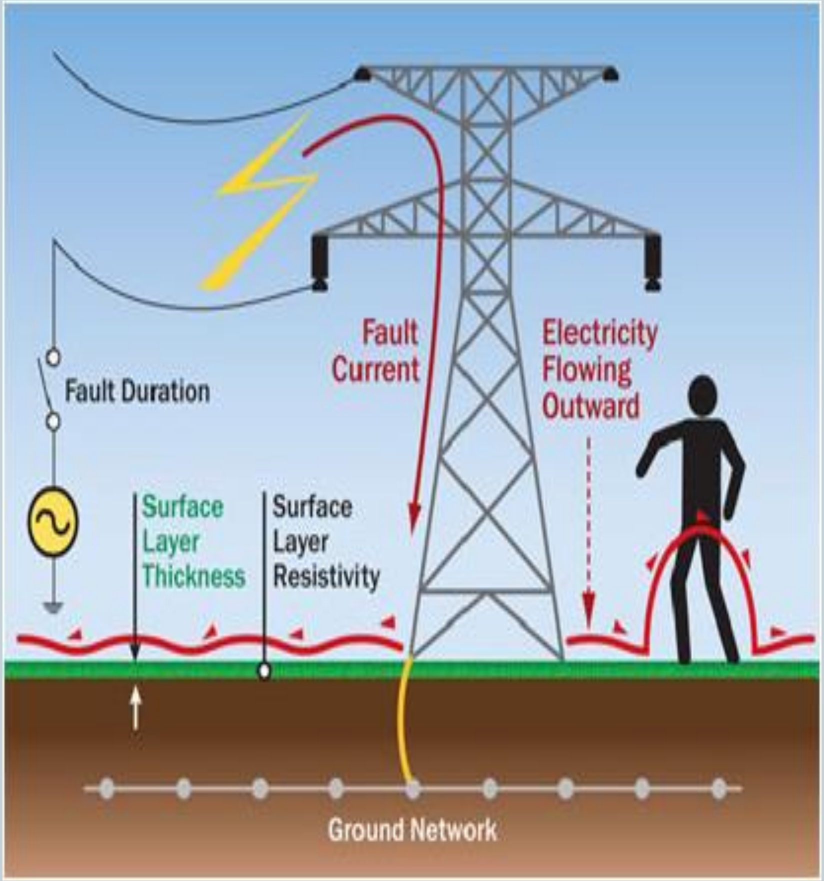
Step & Touch Potential

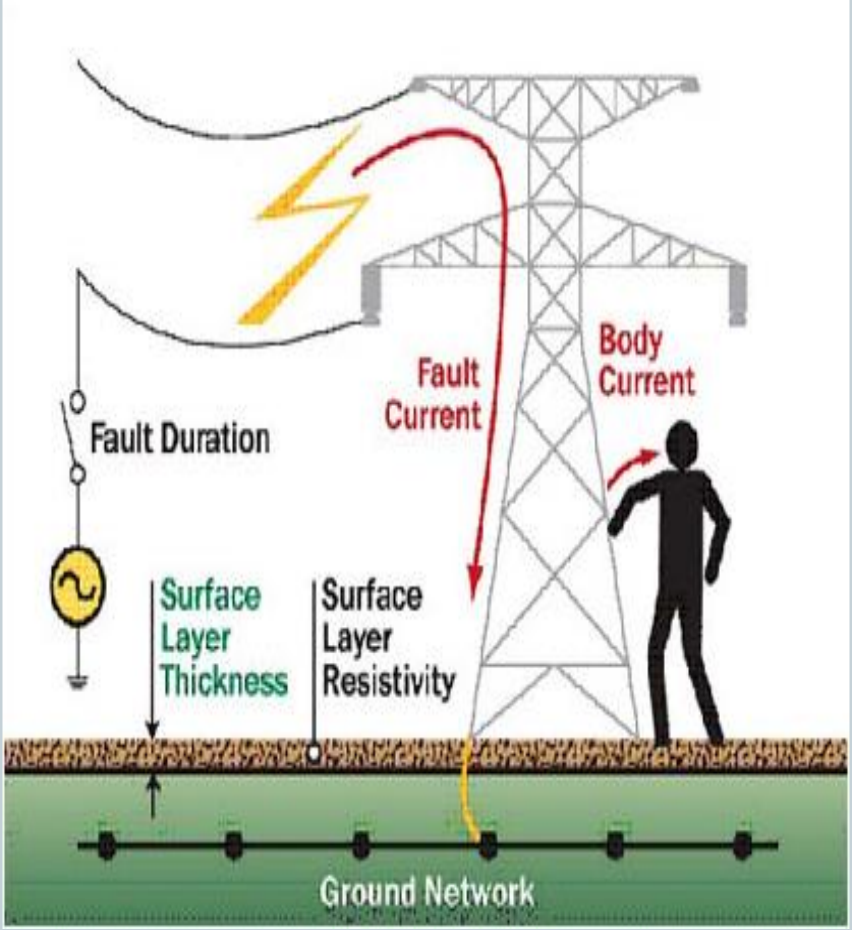
Step Potential

Is the step voltage between the feet of a person standing near an energized grounded object.



Step & Touch Potential

Touch Potential
Is the touch voltage between the energized object and the feet of a person in contact with the object.



Step & Touch Potential

- Assess the Scene to ensure no electrical Hazards present.

- If electrical Hazards are present, remain a minimum of 10 m away

- Take control of the situation- Do not become a casualty

- Contact the local utility immediately

- If life or death situation is present such as fire, have the victim jump clear landing with feet together and continue to jump or shuffle until 10m clear avoiding step potential

Keep In Mind

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You Are the Responder

•••

Don’t Become the Victim

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Stay Safe

Thank You

Appendix 4-G– Customer Focus Group Executive Presentation

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CANADIAN NIAGARA POWER INC.

A FORTIS ONTARIO Company

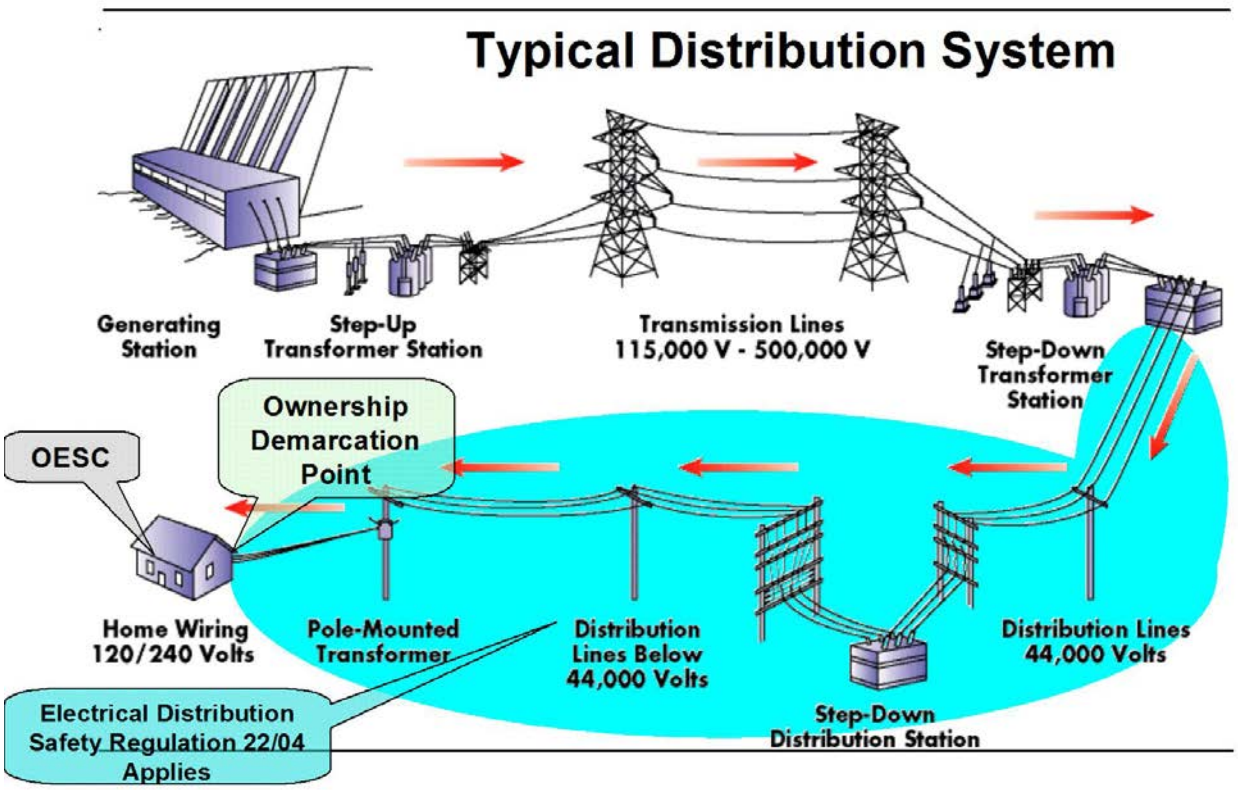
Customer Engagement Focus Group

- Agenda
  - Introductions
  - Overview of Canadian Niagara Power – 15 minutes
  - Discussion and Feedback – 60 minutes
  - Wrap-up -15 minutes

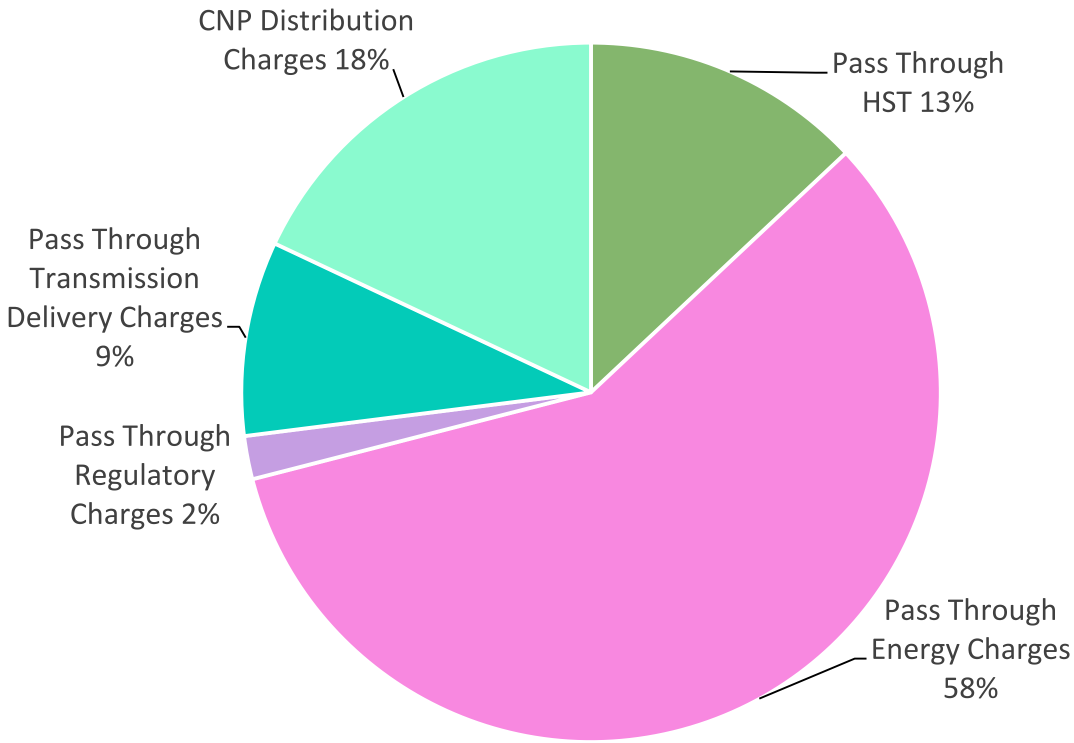
- Who is Canadian Niagara Power (CNP)?
  - CNP is the Local Distribution Company Serving Fort Erie and Port Colborne
  - Serve approximately 24,000 electricity customers
  - Peak Demand- 85 MW
  - Total KM lines - 844.11

- What are our Core Values?
  - ❖Respect for People
  - ❖Safety and the Environment
  - ❖Financial Success
  - ❖Customer Service
  - ❖Productivity
  - ❖Community Involvement

Power System Overview



- What makes up your electricity bill?



- What is a Distribution System Plan (DSP)?
  - ❑A comprehensive document detailing how the distribution system is maintained and upgraded.
    - ✓Distribution Asset Management Plan
    - ✓Distribution System Planning Studies
    - ✓Public inputs
    - ✓Operational inputs
    - ✓Government polices, rules, regulation (OEB, ESA…)
    - ✓It is a five year plan and updated annually
    - ✓Summited to OEB as part of Rate application

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

- What is a Distribution Asset Management Plan (DAMP)?
  - ❑ A comprehensive document detailing all assets within the distribution system.
    - ✓ Details of our equipment
    - ✓ The locations of all of our equipment
    - ✓ The condition of the equipment
    - ✓ The plan for inspecting and maintaining the equipment
    - ✓ Identifies equipment that should be replaced based upon their condition.

- What is a Distribution System Planning Study?
  - ❑ Technical assessment of the system operation and components
    - ✓ Equipment capacity
    - ✓ Power quality
    - ✓ System reliability
    - ✓ Public, employee, and equipment safety
    - ✓ System efficiency (losses)
- Develop the action plan

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

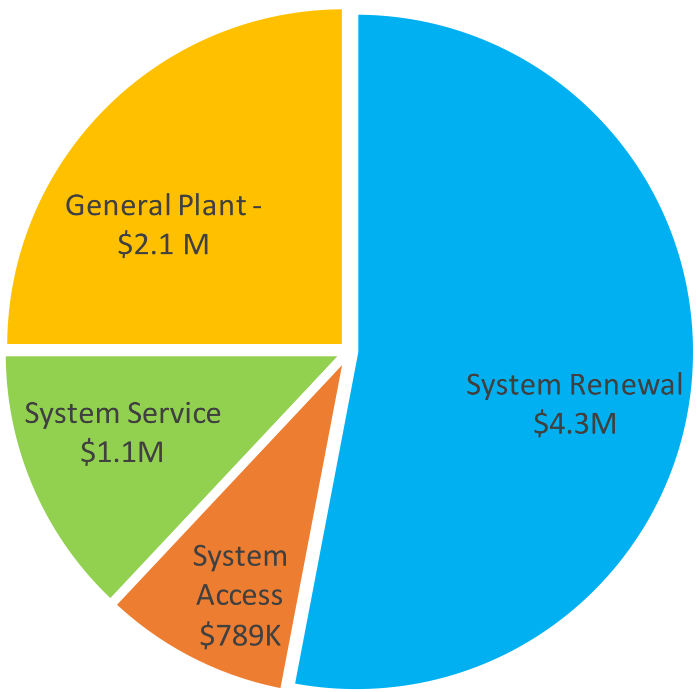
- What are some major capital projects in the current plan?
  - ➢ Rebuild Gilmore Distribution Substation
  - ➢ Voltage conversion in North of Town of Fort Erie
  - ➢ Port Colborne Downtown Conductor Upgrade
  - ➢ Hydro Services for New Subdivisions
    - Westwood
    - South Coast Village Phase 2
    - Ridgeway Shares Phase 2
    - Parklane Place
    - Others …

- How Rates are Determined?
  - CNPI develops and updates the DSP
  - The DSP provides all evidences and the action plan
  - The costs of operating, maintaining and upgrading the system are developed from the action plan
  - CNPI calculates new rates based on Ontario Energy Board (OEB) rules
  - CNPI provides the evidence and new rates to OEB in a Rate Application
  - The public (interveners) challenge the expenses through an intervention process
  - OEB determines the new rates considering all evidences

- What Factors Impact Rates?
  - ❑User pay system
    - Operating cost
    - Depreciation (Capital investment)
    - Taxes
    - Return on Capital

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

- What are our capital investments in 2016?



- Feedback & Discussion

Eastern Ontario Power

A FORTIS ONTARIO Company

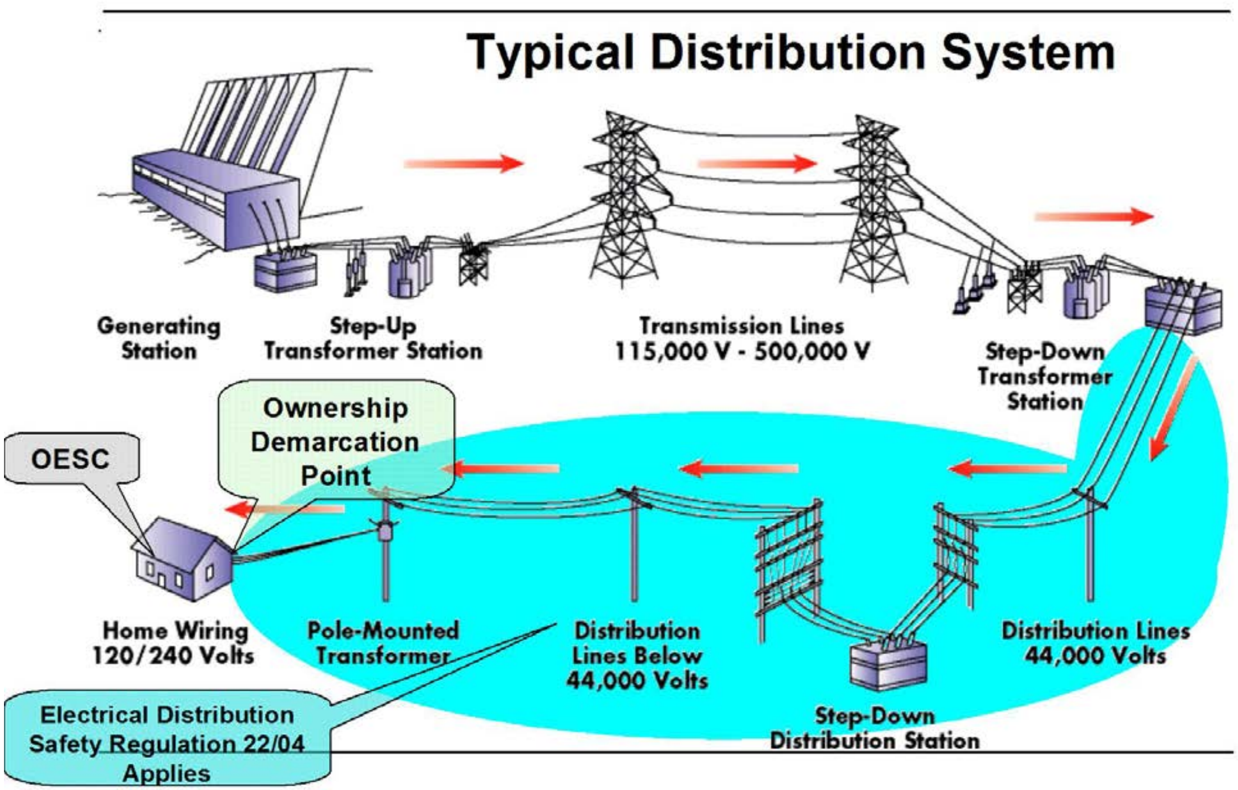
Customer Engagement Focus Group

- Agenda
  - Introductions
  - Overview of Eastern Ontario Power – 10 minutes
  - Discussion and Feedback – 60 minutes
  - Wrap-up -15 minutes

- Who is Eastern Ontario Power?
  - Serve approximately 3,500 electricity customers in Gananoque, Ontario
  - Peak Demand – 14.4 MW
  - Total KM lines - 182

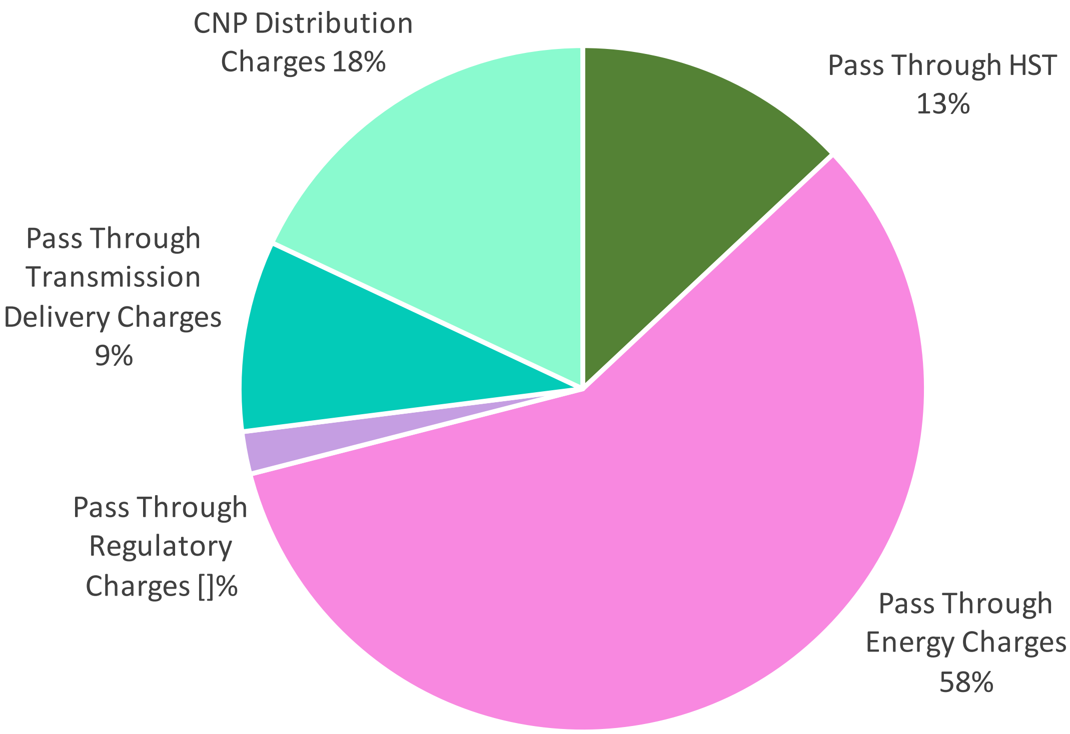
- What are our Core Values?
  - ❖Respect for People
  - ❖Safety and the Environment
  - ❖Financial Success
  - ❖Customer Service
  - ❖Productivity
  - ❖Community Involvement

Power System Overview



CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

- What makes up your electricity bill?



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- What are some major capital projects in the current plan?

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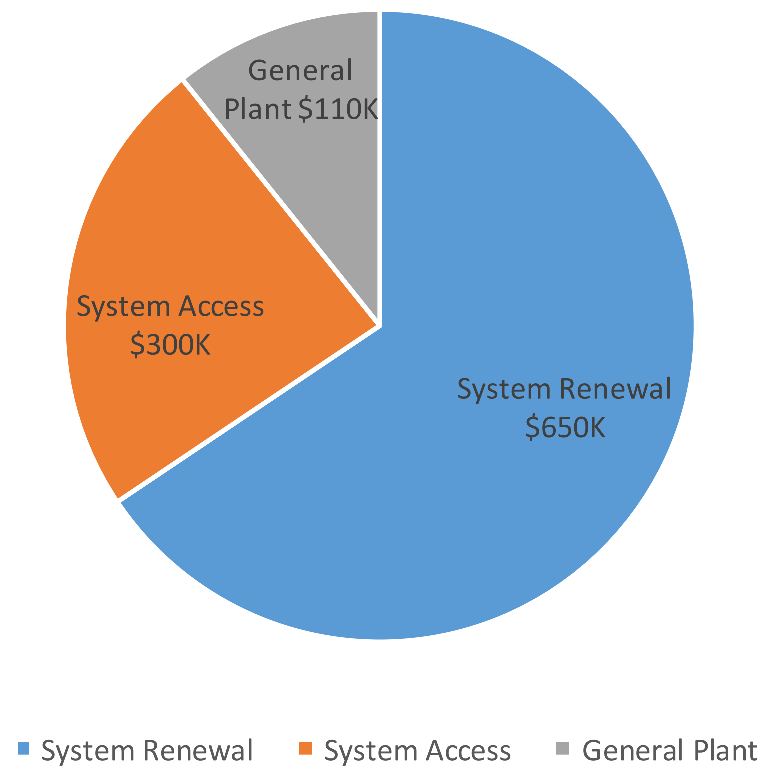
    - Taxes
    - Return on Capital

- How are we planning to spend in 2016?



- Feedback & Discussion

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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.
39,804 calls into call centre	Customer calls to inquire about high bills, to make payment arrangements, inquire as to low income assistance programs available, etc.	1. Expanded training in 2015 for CSRs to deal with payment arrangements (AMP and LAMP) 2. Website enhancement for low income programs (OESP) 3. Updated website with current bill information 4. Increased CDM activities to assist with conservation 5. Promotion of MyHydroEye to assist customers with consumption management
Community Outreach	Customers appreciate additional dialogue regarding the composition of their invoices	Customer Service staff attend community events (usually in conjunction with CDM staff) to interact and engage customers about their electrical invoices.
Accessibility for all customers	All customers should have the same level of service	CNPI is compliant with all accessibility legislation as outlined in the Company's Multi-year Accessibility Plan which is posted on the company website.
Low Income Customers	Low income customers require readily available information about programs available to them	1. CSRs received training on OESP program and DSC requirements related to low income (AMP and LAMP) 2. Website enhancement for low income programs (OESP) 3. Participation in LEAP and OESP programs
Business Customers	Meeting the individualized needs of business customers	1. CNPI held sessions for Class A global adjustment customers on site to ensure the needs of these customers are addressed 2. On-site visits are ongoing to meet with customers on various topics, CDM, and online access to consumption 3. Customers contacts form part of the Business Continuity Plan to ensure customers are informed during power outage events 4. New key account service during power outages to be added in 2016

Bill Inserts, Newsletters, on bill messaging	Calendar Monthly billing provides opportunity to frequently interact with customers. Many customers indicate information included with their monthly invoices as a preferred communication method	1. Inserts are sent throughout the year with monthly invoices on various topics such as low income programs, rate changes, safety, new programs (e-Billing and MyHydroEye), and CDM 2. Semi-annually customer newsletters are sent out to all customers 3. On bill and envelope messages are updated as required
Social Media	Some customers prefer to interact and receive information via social media	1. Social media (Twitter and Facebook) were launched in 2014 and the Company's social media following continues to grow 2. Website updated as required
Automated Phone Calls	Customers indicated automated phone calls to be a preferred method of communication specifically for planned power outages	CNPI began utilizing automated phone calls to assist in communications for planned power outages
Large Customer Engagement	Large customers need to be kept informed of industry updates and initiatives specific to them	1. CNPI participates in the annual industrial round table to provide information and seek feedback from the community's large customers 2. The CDM team meets regularly meets with large customers to identify opportunities to work together to reduce energy consumption
Local Service Provider Information Night	Need for Local Service Providers to understand legislation and CNPI processes and for CNPI to seek feedback from these providers	CNPI hosts an annual information session for local service providers who work for customers and prospective customers in the CNPI service territories. Participants include local builders, electricians, realtors etc.
Contractor Pre-Qualification Session	Need for CNP Contractors to understand legislation and CNPI processes and for CNPI to seek feedback from these contractors	CNPI hosts a bi-annual contractor information session for contractors employed by CNPI. As well, representatives from the local office of the ESA are present.

Emergency Responder Information Night	Need for First Responders to engage and interact with CNPI	CNPI hosts training on a three (3) year rotation for staff of local fire, police and paramedical services. A review of electrical fundamentals and an overview of electrical safety and processes related to emergency situations are reviewed.
Joint Use Partner Interaction	Need to meet with Joint Use customers to stay informed of upcoming projects	CNPI meets regularly with local representatives from Bell and other Joint Use customers to discuss each company's upcoming and ongoing capital and maintenance projects.
Annual Customer Surveys	Residential and General Service customers need to have an opportunity to provide feedback and report how CNPI rates as a service provider	For over ten years CNPI has conducted annual customer surveys. Results of the survey were studied and used in developing the 2017 Cost of Service Application and DSP to ensure both documents are meeting the needs and preferences of customers.
Customer Focus Groups	Residential and General Service customers need to have an opportunity to provide feedback on CNPI’s DSP and DAMP as it relates to the Cost of Service Applications	Results of the focus groups were studied and used in developing the 2017 Cost of Service Application to ensure needs and preferences of customers are addressed.

Electrical Safety – Elementary School Program	Elementary students need to understand electrical safety hazards and how and why to conserve electricity	Electrical safety and energy conservation school presentations offered via a third-party on a four-year rotation to all elementary schools within the service territory. All students from grades 1-8 attend the presentation.
High School Students: Electricity and Careers	High School student need information about electricity and careers.	1. Annually, CNPI hosts Grade 9 students for the *Take Our Kids to Work* ™ national program. The students learn about the utility industry, various career opportunities, as well as complete the Passport to Safety Training. The program supports career development by helping students connect school, the world of work, and their own futures. 2. CNPI participates in career days at local high schools to increase awareness of careers in the electrical industry.
Conservation and Demand Management Activities	All customers need to be aware of CDM program and offerings	1. saveONEnergy programs were promoted via various channels 2. CDM staff conducts one on one site visits to a large number of business customers on an annual basis to promote conservation programs 3. CDM and customer service staff participated in over 30 community outreach events between 2011-2014 to answer customer questions and promote conservation and related programs

AUDITED FINANCIAL STATEMENTS 2014 & 2015

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Financial Statements

Canadian Niagara Power Inc.

December 31, 2014

EY

Building a better working world

INDEPENDENT AUDITORS' REPORT

To the Shareholder of
Canadian Niagara Power Inc.

We have audited the accompanying financial statements of **Canadian Niagara Power Inc.**, which comprise the balance sheet as at December 31, 2014, and the statements of earnings 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 accounting standards for private enterprises, 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.

Auditors' 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 auditors' 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 auditors consider 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 in our audit 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 **Canadian Niagara Power 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 accounting standards for private enterprises.

Ernst & Young LLP

Toronto, Canada
February 10, 2015

Chartered Professional Accountants
Licensed Public Accountants

Canadian Niagara Power Inc.
Incorporated under the laws of Ontario

BALANCE SHEET

[in thousands of dollars]

As at December 31

	2014	2013
	$	$
		[restated]
ASSETS		
Current		
Cash	**1,216**	1,306
Accounts receivable *[note 11]*	**11,690**	11,629
Income taxes receivable	**—**	155
Materials and supplies	**143**	80
Regulatory assets *[note 13]*	**260**	1,742
Prepaid expenses	**469**	496
Total current assets	**13,778**	15,408
Utility capital assets, net *[note 2]*	**98,363**	93,017
Intangible assets *[note 3]*	**8,783**	8,726
Accrued pension benefit asset *[note 4]*	**3,698**	1,086
Regulatory assets *[note 13]*	**9,038**	8,933
Goodwill	**7,232**	7,232
	140,892	134,402
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable and accrued liabilities *[note 11]*	**7,954**	8,910
Income taxes payable	**31**	—
Regulatory liabilities *[note 13]*	**699**	697
Due to related parties *[note 6]*	**10,344**	5,897
Loan payable	**—**	3,000
Total current liabilities	**19,028**	18,504
Promissory notes due to parent company *[notes 6, 11 and 12]*	**20,000**	20,000
Long-term debt *[notes 7, 11 and 12]*	**29,885**	29,853
Future tax liabilities *[note 5]*	**4,318**	3,289
Accrued other retirement benefit liability *[note 4]*	**6,652**	6,498
Contributions in aid of construction	**10,401**	9,011
Regulatory liabilities *[note 13]*	**3,012**	1,872
Total liabilities	**93,296**	89,027
Shareholder's equity		
Capital stock *[note 8]*	**23,900**	23,900
Retained earnings	**23,696**	21,475
Total shareholder's equity	**47,596**	45,375
	140,892	134,402

See accompanying notes

On behalf of the Board:

Director

Director

Canadian Niagara Power Inc.

STATEMENT OF EARNINGS AND RETAINED EARNINGS

[in thousands of dollars]

Year ended December 31

	2014	2013
	$	$
REVENUE		
Sale of energy	**56,490**	53,921
Distribution	**17,783**	17,382
Transmission	**4,854**	4,856
Other	**2,190**	2,029
	81,317	78,188
EXPENSES		
Cost of power purchased	**56,490**	53,921
Operating	**11,034**	10,710
Amortization *[note 9]*	**4,912**	4,658
	72,436	69,289
Operating earnings before the following	**8,881**	8,899
Net smart meter disposition costs *[note 13]*	**—**	(237)
Interest expense *[notes 6, 7 and 11]*	**(3,164)**	(3,154)
Earnings before income taxes	**5,717**	5,508
Provision for income taxes *[note 5]*	**996**	1,448
Net earnings for the year	**4,721**	4,060
Retained earnings, beginning of year	**21,475**	17,415
Dividends paid *[note 6]*	**(2,500)**	—
Retained earnings, end of year	**23,696**	21,475

See accompanying notes

Canadian Niagara Power Inc.

STATEMENT OF CASH FLOWS

[in thousands of dollars]

Year ended December 31

	2014	2013
	$	$
OPERATING ACTIVITIES		
Net earnings for the year	**4,721**	4,060
Add (deduct) items not involving cash		
Amortization *[note 9]*	**5,300**	5,009
Future income taxes	**1,029**	(22)
Loss (gain) on sale of utility capital assets	**(75)**	20
Accrued pension benefits	**(1,471)**	618
Accrued other retirement benefits	**443**	452
Long-term regulatory assets and liabilities	**1,035**	2,360
Accrued pension benefit asset	**(1,141)**	(1,105)
Accrued other retirement benefit liability	**(289)**	(270)
	9,552	11,122
Net change in non-cash working capital balances related to operations *[note 10]*	**5,064**	(2,792)
Cash provided by operating activities	**14,616**	8,330
INVESTING ACTIVITIES		
Additions to utility capital assets	**(10,065)**	(10,748)
Additions to intangible assets	**(919)**	(1,249)
Proceeds on sale of utility capital assets	**88**	380
Decrease in long-term debt	**32**	32
Cash used in investing activities	**(10,864)**	(11,585)
FINANCING ACTIVITIES		
Advance (repayment) of short-term loan payable *[note 11]*	**(3,000)**	3,000
Increase in contributions in aid of construction	**1,658**	865
Dividends	**(2,500)**	—
Cash provided by (used in) financing activities	**(3,842)**	3,865
Net increase (decrease) in cash during the year	**(90)**	610
Cash, beginning of year	**1,306**	696
Cash, end of year	**1,216**	1,306

See accompanying notes

NOTES TO FINANCIAL STATEMENTS

[in thousands of dollars]

December 31, 2014

1. BASIS OF ACCOUNTING AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Incorporation

Canadian Niagara Power Inc. [the "Corporation" or "CNPI"], a wholly owned subsidiary of FortisOntario Inc. [the "parent company"] [formerly Canadian Niagara Power Company, Limited], was incorporated on February 17, 1999 to comply with the Electricity Act, 1998 (Ontario) [the "Act"]. The Act requires that the electric power transmission and distribution businesses, previously carried out by the parent company, be carried out by a separate legal entity. Effective March 31, 1999, the Corporation purchased the electric power transmission and distribution assets of its parent company and commenced operations. On January 1, 2004, the Corporation was amalgamated with Eastern Ontario Power Inc. and continued as Canadian Niagara Power Inc. The business of the Corporation is the transmission and distribution of electricity to customers within Ontario. The business is regulated by the Ontario Energy Board ["OEB"].

These financial statements include the operating results of the Fort Erie, Port Colborne and Eastern Ontario Power [Gananoque] distribution centres and the Fort Erie transmission centre.

A. BASIS OF ACCOUNTING

These financial statements have been prepared in accordance with the accounting standards for private enterprises ["ASPE"], as per Part II of the CPA Handbook – Accounting, which constitutes generally accepted accounting principles for non-publicly accountable enterprises in Canada.

B. SIGNIFICANT ACCOUNTING POLICIES

Regulation

CNPI distribution
The distribution rates of CNPI are based upon cost-of-service rate regulation by the OEB. Earnings are regulated on the basis of a rate of return on rate base plus a recovery of all allowable distribution costs of CNPI.

On May 11, 2012, CNPI filed a Cost of Service Application for electricity distribution rates effective January 1, 2013. The application included the integration of smart meter costs into rate base, the recovery of stranded assets related to conventional meters and a rate rider designed to capture additional smart meter expenditures forecast to the end of 2012. The application also proposed changes to the accounting policy and estimates for utility capital assets. Since the majority of distributors in Ontario are transitioning to International Financial Reporting Standards

["IFRS"], and the OEB is requiring consistency amongst distributors, CNPI updated amortization rates and its capitalization of overhead policy effective for 2013. The OEB commissioned an amortization study, which was used as a guideline in updating the amortization rates. Consistent with International Accounting Standard 16 under IFRS, CNPI proposed that indirect overhead costs not be capitalized.

The OEB issued its Final Decision and Order on December 20, 2012 for new rates effective January 1, 2013, which resulted in a 6.8% increase for the average residential consumer in Fort Erie, a 5.9% increase for the average residential consumer in Gananoque and a 7.4% increase for the average residential consumer in Port Colborne effective January 1, 2013. The Decision and Order approves a 2013 base revenue requirement of $18,966,180 and provides an 8.93% return on equity ["ROE"] with a 60%/40% debt equity structure.

On August 16, 2013, CNPI filed its 2014 4th Generation Incentive Rate-setting Application ["4GIRM"] for electricity distribution rates effective January 1, 2014. This application was based on the OEB's guidelines for 4th Generation Incentive Regulation Mechanism. On January 9, 2014, the OEB issued its Decision and Order for CNPI; the final 4th Generation Incentive Price Index was 1.25% comprising 1.7% inflation, a 0% productivity factor and a 0.45% stretch factor [i.e., 1.7% - (0% + 0.45%)]. Rates were effective January 1, 2014. The overall bill impact for the average residential consumer is a 0.9% increase in Fort Erie, a 0.8% increase for the average residential consumer in Gananoque, and a 0.2% increase for the average residential consumer in Port Colborne.

On August 13, 2014, CNPI submitted its 2015 4GIRM, for electricity distribution rates effective January 1, 2015. This application is a second in a series of rate applications to fully harmonize electricity distribution rates in Port Colborne with those of Fort Erie and Gananoque. The OEB issued its Decision and Order on December 4, 2014, and the net price cap index adjustment for 2015 is 1.15% [i.e. 1.6% - (0% + 0.45%)]. The overall bill impact for the average residential consumer in Fort Erie is a 1.4% decrease, a 1.5% decrease for the average residential consumer in Gananoque, and a 3.2% decrease for the average residential consumer in Port Colborne. These overall decreases are the result of the disposition of regulatory deferral and variance accounts.

CNPI transmission

The transmission rates of CNPI are based upon cost-of-service rate regulation by the OEB. Earnings are regulated on the basis of a rate of return on rate base plus a recovery of all allowable transmission costs of CNPI.

On November 17, 2014, CNPI submitted a Revenue Requirement Application for its Transmission business. This Application seeks approval of CNPI's 2015 and 2016 Transmission Revenue Requirement. It is anticipated that the OEB's review of this Application will occur in the first quarter of 2015.

Materials and supplies

Materials and supplies are recorded at average cost. Materials and supplies expensed to operating expenses in 2014 were $119 [2013 – $82].

Utility capital assets, capitalization policy and service life of utility capital assets

Nature of distribution and transmission assets

Distribution assets

Distribution assets are those used to distribute electricity at lower voltages [generally below 50 kilovolts]. These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

Transmission assets

Transmission assets are those used to transmit electricity at higher voltages [generally at 50 kilovolts and above]. These assets include poles, wires and conductors, substations, support structures and other related equipment.

Utility capital assets are stated at cost less accumulated amortization. Amortization is provided over the estimated useful lives of the utility capital assets using the straight-line method at a composite rate of 3.2% [2013 – 3.2%].

Contributions in aid of construction represent funding of utility capital assets contributed by customers. These accounts are being reduced annually by an amount equal to the charge for amortization provided on the contributed portion of the assets involved.

Capitalization policy and service life of utility capital assets

General expenses capitalized ["GEC"] are capitalized overhead costs that are not directly attributable to specific utility capital assets, but relate to the Corporation's overall capital program. Prior to 2013, GEC was permitted to be capitalized by the OEB's Distribution Rate Handbook and Accounting Procedures Handbook. In 2012, CNPI filed a cost of service application with the OEB based on a 2013 Test Year. The OEB is currently using "modified IFRS" as an accounting basis. As discussed in "Regulation" above, CNPI had proposed changes to its capitalization policy in its last cost of service application. These changes encompass adjustments to the useful lives of utility capital assets, changes to labour rates and the elimination of GEC. The impact of these changes has resulted in higher operating expenses and lower amortization expense. CNPI had requested the recovery of these changes in distribution rates. The changes were approved by the OEB and were incorporated on January 1, 2013.

In 2013, these changes were accounted for prospectively for regulatory purposes, and due to the complex nature of assigning overhead costs to utility capital assets, the Corporation could not reasonably quantify the retrospective impact of these changes.

Intangible assets

Intangible assets are stated at cost less accumulated amortization. Amortization is provided over the estimated useful lives of the intangible assets using the straight-line method.

Asset retirement obligations

ASPE requires the recognition of an asset retirement obligation in the period during which a legal obligation associated with the retirement of a tangible long lived asset is incurred and when a reasonable estimate of this amount can be made.

The Corporation has determined that there are asset retirement obligations associated with some parts of its transmission and distribution systems; however, none of these are material or require recognition under section 3110 of CPA Handbook.

Goodwill

Goodwill represents the excess of the acquisition cost of the shares of the Corporation, and Eastern Ontario Power Inc. [amalgamated with the Corporation as at January 1, 2004] over the assigned value of identifiable net assets acquired, as well as the excess of the purchase price of the remaining utility capital assets of Port Colborne Hydro Inc. ["PCHI"] over the fair value of these assets.

ASPE requires that goodwill shall be tested for impairment whenever events or changes in circumstances indicate that the carrying amount of the reporting unit to which the goodwill is assigned may exceed the fair value of the reporting unit. Any impairment in value is charged to earnings during the year.

Other assets

Other assets are amortized over their useful lives.

Revenue recognition

Revenue from the sale, transmission and distribution of electricity is recognized on the accrual basis. Electricity is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of the year a certain amount of consumed electricity will not have been billed. Electricity that is consumed but not yet billed to the customers is estimated and accrued as revenue in the current year. Unbilled revenue included in accounts receivable as at December 31, 2014 is $6,574 [2013 – $6,383].

Foreign currency translation

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at the exchange rate prevailing at the balance sheet date. Gains and losses on translation are included in the statement of earnings and retained earnings. Revenue and expenses are translated at the exchange rate prevailing on the transaction date.

Employee benefit plans and change in accounting policy

Effective January 1, 2014, the Corporation has adopted new CPA Handbook Section 3462, *Employee Future Benefits,* for its accounting of pension benefits and other retirement benefits. As allowed under new Section 3462, the Corporation has made an accounting policy choice to measure its defined benefit plan obligations using the funding valuation approach. This approach uses the most recent completed actuarial valuations prepared for funding purposes as the basis of measuring defined benefit plan obligations. Even though other retirement benefits are not funded, Section 3462 requires that such liabilities be measured on a basis consistent with funded plans. As well, the Corporation is using a roll-forward technique in the years between valuations to estimate the defined benefit obligations. Pension plan assets are valued at fair value as of the balance sheet date. As required, the adoption of this new ASPE standard has been applied retroactively and the 2013 comparatives reflect these changes.

As a result of adopting CPA Handbook Section 3462 as of January 1, 2014, previously recognized unamortized pension and other retirement benefit amounts as at December 31, 2013 have been retroactively charged to retained earnings. As well, prior years' pension and other retirement expenses have been restated upon adoption of Section 3462. As a result, an amount of $4,310 has been charged to retained earnings effective January 1, 2014, offset by a corresponding increase in recorded pension liabilities of $2,386 and other retirement benefit liabilities of $1,924. The Corporation made application to the OEB to allow recognition of regulatory assets related to unamortized amounts, and restatement of prior years' pension and other retirement benefit expenses that would otherwise be collected from customers through rates in subsequent years. In

December 2013, the OEB issued a Decision and Order approving the establishment of specific deferral accounts to recognize these amounts as long-term regulatory assets, which will be disposed of in future cost of service proceedings, subject to the OEB's prudence review at that time. The Corporation has recorded a corresponding increase in retained earnings for the amount of $4,310 as of January 1, 2014 and has recognized $4,310 in long-term regulatory assets. As well, the Corporation has reversed previously recognized future income tax liabilities in the amount of $1,142 related to the changes in the pension and other retirement benefit liabilities as of January 1, 2014. The Corporation has recognized offsetting regulatory liabilities related to the future income taxes expected to be recovered from customers in future electricity rates as of January 1, 2014 in the amount of $1,142. Therefore, there is no retroactive change to retained earnings as a result of the adoption of Section 3462

The Corporation made an application to the OEB to continue to account for pension and other retirement benefits under the former Section 3461. In December 2013, the OEB issued a Decision and Order approving the establishment of specific variance accounts as of January 1, 2013 to recognize the difference in expense between Sections 3461 and 3462 as long-term regulatory assets or liabilities for 2013 and future years, which will be disposed of in future cost of service proceedings, subject to the OEB's prudence review at that time. For 2014, the difference in expense between former Section 3461 and the new Section 3462 using the funding valuation approach is a charge to income of $2,004 for pension expense, and a charge to income of $26 for other retirement benefits. Therefore, a total of $2,030 has been recognized as long-term regulatory liabilities in accordance with the OEB Decision and Order in 2014. As well, an amount of $538 related to future income taxes on these amounts has been recognized as long-term regulatory assets in 2014.

Income taxes

The Corporation follows the asset and liability method of accounting for income taxes. Under this method, future tax assets and liabilities are recognized for the temporary differences between the tax and accounting bases of assets and liabilities. Future tax assets and liabilities are measured using the enacted and substantively enacted tax rates and laws expected to apply to taxable income in the period in which the temporary differences are expected to be recovered or settled. Effective January 1, 2009, the Corporation recognizes regulatory assets related to future income tax liabilities in the amount of future income taxes expected to be recovered from customers in future electricity rates.

NOTES TO FINANCIAL STATEMENTS

[in thousands of dollars]

December 31, 2014

Use of estimates

The preparation of financial statements in conformity with ASPE 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 revenue and expenses during the reporting periods. Actual results may vary from the current estimates. These estimates are reviewed periodically and, as adjustments become necessary, they are reported in earnings in the period in which they become known.

2. UTILITY CAPITAL ASSETS

Utility capital assets consist of the following:

	2014		
	Cost $	Accumulated amortization $	Net book value $
Transmission	**28,566**	**12,983**	**15,583**
Distribution	**114,068**	**37,170**	**76,898**
Other	**15,846**	**9,964**	**5,882**
	158,480	**60,117**	**98,363**

	2013		
	Cost $	Accumulated amortization $	Net book value $
Transmission	26,223	12,251	13,972
Distribution	107,761	34,341	73,420
Other	14,814	9,189	5,625
	148,798	55,781	93,017

The amounts above include assets under construction of $7,035 [2013 – $4,206] which are not subject to amortization.

NOTES TO FINANCIAL STATEMENTS

[in thousands of dollars]

December 31, 2014

3. INTANGIBLE ASSETS

Intangible assets consist of the following:

	2014		
	Cost $	**Accumulated amortization** $	**Net book value** $
Software costs	**11,002**	**6,649**	**4,353**
Land and transmission rights	**6,985**	**2,763**	**4,222**
Other	**287**	**79**	**208**
	18,274	**9,491**	**8,783**

	2013		
	Cost $	**Accumulated amortization** $	**Net book value** $
Software costs	10,080	5,968	4,112
Land and transmission rights	6,989	2,590	4,399
Other	287	72	215
	17,356	8,630	8,726

[in thousands of dollars]

4. EMPLOYEE FUTURE BENEFITS

The Corporation is a participating employer with its parent company in a defined benefit pension plan and a defined benefit plan providing other retirement benefits. The Corporation also maintains a defined contribution pension plan providing pension benefits and makes contributions to the Ontario Municipal Employees' Retirement System ["OMERS"] plan on behalf of some of its employees. OMERS is a multi-employer defined benefit pension plan providing pension benefits and is accounted for as a defined contribution pension plan.

Information about the Corporation's defined benefit plans is as follows:

	Pension benefit plan		**Other retirement plan**	
	2014	**2013**	**2014**	**2013**
	$	**$**	**$**	**$**
		[restated]		*[restated]*
Accrued benefit obligation				
Balance, beginning of year	**14,752**	14,361	**6,498**	6,386
Current service cost	**386**	368	**90**	86
Finance cost	**700**	682	**309**	303
Benefits paid	**(675)**	(652)	**(291)**	(317)
Actuarial losses (gains)	**(24)**	(7)	**46**	40
Balance, end of year	**15,139**	14,752	**6,652**	6,498
Plan assets				
Fair value, beginning of year	**15,838**	14,635	**—**	—
Interest income	**747**	683	**—**	—
Return on plan assets	**1,807**	46	**—**	—
Contributions	**1,120**	1,126	**291**	317
Benefits paid	**(675)**	(652)	**(291)**	(317)
Fair value, end of year	**18,837**	15,838	**—**	—
Funded status – plan surplus (deficit)	**3,698**	1,086	**(6,652)**	(6,498)

The measurement date for the plan assets and the accrued benefit obligation is December 31, 2014. The effective date of the most recent actuarial valuation was as at December 31, 2011 and the date of the next required valuation for funding purposes is December 31, 2014.

[in thousands of dollars]

The defined benefit pension plan assets held at the measurement date are represented by the following categories:

	%
Canadian equity funds	**14**
US equity funds	**13**
EAFE equity funds	**11**
Canadian fixed income funds	**60**
Cash and short-term investments	**2**

	Pension benefit plans		Other retirement plans	
	2014	**2013**	**2014**	**2013**
	$	**$**	**$**	**$**
		[restated]		*[restated]*
Significant assumptions used				
Discount rate – beginning of year	**4.75%**	4.75%	**4.75%**	4.75%
Discount rate – end of year	**4.75%**	4.75%	**4.75%**	4.75%
Rate of compensation increase	**4.00%**	4.00%	—	—
Initial health care trend rate	—	—	**5.93%**	5.96%
Average remaining service life of active employees [years]	**5**	6	**16**	17
Net benefit expense for the year				
Current service cost	**386**	368	**90**	86
Finance cost	**(47)**	(1)	**309**	303
Remeasurement costs	**(1,823)**	(61)	**46**	40
Regulatory adjustments	**2,004**	312	**26**	23
Net benefit expense	**520**	618	**471**	452

The total expense for the Corporation's defined contribution pension plan for the year amounted to $255 [2013 – $243]. The pension cost associated with the OMERS plan was $156 [2013 – $151].

[in thousands of dollars]

5. INCOME TAXES

The provision for (recovery of) income taxes consists of the following:

	2014 $	2013 $
Current income taxes	**996**	1,448
Future income taxes	**1,029**	(22)
Future income taxes transferred to regulatory liabilities (assets)	**(1,029)**	22
	996	1,448

During the year, the Corporation recorded $1,029 in regulatory assets and a corresponding decrease to future income tax expense, for the amount of future income taxes expected to be recovered from customers in future electricity rates.

Future income taxes are provided for temporary differences. Future tax assets and liabilities consist of the following:

	2014 $	2013 $ *[restated]*
Future tax liabilities (assets)		
Utility capital assets	**5,074**	**4,684**
Employee future benefits	**(786)**	**(1,434)**
Other assets	**30**	**39**
Net future tax liabilities	**4,318**	**3,289**

[in thousands of dollars]

6. RELATED PARTY TRANSACTIONS

During the year, the Corporation entered into the following transactions with related parties:

	2014 $	2013 $
Receipts		
Administrative services to:		
FortisOntario Inc.	**101**	156
Cornwall Street Railway, Light and Power Company Limited	**1,394**	1,354
Algoma Power Inc.	**1,903**	1,892
Reimbursement of expenses paid on behalf of and services provided to:		
FortisOntario Inc.	**433**	380
Fortis Properties Corporation	**—**	16
Fortis Generation East Limited Partnership	**485**	547
Algoma Power Inc.	**255**	34
Westario Power Holdings Inc.	**367**	210
Grimsby Power Inc.	**98**	93
Cornwall Street Railway, Light and Power Company Limited	**318**	194
CH Energy Group Inc.	**19**	—
Payments		
Purchased power from Fortis Generation East Limited Partnership	**1,679**	1,483
Management fees paid to FortisOntario Inc.	**744**	675
Rent paid to FortisOntario Inc.	**525**	515
Dividends paid to FortisOntario Inc.	**2,500**	—
Interest expense paid to FortisOntario Inc.	**899**	945
Interest expense paid to Fortis Inc.	**36**	—
Reimbursement for expenses paid on behalf of and services provided from:		
FortisOntario Inc.	**4,524**	3,426
Cornwall Street Railway, Light and Power Company Limited	**416**	459
Westario Power Holdings Inc.	**—**	3

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

[in thousands of dollars]

As at December 31, the amounts due to (from) related parties are as follows:

	2014 $	2013 $
FortisOntario Inc.	**10,350**	5,825
Fortis Generation East Limited Partnership	**73**	125
Westario Power Holdings Inc.	**(52)**	(39)
Grimsby Power Inc.	**(8)**	(14)
CH Energy Group Inc.	**(19)**	—
	10,344	5,897
Promissory notes due to parent company	**20,000**	20,000

A promissory note of $20,000 due to the parent company bears interest at a rate of 4.03% and is payable on demand. There are no specific terms of repayment for this note.

Details of relationships with related parties are as follows:

- Fortis Inc. owns a 100% interest in the capital stock of FortisOntario Inc.
- FortisOntario Inc. owns a 100% interest in the capital stock of the Corporation
- Fortis Properties Corporation is a wholly owned subsidiary of Fortis Inc.
- Cornwall Street Railway, Light and Power Company Limited is a wholly owned subsidiary of FortisOntario Inc.
- Algoma Power Inc. is a wholly owned subsidiary of FortisOntario Inc
- Westario Power Holdings Inc. is 10% owned by FortisOntario Inc.
- FortisOntario Inc. owns 10 Class B preferred shares of Niagara Power Incorporated.
- FortisOntario Inc. indirectly owns 10% of Grimsby Power Inc. through the ownership of the Class B preferred shares in Niagara Power Incorporated.
- Fortis Generation East Limited Partnership is a wholly owned subsidiary of Fortis Inc.
- CH Energy Group Inc. is a wholly owned subsidiary of Fortis Inc.

[in thousands of dollars]

7. LONG-TERM DEBT

Long-term debt consists of the following:

	2014 $	2013 $
7.092% senior unsecured notes due August 14, 2018	**30,000**	30,000
Unamortized debt issue costs	**(115)**	(147)
	29,885	29,853

The senior unsecured notes bear interest of 7.092% and are repayable at maturity on August 14, 2018. Interest expense on long-term debt for the year was $2,131 [2013 – $2,128].

The Corporation incurred costs of $480 that are being amortized over the term of the loan. As at December 31, 2014, the accumulated amortization was $365 [2013 – $333].

8. CAPITAL STOCK

The authorized and issued shares consist of 23,900,001 common shares without par value.

9. AMORTIZATION

Amortization consists of the following:

	2014 $	2013 $
Amortization of utility capital assets	**4,706**	4,452
Amortization of contributions in aid of construction	**(268)**	(253)
Amortization of intangible assets	**862**	810
	5,300	5,009
Vehicle amortization allocated	**(388)**	(351)
	4,912	4,658

[in thousands of dollars]

10. STATEMENTS OF CASH FLOWS

The net change in non-cash working capital balances related to operations consists of the following:

	2014 $	2013 $
Accounts receivable	**(61)**	(627)
Income taxes receivable	**186**	145
Materials and supplies	**(63)**	29
Prepaid expenses	**27**	71
Accounts payable and accrued liabilities	**(956)**	1,099
Regulatory assets/liabilities	**1,484**	(351)
Due to related parties	**4,447**	(3,158)
	5,064	(2,792)

Supplemental cash flow information:

	2014 $	2013 $
Interest paid	**3,132**	3,130
Income taxes paid	**1,013**	1,525

11. FINANCIAL RISK MANAGEMENT

The Corporation is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit risk:	Risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument.
Liquidity risk:	Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.
Market risk:	Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices.

[in thousands of dollars]

Credit risk

For cash, trade and other accounts receivable due from customers, the Corporation's credit risk is limited to the carrying value on the balance sheet.

The Corporation is exposed to credit risk from its distribution customers but has various policies to minimize this risk. These policies include requiring customer deposits, performing disconnections and using third party collection agencies for overdue accounts. The Corporation has a large and diversified distribution customer base, which minimizes the concentration of this risk.

The aging of the Corporation's trade and other receivables due from customers is as follows:

	2014 $
Not past due	11,213
Past due 0-30 days	381
Past due 31-60 days	86
Past due 61 days and over	170
	11,850
Less allowance for doubtful accounts	160
	11,690

Liquidity risk

Liquidity risk to the Corporation is minimized. Financing of regulated capital and other expenditures is done through internally generated funds. These funds are a result of allowable rate regulated returns and recoveries under the OEB rate regulation mechanism.

The Corporation's parent company is a wholly owned by Fortis Inc., a large, investor owned utility that has had the ability to raise sufficient and cost effective financing. However, the ability to arrange financing on a go forward basis is subject to numerous factors including the results of operations and financial position of Fortis Inc. and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To mitigate any liquidity risk, the Corporation is a party to a committed revolving credit facility and letters of credit facilities totaling $30,000, of which $15,700 is unused. This credit agreement is shared among the subsidiaries of FortisOntario Inc. and is renewed on an annual basis.

[in thousands of dollars]

The facility is guaranteed by the parent company and bears interest at the bankers' acceptance rate plus 1.20% in the case of bankers' acceptances and at the bank's prime lending rate plus 0.20% in the case of bank loans.

The following is an analysis of the contractual maturities of the Corporation's financial liabilities as at December 31, 2014:

	< 1 year $	1-3 years $	4-5 years $	> 5 years $	Total $
Accounts payable and accrued liabilities	**7,139**	**—**	**—**	**—**	**7,139**
Government remittances payable	**209**	**—**	**—**	**—**	**209**
Customer deposits	**251**	**125**	**230**	**—**	**606**
Promissory notes due to parent company	**—**	**—**	**—**	**20,000**	**20,000**
Long-term debt	**—**	**—**	**30,000**	**—**	**30,000**
	7,599	**125**	**30,230**	**20,000**	**57,954**

Interest rate risk

Long-term debt is at fixed interest rates thereby minimizing cash flow and interest rate fluctuation exposure. The Corporation is primarily subject to risks associated with fluctuating interest rates on its short-term borrowings. Short-term borrowings for 2014 is nil [2013 – $3,000].

12. CAPITAL MANAGEMENT

The Corporation manages its capital to approximate the deemed capital structure reflected in the utility's customer rates. Effective January 1, 2013, the distribution rates are based on a deemed capital structure of 60% debt and 40% equity. The Corporation's capital structure consists of third party debt, affiliated debt and common equity but excludes unamortized debt issue costs.

The managed capital is as follows:

	2014 Actual		2013 Actual	
	$	%	$	%
Debt	**50,000**	**51**	50,000	52
Equity	**47,596**	**49**	45,375	48
	97,596	**100**	95,375	100

The Corporation's long-term debt obligations and credit facility agreements have covenants that restrict the issuance of additional debt such that debt cannot exceed 75% of their capital structures as defined in the agreements. As at December 31, 2014, the Corporation was in compliance with its debt covenants.

13. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and regulatory liabilities arise as a result of regulatory requirements.

The Corporation pays the cost of power on behalf of its customers and recovers these costs through retail billings to its customers. The cost of power includes charges for transmission, wholesale market operations and the power itself from Ontario's Independent Electricity System Operator. The balance of the retail settlement variance account represents the costs that have not been recovered from, or settled through, customers as of the balance sheet date. The OEB's Distribution Rate Handbook and Accounting Procedures Handbook allow these costs to be deferred and recovered through future rate adjustments, as discussed in note 1. In the absence of rate regulation, these costs would be expensed in the period that they are incurred.

The OEB has the general power to include or exclude costs, revenues, gains or losses in the rates of a specific period, resulting in the timing of revenue and expense recognition that may differ in the Corporation's regulated operations from those otherwise expected in non-regulated businesses. This change in timing gives rise to the recognition of regulatory assets and liabilities. The Corporation continually assesses the likelihood of recovery of its regulatory assets and believes that its regulatory assets and liabilities will be factored into the setting of future rates as discussed in note 1. If future recovery through rates is no longer considered probable, the appropriate carrying amount will be written off in the period that the assessment is made.

In 2013, upon approval by the OEB, the Corporation integrated smart meters into rate base from amounts previously held as regulatory assets of $4,365 as well as removed stranded meter assets of $1,238 from capital assets and recognized these amounts as regulatory assets.

In 2013 the smart meter revenue and expense balances previously held in regulatory assets were transferred to the statement of earnings and retained earnings per the guidance provided in the OEB Accounting Procedures Handbook. The net disposition costs were $237.

The following table provides the detailed revenue and costs associated with the smart meter disposition costs.

[in thousands of dollars]

	2014 $	2013 $
Billed revenue	—	2,049
Less: return on equity previously booked	—	(1,004)
	—	1,045
Amortization	—	(1,101)
Operating costs	—	(51)
Reduction in regulatory interest income	—	(130)
Net smart meter disposition costs	—	(237)

Regulatory assets and liabilities are not subject to a regulatory return; however, the balances include an accrual for interest recovery/payable as permitted by the regulators.

	2014 $	2013 $ *[restated]*	Remaining rebate period
Current regulatory assets			
Amounts approved in current rates	**260**	1,742	**1 year**
Long-term regulatory assets			
Retail settlement and other variance accounts	**2,343**	1,167	**2 years**
Amounts approved in current rates	**84**	167	**2 years**
Future taxes to be recovered from customers	**4,318**	3,289	**life of assets**
Pension and other retirement benefits	**2,293**	4,310	**EARSL**
	9,038	8,933	
Current regulatory liabilities			
Ontario Clean Energy benefits	**629**	631	**1 month**
Amounts approved in current rates	**6**	—	**1 year**
Other	**64**	66	
	699	697	
Long-term regulatory liabilities			
Retail settlement and other variance accounts	**2,928**	1,704	**2 years**
Other	**84**	168	**2 years**
	3,012	1,872	

[in thousands of dollars]

14. SEGMENTED INFORMATION

[a] Earnings

	2014		
	CNPI Distribution $	**CNPI Transmission** $	**Total** $
Revenue	**76,463**	**4,854**	**81,317**
Purchased power	**56,490**	**—**	**56,490**
Operating expenses	**9,296**	**1,738**	**11,034**
Amortization	**4,014**	**898**	**4,912**
Operating earnings	**6,663**	**2,218**	**8,881**
Interest expense	**2,617**	**547**	**3,164**
Income taxes	**706**	**290**	**996**
Net earnings	**3,340**	**1,381**	**4,721**

	2013		
	CNPI Distribution $	**CNPI Transmission** $	**Total** $
Revenue	73,332	4,856	78,188
Purchased power	53,921	—	53,921
Operating expenses	9,012	1,698	10,710
Amortization	3,864	794	4,658
Operating earnings	6,535	2,364	8,899
Net smart meter disposition costs	237	—	237
Interest expense	2,623	531	3,154
Income taxes	970	478	1,448
Net earnings	2,705	1,355	4,060

[in thousands of dollars]

[b] Utility capital assets

	2014		
	CNPI Distribution $	CNPI Transmission $	Total $
Cost	**129,808**	**28,672**	**158,480**
Accumulated amortization	**47,133**	**12,984**	**60,117**
	82,675	**15,688**	**98,363**

	2013		
	CNPI Distribution $	CNPI Transmission $	Total $
Cost	122,575	26,223	148,798
Accumulated amortization	43,530	12,251	55,781
	79,045	13,972	93,017

15. COMPARATIVE FINANCIAL STATEMENTS

The comparative financial statements have been reclassified from statements previously presented to conform to the presentation of the 2014 financial statements.

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Financial Statements

Canadian Niagara Power Inc.

December 31, 2015

Building a better
working world

INDEPENDENT AUDITORS' REPORT

To the Shareholder of
Canadian Niagara Power Inc.

We have audited the accompanying financial statements of **Canadian Niagara Power Inc.**, which comprise the balance sheet as at December 31, 2015, and the statements of earnings 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 accounting standards for private enterprises, 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.

Auditors' 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 auditors' 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 auditors consider 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 in our audit 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 **Canadian Niagara Power Inc.** as at December 31, 2015, and the results of its operations and its cash flows for the year then ended in accordance with Canadian accounting standards for private enterprises.

Ernst & Young LLP

Chartered Professional Accountants
Licensed Public Accountants

Toronto, Canada
February 3, 2016

Canadian Niagara Power Inc.
Incorporated under the laws of Ontario

BALANCE SHEET

[in thousands of dollars]

As at December 31

	2015	2014
	$	$
ASSETS		
Current		
Cash	**2,680**	1,216
Accounts receivable *[note 11]*	**11,163**	11,690
Income taxes receivable	**230**	—
Materials and supplies	**55**	143
Regulatory assets *[note 13]*	**—**	260
Prepaid expenses	**269**	469
Total current assets	**14,397**	13,778
Utility capital assets, net *[note 2]*	**106,178**	98,363
Intangible assets *[note 3]*	**10,294**	8,783
Accrued pension benefit asset *[note 4]*	**4,619**	3,698
Other assets	**24**	—
Regulatory assets *[note 13]*	**12,043**	11,422
Goodwill	**7,232**	7,232
	154,787	143,276
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable and accrued liabilities *[note 11]*	**8,989**	7,954
Income taxes payable	**—**	31
Regulatory liabilities *[note 13]*	**738**	699
Due to related parties *[note 6]*	**15,240**	10,344
Total current liabilities	**24,967**	19,028
Promissory notes due to parent company *[notes 6, 11 and 12]*	**20,000**	20,000
Long-term debt *[notes 7, 11 and 12]*	**29,917**	29,885
Future tax liabilities *[note 5]*	**7,201**	6,702
Accrued other retirement benefit liability *[note 4]*	**7,402**	6,652
Contributions in aid of construction	**11,362**	10,401
Regulatory liabilities *[note 13]*	**3,095**	3,012
Total liabilities	**103,944**	95,680
Shareholder's equity		
Capital stock *[note 8]*	**23,900**	23,900
Retained earnings	**26,943**	23,696
Total shareholder's equity	**50,843**	47,596
	154,787	143,276

See accompanying notes

On behalf of the Board:

Director

Director

Canadian Niagara Power Inc.

STATEMENT OF EARNINGS AND RETAINED EARNINGS

[in thousands of dollars]

Year ended December 31

	2015 $	2014 $
REVENUE		
Sale of energy	**57,861**	56,490
Distribution	**17,599**	17,783
Transmission	**4,347**	4,854
Other	**2,597**	2,190
	82,404	81,317
EXPENSES		
Cost of power purchased	**57,861**	56,490
Operating	**11,186**	11,034
Amortization *[note 9]*	**4,752**	4,912
	73,799	72,436
Operating earnings before the following	**8,605**	8,881
Other regulatory adjustments *[note 13]*	**(1,250)**	—
Interest expense *[notes 6, 7 and 11]*	**(3,197)**	(3,164)
Earnings before income taxes	**4,158**	5,717
Provision for income taxes *[note 5]*	**911**	996
Net earnings for the year	**3,247**	4,721
Retained earnings, beginning of year	**23,696**	21,475
Dividends paid *[note 6]*	**—**	(2,500)
Retained earnings, end of year	**26,943**	23,696

See accompanying notes

Canadian Niagara Power Inc.

STATEMENT OF CASH FLOWS

[in thousands of dollars]

Year ended December 31

	2015 $	2014 $
OPERATING ACTIVITIES		
Net earnings for the year	**3,247**	4,721
Add (deduct) items not involving cash		
Amortization *[note 9]*	**5,147**	5,300
Future income taxes	**500**	3,413
Gain on sale of utility capital assets	**(47)**	(75)
Accrued pension benefits	**(295)**	(1,471)
Accrued other retirement benefits	**1,045**	443
Long-term regulatory assets and liabilities	**(539)**	(1,349)
Accrued pension benefit asset	**(626)**	(1,141)
Accrued other retirement benefit liability	**(294)**	(289)
	8,138	9,552
Net change in non-cash working capital balances related to operations *[note 10]*	**6,782**	5,064
Cash provided by operating activities	**14,920**	14,616
INVESTING ACTIVITIES		
Additions to utility capital assets	**(12,703)**	(10,065)
Additions to intangible assets	**(2,470)**	(919)
Proceeds on sale of utility capital assets	**445**	88
Increase in other assets	**(24)**	—
Increase in long-term debt	**32**	32
Cash used in investing activities	**(14,720)**	(10,864)
FINANCING ACTIVITIES		
Repayment of short-term loan payable *[note 11]*	—	(3,000)
Increase in contributions in aid of construction	**1,264**	1,658
Dividends	—	(2,500)
Cash provided by (used in) financing activities	**1,264**	(3,842)
Net increase (decrease) in cash during the year	**1,464**	(90)
Cash, beginning of year	**1,216**	1,306
Cash, end of year	**2,680**	1,216

See accompanying notes

NOTES TO FINANCIAL STATEMENTS

[in thousands of dollars]

December 31, 2015

1. BASIS OF ACCOUNTING AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Incorporation

Canadian Niagara Power Inc. [the "Corporation" or "CNPI"], a wholly owned subsidiary of FortisOntario Inc. [the "parent company"] [formerly Canadian Niagara Power Company, Limited], was incorporated on February 17, 1999 to comply with the Electricity Act, 1998 (Ontario) [the "Act"]. The Act requires that the electric power transmission and distribution businesses, previously carried out by the parent company, be carried out by a separate legal entity. Effective March 31, 1999, the Corporation purchased the electric power transmission and distribution assets of its parent company and commenced operations. On January 1, 2004, the Corporation was amalgamated with Eastern Ontario Power Inc. and continued as Canadian Niagara Power Inc. The business of the Corporation is the transmission and distribution of electricity to customers within Ontario. The business is regulated by the Ontario Energy Board ["OEB"].

These financial statements include the operating results of the Fort Erie, Port Colborne and Eastern Ontario Power [Gananoque] distribution centres and the Fort Erie transmission centre.

A. BASIS OF ACCOUNTING

These financial statements have been prepared in accordance with Canadian accounting standards for private enterprises ["ASPE"], as per Part II of the CPA Handbook – Accounting, which constitutes generally accepted accounting principles for non-publicly accountable enterprises in Canada.

B. SIGNIFICANT ACCOUNTING POLICIES

Regulation

CNPI distribution

The distribution rates of CNPI are based upon cost-of-service rate regulation by the OEB. Earnings are regulated on the basis of a rate of return on rate base plus a recovery of all allowable distribution costs of CNPI.

On August 16, 2013, CNPI filed its 2014 4th Generation Incentive Rate-setting Application ["4GIRM"] for electricity distribution rates effective January 1, 2014. This application was based on the OEB's guidelines for 4th Generation Incentive Regulation Mechanism. On January 9, 2014, the OEB issued its Decision and Order for CNPI; the final 4th Generation Incentive Price Index was 1.25% comprising 1.7% inflation, a 0% productivity factor and a 0.45% stretch factor [i.e., 1.7% – (0% + 0.45%)]. Rates were effective January 1, 2014. The overall bill impact for the average residential consumer in Fort Erie is a 0.9% increase, a 0.8% increase for the average residential consumer in Gananoque, and a 0.2% increase for the average residential consumer in Port Colborne.

On August 13, 2014, CNPI submitted its 2015 4GIRM for electricity distribution rates effective January 1, 2015. This application was a second in a series of rate applications to fully harmonize electricity distribution rates in Port Colborne with those of Fort Erie and Gananoque. The OEB issued its Decision and Order on December 4, 2014, and the net price cap index adjustment for 2015 is 1.15% [i.e. 1.6% – (0% + 0.45%)]. The overall bill impact for the average residential consumer in Fort Erie was a 1.4% decrease, a 1.5% decrease for the average residential consumer in Gananoque, and a 3.2% decrease for the average residential consumer in Port Colborne. These overall decreases include the impact of the disposition of regulatory deferral and variance accounts.

On August 14, 2015, CNPI submitted its 2016 4GIRM for electricity distribution rates effective January 1, 2016. The OEB has calculated the value of the inflation factor for incentive rate setting, for rate changes effective in 2016, to be 2.1%. The OEB assigned a stretch factor of 0.45% based on the updated benchmarking study for use for rates effective in 2016. As a result, the net price cap index adjustment for CNPI is 1.65% [i.e. 2.1% – (0% + 0.45%)]. The 1.65% adjustment applies to distribution rates [fixed and variable charges] uniformly across all customer classes.

Beginning with electricity distribution rates effective in 2016, decoupling of electricity distribution rates for the Residential customer class is being introduced; complete decoupling is expected to take four consecutive years to fully implement.

CNPI transmission

The transmission rates of CNPI are based upon cost-of-service rate regulation by the OEB. Earnings are regulated on the basis of a rate of return on rate base plus a recovery of all allowable transmission costs of CNPI.

On November 17, 2014, CNPI submitted a Revenue Requirement Application for its Transmission business. The Application sought approval of CNPI's 2015 and 2016 Transmission Revenue Requirement.

On June 25, 2015, the OEB issued its Decision and Order. The Decision and Order approves final revenue requirements of $4,246,478 and $4,647,201 for 2015 and 2016, respectively and provides a 9.30% Return on Equity with a 60%/40% debt equity structure. On January 14, 2016, the OEB issued its Decision and Order approving an adjusted 2016 revenue requirement of $4,457,953.

Materials and supplies

Materials and supplies are recorded at average cost. Materials and supplies expensed to operating expenses in 2015 were $53 [2014 – $119].

Utility capital assets and capitalization policy

Nature of distribution and transmission assets

Distribution assets

Distribution assets are those used to distribute electricity at lower voltages [generally below 50 kilovolts]. These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

Transmission assets

Transmission assets are those used to transmit electricity at higher voltages [generally at 50 kilovolts and above]. These assets include poles, wires and conductors, substations, support structures and other related equipment.

Utility capital assets are stated at cost less accumulated amortization. Amortization is provided over the estimated useful lives of the utility capital assets using the straight-line method at a composite rate of 2.8% [2014 – 3.2%].

Contributions in aid of construction represent funding of utility capital assets contributed by customers. These accounts are being reduced annually by an amount equal to the charge for amortization provided on the contributed portion of the assets involved.

Capitalization policy

The Corporation's capitalization policy is in accordance with the OEB's requirements to use a "modified IFRS" accounting basis.

Intangible assets

Intangible assets are stated at cost less accumulated amortization. Amortization is provided over the estimated useful lives of the intangible assets using the straight-line method.

Asset retirement obligations

ASPE requires the recognition of an asset retirement obligation in the period during which a legal obligation associated with the retirement of a tangible long-lived asset is incurred and when a reasonable estimate of this amount can be made.

The Corporation has determined that there are asset retirement obligations associated with some parts of its transmission and distribution systems; however, none of these are material or require recognition under Section 3110 of the CPA Handbook.

Goodwill

Goodwill represents the excess of the acquisition cost of the shares of the Corporation, and Eastern Ontario Power Inc. [amalgamated with the Corporation on January 1, 2004] over the assigned value of identifiable net assets acquired, as well as the excess of the purchase price of the remaining utility capital assets of Port Colborne Hydro Inc. ["PCHI"] over the fair value of these assets.

ASPE requires that goodwill shall be tested for impairment whenever events or changes in circumstances indicate that the carrying amount of the reporting unit to which the goodwill is assigned may exceed the fair value of the reporting unit. Any impairment in value is charged to earnings during the year.

Other assets

Other assets are amortized over their useful lives.

Revenue recognition

Revenue from the sale, transmission and distribution of electricity is recognized on the accrual basis. Electricity is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of the year a certain amount of consumed electricity will not have been billed. Electricity that is consumed but not yet billed to the customers is estimated and accrued as revenue in the current year. Unbilled revenue included in accounts receivable as at December 31, 2015 is $6,427 [2014 – $6,574].

Foreign currency translation

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at the exchange rate prevailing at the balance sheet date. Gains and losses on translation are included in the statement of earnings and retained earnings. Revenue and expenses are translated at the exchange rate prevailing on the transaction date.

Employee benefit plans

Effective January 1, 2014, the Corporation adopted the new CPA Handbook Section 3462, *Employee Future Benefits,* for its accounting of pension benefits and other retirement benefits. As allowed under new Section 3462, the Corporation made an accounting policy choice to measure its defined benefit plan obligations using the funding valuation approach. This approach uses the most recent completed actuarial valuations prepared for funding purposes as the basis of measuring defined benefit plan obligations. Even though other retirement benefits are not funded, Section 3462 allows that such liabilities can be measured on a basis consistent with funded plans. As well, the Corporation is using a roll-forward technique in the years between valuations to estimate the defined benefit obligations. Pension plan assets are valued at fair value as of the balance sheet date.

In 2013, the Corporation made an application to the OEB to continue to account for pension and other retirement benefits under the former Section 3461. In December 2013, the OEB issued a Decision and Order approving the establishment of specific variance accounts as of January 1, 2013 to recognize the difference in expense between Sections 3461 and 3462 as long-term regulatory assets or liabilities for 2013 and future years, which will be disposed of in future cost of service proceedings, subject to the OEB's prudence review at that time.

Income taxes

The Corporation follows the asset and liability method of accounting for income taxes. Under this method, future tax assets and liabilities are recognized for the temporary differences between the tax and accounting bases of assets and liabilities. Future tax assets and liabilities are measured using the enacted and substantively enacted tax rates and laws expected to apply to taxable income in the period in which the temporary differences are expected to be recovered or settled. The Corporation recognizes regulatory assets related to future income tax liabilities in the amount of future income taxes expected to be recovered from customers in future electricity rates.

NOTES TO FINANCIAL STATEMENTS

[in thousands of dollars]

December 31, 2015

Use of estimates

The preparation of financial statements in conformity with ASPE 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 revenue and expenses during the reporting period. Actual results may vary from the current estimates. These estimates are reviewed periodically and, as adjustments become necessary, they are reported in earnings in the period in which they become known.

2. UTILITY CAPITAL ASSETS

Utility capital assets consist of the following:

	2015		
	Cost $	Accumulated amortization $	Net book value $
Transmission	**32,481**	**13,272**	**19,209**
Distribution	**121,405**	**39,969**	**81,436**
Other	**16,538**	**11,005**	**5,533**
	170,424	**64,246**	**106,178**

	2014		
	Cost $	Accumulated amortization $	Net book value $
Transmission	28,566	12,983	15,583
Distribution	114,068	37,170	76,898
Other	15,846	9,964	5,882
	158,480	60,117	98,363

The amounts above include assets under construction of $3,018 [2014 – $7,035] which are not subject to amortization.

[in thousands of dollars]

3. INTANGIBLE ASSETS

Intangible assets consist of the following:

	2015		
	Cost **$**	**Accumulated amortization** **$**	**Net book value** **$**
Software costs	**11,810**	**7,428**	**4,382**
Land and transmission rights	**8,648**	**2,937**	**5,711**
Other	**287**	**86**	**201**
	20,745	**10,451**	**10,294**

	2014		
	Cost **$**	**Accumulated amortization** **$**	**Net book value** **$**
Software costs	11,002	6,649	4,353
Land and transmission rights	6,985	2,763	4,222
Other	287	79	208
	18,274	9,491	8,783

[in thousands of dollars]

4. EMPLOYEE FUTURE BENEFITS

The Corporation is a participating employer with its parent company in a defined benefit pension plan and a defined benefit plan providing other retirement benefits. The Corporation also maintains a defined contribution pension plan providing pension benefits and makes contributions to the Ontario Municipal Employees' Retirement Plan ["OMERS"] plan on behalf of some of its employees. OMERS is a multi-employer defined benefit pension plan providing pension benefits and is accounted for as a defined contribution pension plan.

Information about the Corporation's defined benefit plans is as follows:

	Pension benefit plan		Other retirement plan	
	2015	**2014**	**2015**	**2014**
	$	$	$	$
Accrued benefit obligation				
Balance, beginning of year	**15,139**	14,752	**6,652**	6,498
Current service costs	**404**	386	**94**	90
Finance costs	**719**	700	**316**	309
Benefits paid	**(648)**	(675)	**(295)**	(291)
Actuarial losses (gains)	**(126)**	(24)	**635**	46
Balance, end of year	**15,488**	15,139	**7,402**	6,652
Plan assets				
Fair value, beginning of year	**18,837**	15,838	**—**	—
Interest income	**895**	747	**—**	—
Return on plan assets	**397**	1,807	**—**	—
Contributions	**626**	1,120	**295**	291
Benefits paid	**(648)**	(675)	**(295)**	(291)
Fair value, end of year	**20,107**	18,837	**—**	—
Funded status – plan surplus (deficit)	**4,619**	3,698	**(7,402)**	(6,652)

The measurement date for the plan assets and the accrued benefit obligation is December 31, 2015. The effective date of the most recent actuarial valuation was as of December 31, 2014 and the date of the next required valuation for funding purposes is as of December 31, 2017.

[in thousands of dollars]

The defined benefit pension plan assets held at the measurement date are represented by the following categories:

	%
Canadian equity funds	**13**
US equity funds	**13**
EAFE equity funds	**13**
Canadian fixed income funds	**60**
Cash and short-term investments	**1**

	Pension benefit plan		Other retirement plan	
	2015	**2014**	**2015**	**2014**
	$	$	$	$
Significant assumptions used				
Discount rate – beginning of year	**4.75%**	4.75%	**4.75%**	4.75%
Discount rate – end of year	**4.75%**	4.75%	**4.75%**	4.75%
Rate of compensation increase	**3.50%**	4.00%	**—**	—
Initial health care trend rate	**—**	—	**5.57%**	5.93%
Average remaining service life of active employees [years]	**5**	5	**17**	16
Net benefit expense for the year				
Current service costs	**404**	386	**94**	90
Finance costs	**(176)**	(47)	**316**	309
Remeasurement costs	**(523)**	(1,823)	**635**	46
Regulatory adjustments	**802**	2,004	**(453)**	26
Net benefit expense	**507**	520	**592**	471

The total expense for the Corporation's defined contribution pension plan for the year amounted to $272 [2014 – $255]. The pension cost associated with the OMERS plan was $167 [2014 – $156].

NOTES TO FINANCIAL STATEMENTS
[in thousands of dollars]

December 31, 2015

5. INCOME TAXES

The provision for income taxes consists of the following:

	2015 $	2014 $
Current income taxes	**644**	996
Future income taxes	**500**	3,413
Future income taxes transferred to regulatory assets	**(233)**	(3,413)
	911	996

During the year, the Corporation recorded $233 in regulatory assets and a corresponding decrease to future income tax expense, for the amount of future income taxes expected to be recovered from customers in future electricity rates.

Future income taxes are provided for temporary differences. Net future tax liabilities consist of the following:

	2015 $	2014 $
Future tax liabilities (assets)		
Utility capital assets	**5,569**	5,074
Employee future benefits	**(227)**	(178)
Regulatory assets	**1,837**	1,776
Other assets	**22**	30
Net future tax liabilities	**7,201**	6,702

[in thousands of dollars]

6. RELATED PARTY TRANSACTIONS

During the year, the Corporation entered into the following transactions with related parties:

	2015 $	2014 $
Receipts		
Administrative services to:		
FortisOntario Inc.	**105**	101
Cornwall Street Railway, Light and Power Company Limited	**1,481**	1,394
Algoma Power Inc.	**2,023**	1,903
Reimbursement of expenses paid on behalf of and services provided to:		
FortisOntario Inc.	**258**	433
Fortis Inc.	**529**	—
Fortis Generation East Limited Partnership	**303**	485
Algoma Power Inc.	**292**	255
Westario Power Holdings Inc.	**344**	367
Grimsby Power Inc.	**94**	98
Cornwall Street Railway, Light and Power Company Limited	**377**	318
CH Energy Group Inc.	**2**	19
Payments		
Purchased power from Fortis Generation East Limited Partnership	**662**	1,679
Management fees paid to FortisOntario Inc.	**759**	744
Rent paid to FortisOntario Inc.	**535**	525
Dividends paid to FortisOntario Inc.	**—**	2,500
Interest expense paid to FortisOntario Inc.	**927**	899
Interest expense paid to Fortis Inc.	**—**	36
Reimbursement for expenses paid on behalf of and services provided from:		
FortisOntario Inc.	**10,113**	4,524
Cornwall Street Railway, Light and Power Company Limited	**493**	416
Fortis Inc.	**58**	—
Maritime Electric Company Limited	**1**	—

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

[in thousands of dollars]

As at December 31, the amounts due to (from) related parties are as follows:

	2015 $	2014 $
FortisOntario Inc.	**15,790**	10,350
Fortis Generation East Limited Partnership	**—**	73
Westario Power Holdings Inc.	**(31)**	(52)
Grimsby Power Inc.	**(11)**	(8)
CH Energy Group Inc.	**—**	(19)
Fortis Inc.	**(508)**	—
	15,240	10,344
Promissory notes due to parent company	**20,000**	20,000

A promissory note of $20,000 due to the parent company bears interest at a rate of 4.03% and is payable on demand. There are no specific terms of repayment for this note.

Details of relationships with related parties are as follows:

- Fortis Inc. owns a 100% interest in the capital stock of FortisOntario Inc.
- FortisOntario Inc. owns a 100% interest in the capital stock of the Corporation
- Cornwall Street Railway, Light and Power Company Limited is a wholly owned subsidiary of FortisOntario Inc.
- Algoma Power Inc. is a wholly owned subsidiary of FortisOntario Inc
- Westario Power Holdings Inc. is 10% owned by FortisOntario Inc.
- FortisOntario Inc. owns 10 Class B preferred shares of Niagara Power Incorporated.
- FortisOntario Inc. indirectly owns 10% of Grimsby Power Inc. through the ownership of the Class B preferred shares in Niagara Power Incorporated.
- Fortis Generation East Limited Partnership is a former wholly owned subsidiary of Fortis Inc.
- CH Energy Group Inc. is a wholly owned subsidiary of Fortis Inc.
- Maritime Electric Company Limited is a wholly owned subsidiary of FortisWest Inc., which also is a wholly owned subsidiary of Fortis Inc.

[in thousands of dollars]

7. LONG-TERM DEBT

Long-term debt consists of the following:

	2015 $	2014 $
7.092% senior unsecured notes due August 14, 2018	**30,000**	30,000
Unamortized debt issue costs	**(83)**	(115)
	29,917	29,885

The senior unsecured notes bear interest at 7.092% and are repayable at maturity on August 14, 2018. Interest expense on long-term debt for the year was $2,127 [2014 – $2,131].

The Corporation incurred costs of $480 that are being amortized over the term of the loan. As at December 31, 2015, the accumulated amortization was $397 [2014 – $365].

8. CAPITAL STOCK

The authorized and issued capital stock consists of 23,900,001 common shares without par value.

9. AMORTIZATION

Amortization consists of the following:

	2015 $	2014 $
Amortization of utility capital assets	**4,490**	4,706
Amortization of contributions in aid of construction	**(303)**	(268)
Amortization of intangible assets	**960**	862
	5,147	5,300
Vehicle amortization allocated	**(395)**	(388)
	4,752	4,912

[in thousands of dollars]

10. STATEMENT OF CASH FLOWS

The net change in non-cash working capital balances related to operations consists of the following:

	2015 $	2014 $
Accounts receivable	**526**	(61)
Income taxes receivable/payable	**(261)**	186
Materials and supplies	**88**	(63)
Prepaid expenses	**200**	27
Accounts payable and accrued liabilities	**1,034**	(956)
Regulatory assets/liabilities	**299**	1,484
Due to related parties	**4,896**	4,447
	6,782	5,064

Supplemental cash flow information:

	2015 $	2014 $
Interest paid	**3,165**	3,132
Income taxes paid	**915**	1,013

11. FINANCIAL RISK MANAGEMENT

The Corporation is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit risk:	Risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument.
Liquidity risk:	Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.
Market risk:	Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices.

[in thousands of dollars]

Credit risk

For cash, trade and other accounts receivable due from customers, the Corporation's credit risk is limited to the carrying value on the balance sheet.

The Corporation is exposed to credit risk from its distribution customers but has various policies to minimize this risk. These policies include requiring customer deposits, performing disconnections and using third party collection agencies for overdue accounts. The Corporation has a large and diversified distribution customer base, which minimizes the concentration of this risk.

The aging of the Corporation's trade and other receivables due from customers is as follows:

	2015 $
Not past due	**10,696**
Past due 0-30 days	**243**
Past due 31-60 days	**87**
Past due 61 days and over	**264**
	11,290
Less allowance for doubtful accounts	**127**
	11,163

Liquidity risk

Liquidity risk to the Corporation is minimized. Financing of regulated capital and other expenditures is done through internally generated funds. These funds are a result of allowable rate regulated returns and recoveries under the OEB rate regulation mechanism.

The Corporation's parent company is a wholly owned by Fortis Inc., a large investor owned utility that has had the ability to raise sufficient and cost-effective financing. However, the ability to arrange financing on a go forward basis is subject to numerous factors including the results of operations and financial position of Fortis Inc. and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To mitigate any liquidity risk, the Corporation is a party to a committed revolving credit facility and letters of credit facilities totalling $30,000, of which $15,700 is unused. This credit agreement is shared among the subsidiaries of FortisOntario Inc. and is renewed on an annual basis.

[in thousands of dollars]

The facility is guaranteed by the parent company and bears interest at the bankers' acceptance rate plus 1.20% in the case of bankers' acceptances and at the bank's prime lending rate plus 0.20% in the case of bank loans.

The following is an analysis of the contractual maturities of the Corporation's financial liabilities as at December 31, 2015:

	< 1 year $	1-3 years $	4-5 years $	> 5 years $	Total $
Accounts payable and accrued liabilities	8,219	—	—	—	8,219
Government remittances payable	141	—	—	—	141
Customer deposits	284	190	155	—	629
Promissory notes due to parent company	—	—	—	20,000	20,000
Long-term debt	—	30,000	—	—	30,000
	8,644	30,190	155	20,000	58,989

Interest rate risk

Long-term debt is at fixed interest rates thereby minimizing cash flow and interest rate fluctuation exposure. The Corporation is primarily subject to risks associated with fluctuating interest rates on its short-term borrowings. Short-term borrowings for 2015 is nil [2014 – nil].

12. CAPITAL MANAGEMENT

The Corporation manages its capital to approximate the deemed capital structure reflected in the utility's customer rates. Effective January 1, 2013, the distribution rates are based on a deemed capital structure of 60% debt and 40% equity. The Corporation's capital structure consists of third party debt, affiliated debt and common equity but excludes unamortized debt issue costs.

The managed capital is as follows:

	2015 Actual		2014 Actual	
	$	%	$	%
Debt	50,000	50	50,000	51
Equity	50,843	50	47,596	49
	100,843	100	97,596	100

The Corporation's long-term debt obligations and credit facility agreements have covenants that restrict the issuance of additional debt such that debt cannot exceed 75% of their capital structures as defined in the agreements. As at December 31, 2015, the Corporation was in compliance with its debt covenants.

13. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and regulatory liabilities arise as a result of regulatory requirements.

The Corporation pays the cost of power on behalf of its customers and recovers these costs through retail billings to its customers. The cost of power includes charges for transmission, wholesale market operations and the power itself from Ontario's Independent Electricity System Operator. The balance of the retail settlement variance account represents the costs that have not been recovered from, or settled through, customers as of the balance sheet date. The OEB's Distribution Rate Handbook and Accounting Procedures Handbook allow these costs to be deferred and recovered through future rate adjustments, as discussed in note 1. In the absence of rate regulation, these costs would be expensed in the period that they are incurred.

The OEB has the general power to include or exclude costs, revenues, gains or losses in the rates of a specific period, resulting in the timing of revenue and expense recognition that may differ in the Corporation's regulated operations from those otherwise expected in non-regulated businesses. This change in timing gives rise to the recognition of regulatory assets and liabilities. The Corporation continually assesses the likelihood of recovery of its regulatory assets and believes that its regulatory assets and liabilities will be factored into the setting of future rates as discussed in note 1. If future recovery through rates is no longer considered probable, the appropriate carrying amount will be written off in the period that the assessment is made.

Regulatory assets and liabilities are not subject to a regulatory return; however, the balances include an accrual for interest recovery/payable as permitted by the regulators.

In 2015, as a result of the Transmission OEB Decision and Order, the Corporation expensed certain disallowed capital project costs in the amount of $1,250. These amounts were previously recorded as capital assets under construction.

NOTES TO FINANCIAL STATEMENTS

[in thousands of dollars]

December 31, 2015

	2015 $	2014 $	Remaining rebate period
Current regulatory assets			
Amounts approved in current rates	—	260	1 year
Long-term regulatory assets			
Retail settlement and other variance accounts	**3,048**	2,343	2 years
Smart meter variance account	**7**	—	
Amounts approved in current rates	**127**	84	2 years
Future income taxes to be recovered from customers	**6,934**	6,702	life of assets
Pension and other retirement benefits	**1,927**	2,293	EARSL
	12,043	11,422	
Current regulatory liabilities			
Ontario Clean Energy benefits	**496**	629	1 month
Amounts approved in current rates	**176**	6	1 year
Other	**66**	64	
	738	699	
Long-term regulatory liabilities			
Retail settlement and other variance accounts	**3,095**	2,928	2 years
Other	—	84	2 years
	3,095	3,012	

NOTES TO FINANCIAL STATEMENTS

[in thousands of dollars]

December 31, 2015

14. SEGMENTED INFORMATION

[a] Earnings

	2015		
	CNPI Distribution $	**CNPI Transmission $**	**Total $**
Revenue	**78,057**	**4,347**	**82,404**
Purchased power	**57,861**	**—**	**57,861**
Operating expenses	**9,299**	**1,887**	**11,186**
Amortization	**4,175**	**577**	**4,752**
Operating earnings	**6,722**	**1,883**	**8,605**
Other regulatory adjustments	**—**	**1,250**	**1,250**
Interest expense	**2,639**	**558**	**3,197**
Income taxes	**906**	**5**	**911**
Net earnings	**3,177**	**70**	**3,247**

	2014		
	CNPI Distribution $	**CNPI Transmission $**	**Total $**
Revenue	76,463	4,854	81,317
Purchased power	56,490	—	56,490
Operating expenses	9,296	1,738	11,034
Amortization	4,014	898	4,912
Operating earnings	6,663	2,218	8,881
Interest expense	2,617	547	3,164
Income taxes	706	290	996
Net earnings	3,340	1,381	4,721

[in thousands of dollars]

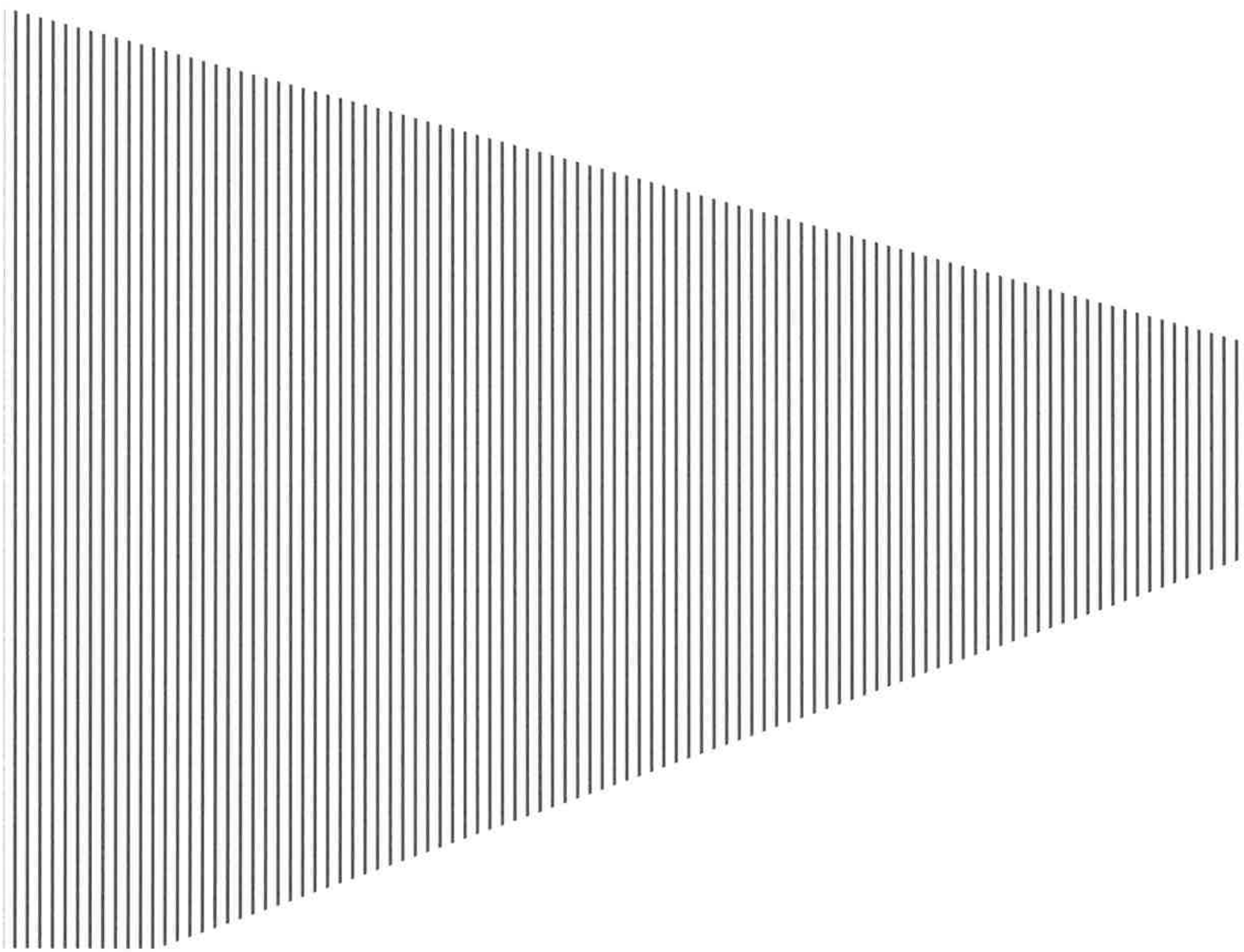
[b] Utility capital assets

	2015		
	CNPI Distribution $	CNPI Transmission $	Total $
Cost	**137,641**	**32,783**	**170,424**
Accumulated amortization	**50,962**	**13,284**	**64,246**
	86,679	**19,499**	**106,178**

	2014		
	CNPI Distribution $	CNPI Transmission $	Total $
Cost	129,808	28,672	158,480
Accumulated amortization	47,133	12,984	60,117
	82,675	15,688	98,363

15. COMPARATIVE FINANCIAL STATEMENTS

The comparative financial statements have been reclassified from statements previously presented to conform to the presentation of the 2015 financial statements.



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RECONCILIATION TO REGULATORY FILINGS

The following tables illustrate the variances between the audited financial statements ("AFS") and the RRR filings for each of 2013, 2014 and 2015.

CANADIAN NIAGARA POWER INC.
FORT ERIE, PORT COLBORNE AND GANANOQUE
($000's)

BALANCE SHEET VARIANCES	2013 AUDITED FINANCIAL STATEMENTS("AFS")	2013 RRR	VARIANCE	EXPLANATION
Goodwill	7,232	7,232	-	
Capital Assets	122,575	122,379	(196)	Some assets, net of amortization, grouped with intangibles in AFS
Net Intangibles	4,536	4,545	9	Some assets, net of amortization, grouped with intangibles in AFS
Contributions and Grants	(8,993)	(8,993)	-	
Accumulated Amortization of Assets	(43,530)	(43,343)	187	Some assets, net of amortization, grouped with intangibles in AFS
Net Balance Sheet Variance			-	
INCOME STATEMENT VARIANCES				
Sales of Electricity		(53,744)		
Distribution Services Revenue		(19,455)		
Other Distribution Revenue		-		
Other Operating Revenue		78		
Other Revenue		(1,140)		
Revenue	(73,332)	(74,261)	(929)	Other operating revenue(costs) grouped with expenses and interest income grouped with revenue in AFS, smart meter revenue grouped with net smart meter disposition costs on AFS
Power Supply Expenses (Working Capital)		53,744		
Operation and Maintenance (Working Capital)		3,473		
Non-Distribution		-		
Billing and Collection (Working Capital)		1,896		
Administrative and General Expenses (Working Capital)		3,367		
Other Distribution Expenses				
Operating Expenses	62,582	62,480	(102)	Other revenue(costs), donations and property taxes grouped with expenses in AFS, smart meter expenses grouped with net smart meter disposition costs on AFS
Amortization of Assets	4,215	5,317	1,102	Amortization on smart meters grouped in net smart disposition costs on AFS
Net Smart Meter Disposition Costs	237		(237)	
Donations	-	23	(23)	Donations grouped with operating expenses in AFS
Interest Expense	2,623	2,663	40	Interest grouped with revenue in AFS
Income Tax Expense	970	1,073	103	Property taxes grouped with operating expenses in AFS
Profit(Loss)	2,705	2,705	-	
Net Income Statement Variance			-	

CANADIAN NIAGARA POWER INC.
FORT ERIE, PORT COLBORNE AND GANANOQUE
($000's)

BALANCE SHEET VARIANCES	2014 AUDITED FINANCIAL STATEMENTS("AFS")	2014 RRR	VARIANCE	EXPLANATION
Goodwill	7,232	7,232	-	
Capital Assets	129,808	129,612	(196)	Some assets, net of amortization, grouped with intangibles in AFS
Net Intangibles	4,769	4,770	1	Some assets, net of amortization, grouped with intangibles in AFS
Contributions and Grants	(10,385)	(10,385)	-	
Accumulated Amortization of Assets	(47,133)	(46,938)	195	Some assets, net of amortization, grouped with intangibles in AFS
Net Balance Sheet Variance			-	
INCOME STATEMENT VARIANCES				
Sales of Electricity		(56,490)		
Distribution Services Revenue		(17,809)		
Other Distribution Revenue		-		
Other Operating Revenue		(907)		
Other Revenue		(1,439)		
Revenue	(76,463)	(76,645)	(182)	Other operating revenue(costs) grouped with expenses and interest income grouped with revenue in AFS
Power Supply Expenses (Working Capital)		56,490		
Operation and Maintenance (Working Capital)		3,620		
Non-Distribution		-		
Billing and Collection (Working Capital)		1,783		
Administrative and General Expenses (Working Capital)		3,908		
Other Distribution Expenses				
Operating Expenses	65,785	65,801	16	Other revenue(costs), donations and property taxes grouped with expenses in AFS
Amortization of Assets	4,014	4,014	-	
Donations	-	23	(23)	Donations grouped with operating expenses in AFS
Interest Expense	2,617	2,661	44	Interest grouped with revenue in AFS
Income Tax Expense	707	806	99	Property taxes grouped with operating expenses in AFS
Profit(Loss)	3,340	3,340	-	
Net Income Statement Variance			-	

CANADIAN NIAGARA POWER INC.
FORT ERIE, PORT COLBORNE AND GANANOQUE
($000's)

BALANCE SHEET VARIANCES	2015 AUDITED FINANCIAL STATEMENTS("AFS")	2015 RRR	VARIANCE	EXPLANATION
Goodwill	7,232	7,232	-	
Capital Assets	137,641	137,438	(203)	Some assets, net of amortization, grouped with intangibles in AFS
Net Intangibles	4,788	4,787	(1)	Some assets, net of amortization, grouped with intangibles in AFS
Contributions and Grants	(11,347)	(11,347)	-	
Accumulated Amortization of Assets	(50,962)	(50,758)	204	Some assets, net of amortization, grouped with intangibles in AFS
Net Balance Sheet Variance			-	
INCOME STATEMENT VARIANCES				
Sales of Electricity		(57,861)		
Distribution Services Revenue		(17,621)		
Other Distribution Revenue		-		
Other Operating Revenue		(934)		
Other Revenue		(1,858)		
Revenue	(78,057)	(78,274)	(217)	Other operating revenue(costs) grouped with expenses and interest income grouped with revenue in AFS
Power Supply Expenses (Working Capital)		57,861		
Operation and Maintenance (Working Capital)		3,615		
Non-Distribution		-		
Billing and Collection (Working Capital)		1,777		
Administrative and General Expenses (Working Capital)		4,000		
Other Distribution Expenses				
Operating Expenses	67,160	67,253	93	Other revenue(costs), donations and property taxes grouped with expenses in AFS
Amortization of Assets	4,175	4,175	-	
Donations	-	23	(23)	Donations grouped with operating expenses in AFS
Interest Expense	2,639	2,639	-	Interest grouped with revenue in AFS
Income Tax Expense	906	1,007	101	Property taxes grouped with operating expenses in AFS
Profit(Loss)	3,177	3,177	-	
Net Income Statement Variance			-	

ANNUAL REPORT AND MANAGEMENT'S DISCUSSION AND ANALYSIS

CNPI does not prepare an Annual Report or a Management's Discussion and Analysis.

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CREDIT RATING AGENCY REPORTS

CNPI does not have a credit rating and thus, no credit rating agency reports.

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PROSPECTUSES AND INFORMATION CIRCULARS / DEBT OR EQUITY OFFERINGS

CNPI has not produced either a prospectus or an information circular to support its third party debt or shareholder equity offerings.

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CHANGES TO TAX STATUS

There has been no change to CNPI’s tax status.

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EXISTING ACCOUNTING ORDERS

On December 12, 2013, CNPI received a Decision and Order from the Board (EB-2013-0369) approving the establishment of specific deferral and variance accounts related to pension and other post-employment benefits ("P&OPEB") subject to the conditions of the Order. The description of these deferral and variance accounts can be found in Exhibit 9, Tab 1, Schedule 1.

BACKGROUND OF ACCOUNTING ORDER EB-2013-0369

The Decision and Order from the Board, dated December 12, 2013, highlighted some of the details laid out in CNPI's application, which was submitted to seek the establishment of specific deferral and variance accounts related to P&OPEB. In its application, CNPI noted that it uses the Chartered Professional Accountants of Canada ("CPA Canada") Handbook Part II, Accounting Standards for Private Enterprises ("ASPE") for financial reporting purposes. CNPI is continuing use of ASPE for regulatory accounting purposes for this Application (Exhibit 1, Tab 4, Schedule 8.)

As of January 1, 2014, CNPI had adopted ASPE Section 3462 which required that unamortized actuarial gains and losses for P&OPEB, as of December 31, 2013, be charged to retained earnings. For the purposes of 2014 financial reporting, the 2013 amounts were retroactively restated to reflect the new Section 3462 as of January 1, 2013.

Additionally, the adoption of Section 3462 by CNPI would have impacted P&OPEB expenses charged to the income statement. Under the former accounting standard, Section 3461, the corridor method was allowed which smoothed P&OPEB expenses by amortizing these costs over a period of time. With the introduction of Section 3462, CNPI would no longer have been able to smooth these expenses and would have had to recognize certain P&OPEB costs immediately in expense. These charges to current earnings would have created volatility in the income statement. In its application, CNPI requested to record the expense variances between Section 3461 and 3462 in the proposed new variance accounts as at December 31, 2013, rather than charge these amounts to the 2013 income statement.

CNPI also requested that such adjustments to P&OPEB expense be recorded in the variance accounts on an annual basis until the Applicant's next cost of service reviews.

With Board approval, per the Decision and Order, CNPI filed a draft Accounting Order dated December 20, 2013 that listed the establishment of the following deferral and variance accounts effective January 1, 2013

- Account 1508 Other Regulatory Assets
  - Subaccount – Pension Deferral Account
  - Subaccount – Pension Expense Variance Account
  - Subaccount – Other Post Employment Benefits Deferral Account
  - Subaccount – Other Post Employment Benefits Expense Variance Account

The draft Accounting Order also provided a sample of journal entries that would have been made by CNPI, including: a journal entry to record the retroactive transitional entries to Section 3462, Employee Future Benefits, in Part II of the CPA Canada Handbook, as of January 1, 2013 for unamortized pension and OPEB amounts, and additional journal entries to record the difference between pension and OPEB expense under Section 3461 and Section 3462 retroactively for 2013.

On January 9, 2014, the Board approved the draft Accounting Order submitted by CNPI, and deemed it to be effective January 1, 2013.

With the Board approving the draft Accounting Order, CNPI booked a transitional journal entry in January 2014 taking into account unamortized actuarial gains and loss balances as of January 1, 2013, plus 2013 pension and OPEB variances. These journal entries were recorded in fiscal 2014, and resulted in the following audited additional amounts to the balance sheet as at January 1, 2014:

Account Desciption	1-Jan-14
Subaccount 1508 Pension Deferral Account	2,386,153
Subaccount 1508 OPEB Deferral Account	1,923,679
Pension liability	(2,386,153)
OPEB liability	(1,923,679)
Total	-

Beginning in 2014, monthly accrual journal entries have been booked in accordance with the Accounting Order to record the estimated difference between pension and OPEB expense under Section 3461 and Section 3462, with true-up journal entries being recorded at the end of each fiscal year when the re-measurement costs could be calculated by CNPI's actuarial service provider. Also, the 2013 comparative balance sheet amounts were restated to reflect the new Section 3462 as of January 1, 2013.

The 2016 Bridge and 2017 Test Year revenue requirement model was developed assuming Section 3461 utilizing the corridor method to smooth P&OPEB expenses. Therefore, within this Application, CNPI is not seeking recovery of any transitional balances, nor is it requesting recovery of any variances calculated for 2013, 2014 and 2015. Instead, CNPI will continue to assess the balances within the established deferral and variance accounts and may look to seek disposition of these balances in a future proceeding.

DEPARTURE FROM THE UNIFORM SYSTEM OF ACCOUNTS

CNPI has not departed from the Uniform System of Accounts, but for an exception in one area. Due to the non-significant dollars associated with Retail Service Charges, CNPI has not followed the Article 490, Retail Services and Settlement Variances of the Accounting Procedures Handbook for Account 1518 and Account 1548.

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ACCOUNTING STANDARD

Effective January 1, 2011, CNPI adopted Accounting Standards for Private Enterprises ("ASPE"). ASPE allows for the recognition of regulatory assets and liabilities.

In CNPI's last Cost of Service Application (EB-2012-0112), CNPI changed the estimated useful lives of its assets consistent with the guidelines in the Kinectrics Report as commissioned by the Board. CNPI also changed its accounting policy for the accounting of overhead costs associated with capital work as clarified by the Board in its letter dated February 24, 2010. These accounting changes are reflected in the 2013 Board Approved, 2013, 2014 and 2015 Actuals, 2016 Bridge, and 2017 Test Year data provided within this Application as well as additional capital expenditure forecast data for 2018 to 2021 as provided in Exhibit 2. CNPI references this as MIFRS accounting in the various Exhibits within this Application.

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NON-UTILITY BUSINESSES

CNPI has transmission and distribution business units; both are regulated by the Ontario Energy Board. This Application has been prepared using accounting values attributable to the distribution division only; transmission has been appropriately excluded.

CNPI is not engaged in any non-utility activities.

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MATERIALITY THRESHOLDS

CNPI has determined its materiality thresholds in accordance with the Filing Requirements which states the threshold is to be based on 0.5% of distribution revenue requirement for a distributor with revenue requirement greater than $10 million. CNPI is using a materiality threshold of $100,000 for both operating variances and capital projects in this Application.

	Base Revenue Requirement	%	Threshold	Threshold (Rounded)
CNPI	$19,912,813	0.5%	$99,564	$100,000

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ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, C. S.O. 1998, c.15 (Sched. B);

AND IN THE MATTER OF an Application by Canadian Niagara Power Inc. for an Order or Orders pursuant to Section 78 of the *Ontario Energy Board Act, 1998* approving or fixing just and reasonable rates and other service charges for the distribution of electricity.

APPLICATION

Introduction

1. The applicant is Canadian Niagara Power Inc. ("CNPI" or the "Applicant"), a wholly-owned subsidiary of FortisOntario Inc. ("FortisOntario"). The Applicant, an Ontario corporation with its head office in Fort Erie, Ontario carries on the business, among other things, of owning and operating electricity distribution facilities within Ontario. The Applicant carries on its distribution business in the following service territories: Niagara (Fort Erie and Port Colborne) and Eastern Ontario Power ("EOP") (Gananoque). The Applicant is submitting a single application for all of the service territories. Electricity distribution rates are already harmonized for Niagara and EOP. In this Application CNPI proposes to complete the harmonization for its disposition of deferral/variance accounts and Global Adjustment accounts.

2. Except where specifically identified in this Application, the Applicant followed Chapter 2, Cost of Service, of the *Filing Requirements for Electricity Distribution Rate Applications – 2015 Edition for 2016 Rate Applications – dated July 16, 2015* (the "Filing Requirements") in preparing this Application.

Relief Sought

3. CNPI hereby applies to the Ontario Energy Board (the "Board" or the "OEB"), pursuant to Section 78 of the *Ontario Energy Board Act, 1998* as amended (the "OEB Act") for approval of its proposed distribution rates and other charges, effective January 1, 2017.

4. The Tariff of Rates and Charges proposed in this Application are identified in Exhibit 8, Tab 2, Schedule 9, of this Application and the material being filed in support of this Application sets out CNPI's approach to its distribution rates and charges.

5. The specific orders/approvals that CNPI is seeking are as follows:

   a. Approval of the Distribution System Plan as presented in Exhibit 2, Tab 2 of this Application.

   b. Approval of a revenue requirement of $22,294,747 for the 2017 Test Year. CNPI acknowledges that the Board will publish an update to the prescribed Cost of Capital parameters and that these matters may affect the revenue requirement that CNPI has requested in this Application.

   c. The establishment of a new Embedded Distributor rate class in relation to the service provided to Hydro One Networks Inc., as described in Exhibit 7, Tab 1, Schedule 2 of this Application.

   d. Approval of CNPI's electricity distribution rates, effective January 1, 2017, designed to recover the base revenue requirement with transformer ownership credit add back, the low voltage rates, and the retail transmission service rates as presented in Exhibit 8 of this Application. CNPI acknowledges that changes to the Cost of Capital parameters and the Uniform Transmission Rates may impact the proposed Tariff of Rates and Charges presented in Exhibit 8, Tab 1, Schedule 9 of this Application.

   e. Approval to continue to charge the Specific Service Charges, the Wholesale Market Service Rate, the Rural or Remote Electricity Rate Protection Charge, the

Ontario Electricity Support Program Charge, the Standard Supply Service charge, and the Transformer Allowance approved in the OEB Decision and Order in the matter of CNPI's 2016 Distribution Rates (EB-2015-0058).

f. Approval of the distribution loss adjustment factors as presented in Exhibit 8, Tab 1, Schedule 8 of this Application.

g. Approval of the approach for rate mitigation in relation to the Residential rate class as presented in Exhibit 8, Tab 1, Schedule 12 of this Application.

h. Approval of CNPI's request to harmonize the existing distribution rate riders in its Fort Erie, Gananoque, and Port Colborne service territories, as presented in Exhibit 9, Tab 5 , Schedule 1 of this Application.

i. Approval to dispose of the balances in certain deferral and variance accounts as presented in Exhibit 9, Tab 5, Schedule 1 of this Application.

j. Approval to dispose of the balances in the LRAM variance account, as presented in Exhibit 9, Tab 6, Schedule 1 of this Application.

k. Approval of a rate rider related to the disposition of cost related to implementation of the MIST Metering initiative as presented in Exhibit 9, Tab 3, Schedule 1 of this Application.

l. Approval to establish certain new deferral and variance accounts as presented in Exhibit 9, Tab 1, Schedule 1 of this Application.

m. Such other approvals that CNPI may request and that the OEB accepts.

n. Approving the Tariff of Rates and Charges set out in this Application to be effective January 1, 2017.

o. An order making CNPI's current rates and charges interim as of January 1, 2017 in the event that the rates approved in this proceeding are not implemented by that date.

Form of Hearing Requested

6. The Applicant requests that, pursuant to section 34.01 of the Board's *Rules of Practice and Procedure,* this proceeding be conducted by way of written hearing with willingness to conduct by way of an oral hearing.

7. The written evidence, as filed with the Board, may be amended from time to time prior to the Board's final decision on the Application.

8. CNPI requests that a copy of all documents filed with the Board by each party to this Application be served on the Applicant and the Applicant's counsel as follows:

(a) The Applicant:

Mr. Gregory Beharriell
Manager, Regulatory Affairs
Canadian Niagara Power Inc.

Address for personal service:	1130 Bertie Street P. O. Box 1218 Fort Erie, Ontario L2A 5Y2
Mailing Address:	1130 Bertie Street P. O. Box 1218 Fort Erie, Ontario L2A 5Y2
Telephone:	(905) 871-0330 ext. 3279
Fax:	(905) 994-2207
Email Address:	regulatoryaffairs@fortisontario.com

(b) The Applicant's counsel:

Mr. R. Scott Hawkes
Vice President, Corporate Services and General Counsel
Canadian Niagara Power Inc.

Address for personal service:	1130 Bertie Street P. O. Box 1218 Fort Erie, Ontario L2A 5Y2
Mailing Address:	1130 Bertie Street P. O. Box 1218 Fort Erie, Ontario L2A 5Y2
Telephone:	(905) 994-3642
Fax:	(905) 994-2211
Email Address:	scott.hawkes@cnpower.com

– and –

Mr. Andrew Taylor
The Energy Boutique

Mailing Address:	120 Adelaide Street West Suite 2500 Toronto, Ontario M5H1T1
Telephone:	(416) 664-1568
Fax:	(416) 367-1954
Email Address:	ataylor@energyboutique.ca

DATED at Fort Erie, Ontario this 29th day of April, 2016.

CANADIAN NIAGARA POWER INC.

By its counsel,

R. Scott Hawkes

CANADIAN NIAGARA POWER INC.
APPLICATION FOR APPROVAL OF ELECTRICITY RATES
EFFECTIVE JANUARY 1, 2017

Exhibit	Tab	Schedule	Appendix	Contents
7 – Cost Allocation				
	1			**Cost Allocation**
		1		Current Status of Cost Allocation
		2		Discussion on 2017 Cost Allocation
			A	2017 Cost Allocation Study
			B	Input & Output Sheets
			C	HONI Correspondence
		3		Appendix 2-P

Exhibit	Tab	Schedule	Appendix	Contents
8		12		Rate Mitigation

Exhibit	Tab	Schedule	Appendix	Contents
9			A	Burman Energy Report
			B	OPA 2014 CDM Year End Report

ABREVIATIONS

Accounting Standards for Private Enterprises (“ASPE”)
Advanced Capital Module (“ACM”)
Advanced Metering Infrastructure (“AMI”)
Algoma Power Inc. (“API”)
Aluminum Conductor Steel Reinforced (“ACSR”)
American National Standards Institute (“ANSI”)
Area Planning Studies (“APS”)
Arrears Management Plan (“AMP”)
Asset Management (“AM”)
Audited Financial Statements (“AFS”)
BDR North America (“BDR”)
Canadian Motor Speedway (“CMS”)
Canadian National Railway (“CNR”)
Canadian Niagara Power Inc. (“CNPI”)
Canadian Niagara Power Transmitter (“CNPI Tx”)
Canadian Professional Accountants of Canada (“CPA Canada”)
Canadian Standards Association (“CSA”)
Capital Cost Allowance (“CCA”)
Central Environmental and Safety Committee (“CESC”)
CNPI’s information technology strategy (“IT Strategy”)
Code of Conduct (the "Code" or "Code of Conduct")
Computer-aided design (“CAD”)
Conditions of Service (“Cond. Of Serv.”)
Connection Impact Assessment (“CIA”)
Connection Service Charges (“CN”)
Conservation and Demand Management (“CDM”)
Conservation and Demand Management Code for Electricity Distributors (“the CDM Code”)
Construction Verification Program (“CVP”)
Contributions In Aid of Construction (“CIACs”)

Cost of Service (“COS”)

Cross Linked Polyethylene (“XLPE”)

Current Transformers (“CT”)

Customer Delivery Points (“CDP”)

Customer Information System (“CIS”)

Customer Service Representatives (“CSR”)

Deferral and Variance Accounts (“DVA”)

Detailed Technical Connection Assessments (“DTCA”)

Dissolved Gas Analysis (“DGA”)

Distributed Generation (“DG”)

Distribution Asset Management Plan (“DAMP”)

Distribution Automation (”DA”)

Distribution Substations (“DS”)

Distribution System Code (“DSC”)

Distribution System Inspection Program (“DSIP”)

Distribution System Plan (“DSP”)

Dual Element Spot Network version 1 (“DESN1”)

Eastern Ontario Power (“EOP”)

Electrical Safety Authority (“ESA”)

Electrical Service Quality Requirements (“ESQR”)

Electrical Utility Safety Association (“E&USA”)

Electricity Act, 1998 (“Electricity Act”)

Electricity Distributers Scorecard (“Scorecard”)

Electricity Distribution Rate (“EDR”)

Electronic Business Transactions (“EBT”)

Electronic File Transfer (“EFT”)

Elenchus Research Associates (“ERA”)

Emerald Ash Borer (“EAB”)

Engineering Analysis (“EA”)

Enterprise Resource Planning (“ERP”)

Executive Environment and Safety Team (“EEST”)

Feeder SAIDI (“F-SAIDI”)

Feeder SAIFI (“F-SAIFI”)

Feed-In Tariff (“FIT”)

Filing Requirements for Transmission and Distribution Applications (the “Filing Requirements”)

Fixed Asset Continuity schedules (“FAC”)

Fort Erie (“FE”)

Fortis Inc. (“Fortis”)

FortisOntario Inc. (“FortisOntario”)

Full Time Equivalent (“FTE”)

Future Value (“FV”)

General and administrative overhead (“G&A”)

General Plant (“GP”)

General Service 50 to 4999 kW (“GS 50 to 4999 kW”)

General Service Less than 50 kW (“GS < 50 kW”)

Generating Station (“GS”)

Geographic Information System (“GIS”)

Global Positioning System (“GPS”)

Grounded Wye (“Y-GND”)

Guidelines for Electricity Distributor Conservation and Demand Management (the "CDM Guidelines")

Health, Safety and Environment (“HS&E”)

Health, Safety and Environmental Management System (“HSEMS”)

Heating, Ventilation and Air-conditioning (“HVAC”)

Hertz (“Hz”)

Human Resources (“HR”)

Hydro One Networks Inc (“HONI”)

Incentive Regulation (“IR”)

Incentive Regulation Mechanism (“IRM”)

Incremental Capital Module (“ICM”)

Independent Electricity System Operator (the “IESO”)

Information Technology (“IT”)

Input Tax Credit (“ITC”)

Integrated Regional Resource Plan (“IRRP”)

International Accounting Standards (“IAS”)

International Brotherhood of Electrical Workers (“IBEW Local 636”)

International Financial Reporting Standards (“IFRS”)

Joint Health and Safety Committee (“JHSC”)

Joint Use (‘”JU’”)

Kilometers per hour (“km/h”)

Kilovolt (“kV”)

Kilovolt-ampere (“kVA”)

Kilowatt (“kW”)

Kilowatt hours (“kWhs”)

Linear Low-Density Polyethylene (“LLDPE”)

Local Distribution Company (“LDC”)

Long Term Load Transfer (“LTLT”)

Lost Revenue Adjustment Mechanism (“LRAM”)

Lost Revenue Adjustment Mechanism Variance Account (“LRAMVA”)

Low Income Arrears Management Plan (“LAMP”)

Low-Income Energy Consumer Program (“LEAP”)

Managed Asset (“MA”)

Mean Time between Failures (“MTBF”)

Measurement Canada (“MC”)

Mega Volt Amp (“MVA”)

Mega Watts (“MW”)

Mercer’s Human Resource Consulting (“Mercers”)

Metering Inside the Settlement Timeframe (“MIST”)

Micro feed-in-tariff (“MicroFIT”)

Minister of Energy and Infrastructure issued a directive (the "Directive")

Ministry of Environment (“MOE”)

Ministry of Natural Resources (“MNR”)

Ministry of Natural Resources and Forestry (“MNRF”)

Ministry of Transportation (“MTO”)

Modified International Financial Reporting Standards (“MIFRS”)

Net Book Value (“NBV”)

Net-Present-Value (“NPV”)

Network Service Charges (“NW”)

North American Electric Reliability Corporation (“NERC”)

Occupational Health and Safety Act (“OHSA”)

Oil-Normal Air-Forced (“ONAF”)

Ontario Clean Energy Benefit (“OCEB”)

Ontario Electricity Support Program (“OESP”)

Ontario Energy Board (the “Board” or the “OEB”)

Ontario Energy Board Act, 1998 (the “OEB Act”)

Ontario Energy Board Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5, Consolidated Distribution System Plan Filing Requirements, March 28, 2013 (“Chapter 5”)

Ontario Municipal Employees Retirement System (“OMERS”)

Ontario Power Authority (“OPA”)

Operating Technology (“OT”)

Operations and Maintenance (“O&M”)

Operations, Maintenance and Administration (“OM&A”)

Other post-employment benefits (“OPEB”)

Outage Management System (“OMS”)

Payments in Lieu of Taxes (“PILS”)

Peak demand factor (“PDF”)

Peak Load Carrying Capability (“PLCC”)

Pension and other post-employment benefits (“P&OPEB”)

PILs and Tax Variance for 2006 and Subsequent Years (“PILS$_{\text{Post 2006}}$”)

Polychlorinated Biphenyls (“PCB”)

Port Colborne (“PC”)

Potential or Voltage Transformers (“PT”)

Power Take Off (“PTO”)

Present Value (“PV”)

Probably Remaining Life (“PRL”)

Professional Engineers Ontario Act (“PEO”)

Property, plant and equipment (“PP&E”)

Queen Elizabeth Way (“QEW”)

Ratio banks (“RB”)

Regional Infrastructure Planning (“RIP”)

Regulated Price Plan (“RPP”)

Renewable Energy Generation (“REG”)

Renewed Regulatory Framework For Electricity (“RRFE”)

Reporting and Record Keeping Requirements (“RRR”)

Request for Information (“RFI”)

Request for Proposals (“RFP”)

Request for Quotations (“RFQ”)

Retail Settlement Variance Account – Global Adjustment (“RSVA$_{\text{GA}}$”)

Retail Settlement Variance Account – One-time Wholesale Market Service (“RSVA$_{\text{One-Time}}$”)

Retail Settlement Variance Account – Power (“RSVA$_{\text{POWER}}$”)

Retail Settlement Variance Account – Retail Transmission Connection Charges (“RSVA$_{\text{CN}}$”)

Retail Settlement Variance Account – Retail Transmission Network Charges (“RSVA$_{\text{NW}}$”)

Retail Settlement Variance Account – Wholesale Market Service Charges (“RSVA$_{\text{WMS}}$”)

Retail Settlement Variance Account (“RSVA”)

Retail Transmission Service Rates (“RTSRs”)

Return on equity (“ROE”)

Revenue-to-cost (“R/C”)

Rights of Way (“ROW”)

Royal Bank of Canada (“RBC”)

Schweitzer Engineering Laboratories (“SEL”)

Short-term incentive (“STI”)

Single Line Diagram (“SLD”)

Smart Meter Entity (“SME”)

Square kilometers Square (“sq. km”)

Station (“ST”)

Supervisory Control and Data Acquisition (“SCADA”)

System Access (“SA”)

System Average Interruption Duration Index (“SAIDI”)

System Average Interruption Frequency Index (“SAIFI”)

System Control Centre (“SCC”)

System Renewal (“SR”)

System Service (“SS”)

Systems, Applications and Products (“SAP”)

Time-of-use (“TOU”)

Transformer Station (“TS”)

Transmission Asset Management Plan (“TAMP”)

Uninterruptible Power Supply (“UPS”)

Unmetered Scattered Load (“USL”)

Utilities Standard Forum (“USF”)

Utility billing and front office customer care and service (“IS-U/CCS”)

Validation, Editing and Estimated (“VEE”)

Virtual Private Network (“VPN”)

Weighted Average Cost of Capital (“WACC”)

Wholesale Market Service Charges (“WMS”)

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CONTACT INFORMATION

CNPI – contact information for matters related to this application is as follows:

(a) The Applicant:

Mr. Gregory Beharriell
Manager, Regulatory Affairs
Canadian Niagara Power Inc.

Mailing Address:	1130 Bertie Street P. O. Box 1218 Fort Erie, Ontario L2A 5Y2
Telephone:	(905) 871-0330 ext. 3279
Fax:	(905) 994-2207
Email:	regulatoryaffairs@fortisontario.com

Mr. R. Scott Hawkes
Vice President, Corporate Services and General Counsel
Canadian Niagara Power Inc.

Mailing Address:	1130 Bertie Street P. O. Box 1218 Fort Erie, Ontario L2A 5Y2
Telephone:	(905) 994-3642
Fax:	(905) 871-8676
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(b) The Applicant's Counsel:

Andrew Taylor
The Energy Boutique

Mailing Address:	120 Adelaide Street West Suite 2500 Toronto, Ontario M5H 1T1
Telephone:	(416) 644-1568
Fax:	(416) 367-1954
Email:	ataylor@energyboutique.ca

SOCIAL MEDIA CONTACT INFORMATION

Interested parties can also view the application on CNPI's website at www.cnpower.com or www.easternontariopower.com.

CNPI also uses Twitter and Facebook to communicate with its customers;

Twitter:

@CNPpower
@EOPpower

Facebook:

Canadian Niagara Power Inc.
Eastern Ontario Power

CUSTOMERS AND GROUPS AFFECTED BY PROPOSED CHANGES

The persons affected by this Application are the ratepayers of CNPI. It is impractical to set out their names and addresses because they are too numerous.

Recommendations to the Board regarding publication of the notice of hearing are provided in Exhibit 1, Tab 6, Schedule 6, with the objective of reaching as many of the affected parties as possible.

Interested parties can also view the Application on CNPI's website at www.cnpower.com

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STATEMENT OF PUBLICATION

For the Notice of Application related to customers residing in the Fort Erie area, CNPI recommends that it be published in the Fort Erie Times, a local newspaper with a circulation of approximately 12,000. The Fort Erie Times is a free publication, has the greatest readership in Fort Erie and is used by local government to publish public notices. CNPI submits that the Fort Erie Times will reach more of its customers in Fort Erie than any other available print media.

For the Notice of Application related to customers residing in the Gananoque area, CNPI recommends that it be published in the Gananoque Reporter, a local newspaper with a circulation of approximately 3,000. The Gananoque Reporter is a free publication, and has the greatest readership in Gananoque. CNPI submits that the Gananoque Reporter will reach more of its customers in Gananoque than any other available print media.

For the English version of the Notice of Application related to customers residing in the Port Colborne area, CNPI recommends that it be published in the Port Colborne Leader, a local newspaper with a circulation of approximately 11,000. The Port Colborne Leader is a free publication, and has the greatest readership in Port Colborne. CNPI submits that the Port Colborne Leader will reach more of its customers in Port Colborne than any other available print media.

For the French version of the Notice of Application related to customers residing in the Port Colborne area, CNPI recommends that it be published in *Le Régional* of Niagara, a Niagara Region French language newspaper with a circulation of 7,500 subscribers and French non-profit organizations. *Le Régional* of Niagara is a paid publication. CNPI submits that the *Le Régional* of Niagara will reach more of its French Language customers in Port Colborne than any other available print media.

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BILL IMPACTS FOR USE IN THE NOTICE OF APPLICATION

The following bill impacts, as per sub-total A of Appendix 2-W, are intended to be used in CNPI's Notice of Application. These bill impacts are for a typical residential consumer using 750 kWh per month and for a general service consumer using 2,000 kWh per month. The reduction from 800 kWh per month, as specified in the Filing Requirements, to 750 kWh per month, as specified in the table below is in accordance with the direction provided in the *Report of the Ontario Energy Board – Defining Ontario's Typical Electricity Customer*, issued April 14, 2016.

Rate Class	kWh	Distribution Excluding Pass Through (Sub-Total A from Appendix 2-W) - Fort Erie			
		2016 Bill	2017 Bill	$ Difference	% Difference
Residential	750	$ 34.84	$ 39.40	$ 4.56	13.09%
GS < 50 kW	2,000	$ 74.26	$ 88.02	$ 13.76	18.53%

In this Application, CNPI is applying to the Board to increase the amount it charges by approximately $4.56 (13.09%) each month for the typical residential customer consuming 750 kWh per month and by approximately $13.76 (18.53%) each month for the typical general service customer consuming 2,000 kWh per month beginning January 1, 2017.

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STATEMENT AS TO FORM OF HEARING REQUESTED

The Applicant requests that this Application be disposed of by way of a written hearing. It is the Applicant's view that this Application is of standard form, and a written hearing will expedite the proceeding to ensure rates may be implemented by January 1, 2017. Should a technical conference, settlement conference or an oral hearing be necessary, CNPI will provide a list of potential witnesses as required.

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LIST OF APPROVALS REQUESTED

Pursuant to section 78 of the *Ontario Energy Board Act, 1998,* CNPI is requesting in this Application approval of the specific matters listed below.

1. Approval of the Distribution System Plan as presented in Exhibit 2, Tab 2 of this Application.

2. Approval of a revenue requirement of $22,294,747 for the 2017 Test Year. CNPI acknowledges that the Board will publish an update to the prescribed Cost of Capital parameters and that these matters may affect the revenue requirement that CNPI has requested in this Application.

3. The establishment of a new Embedded Distributor rate class in relation to the service provided to Hydro One Networks Inc., as described in Exhibit 7, Tab 1, Schedule 2 of this Application.

4. Approval of CNPI's electricity distribution rates, effective January 1, 2017, designed to recover the base revenue requirement with transformer ownership credit add back, the low voltage rates, and the retail transmission service rates as presented in Exhibit 8 of this Application. CNPI acknowledges that changes to the Cost of Capital parameters and the Uniform Transmission Rates may impact the proposed Tariff of Rates and Charges presented in Exhibit 8, Tab 1, Schedule 9 of this Application.

5. Approval to continue to charge the Specific Service Charges, the Wholesale Market Service Rate, the Rural or Remote Electricity Rate Protection Charge, the Ontario Electricity Support Program Charge, the Standard Supply Service charge, and the Transformer Allowance approved in the OEB Decision and Order in the matter of CNPI's 2016 Distribution Rates (EB-2015-0058).

6. Approval of the distribution loss adjustment factors as presented in Exhibit 8, Tab 1, Schedule 8 of this Application.

7. Approval of the approach for rate mitigation in relation to the Residential rate class as presented in Exhibit 8, Tab 1, Schedule 12 of this Application.

8. Approval of CNPI's request to harmonize the existing distribution rate riders in its Fort Erie, Gananoque, and Port Colborne service territories, as presented in Exhibit 9, Tab 5, Schedule 1 of this Application.

9. Approval to dispose of the balances in certain deferral and variance accounts as presented in Exhibit 9, Tab 5, Schedule 1 of this Application.

10. Approval to dispose of the balances in the LRAM variance account, as presented in Exhibit 9, Tab 6, Schedule 1 of this Application.

11. Approval of a rate rider related to the disposition of cost related to implementation of the MIST Metering initiative as presented in Exhibit 9, Tab 3, Schedule 1 of this Application.

12. Approval to establish certain new deferral and variance accounts as presented in Exhibit 9, Tab 1, Schedule 1 of this Application.

13. Such other approvals that CNPI may request and that the OEB accepts.

Proposed Effective Date of Rate Order

1. The Applicant requests that the OEB make its Rate Order effective January 1, 2017 in accordance with the Filing Requirements.

2. In the event that the OEB is unable to provide a Decision and Order in this application for implementation by the Applicant as of January 1, 2017, the Applicant requests that the OEB declare its current rates interim, effective January 1, 2017, pending the implementation of the OEB's Rate Order for the 2017 rate year.

STATEMENT OF CERTIFICATION

As Vice President, Corporate Services and General Counsel of Canadian Niagara Power Inc., I certify that, to the best of my knowledge, the evidence filed in this Application is accurate, complete, and consistent with the Ontario Energy Board's Filing Requirements for Electricity Distribution Rate Applications – 2015 Edition for 2016 Rate Applications - issued on July 16, 2015.

R. Scott Hawkes
Vice President Corporate Services & General Counsel
Dated at Fort Erie, Ontario, this 29th day of April, 2016

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CHANGES TO METHODOLOGIES USED IN PREVIOUS APPLICATIONS

This Schedule summarizes changes to methodologies in the current application, as compared to CNPI's previous Cost of Service application (EB-2012-0112).

Changes to Allocation of Shared Assets

In CNPI's previous Cost of Service Application (EB-2012-0112), the removal of the portion of shared capital costs allocated to related companies outside of CNPI Distribution, was accounted for by removing the cost and accumulated depreciation within the Fixed Asset Continuity schedules ("FAC"). The FAC schedules provided in Exhibit 2, Tab 1, Schedule 2 of this Application show the removal of these shared costs for 2013, 2014 and 2015 Actuals. However, in accordance with Board staff's preference in API's previous Cost of Service Application (EB-2014-0055), a different approach was taken such that the amounts have not been removed for 2016 and 2017. In lieu of this, CNPI has included shared IT and equipment charges as revenue offsets within the RRWF for 2017. Shared services have been discussed further in Exhibit 4, Tab 5, Schedule 1.

Changes to Load Forecast Methodology

CNPI has presented a load forecast based on a Multivariate Regression Model in the current Application, whereas the load forecast presented in EB-2012-0112 was based on the Normalized Average Use per Customer Model. The current Application also includes the impact of forecasted CDM activities on the Test Year load forecast.

Establishment of an Embedded Distributor Class

In accordance with the Chapter 2 Filing Requirements updated on July 16, 2015, CNPI consulted with its single Embedded Distributor customer – Hydro One Networks Inc. ("HONI") with regards to CNPI's approach to allocation of costs. In reply to CNPI's proposal to continue as a GS 50 to 4999 kW customer, HONI requested that "a separate embedded distributor rate be developed that appropriately reflects the cost of serving Hydro One". CNPI therefore proposes to establish an Embedded Distributor Class in the current Application.

Cost Allocation

On June 12, 2015, the Board issued a letter outlining a new cost allocation policy for the Street Lighting rate class, and narrowing the revenue to cost ratio policy range for this class to 80%-120%. Subsequently, the Board issued version 3.3 of its Cost Allocation Model on July 16, 2015, incorporating this new cost allocation policy. CNPI has used version 3.3 of the Cost Allocation Model in preparing this Application, which includes significant changes to the methodology for allocation of costs to the Street Lighting class as compared to the methodology used in EB-2012-0112.

Residential Rate Design

On April 2, 2015, the OEB released its Board Policy: A New Distribution Rate Design for Residential Electricity Customers (EB-2014-0210), which stated that electricity distributors will transition to a fully fixed monthly distribution service charge for residential customers. This will be implemented over a period of four years, beginning in 2016. CNPI made the first of four annual adjustments as part of its 2016 IRM application (EB-2015-0058), and has proposed to make a second adjustment in the current application.

The resulting rate design methodology can be summarized as follows:

1. Start with the same rate design methodology used in EB-2012-0112.
2. Upon completion of Step 1, make a further adjustment to the fixed/variable split for the Residential class, in order to further the transition to a fully fixed monthly distribution charge for that class.
3. Evaluate resulting Residential bill impacts at the 10^{th} percentile of consumption and re-adjust the fixed/variable adjustment performed in Step 2 to limit the total bill impact to 10%.

EXISTING ONTARIO ENERGY BOARD DIRECTIVES

At the date of submittal, CNPI is not aware of any Board Directives from any previous Board Decisions and/or Orders that require addressing in this Application.

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REFERENCE TO CONDITIONS OF SERVICE

The current version of CNPI's Conditions of Service is publicly available for on-line viewing, printing and downloading from CNPI's website www.cnpower.com. There have been no changes to CNPI's Conditions of Service since its last cost of service application.

CNPI notes that it is currently in the process of updating its Conditions of Service, and hopes to complete this process by July 31st, 2016. At this time, CNPI expects that the following changes will be made:

1. Section 2.2 DISCONNECTION
   - Disconnection Notice revised
   - Disconnection Notice to a designated third party information added
   - Load Limiter Device information to be added.

2. Section 2.4.3 DEPOSITS
   - Residential deposit information to be updated.

3. Section 2.4.4 BILLING
   - Updating and additional information for Prorating Bills, Service Charges, Estimating Bills, and Billing Disputes.

4. Section 2.4.5 PAYMENTS
   - Updating and additional information for Payment Options, Payment Allocation, and Interest.

5. Section 3.2 GENERAL
   - Update of connection process for Distributed Generation to align with current version of Distribution System Code, incorporating Embedded Generation such as MicroFIT's and FIT's.

6. Section 3.3 GENERAL SERVICE (ABOVE 50 KW)
    - Add Section and pertinent information.

7. Section 3.4 GENERAL SERVICE (ABOVE 1000 KW)

- Add Section and pertinent information.

DESCRIPTION OF SERVICE AREA

General Introduction and System Overview

Section 3 of CNPI's Distribution System Asset Management Plan ("DAMP") provides a much more detailed description of CNPI's distribution systems. The following is a brief summary.

Canadian Niagara Power Inc. ("CNPI") is a Licensed Local Distribution Company ("LDC") in Ontario, and supplies electricity to over 25,200 customers in Town of Fort Erie ("FE") and City of Port Colborne ("PC") and over 3,600 customers in the Town of Gananoque and surrounding areas.

CNPI operates as Eastern Ontario Power ("EOP") for the portion of its service territory in and around Gananoque.

CNPI Service Territory

The following three figures indicate the service territories of CNPI. More detailed maps may be found in Appendix A of the DAMP. The first is an overview, and the next two show the two distinct operating areas:

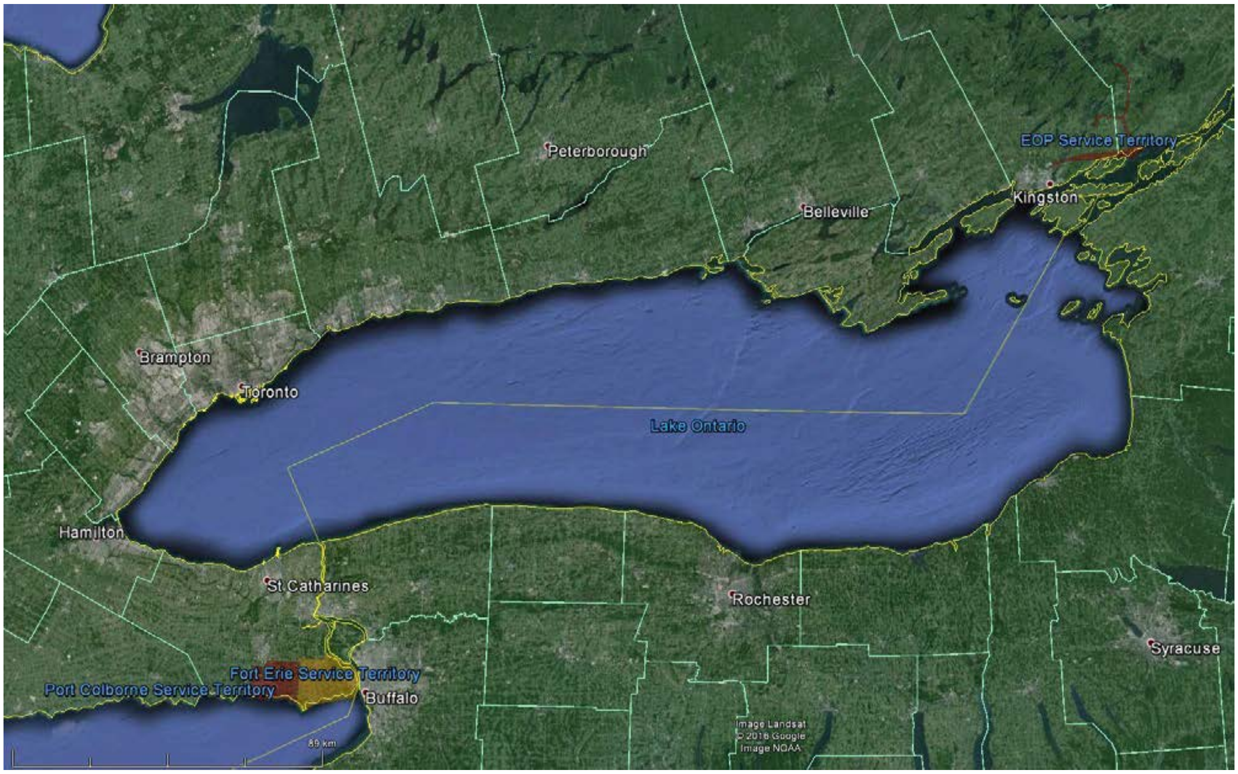

Figure 1: Overview of Service Territory for CNPI

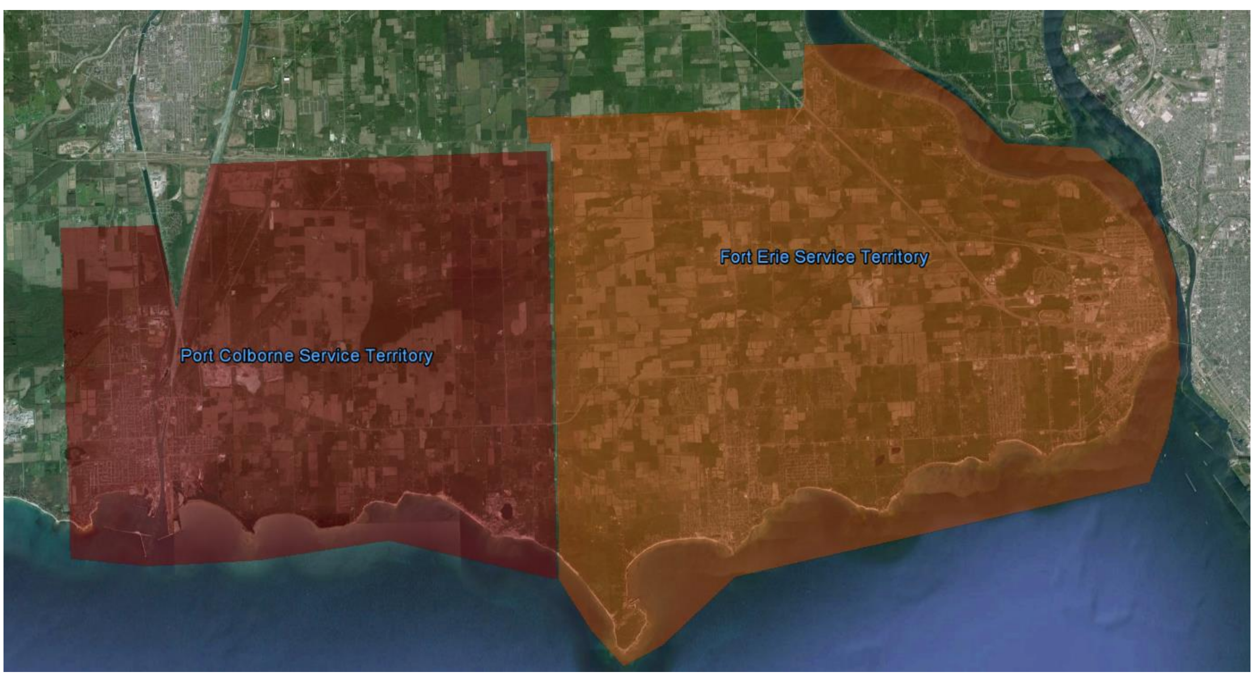

Figure 2: CNPI Service Territory in the Municipality of Fort Erie and Port Colborne

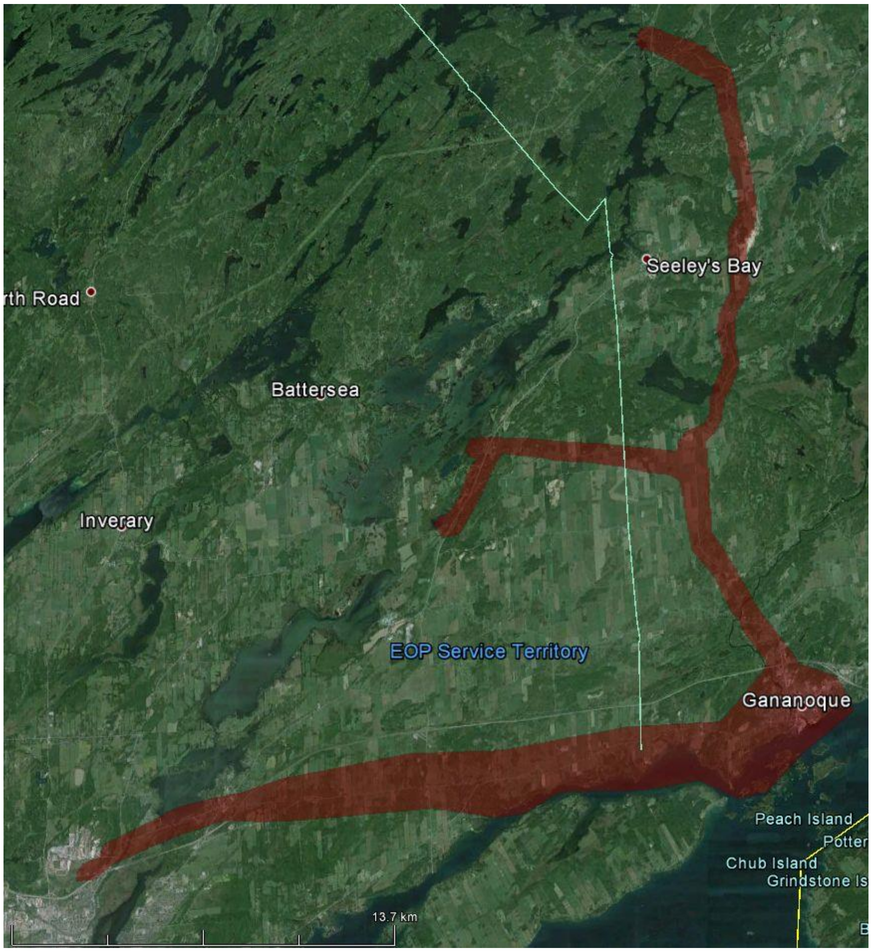

Figure 3: CNPI Service Territory for Gananoque (EOP)

Service Territory Features

Town of Fort Erie (FE)

The Town of Fort Erie is normally supplied by a single 115kV transmission line (Line 2) owned by CNPI Transmission. Line 2 originates from Murray Transmission Station ("TS") owned by Hydro One Network Inc. ("HONI"). In 2015, the total system load was approximately 35MW. Two transmission substations (Station 17 and Station 18) supply ten (10) 34.5kV (wye) distribution feeders (4 from Station 17 and 6 from Station 18). With the proper feeder switching arrangements, either TS can supply the entire load of Fort Erie. There are three (3) major lower distribution voltages: 4.16kV (wye), 4.8kV (delta), and 8.3kV (wye).

The major issues of the Fort Erie distribution system are aging assets and 4.8kV delta configuration.

City of Port Colborne (PC)

The majority of the City of Port Colborne load is supplied by a single 115kV transmission line (C2P) and the dual elements Port Colborne TS owned by HONI. In 2015, the total system load was approximately 37MW. The four (4) 27.6kV (wye) feeders originated from PC TS can back up each other via a number of intertie switching points and provide some operating flexibilities. A small portion of the load is supplied from a 27.6kV feeder originated from Crowland TS located in the City of Welland. 4.16kV is the lower voltage which serves the distribution load in much of the urban areas of Port Colborne.

The major issues of the Port Colborne distribution system is aging distribution substations and lines.

Gananoque and surrounding areas (EOP)

As an embedded distributor, EOP is supplied by a single 44 kV sub-transmission line (M8) originated from Frontenac substation owned by HONI. In 2015, the system peak load was approximately 12MW. The EOP owned Main Substation, transforms the 44 kV to a legacy 26.4kV (delta) voltage, which supplies only distribution substations, ratio banks, and a few customer owned substations for large industrial loads and embedded generating plants. There are few distributed loads connected to the 26.4kV system due to the delta configuration. Almost all distribution loads are connected to 4.16kV system.

The major issues of the EOP distribution system are aging assets and 26.4kV delta configuration.

Summary of Key Statistics

The following table summarizes some key statistics for the two operating areas that comprise CNPI as of December of 2015:

	Niagara Area Operating as CNPI	Gananoque Area Operating as EOP	Total
Customers			
Residential	22,836	3,144	25,980
General Service	2,276	419	2,695
Distribution Line Assets			
Poles, owned by CNPI	19,918	2,954	22,872
Distribution Transformers	5,282	886	6,168
Service Area (km^2)	292	65	357
Total Overhead Line (km)	775	172	947
Total Underground Line (km)	69	11	80
Ratio (step-down) banks	36	3	39
Distribution Substations	8	4	12
power transformers	14	6	20
circuit breakers	54	20	74
distribution feeders	43	17	60

Figure 4: Summary of Key Statistics

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DESCRIPTION OF HOST DISTRIBUTOR / EMBEDDED DISTRIBUTOR

CNPI is an electricity distributor licensed by the OEB (ED-2002-0572). It has two distinct operating territories; the Niagara service territory (comprised of the Fort Erie and Port Colborne service territories) and Eastern Ontario Power located primarily in the town of Gananoque.

In the Niagara Service territory, CNPI is supplied the majority of its load from three transmission delivery points. In the city of Port Colborne, supply is primarily provided at Hydro One Network's Port Colborne Transmission Station. A small proportion of CNPI's load associated with Port Colborne, less than one percent, is supplied from an embedded delivery point located on Hydro One Network's distribution system emanating from the Crowland Transmission Station.

In the town of Fort Erie, the entire supply is provided from two CNPI Transmission Stations, Station 17 and Station 18, both located in the town of Fort Erie. These two transmission stations are owned and operated by CNPI's transmission business.

In the Eastern Ontario Power service territory, CNPI is supplied entirely, as an embedded distributor, from Hydro One Network's sub-transmission (44 kV) system.

In total, CNPI receives approximately 88% of its supply from the IESO-controlled grid and 12% of its supply is through Hydro One Networks' distribution system.

In the Niagara service territory, CNPI is a host distributor to Hydro One Networks in the Wainfleet area. On an annual basis, CNPI provides approximately 5 GWh to the Hydro One Networks distribution system at an average demand of 1 MW. Historically, CNPI has billed Hydro One Networks as a general service customer. In September 2015, CNPI consulted Hydro One Networks to determine whether or not Hydro One Networks supported the current method of cost allocation and customer classification. Hydro One Networks has asked that a separate embedded distributor rate be developed that appropriately reflects the cost of serving Hydro One Networks. In this Application, CNPI is complying with Hydro One Networks' request.

TRANSMISSION ASSETS DEEMED TO BE DISTRIBUTION ASSETS

CNPI confirms that it does not have transmission assets, i.e. assets operating at greater than 50 kV, in its distribution system that had previously been deemed by the Board as distribution assets. Further, CNPI confirms that it is not seeking approval in this Application for any such assets.

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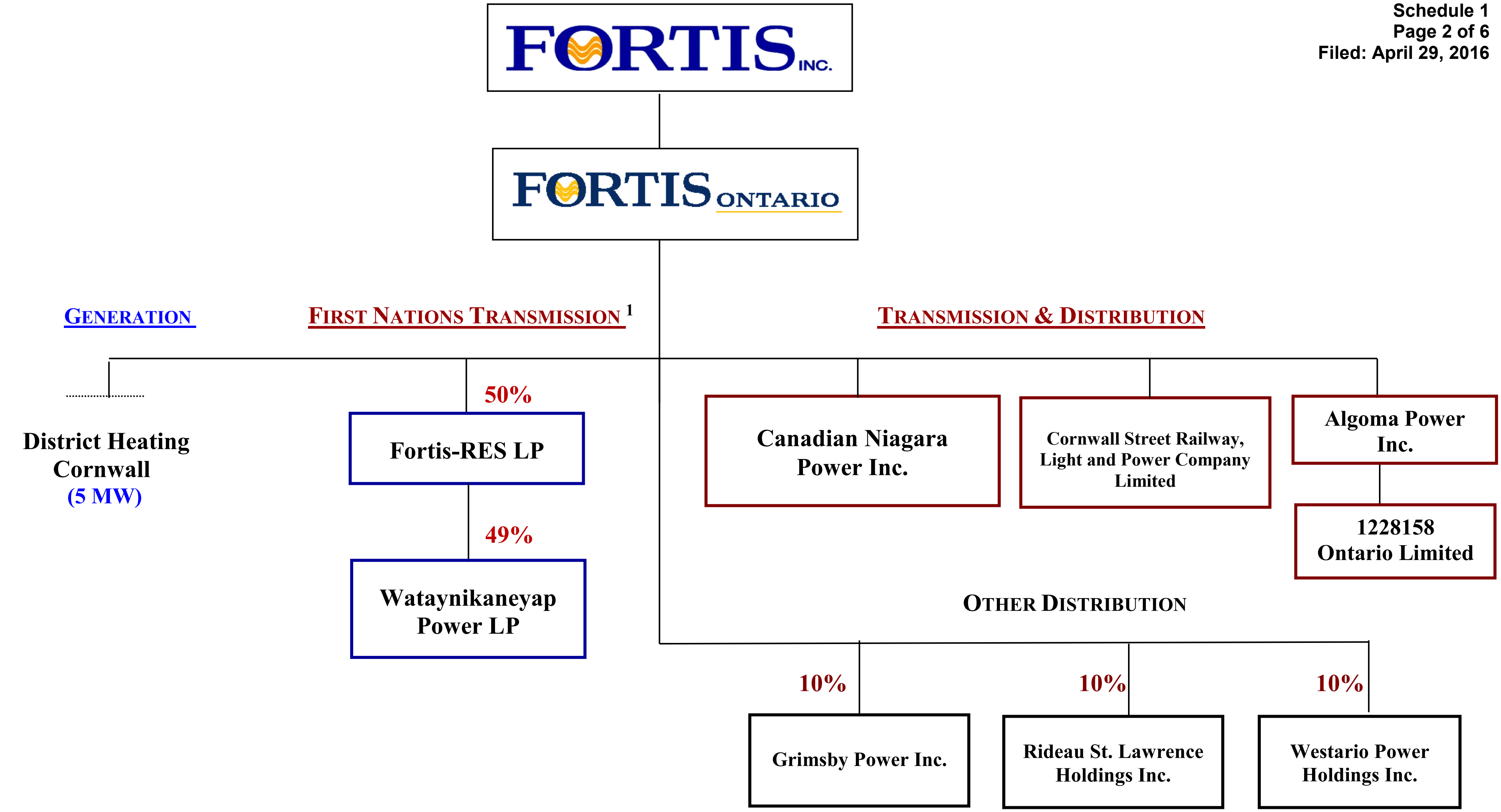
CORPORATE ENTITIES RELATIONSHIP CHART AND UTILITY ORGANIZATIONAL STRUCTURE

The following chart illustrates the corporate entities relationship of Canadian Niagara Power Inc. ("CNPI") (including the transmission and distribution businesses), its shareholder and its affiliates carrying on business in Ontario:



[1]FortisOntario also has a 50% interest in the Project Manager, Fortis-RES PM Inc., and Fortis-RES GP Inc., the General Partner of Fortis-RES LP

Organization of Entities

CNPI is a wholly-owned subsidiary of FortisOntario Inc. (“FortisOntario”), which is headquartered in Fort Erie, Ontario. CNPI is a single corporate entity which has two internal business units: a transmission business and a distribution business. FortisOntario owns and operates generation, transmission and distribution businesses in the province of Ontario. Founded in 1892, FortisOntario began generating electricity in 1905 from its Rankine Generating Station located on the Canadian side of the Niagara River and subsequently began distributing electricity to the Town of Fort Erie in 1907. The Rankine Generating Station ceased operations in 2005 and was transferred to the Niagara Parks Commission in 2009. Accordingly, FortisOntario’s operations in Ontario are primarily transmission and distribution.

FortisOntario is the Ontario-based subsidiary of Fortis Inc. ("Fortis"), which is the largest investor-owned gas and electric distribution utility in Canada. With 2015 total assets of approximately $29 billion and annual revenues of approximately $6.7 billion, Fortis serves more than 3 million gas and electricity consumers across Canada, the United States and the Caribbean. Fortis is a publicly traded company listed on the TSX.

FortisOntario also owns Algoma Power Inc. (“API”) (ED-2009-0072) which serves 12,103 customers, and Cornwall Street Railway Light and Power Company Limited (“Cornwall Electric”) (ED-2004-0405), which serves 24,367 customers. FortisOntario holds a ten percent (10%) interest in Westario Power Inc. (ED-2002-0515), a 22,937 customer electricity distributor located in mid-western Ontario, a ten percent (10%) interest in Rideau St. Lawrence Holdings Inc. (ED-2003-0003), a 5,893 customer electricity distributor located in southeastern Ontario, and a ten percent (10%) interest in Grimsby Power Inc. (ED-2002-0554), a 11,142 customer electricity distributor located in the Niagara region. Accordingly, Westario Power Inc., Rideau St. Lawrence Holdings Inc. and Grimsby Power Inc. are not affiliates of CNPI as defined by the *Ontario Energy Board Act, 1998*.

FortisOntario is a licenced generator (EG-2003-0107), which owns a 5 MW natural gas cogeneration district heating plant located in Cornwall, Ontario. The Cornwall district heating facility is an embedded generator selling district heating to local customers and electricity directly to Cornwall Electric, which is isolated from the IESO-controlled grid.

As noted above, CNPI serves the Fort Erie, Port Colborne and Gananoque service territories and is owned and operated by CNPI. The utility distribution business for the Cornwall service area is owned and operated by Cornwall Electric. The utility distribution business for the Algoma service area is owned and operated by Algoma Power Inc..

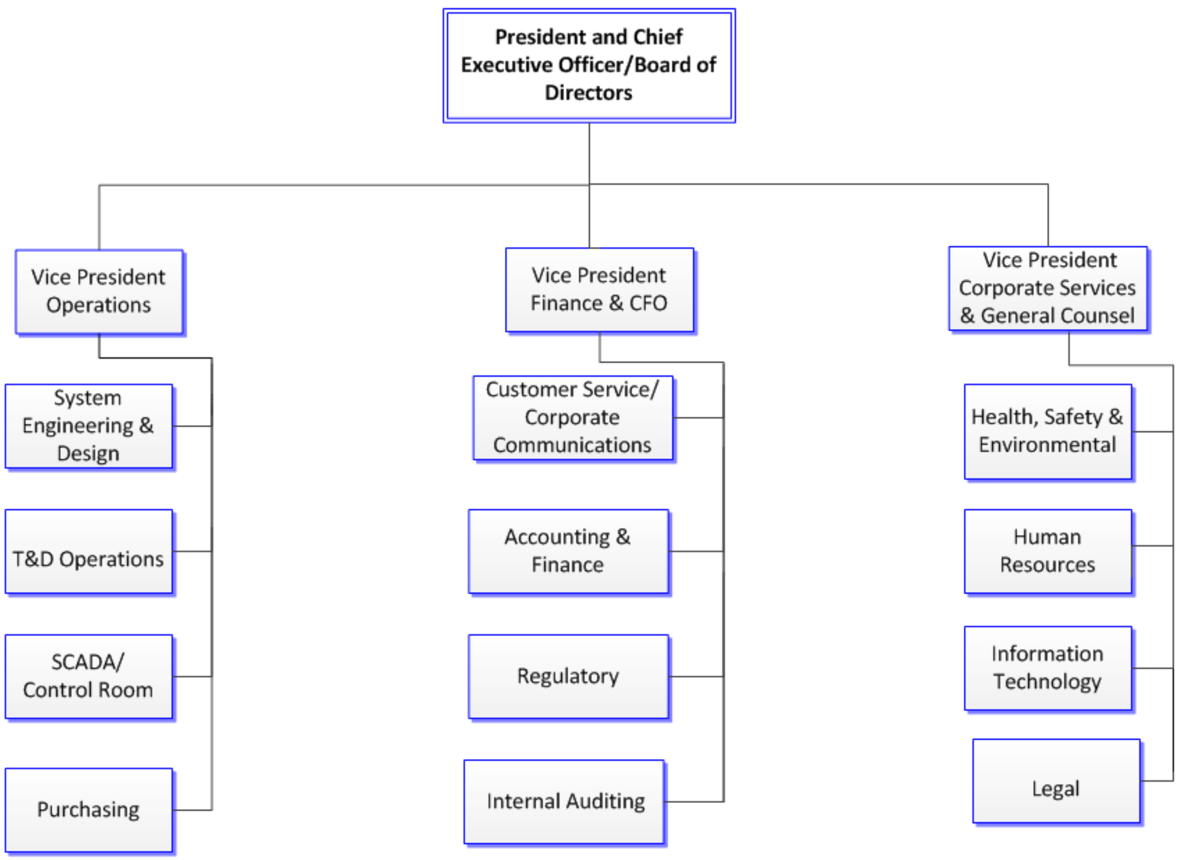
CNPI is also a licenced transmitter (ET-2003-0073).

FortisOntario is also a partner in the Wataynikaneyap Power LP transmission partnership (ET-2015-0264) with RES Canada, and 20 First Nations partners.

Utility Organizational Structure

The following chart illustrates the utility's organization structure showing main units and senior management positions with the utility:

FORTIS ONTARIO



Shared Corporate Services

Shared corporate services being provided to CNPI include the following:

- Executive Services
- Finance
- Information Technology
- Human Resources
- Health, Safety and Environment
- Regulatory
- Engineering

It is anticipated that shared corporate services will continue to be provided to CNPI from affiliates in the future.

OEB Licence Numbers

API has distribution licence (ED-2009-0072). CNPI has distribution licence (ED-2002-0572) and a transmission licence (ET-2003-0073). Cornwall Electric is also a licensed distributor (ED-2004-0405). FortisOntario has a generation licence (EG-2003-0107). Wataynikaneyap Power LP has a transmission licence (ET-2015-0264).

CORPORATE GOVERNANCE

CNPI has three (3) directors who serve on its board of directors. Two (2) of the CNPI directors are also officers of API, CNPI, FortisOntario and Cornwall Electric and one (1) director is independent. While there is no specific policy on the number of independent directors, the board follows a guideline of one third of the board members being independent. Please refer to Board of Directors' Mandate for a discussion on exercising independent judgement. Article of Incorporation indicates a minimum of 1 and a maximum of 10 directors.

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BOARD OF DIRECTORS' MANDATE

FortisOntario ensures a level of consistency in the governance function of its Ontario operating subsidiaries. The CNPI board does not have a written mandate. The role of the CNPI board is to supervise the management of the business and affairs of CNPI. In doing so, the directors are required to act honestly and in good faith with a view to the best interests of the corporation. Both in legal and practical terms, this means that the board must have regard to the interests of varying CNPI stakeholders, including shareholders, customers and creditors, as well as exercising independent judgement in determining the best interests of the Company. In a number of respects, FortisOntario provides key services relating to CNPI's operations and defines the strategic direction for CNPI. This ensures that the CNPI board has the resources it requires to ensure that its strategy, risk management and internal controls and processes are consistent.

In conjunction with these responsibilities, the directors of CNPI understand that they have a fiduciary duty to the Company.

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SCHEDULE OF MEETINGS

2016/2017 Meeting Schedule

YEAR	DATE
2016	2nd & 4th Quarter TBD
2017	2nd & 4th Quarter TBD

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CONTINUING EDUCATION

CNPI's non-independent directors are also executive officers and/or directors of CNPI, its affiliates and its parent company, FortisOntario. This ongoing active engagement on the boards and executive management of the parent and affiliates of CNPI ensures that these directors maintain the knowledge, skill, continuing education and experience necessary to meet their obligations as directors of CNPI. The non-independent directors and officers of CNPI are also involved in the selection of the independent board member of CNPI to ensure their independence, and level of skill and knowledge necessary to meet their obligations as directors. CNPI's current independent director is a President & CEO of another licensed distributor with expertise in the industry.

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CODE OF CONDUCT

The board of directors of CNPI has adopted a written Code of Conduct for the directors, officers and employees, which is attached as Appendix A (the "Code" or "Code of Conduct"). This Code of Conduct is the same code for FortisOntario and all of its operating subsidiaries. The monitoring of ethical business conduct of CNPI's employees, officers and directors is a governance function exercised primarily by CNPI's parent, FortisOntario.

The CNPI board monitors compliance with its Code by updates from executive management of CNPI (who act in a dual capacity as executive management of FortisOntario) on Code of Conduct violations. The board of CNPI has also adopted a Policy on Reporting Allegations of Suspected Improper Conduct and Wrongdoing to satisfy itself regarding compliance with the Code. In other words, allegations of Code of Conduct violations would be brought to the attention of the parent company; FortisOntario, and managed in accordance with its policies. Any reporting of a Code of Conduct violation involving CNPI would be brought to the attention of the CNPI board by management of CNPI and/or the management or board of FortisOntario.

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Appendix A
Code of Conduct

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FORTIS ONTARIO

CODE OF CONDUCT AND ETHICS POLICY

1.0 POLICY STATEMENT

FortisOntario Inc.'s ("FortisOntario" or the "Corporation") Code of Conduct and Ethics Policy (the "Code") is comprised of the core values and specific standards of conduct, designed to govern our business decisions and actions. The Code is an expression of fundamental values and represents a framework for decision-making. The integrity, reputation, and profitability of FortisOntario and its parent company, Fortis Inc. ("Fortis"), ultimately depend upon the individual actions of its employees. Each is personally responsible and accountable for compliance with the Code.

2.0 OBJECTIVE

2.1 The vision of FortisOntario is to be a leader in the Ontario utility industry and the leading service provider within our service areas.

2.2 In pursuing this vision, we are committed to the highest standards of ethical business practice and conduct. We make this commitment to our shareholders, employees, customers, partners, and to the communities we serve.

2.3 The objective of this policy is to meet the commitment embodied in paragraph 2.2 by conducting ourselves in accordance with the values and principles embodied in the Code.

3.0 APPLICATION

3.1 The Code applies to the employees, officers, directors, and to the extent feasible also to consultants, contractors and representatives of FortisOntario and each FortisOntario subsidiary (in each case, for purposes of the Code, an "**employee**"). For the purposes of the Code, "**FortisOntario**" or the "**Corporation**" refers to FortisOntario Inc. and, for those employees of a FortisOntario subsidiary, that subsidiary.

3.2 The Code describes the specific standards of ethical business practice and conduct expected of each of its employees in each territory in which FortisOntario does business. The Code must be interpreted within the context of FortisOntario policies and good common sense. Reasons such as "everyone does it", or "it's not illegal" are unacceptable reasons for violating the Code. All employees must be mindful of avoiding at all times, on and off the job, circumstances and actions that give the slightest appearance of an impropriety or wrongdoing, which could discredit FortisOntario. Should an employee have any doubt about the correct legal or ethical action in a given situation, such employee should seek guidance from their supervisor, a member of senior management or the Vice President, Corporate

Services, General Counsel and Corporate Secretary of FortisOntario (the **"General Counsel"**).

3.3 Any questions with respect to the Code should be directed to the General Counsel.

4.0 COMPLIANCE WITH LAWS AND STANDARD OF BUSINESS CONDUCT

4.1 Employees are required to conduct the business of FortisOntario in accordance with the applicable laws, rules and regulations of Ontario and Canada.

4.2 All relationships with customers, business partners, potential business partners, suppliers, competitors, government officials, regulators, the general public and other stakeholders must be honest, fair, courteous, respectful, conducted with integrity and with due regard for the protection of the interests involved.

4.3 Employees shall not, directly or indirectly, offer bribes or kickbacks, nor promise any other improper benefit for the purpose of influencing any customer, supplier, public official or any other person, nor will they, directly or indirectly, accept bribes, kickbacks or any other improper benefit which could influence or appear to influence them in the performance of their duties.

5.0 CORE VALUES

The Corporation has established six core values that all employees should strive to promote and comply with each working day. To be effective, these values must be understood, communicated, reinforced and integrated into all our daily activities. FortisOntario's six core values are the following:

- **Respect for People:** Treat others, as you would have others treat you. Honesty, integrity and ethics are never compromised.

- **Safety and the Environment:** Demonstrate a personal, unrelenting commitment to safety and environmental excellence. Protect yourself, your fellow employees, the public and the environment.

- **Financial Success:** Produce solid earnings, with dividends that meet the expectations of our shareholder. Grow the Corporation through acquisition and business development. Ensure that debt obligations are always met in a timely manner.

- **Customer Service:** Everyone has customers. Determine your customers' needs by listening. When you can meet these needs, do so; when you cannot, tell your customers you cannot – or tell them who can. When in doubt about how to treat a customer, do what you believe is right. When serving customers be pleasant, courteous and accurate; smile, act professionally and enjoy yourself. Attitudes are contagious.

- **Productivity:** Effective teamwork combined with employee innovation produces productivity gains. Employees are encouraged to pursue opportunities to implement new ideas and methods that enhance overall individual and team performance. Remember…..if you have a better way to do something; just do it.

- **Community Involvement:** Each of us has an obligation to support the communities that support our employer. This means time as much as money. Success is measured by the reaction of community leaders and by the opinions expressed by community residents.

6.0 CORPORATE PROPERTY

6.1 Every employee has a personal responsibility to protect the assets of the Corporation, including, without limitation, tangible assets, (such as equipment and facilities) and intangible assets (corporate opportunities, intellectual property, trade secrets and business information) from misuse or misappropriation. Subject to the provision of this Code, no employee shall obtain, use or divert FortisOntario property for personal use or benefit or use the Corporation's name or purchasing power to obtain personal benefits. All assets of FortisOntario must be used lawfully in furtherance of corporate objectives.

6.2 Company equipment utilized for personal use in accordance with this Code (including compliance with Section 17) is the sole responsibility of the employee that borrowed the equipment and any damage that may result is the responsibility of that employee.

6.3 Contracts to which FortisOntario is a party shall be in writing. Any "side" or "comfort" letters, which are not attachments to the main contract should not be accepted without the prior advice and approval of the General Counsel.

7.0 PROPRIETARY AND CONFIDENTIAL INFORMATION

7.1 Employees shall not disclose any confidential or proprietary information about the Corporation, or any person or organization with which the Corporation has a current or potential business relationship, to any person or entity, either during or after service with the Corporation, except (i) in furtherance of the business of FortisOntario, (ii) with the written authorization of a member of senior management or (iii) as may be required by law. Employees shall return all proprietary and confidential information in their possession forthwith upon the termination of their employment with FortisOntario.

7.2 Employees must disclose any invention, improvement, concept, trademark or design prepared or developed in connection with their employment with FortisOntario and FortisOntario is the exclusive owner of such property.

7.3 Employees shall comply with the Corporation's Privacy Policy and any applicable privacy policy established by FortisOntario.

8.0 INSIDER TRADING

8.1 "**Material Information**" is any information relating to the business and affairs of FortisOntario or Fortis that results in, or would reasonably be expected to result in, a significant change in the market price or value of any of Fortis' securities, and includes any information that a reasonable investor would consider important in making an investment decision.

8.2 It is a breach of securities laws and this Code for an employee in possession of Material Information to trade or tip others to trade in the securities of Fortis or its subsidiaries or those of any party to any undisclosed transaction to which a FortisOntario entity is a party.

8.3 Please refer to the *Fortis Inc. Insider Trading Policy* prior to trading in, or providing anyone else with information to trade in, the securities of Fortis Inc. Any questions regarding the *Fortis Inc. Insider Trading Policy*, what constitutes "Material Information" or insider trading generally should be directed to the General Counsel.

9.0 CONFLICTS OF INTEREST

9.1 Employees must not engage in any activity, which could give rise, or could be perceived to give rise to, a conflict between an employee's personal interests and the interests of FortisOntario. Outside interests must not adversely affect employee performance or objectivity at work. Employees are required to arrange their private affairs in a manner which prevents conflicts or the appearance of conflicts. If an employee believes they may have a conflict such interest should be discussed and direction sought from their Vice President or the General Counsel.

9.2 The remainder of this Section 9 is a non-exhaustive list of examples where a conflict of interest could arise.

Employee Interests and Activities

9.3 In the absence of express approval from a member of senior management, employees must not, either directly or indirectly (through families, friends or otherwise):

(1) place themselves in a position where any benefit or interest other than employment could be derived from a transaction with FortisOntario;

(2) contract with or render services to FortisOntario outside of their employment;

(3) participate in activities that compete with FortisOntario or that interfere or appear to interfere with their duties and responsibilities to FortisOntario;

(4) appropriate to themselves any business opportunity in which FortisOntario may be interested;

(5) convey Material Information to others or take Material Information for their own use or benefit; or have a financial or other interest in any entity doing business;

(6) have a financial or other interest in any entity doing business with FortisOntario (other than an interest of 1% or less in a publicly traded entity);

(7) engage in a consulting or employment relationship in any capacity with any person or entity with which the Corporation has a current or potential business relationship may give rise to a conflict of interest;

(8) engage in an outside activity or personal interest that hinders or distracts from the employee's job performance;

(9) use of Corporation's assets for other than Corporation approved activities or in violation of the Code (including Sections 5 and 17) of this policy;

(10) use an employee's position with FortisOntario to obtain personal favours or special consideration from organizations with which the Corporation conducts business or which wish to do business with the Corporation;

(11) engage in outside employment with a competitor of FortisOntario or its affiliates;

(12) conduct business with a vendor with whom an employee or an employee's family member has a substantial financial or management interest; or

(13) communicate any confidential or proprietary information about the Corporation to vendors or competitors.

9.4 Employees must consult with the President and Chief Executive Officer of FortisOntario (the "CEO") before agreeing to serve on the board of directors or similar body of a for profit seeking enterprise or government agency. Serving on a board of directors of a not-for-profit organization does not require prior approval, provided such appointment does not pose a conflict of interest with the Corporation in respect of contributions or supply of services.

10.0 EMPLOYEE RELATIONS, HEALTH, SAFETY, ENVIRONMENT AND HUMAN RIGHTS

10.1 FortisOntario is committed to ensuring its employees are treated fairly, compensated appropriately, and hired and promoted without discrimination by reason of race, nationality, ethnic origin, color, religion, age, gender, marital status, family status, sexual orientation, political belief or disability.

10.2 FortisOntario shall establish and maintain safe working conditions and conduct its operations in an environmentally responsible manner in accordance with applicable environmental laws, regulations and standards.

11.0 FITNESS FOR DUTY – ILLEGAL DRUGS & ALCOHOL

11.1 For the health and safety of all FortisOntario employees, the use of illegal drugs and the consumption of alcoholic beverages is strictly prohibited during working hours and at all times when on Corporate property.

11.2 Use of Illegal Drugs

(1) The use, sale, purchase or possession of illegal drugs while on the job or Corporate property is strictly prohibited.

(2) Employees may not report to work under the influence of illegal drugs.

(3) Employees are required to immediately notify their supervisor of any suspected instance of use, possession, or knowledge of someone under the influence of such substances on Corporate property.

(4) Off-the-job illegal use of drugs that adversely affects an employee's job performance, or jeopardizes the safety of other employees or Corporate equipment, is strictly prohibited.

(5) Prescribed medical treatment with a controlled substance should be reported to the employee's Manager or department head when an employee's ability to perform the job assignment in a safe manner is affected. It is critical for the Corporation to know such use is occurring, as a temporary job reassignment may be necessary.

11.3 Use of Alcohol

(1) No employee shall consume alcoholic beverages during working hours (regular or overtime) or during meal hours (noon, overtime or emergency call-out).

(2) No employee shall report to work under the influence of alcohol or possess alcoholic beverages on Corporate property.

(3) Employees are required to immediately notify their supervisor of any suspected instances of use or knowledge of someone being under the influence of alcohol on Corporate property.

(4) Assistance in handling drug or alcohol related issues are available through the Employee Assistance Program. Details of this program are available through Human Resources.

12.0 HARASSMENT-FREE WORKPLACE

12.1 FortisOntario is committed to providing a work environment that is free of harassment and supportive of the dignity, self-esteem and productivity of every employee. The Corporation will not tolerate any form of harassment of, or by, employees, customers, students, contractors, suppliers or other individuals associated with the Corporation while engaged in activities pertaining to the workplace.

12.2 According to the Human Rights Code, Harassment is defined as "engaging in a course of vexatious comment or conduct that is known or ought reasonably to be known to be unwelcome". It is a form of discrimination and can include behaviour such as demands, threats, gestures, innuendo, unwelcome remarks, jokes, slurs, display of offensive material, physical or sexual assault or taunting about a person's body, clothing, habits, customs or mannerisms. Harassment can also include inappropriate or unwelcome comments regarding a person's physical characteristics and/or mental health.

12.3 The Corporation has a legal obligation to use reasonable efforts to ensure the safety and well-being of all employees; therefore, depending on the nature and gravity of an incident, the Corporation reserves the right to conduct an investigation regardless of whether or not a formal complaint has been filed.

12.4 It is the responsibility of any employee experiencing or aware of any type of harassment within the Corporation to report the situation to his/her supervisor or the Human Resources Department. The Corporation has developed a more comprehensive policy addressing the details surrounding this issue; please refer to A-110 Harassment-Free Workplace.

13.0 OUTSIDE EMPLOYMENT AND VOLUNTEERING

13.1 FortisOntario recognizes the right of its employees to privacy and to make use of personal time outside of working hours as they see fit. However, outside employment opportunities should be carefully considered to ensure the employee's ability to perform their responsibilities at FortisOntario is not adversely affected. Outside employment and volunteering that poses a conflict of interest pursuant to Section 9.0 is prohibited. Employees may engage in outside employment that complies with the following:

(1) All outside employment and associated activities must be kept separate from the FortisOntario employees' responsibilities.

(2) Employees are prohibited from using time, tools, equipment, materials, personnel or information obtained through the Corporation for outside activities.

(3) Where the possibility of a conflict of interest exists, an employee should discuss these activities with their supervisor prior to engaging in such activities.

(4) The outside employment should not embarrass or discredit the Corporation or its affiliates.

(5) The outside employment must not impact the Corporation's competitive position.

(6) Soliciting FortisOntario customers for outside employment is strictly prohibited.

(7) On Corporate time, employees are not permitted to engage in any inquiry or request by a customer for the employee's "off-duty" services.

(8) Employees are not permitted to recommend or refer customers of the Corporation to other businesses, including those operated by themselves or other FortisOntario employees. When leads for services being offered are not in conflict with services offered by FortisOntario and are obtained through means that are unrelated to an employee's FortisOntario duties, FortisOntario may consider these acceptable.

14.0 PARTICIPATION IN COMMUNITY ACTIVITIES ON OR OFF CORPORATE TIME

14.1 FortisOntario strongly encourages individuals to participate in community activities that promote the general welfare of the community in which we work. Employees who participate in such activities on or off Corporate time must recognize that they are representatives of FortisOntario and should act accordingly.

14.2 While FortisOntario encourages community contribution and charitable service, the contribution of Corporate time or resources for such activities should only be provided with the approval of senior management.

15.0 PROPRIETARY AND CONFIDENTIAL INFORMATION

15.1 Employees shall not disclose any confidential or proprietary information about the Corporation, or any person or organization with which the Corporation has a current or potential business relationship, to any person or entity, either during or after service with the Corporation, except (i) in furtherance of the business of FortisOntario, (ii) with the written authorization of a member of senior management or (iii) as may be required by law. Employees shall return all proprietary and confidential information in their possession forthwith upon the termination of their employment with FortisOntario.

15.2 Employees must disclose any invention, improvement, concept, trademark or design prepared or developed in connection with their employment with FortisOntario and FortisOntario is the exclusive owner of such property.

15.3 Employees shall comply with the Corporation's Privacy Policy and any applicable privacy policy established by a FortisOntario subsidiary.

16.0 SOLICITATION ON CORPORATE PROPERTY

16.1 FortisOntario employees must provide their dedication during the performance of job responsibilities to ensure the fulfillment of the goals and objectives of the Corporation.

(1) Employees must refrain from any activity directed toward private gain during working hours.*

(2) Collection of gifts for fellow employees and Corporation supported solicitations, for sale of merchandise raffle tickets, club memberships or organizations are permitted provided the time does not interfere significantly with the productivity of employees and the activity has been approved by a senior officer of the Corporation.

* Normal working hours does not include unpaid break periods.

17.0 PERSONAL USE OF CORPORATE EQUIPMENT AND SMALL TOOLS

17.1 FortisOntario's resources should be used for the benefit of the Corporation. Employees will be allowed personal use of office equipment and small tools provided:

(1) Advance approval by a Manager or department head is obtained.

(2) The item is portable.

(3) The item is non-consumable.

(4) The cost to FortisOntario is negligible.

- Only authorized personnel, in specific arrangements with senior management, are allowed personal use of Corporate vehicles.
- FortisOntario's resources must not be used for personal financial gain.
- Use of Corporate resources for community or charitable activities must be approved in advance by a Manager or department head.
-

18.0 COMMUNICATION DEVICES

18.1 The Corporation's communication resources (phone systems, computers, faxes and mobile devices):

(1) are to be used for business purposes, with incidental personal use permitted provided such use does not negatively impact productivity, compromise system capacity or contravene applicable law or any FortisOntario policy; and

(2) are not to be used for improper or illegal activities such as the communication of defamatory, pornographic, obscene or demeaning material, hate literature, inappropriate blogging, gambling, copyright infringement, harassment or obtaining illegal software or files.

18.2 The Corporation's communication resources are owned by FortisOntario and are monitored and audited for improper usage, security purposes and network management.

18.3 When using these resources to transmit or receive confidential, sensitive or proprietary information, appropriate security precautions should be taken.

19.0 REPORTING OF FINANCIAL TRANSACTIONS

19.1 Compliance with generally accepted accounting principles and internal controls is expected at all times and all FortisOntario books of account, records and other documents must accurately account for and report all assets, liabilities and transactions. For example, no employee shall:

(1) cause the FortisOntario books or records to be incorrect or misleading in any way;

(2) participate in creating a record intended to conceal any improper transaction;

(3) delay the prompt or correct recording of disbursements of funds;

(4) hinder or fail to cooperate to ensure full disclosure with internal or external auditors, the Chief Financial Officer or other officers of FortisOntario to ensure that all issues relating to internal and external audit reports are resolved;

(5) conceal knowledge of any untruthful, misleading or inaccurate statement or record, whether intentionally or unintentionally made; or

(6) conceal or fail to bring to the attention of appropriate supervisors transactions that do not seem to serve a legitimate commercial purpose.

19.2 Any inquiry that an employee receives from financial analysts and others associated with the financial and investment communities shall be directed to the Chief Financial Officer.

19.3 Employees must report any violation of this Code, including any potential or suspected violations of accounting standards or securities laws and regulations in accordance with the Corporation's *Policy on Reporting Allegations of Suspected*

Improper Conduct and Wrongdoing. Employees are protected from any form of punishment when they report concerns honestly.

20.0 POLITICAL CONTRIBUTIONS

20.1 No funds or assets of FortisOntario shall be contributed to any political party or organization, or any candidate for public office, except where such contribution is permitted by applicable law and authorized by senior management or the Board, in accordance with Corporation's *Political Contributions Policy*.

20.2 No employee shall, directly or indirectly, exert influence on another employee to support any political cause, party or candidate. Any attempt at such exertion of influence must be reported.

21.0 PAYMENTS TO AGENTS, CONSULTANTS AND GOVERNMENT OFFICIALS

21.1 All commissions, fees or other payments to agents or consultants acting on behalf of FortisOntario shall be made in accordance with sound business practices and be reflective of the reasonable value of the services performed.

21.2 No payments, gifts or favours may be made to any person in a position of trust or responsibility with the intent to induce them to violate their duties or to obtain favourable treatment for FortisOntario or any of its employees.

21.3 Except as specifically permitted by law, payments, gifts of substantial value or lavish entertainment provided to government officials or personnel are prohibited.

21.4 Neither FortisOntario nor its employees shall knowingly aid or abet any person or entity to circumvent laws, evade income taxes or defraud the interests of FortisOntario shareholders or creditors.

22.0 GIFTS, PAYMENTS AND ENTERTAINMENT

22.1 No gift or benefit of any kind shall be given or received by any employee conducting business on behalf of FortisOntario where it might be perceived that an obligation is created or a favour expected of the recipient. The giving of gifts or promotional items of modest value in the context of appropriate business conduct is permissible.

22.2 Receipt of excessive entertainment is prohibited, however it is permitted to accept hospitality or entertainment, provided it is reasonably within the limits of responsible and generally accepted business practice.

22.3 In circumstances where doubt arises as to the propriety of accepting a gift, direction from senior management should be sought as to the gift's acceptance and disposition.

23.0 COMPETITION AND ANTI-TRUST LEGISLATION

23.1 FortisOntario and its employees must comply with all Canadian and other applicable foreign competition and antitrust legislation. Behavior which is prohibited under such legislation includes activities such as agreements with competitors to allocate markets or customers, price fixing or agreements to control prices, the boycotting of certain suppliers or customers, bid-rigging, misleading advertising, price discrimination, predatory pricing, price maintenance, refusal to deal, exclusive dealing, tied selling, delivered pricing and the abuse of dominant position.

23.2 Should an employee face a situation which may constitute a breach of such legislation or creates any doubt about the correct legal or ethical action, such employee should seek guidance from their supervisor, senior management or General Counsel.

24.0 COMPLIANCE AND ENFORCEMENT

Compliance

24.1 Strict adherence to this Code and all other FortisOntario policies applicable to employees is mandatory. Failure to comply may result in disciplinary action up to and including termination. In interpreting this Code, the spirit as well as the literal meaning, of the language shall be observed. Employees should seek guidance from senior management if they have any questions regarding the interpretation or application of this Code.

Reporting Violations and Non-Retaliation

24.2 Any violations of this Code or other FortisOntario policies shall be reported promptly and in accordance with the *Policy on Reporting Allegations of Suspected Improper Conduct and Wrongdoing*. Reports, discussions or inquiries will be kept in strict confidence to the extent appropriate or permitted by policy or law. Requests to remain anonymous will be respected in accordance with applicable laws. No retaliatory action will be taken against an employee or contractor for providing good faith information, either internally or to a government authority, or for participating in any proceeding concerning alleged violations of any laws or policies. Disciplinary measures may be taken against an employee or contractor if they participated in prohibited activity, even if they reported it. In accordance with such policies, Fortis has retained the services of EthicsPoint, a third-party provider of confidential, anonymous reporting services, accessible by telephone at 1-866-294-5534 or through the internet at www.FortisInc.ethicspoint.com.

Waiver and Amendment

24.3 Waivers of this Code may be granted from time to time in limited circumstances where the Person seeking waiver makes written application to the CEO. Any such waivers will be disclosed to the Board of Directors of the Corporation in accordance with applicable laws, rules and regulations.

24.4 FortisOntario may, in its sole discretion and without prior notice, amend or modify any provisions of this Code.

25.0 EFFECTIVE DATE

25.1 This Code is dated and effective as ofNovember 6 2015.

26.0 CODE REVIEW

26.0 This Code shall be reviewed periodically.

SELECTION OF NEW CANDIDATES

Members of the FortisOntario executive team serve as non-independent directors of CNPI. The non-independent directors and officers of CNPI identify and select the independent board member, which is subject to parent company, FortisOntario approval.

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BOARD COMMITTIEES

There are no committees of the CNPI board.

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LETTERS OF COMMENT AND CNPI RESPONSES

No letters of comment have been filed with the Board during the course of this proceeding.

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OVERVIEW OF 2014 SCORECARD

On October 18, 2012, the Board released its “Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach” (the “RRFE Report”). The RRFE framework is a comprehensive performance-based approach to regulation that is based on the achievement of outcomes that ensure that Ontario’s electricity system provides value for money for customers. The Board emphasizes outcomes rather than activities, to better respond to customer preferences, to enhance distributor productivity and to promote innovation.

The RRFE focuses on the following four outcomes:

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; and savings from operational effectiveness are sustainable.

CNPI reports on the results of specific Performance Categories related to each of the four outcomes listed above. On an annual basis, the OEB publishes a summary Scorecard for all distributors, including CNPI. These scorecards provide a five-year summary of results and trends for each Performance Category, as well as comparisons to Industry and Distributor targets where appropriate. CNPI’s 2014 Scorecard is included as Appendix A to this Schedule. The Management Discussion and Analysis (“2014 Scorecard MD&A”) is included with the attached Scorecard, and provides further insight into CNPI’s performance and trending for each category.

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Appendix A
2014 Scorecard and MD&A

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Scorecard - Canadian Niagara Power Inc.

9/28/2015

Performance Outcomes	Performance Categories	Measures		2010	2011	2012	2013	2014	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		94.70%	97.70%	95.70%	93.10%	96.00%	↓	90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	100.00%	100.00%	100.00%	→	90.00%	
		Telephone Calls Answered On Time		85.10%	83.40%	84.60%	82.60%	78.20%	↓	65.00%	
	Customer Satisfaction	First Contact Resolution						99.9%			
		Billing Accuracy						99.92%	→	98.00%	
		Customer Satisfaction Survey Results					80.84%	79.59%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public awareness [measure to be determined]									
		Level of Compliance with Ontario Regulation 22/04		NI	C	C	C	C	→		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	1	→		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.978	→		0.137
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted		0.90	1.82	1.89	3.22	1.95	↑		at least within 0.90 - 3.22
		Average Number of Times that Power to a Customer is Interrupted		1.27	1.63	2.21	2.72	2.07	↑		at least within 1.27 - 2.72
	Asset Management	Distribution System Plan Implementation Progress						Completed			
	Cost Control	Efficiency Assessment				4	4	4			
		Total Cost per Customer [1]		$715	$727	$679	$726	$749			
		Total Cost per Km of Line [1]		$19,893	$20,204	$18,790	$20,275	$21,202			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Annual Peak Demand Savings (Percent of target achieved) [2]			8.06%	14.05%	37.28%	54.56%	●		4.07MW
		Net Cumulative Energy Savings (Percent of target achieved)			30.41%	46.13%	64.52%	82.55%	●		15.81GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time					0.00%				
		New Micro-embedded Generation Facilities Connected On Time					97.78%	95.65%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.77	0.65	0.33	0.34	0.33			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		2.68	2.97	2.53	2.30	2.02			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)		8.01%	8.01%	8.93%	8.93%			
			Achieved		7.21%	9.42%	6.71%	8.31%			

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 include any persisting peak demand savings from the previous years.

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

Appendix A – 2014 Scorecard Management Discussion and Analysis ("2014 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2014 Scorecard MD&A:
http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

In 2014, CNPI met or exceeded 83% of all performance targets.

In 2015, CNPI expects to continue to improve its overall scorecard performance results as compared to previous years. These performance improvements are expected as a result of enhanced system reliability due to CNPI's investment in its distribution system and continued responsiveness to customer feedback.

Service Quality

- **New Residential/Small Business Services Connected on Time**

In 2014, CNPI connected 96% of the 150 new eligible low-voltage residential and small business customers within the Ontario Energy Board's prescribed five day timeline. Since 2010, CNPI has consistently met the Ontario Energy Board's target and continues to trend upwards.

- **Scheduled Appointments Met On Time**

CNPI continues to exceed the Ontario Energy Board standard of meeting customers as requested within the prescribed timelines set out by the Ontario Energy Board.

- **Telephone Calls Answered On Time**

In 2014, customer service representatives answered 78.20% of its 42,361 calls within 30 seconds. This exceeds the Ontario Energy Board's mandated 65% target. 2014 results are slightly lower than previous years. CNPI continues to offer and promote self-serve options and utilizes social media to engage and inform customers in an effort to offer customers additional channels to interact with the Company.

Customer Satisfaction

- **First Contact Resolution**

CNPI measured First Contact Resolution by tracking the number of escalated calls as a percentage of total calls taken by the customer contact center from July 1, 2014 to December 31, 2014. For this period, less than one percent of calls were escalated.

- **Billing Accuracy**

For the period from October 1, 2014 – December 31, 2014, CNPI issued approximately than 87,000 invoices and 99.9% were accurate. This is above the industry standard of 98%.

- **Customer Satisfaction Survey Results**

CNPI utilizes a third party to conduct a telephone survey for its residential customers. The survey includes questions regarding the quality of service, safety, billing, customer communications and information on the industry. The results cited on the scorecard represent customers who indicated that they were 'completely' and 'mostly' satisfied with the overall quality of service. To date, CNPI has not included responses of being 'somewhat' satisfied in the scorecard result. 2014 results were slightly lower than 2013 which is consistent with lower 2014 industry results. This reduction may be attributable to well published events in the industry as a whole, such as the Ombudsman's report on electricity billing and the increasing cost of energy. However, within the survey, customers continue to rate CNPI very high for the safe and reliable delivery of service and providing timely and accurate bills at 90% and 91%, respectively.

The survey provides useful information to better meet the needs of CNPI's customers and is incorporated into the distribution system plan, capital planning and overall company objectives.

Safety

- **Public Safety**
  - **Component A – Public Awareness of Electrical Safety**

CNPI has a number of internal initiatives to communicate Public Awareness of Electrical Safety to our customers. Additionally, CNPI partners with ESA in promoting ESA provincial wide public safety campaigns.

  - **Component B – Compliance with Ontario Regulation 22/04**

This component includes the results of an Annual Audit, Declaration of Compliance, Due Diligence Inspections, Public Safety Concerns and Compliance Investigations. All the elements are evaluated as a whole and determine the status of compliance (Non-Compliant, Needs Improvement, or Compliant).

Results provided by ESA, CNPI's status for 2014 is Compliant.

  - **Component C – Serious Electrical Incident Index**

"Serious electrical incidents", as defined by Regulation 22/04, make up Component C. The metric details the number of and rate of "serious electrical incidents" occurring on a distributor's assets and is normalized per 10, 100 or 1,000 km of line (10km for total lines under 100km, 1000km for total lines over 1000km, and 100km for all the others).

Results provided by ESA, CNPI had one incident in 2014.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**

CNPI's customers experienced a decrease in the average duration of electrical service disruptions in 2014 over the previous year. CNPI continues to invest in grid modernization in order to gain visibility on the state of the distribution system and improve overall response and restoration times. Grid modernization initiatives include the deployment of automated devices and implementation of an outage management system. CNPI understands that reliability of electrical service is a high priority for its customers and continues to invest in replacement of end-of-life assets as well as vegetation management.

- **Average Number of Times that Power to a Customer is Interrupted**

CNPI's customers have experienced a reduction in the average number of electrical service disruptions in 2014 over the previous year. CNPI has deployed several initiatives aimed at reducing the number of electrical service interruptions such as the vegetation management program and cyclical asset preventative maintenance programs.

CNPI reviews outage statistics on a monthly basis to identify areas of poor distribution system performance. This process indicates any trends in poor performance and identifies opportunities to improve reliability. CNPI has also completed an asset condition assessment to identify assets that present a risk of impacting system reliability. CNPI uses reliability indicators and asset condition assessment data as key drivers into the system planning process.

Asset Management

- **Distribution System Plan Implementation Progress**

CNPI currently follows an internally developed five year capital planning process for expenditures on the distribution system. CNPI is in the process of aligning its internally developed process with the requirements outlined in the Chapter 5 Consolidated Distribution System Plan Filing guideline, including the Distribution System Plan. CNPI will be filing a formal Distribution System Plan in accordance with Chapter 5 in 2016 as part of evidence for its next cost of service application.

Cost Control

- **Efficiency Assessment**

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC on behalf of the Ontario Energy Board to produce a single efficiency ranking. The electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs. The model developed by Pacific Economics Group to predict a distributor's costs relies on a data set that includes all distributors in Ontario. For 2014, CNPI was placed in Group 4 indicating that actual costs are within +/- 25% of predicted costs.

However, CNPI uses industry-standard budgeting and accounting practices to predict and track its costs. The actual costs incurred each year by CNPI to deliver all of its programs generally compare favorably to the costs predicted by these practices. For 2014, these actual costs were within 5% of predicted (budgeted) costs. CNPI believes that this variance is minimal and indicative of sound performance from its distribution system planning process. CNPI's forward looking goal is that this efficiency performance will not decline in future years.

- **Total Cost per Customer**

Total cost is calculated as the sum of CNPI's OM&A costs, including depreciation and financing costs. This amount is then divided by the total number of customers that CNPI serves to determine Total Cost per Customer. The cost performance result for 2014 is $749 /customer which is a 3.2% increase over 2013. However, CNPI's Total Cost per Customer has increased on average by only 1.3% per annum over the period 2010 through 2014. This compares favorably with the Consumers Price Index (CPI) over the same period.

Historical cost measures are reflective of the fact that 80% of CNPI's service territory is located in rural areas, subject to more severe weather due to its location on the shore of Lake Erie (Lake Ontario for Eastern Ontario Power's service territory) with its prevailing winds and lake effect precipitation, and the operation and maintenance of several distribution substations. CNPI performs a comprehensive series of programs to meet all legal and regulatory requirements, with special emphasis on public safety, optimizing reliability, meeting customers' needs, and general cost control.

CNPI will continue to replace distribution assets proactively along a carefully managed timeframe in a manner that balances system risks and customer rate impacts. CNPI will continue to seek and implement productivity and system reliability improvement initiatives to help offset some of the costs associated with future system enhancements. Customer engagement initiatives will continue in order to ensure customers have an opportunity to share their viewpoint on CNPI's capital spending plans.

- **Total Cost per Km of Line**

This measure uses the same total cost that is used in the Cost per Customer calculation above. The total cost is divided by the total kilometers of line that CNPI operates to serve its customers. CNPI's 2014 rate is $21,202 per km of line, a 4.6% increase over 2013. However, CNPI's Total Cost per Customer has increased on average by only 1.8% per annum over the period 2010 through 2014. This compares favorably with the CPI over the same period.

As outlined on Total Cost per Customer above, historical cost measures are reflective of the fact that 80% of CNPI's service territory is located in rural areas, subject to more severe weather due to its location on the shore of Lake Erie (Lake Ontario for Eastern Ontario Power's service territory) with its prevailing winds and lake effect precipitation, and the operation and maintenance of several distribution substations. . CNPI performs a comprehensive series of programs to meet all legal and regulatory requirements, with special emphasis on public safety, optimizing reliability, meeting customers' needs, and general cost control.

As outlined on Total Cost per Customer above, CNPI will continue to replace distribution assets proactively along a carefully managed timeframe in a manner that balances system risks and customer rate impacts. CNPI will continue to seek and implement productivity and system reliability improvement initiatives to help offset some of the costs associated with future system enhancements. Customer engagement initiatives will continue in order to ensure customers have an opportunity to share their viewpoint on CNPI's capital spending plans.

Conservation & Demand Management

- **Net Annual Peak Demand Savings (Percent of target achieved)**

On the basis of the IESO's "2011 – 2014 Final Results Report" issued on September 1, 2015, CNPI achieved 54.6% of its Net Annual Peak Demand Savings. CNPI fully leveraged the suite of Independent Electricity System Operator ("IESO") province-wide demand management programs and placed emphasis on supporting the conservation efforts of large commercial, industrial and institutional customers.

CNPI had been challenged in its efforts to meet the assigned target due to a significant reduction in customer demand and energy consumption, in 2011, which has continued into 2014 with a decline in customer demand coupled with customer closures. This resulted in significant adverse economic impacts affecting the entire service territory. Due to these negative economic impacts, a lack of growth and decline in the larger customer base, the CNPI service territories have seen a dramatic overall decline in energy throughput and system

demand since 2008; the year that was used as the base year to set the mandated targets.

- **Net Cumulative Energy Savings (Percent of target achieved)**

On the basis of the IESO's "2011 – 2014 Final Results Report" issued on September 1, 2015, CNPI achieved 82.6% of its Net Energy Savings. CNPI fully leveraged the suite of Independent Electricity System Operator ("IESO") province-wide demand management programs and placed emphasis on supporting the conservation efforts of large commercial, industrial and institutional customers.

CNPI had been challenged in its efforts to meet the assigned target due to a significant reduction in customer demand and energy consumption, in 2011, which has continued into 2014 with a decline in customer demand coupled with customer closures. This resulted in significant adverse economic impacts affecting the entire service territory. Due to these negative economic impacts, a lack of growth and decline in the larger customer base, the CNPI service territories have seen a dramatic overall decline in energy throughput and system demand since 2008; the year that was used as the base year to set the mandated targets.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**

CNPI did not receive any requests for a renewable generation connections in 2014.

- **New Micro-embedded Generation Facilities Connected On Time**

In 2014, CNPI connected twenty-three (23) new micro-embedded generation facilities (microFIT projects of less than 10 kW). All but one facilities were connected within the prescribed time frame of five business days. Only one facility was connected on the sixth day. The minimum acceptable performance level for this measure is 90% of the time. CNPI works closely with its customers and their contractors to make the connection process as streamlined and transparent as possible.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

The Scorecard reports the current ratio for CNPI's segmented distribution business. On a consolidated basis, the 2014 liquidity current

ratio based on CNPI’s audited financial statements is 1.59 (2013 1.22). The liquidity ratio has remained relatively unchanged over the past several years and going forward it is expected to, at a minimum, be held relatively constant. CNPI has consistently shown a liquidity ratio greater than 1.0, which is an indication that CNPI is appropriately leveraged.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**

The Ontario Energy Board uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5.

The Scorecard reports the total debt to equity ratio for CNPI’s segmented distribution business. On a consolidated basis, the 2014 leverage debt to equity ratio based on CNPI’s audited financial statements is 1.27. The leverage ratio has remained relatively unchanged over the past several years and going forward it is expected to be held relatively constant.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**

CNPI's 2014 distribution rates were approved by the Ontario Energy Board as part of its last Cost of Service application for rates effective January 1, 2013 and this included an expected (deemed) regulatory return on equity of 8.93%. The Ontario Energy Board allows a distributor to earn within +/- 3% of the expected return on equity.

- **Profitability: Regulatory Return on Equity – Achieved**

CNPI’s return achieved in 2014 was 8.31%, which is within the +/- 3% range allowed by the Ontario Energy Board. CNPI achieved returns are higher in 2014 as compared to 2013 due to a higher adjusted regulated net income, as a result of decreased expenses offset by a decline in distribution revenue.

Note to Readers of 2014 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management’s best judgement on the reporting date of the performance scorecard, and could be markedly different in the future.

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IMPACT OF RRFE ON THE CURRENT APPLICATION

The RRFE Report contemplates enhanced engagement between distributors and their customers to provide better alignment between distributor operational plans and customers' needs and expectations. This Schedule focuses on interaction between the various RRFE outcomes.

Financial Performance

CNPI has historically maintained financial ratios in line with Board expectations and industry norms. More detailed information is provided in the Financial Ratios section of 2014 Scorecard MD&A, at Exhibit 1, Tab 10, Schedule 1, Appendix A. CNPI expects that its financial viability will be maintained as a result of the current Application, and that the plans presented are sustainable in the long term. No significant variations in financial ratios are expected within the 5-year period following this Application.

Public Policy Responsiveness

As described in Exhibit 3, Tab 2, Schedule 1, CNPI intends to fully meet its 2015-2020 CDM targets. The impact of projected CDM reductions to billing consumption and demand have been fully incorporated into CNPI's Load Forecast for the 2017 Test Year.

CNPI has adequate distribution system capacity for connection of Renewable Energy Generation (REG), however it continues to face restrictions to connecting larger projects due to upstream transmission system limitations. Details of available capacity and restrictions are provided in Section 5.4.3 of CNPI's Distribution System Plan (DSP), at Exhibit 2, Tab 2, Schedule 1, Appendix A.

Customer Focus and Operational Effectiveness

CNPI has seen a declining trend in overall system load over the historical period, and the Load Forecast presented at Exhibit 3, Tab 1, Schedule 2 projects a continued downward trend. Coupled with the CDM impacts and REG restrictions identified in the section above, CNPI is unlikely to see any material addition of either load or generation to its system during the five-year period following this application. As a result, the capital and maintenance programs proposed in this application have focused on outcomes related to the RRFE Performance Categories of Service Quality, Safety, System Reliability, and Asset Management.

CNPI conducted extensive customer engagement leading up to the preparation of this Application, as detailed in Tab 3 of this Exhibit. The feedback received through these activities was helpful in informing the development of the plan presented in this application, and reinforced the need to balance the outcomes of Service Quality, Safety, System Reliability, and Asset Management, with measures of Customer Satisfaction and Cost Control.

Feedback received from customer engagement activities suggests that customers desire CNPI to maintain, or even improve its system reliability levels. At the same time, however, customers emphasized the desire for minimal or no increases to rates.

CNPI has presented a comprehensive Distribution System Plan (DSP) that attempts to strike a balance between addressing priority safety issues, with the desire to levelize long-term sustaining asset replacement requirements and the customer preferences related to reliability and rate impacts identified as important to its customers.

The significant delta to wye conversion program described throughout the DSP is justified on resolving high-priority safety concerns, but incorporates many elements of sustaining asset replacement (poles and substations), as well as reliability improvement. Historical levels of capital investment with respect to some asset categories (poles in particular) have fallen slightly short of sustaining replacement levels, as illustrated in Section 5.4.6.17 of the DSP. Recent trends in pole replacement levels from 2011 to 2015 show a narrowing of this historical gap. In an effort to manage rate impacts, however, the total asset replacement levels proposed in the current DSP remain slightly short of long-term sustainment levels. In addition, CNPI has proposed a rate mitigation strategy for its Residential class in order to limit total bill impacts for low-consumption Residential customers (i.e. those with consumption levels at the 10th percentile) to a maximum of 10%.

CNPI believes that the levels of investment proposed in this Application will allow efficient implementation of the capital and maintenance programs that have been identified to resolve high priority issues in the next five years. Further, in developing the plan presented in its DSP, CNPI has considered how the investments in the 2017 to 2021 forecast period will transition into its next DSP. As an example of this consideration, it is expected that the proposed pole testing program, starting in 2016, will provide enhanced asset condition information for all of CNPI's poles, which comprise a significant portion of its asset base. CNPI anticipates that the results of this program will inform the appropriate investment in annual asset replacement required to achieve the long-term sustainable levels to be included in its next DSP. CNPI also anticipates that the timing of the ramping-up of a pole replacement program to sustainable levels will coincide with ramping-down of its delta to wye conversion program in order to keep rate impacts at manageable levels.

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OVERVIEW OF RATE BASE

The rate base for the purpose of calculating the revenue requirement used in this Application follows Chapter 2 of the Filing Requirements for Transmission and Distribution Applications issued on July 16, 2015 (the "Filing Requirements"). In accordance with the Filing Requirements, CNPI has calculated the rate base for the 2017 Test Year based on the average of the opening and closing balances of gross fixed assets and accumulated depreciation, plus a working capital allowance based on 7.5% of the sum of the cost of power and controllable expenses. CNPI has applied the 7.5% default working capital allowance in accordance with the OEB letter dated June 3, 2015, Allowance for Working Capital for Electricity Distribution Rate Applications which states:

"Effective immediately, the OEB is adopting a new default value of 7.5% of the sum of the cost of power and operating, maintenance and administration (OM&A) costs."

CNPI adopted the change-over to Modified International Financial Reporting Standards ("MIFRS") as of January 1, 2013 and incorporated this accounting change into its last Cost of Service Application (EB-2012-0112). Therefore, all information being presented within this Application including prior year actuals and last Board approved values have been presented under MIFRS accounting.

CNPI has not applied for, nor received any Incremental Capital Module ("ICM") adjustments (Exhibit 2, Tab 6, Schedule1).

CNPI has provided its rate base calculations for the years 2013 Actual and Board Approved, 2014 Actual, 2015 Actual, 2016 Bridge Year and 2017 Test Year in Table 2.1.1.1 below. The calculated 2017 rate base is $89,824,481.

Table 2.1.1.1

TABLE 2-1-1-1
RATE BASE VARIANCES

Description	2013 Board Approved	2013 Actual	Variance from 2013 EDR	2014 Actual	Variance from 2013 Actual	2015 Actual	Variance from 2014 Actual	2016 Bridge	Variance from 2015 Actual	2017 Test	Variance from 2016 Bridge
Gross Fixed Assets	111,842,558	109,205,357	(2,637,201)	112,887,119	3,681,763	121,038,612	8,151,493	143,730,451	22,691,839	153,487,610	9,757,158
Gross Write Up	(1,400,000)	(1,400,000)	-	(1,400,000)	-	(1,400,000)	-	(1,400,000)	-	(1,400,000)	-
Accumulated Depreciation Write Up	456,989	456,989	-	499,499	42,511	542,010	42,511	584,520	42,511	627,031	42,511
Accumulated Depreciation	(42,654,127)	(41,404,796)	1,249,331	(44,298,957)	(2,894,161)	(47,827,244)	(3,528,286)	(60,761,942)	(12,934,698)	(65,936,769)	(5,174,828)
Net Book Value	68,245,419	66,857,550	(1,387,870)	67,687,661	830,112	72,353,378	4,665,717	82,153,030	9,799,652	86,777,871	4,624,841
Average Net book Value	65,400,087	64,425,120	(974,967)	67,272,605	2,847,486	70,020,520	2,747,914	77,253,204	7,232,685	84,465,451	7,212,247
Working Capital Requirement											
Cost of Power	52,454,045	53,921,476	1,467,431	56,490,297	2,568,822	57,860,531	1,370,234	63,112,224	5,251,693	62,242,349	(869,875)
Controllable Expenses	9,835,961	8,864,063	(971,898)	9,434,813	570,750	9,518,933	84,120	10,130,816	611,883	10,544,723	413,906
	62,290,005	62,785,539	495,533	65,925,111	3,139,572	67,379,465	1,454,354	73,243,040	5,863,576	72,787,072	(455,969)
Working Capital Allowance	8,097,701	8,162,120	64,419	8,570,264	408,144	8,759,330	189,066	9,521,595	762,265	5,459,030	(4,062,565)
Rate Base	73,497,788	72,587,240	(910,548)	75,842,870	3,255,630	78,779,850	2,936,980	86,774,799	7,994,949	89,924,481	3,149,682

RATE BASE VARIANCE ANALYSIS

In Exhibit 1, Tab 5, Schedule 1, CNPI calculated the materiality threshold as being $100,000. Variances greater than this threshold in Table 2.1.1.1 above have been explained below.

Gross Fixed Assets Variances – All Years

Additions noted in the Asset Continuity Schedules as provided in Exhibit 2, Tab 1, Schedule 2, have been explained within the Capital Expenditure Analysis completed in Exhibit 2, Tab 2, Schedule 2. Additional non-recurring material items that impacted the variances in Gross Fixed Assets were the removal of $2,959,931 in stranded meters in 2013, the sale of a $340,374 property in Port Colborne in 2013, the sale of a $518,891 property in the Gananoque region in 2015, the addition of $249,365 relating to MIST meter implementation in 2016, and the removal of $79,179 of meters stranded as a result of MIST meter implementation in 2016. The MIST addition and removal amounts have been recorded in “Adjustments” and “Disposals” in the 2016 Asset Continuity Schedules to ensure appropriate calculation of rate base in 2017. Additional discussion of the MIST program has been included in Exhibit 2, Tab 1, Schedule 8 and Exhibit 9, Tab 4, Schedule 1, within this Application.

Accumulated Depreciation Variances – All Years

CNPI’s capitalization policy is outlined in Exhibit 2, Tab 3, Schedule 1 and depreciable lives are outlined in Exhibit 2, Tab 11, Schedule 1. Accumulated depreciation reflects the accumulation of depreciation on both the opening Gross Fixed Assets and additions during any given year. Depreciation expense analysis has been completed in Exhibit 2, Tab 11, Schedule 2. Additional non-recurring material items that impacted the variances in Accumulated Depreciation were the removal of $134,266 in stranded meters in 2013 and the sale of a $139,891 property in the Gananoque region in 2015.

Allocation of Shared Assets

In CNPI's previous Cost of Service Application (EB-2012-0112), the removal of the portion of shared capital costs allocated to related companies outside of CNPI Distribution, was accounted for by removing the cost and accumulated depreciation within the Fixed Asset Continuity schedules ("FAC"). The FAC schedules provided in Exhibit 2, Tab 1, Schedule 2 of this Application show the removal of these shared costs for 2013, 2014 and 2015 Actuals. However, in accordance with Board staff's preference in API's previous Cost of Service Application (EB-2014-0055), a different approach was taken such that the amounts have not been removed for 2016 and 2017. In lieu of this, CNPI has included shared IT and equipment charges as revenue offsets within the RRWF for 2017. Shared services have been discussed further in Exhibit 4, Tab 7, Schedule 1. The exclusion of the removal of shared cost and accumulated depreciation has contributed to the variances reported in the "Variance from 2015 Actual" and "Variance from 2016 Bridge" columns in Table 2.1.1.1 above.

Working Capital Allowance – All Years

The Cost of Power is the primary cause of the increases in Working Capital Allowance noted in the "Variance from 2013 EDR," "Variance from 2013 Actual," "Variance from 2014 Actual," and "Variance from 2015 Actual" columns of Table 2.1.1.1 above. Although CNPI has not seen a significant increase in load (see Exhibit 3 for Load analysis), the flow-through Cost of Power has increased. A 7.5% Working Capital Allowance has been calculated for 2017, and this primarily contributes to the decrease noted in the "Variance from 2016 Bridge" column of Table 2.1.1.1 above. Variances related to Controllable Expenses have been analyzed in greater detail within Exhibit 4 of this Application.

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FIXED ASSET CONTINUITY SCHEDULES

See Tables 2.1.2.1 to 2.1.2.5 below for fixed asset continuity schedules prepared for 2013 to 2015 Actuals, 2016 Bridge and 2017 Test Years, as per Appendix 2-BA of the Filing Requirements. The net book value balances, excluding construction work in progress, are the balances that have been included in the rate base calculations noted in Table 2.1.1.1 of Exhibit 2, Tab 1, Schedule 1.

Table 2.1.2.1

APPENDIX 2-BA
CANADIAN NIAGARA POWER INC.
FIXED ASSETS CONTINUITY SCHEDULE
December 31, 2013

		COST								ACCUMULATED DEPRECIATION							NBV
OEB ACCT #	ACCOUNT DESCRIPTION	COST BEGINNING OF THE YEAR	ADDITIONS	DISPOSALS	ADJUSTMENTS	COST END OF PERIOD	ALLOCATIONS	ADJUSTED COST END OF PERIOD	USEFUL LIFE	ACC DEP'N BEGINNING OF THE YEAR	ADDITIONS	DISPOSALS	ADJUSTMENTS	ACC DEP'N END OF PERIOD	ALLOCATIONS	ADJUSTED ACC DEP'N END OF PERIOD	
1606	Organization & Rec	-	-	-	-	-	-	-	40	-	-	-	-	-	-	-	-
1608	Franchises & Consents	156,053	-	-	-	156,053	-	156,053	40	(35,112)	(3,901)	-	-	(39,013)	-	(39,013)	117,040
1610	Misc. Intangible Plant	40,576	-	-	-	40,576	-	40,576	40	(3,681)	(1,014)	-	-	(4,695)	-	(4,695)	35,881
1611	GA Comp Software	8,351,231	1,101,559	(49,303)	(8,931,174)	472,313	-	472,313	5	(5,405,273)	(410,332)	16,079	5,604,364	(195,162)	-	(195,162)	277,151
1611A	GA Comp Software	-	871,758	-	8,931,174	9,802,932	(6,048,045)	3,754,887	10	-	(355,512)	-	(5,604,364)	(5,959,875)	3,532,333	(2,427,543)	1,327,344
1612	D Land Rights	308,655	8,934	-	-	317,589	-	317,589	40	(85,542)	(6,527)	-	-	(92,069)	-	(92,069)	225,520
1805	D Land	211,728	-	(3,645)	-	208,084	-	208,084		-	-	-	-	-	-	-	208,084
1808	D Bldgs & Fixtures	4,074,238	128	(107,629)	-	3,966,736	-	3,966,736	50	(980,717)	(88,375)	19,776	-	(1,049,315)	-	(1,049,315)	2,917,421
1820	D Station Equipment < 50KV	11,690,309	373,772	-	(1,602,023)	10,462,058	-	10,462,058	50	(2,955,034)	(193,776)	-	208,295	(2,940,515)	-	(2,940,515)	7,521,543
1820A	D Station Equipment < 50KV	-	58,085	-	1,602,023	1,660,109	-	1,660,109	40	-	(39,141)	-	(208,295)	(247,437)	-	(247,437)	1,412,672
1830	D Poles,Towers&Fixtures	20,707,224	1,288,276	(6,778)	-	21,988,722	-	21,988,722	45	(8,898,323)	(492,071)	5,414	-	(9,384,980)	-	(9,384,980)	12,603,742
1835	D OH Cond & Devices	25,832,962	2,055,900	(1,029)	-	27,887,833	-	27,887,833	45	(7,933,875)	(600,220)	1,029	(10,909)	(8,543,975)	-	(8,543,975)	19,343,859
1840	D UG Conduit & Manholes	1,059,086	2,208	(0)	-	1,061,295	-	1,061,295	50	(267,543)	(66,299)	-	-	(333,843)	-	(333,843)	727,452
1845	D UG Cond & Devices	7,757,026	227,556	(904)	-	7,983,678	-	7,983,678	40	(1,666,162)	(200,239)	904	-	(1,865,498)	-	(1,865,498)	6,118,180
1850	D Line Transformers	13,457,782	708,846	(122,090)	-	14,044,539	-	14,044,539	40	(5,044,354)	(388,317)	122,090	-	(5,310,582)	-	(5,310,582)	8,733,957
1855	D Services	9,243,479	509,442	(0)	-	9,752,921	-	9,752,921	40	(2,613,314)	(211,241)	-	-	(2,824,555)	-	(2,824,555)	6,928,365
1860	D Meters	4,065,255	4,854,305	(2,959,931)	(5,488,009)	471,620	-	471,620	30	(2,103,744)	(1,004,281)	1,721,470	1,245,386	(141,169)	-	(141,169)	330,451
1860A	D Meters	-	101,144	-	4,963,473	5,064,617	-	5,064,617	15	-	(389,045)	-	(975,187)	(1,364,232)	-	(1,364,232)	3,700,385
1860B	D Meters	-	24,757	-	524,536	549,293	-	549,293	30	-	(21,299)	-	(269,447)	(290,747)	-	(290,747)	258,546
1865	D Other Install on Cust Prem	64,218	69,554	-	-	133,772	-	133,772	10	(13,830)	(29,493)	-	(752)	(44,075)	-	(44,075)	89,697
1875	D St Lites & Signal Systems	-	-	-	-	-	-	-	20	-	-	-	-	-	-	-	-
1908	GA Bldgs & Fixtures	1,026,044	193,954	(329,502)	-	890,495	-	890,495	50	(193,870)	(19,400)	25,103	-	(188,167)	-	(188,167)	702,328
1910	GA Leasehold Improvements	418,750	276,500	-	-	695,250	-	695,250	5	(135,374)	(87,505)	-	-	(222,880)	-	(222,880)	472,370
1915	GA Office Furn & Equipment	1,366,350	(1,485)	-	-	1,364,865	(266,483)	1,098,382	10	(1,259,198)	(26,002)	-	-	(1,285,200)	251,056	(1,034,144)	64,239
1920	GA Comp Hardware	3,241,344	198,011	-	396	3,439,751	(2,139,383)	1,300,368	5	(2,049,421)	(421,386)	-	(396)	(2,471,203)	1,534,420	(936,783)	363,585
1930	GA Transportation Equipment	3,505,670	479,487	(419,551)	(2,982,505)	583,101	-	583,101	5	(2,050,965)	(109,717)	399,966	1,388,989	(371,727)	-	(371,727)	211,374
1930A	GA Transportation Equipment	-	31,527	-	3,038,347	3,069,874	(529,221)	2,540,653	10	-	(242,440)	-	(1,433,922)	(1,676,362)	324,150	(1,352,211)	1,188,442
1935	GA Stores Equip	166,638	-	-	-	166,638	(33,328)	133,311	10	(154,649)	(4,628)	-	-	(159,276)	31,855	(127,421)	5,889
1940	GA tools,shop&garage equip	757,185	8,551	-	-	765,737	(145,163)	620,574	10	(654,528)	(16,596)	-	-	(671,124)	131,359	(539,764)	80,809
1945	GA measure&test equip	478,244	-	-	-	478,244	(91,715)	386,529	10	(419,318)	(18,300)	-	-	(437,618)	84,363	(353,256)	33,274
1950	GA power op equip	109,339	-	-	-	109,339	-	109,339	10	(92,907)	(2,414)	-	-	(95,321)	-	(95,321)	14,019
1955	GA Comm Equipment	1,065,541	(2,676)	-	-	1,062,865	(183,433)	879,432	10	(516,539)	(95,563)	-	-	(612,103)	94,196	(517,906)	361,525
1960	GA Misc. Equip	142,550	-	-	(67,513)	75,037	(27,798)	47,239	10	(99,998)	(7,504)	-	54,059	(53,442)	22,095	(31,347)	15,892
1960A	GA Misc. Equip	-	-	-	67,513	67,513	-	67,513	5	-	(5,455)	-	(54,059)	(59,515)	-	(59,515)	7,998
1980	GA System Supv Equip	776,127	51,051	-	-	827,178	(164,998)	662,181	20	(690,423)	(7,801)	-	-	(698,224)	139,207	(559,017)	103,164
1995	Contributions & Grants	(9,791,083)	(1,062,493)	185,285	(117,411)	(10,785,703)	-	(10,785,703)		1,922,691	225,554	(77,036)	12,857	2,084,067	-	2,084,067	(8,701,636)
	Total before AUC	110,282,520	12,428,651	(3,815,076)	(61,173)	118,834,922	(9,629,565)	109,205,357		(44,401,004)	(5,340,241)	2,234,795	(43,380)	(47,549,831)	6,145,034	(41,404,796)	67,800,561
2055	Asset Under Construction	2,557,006	886,239	-	104,554	3,547,798	-	3,547,798		-	-	-	-	-	-	-	3,547,798
	Total after AUC	112,839,526	13,314,890	(3,815,076)	43,380	122,382,720	(9,629,565)	112,753,155		(44,401,004)	(5,340,241)	2,234,795	(43,380)	(47,549,831)	6,145,034	(41,404,796)	71,348,359

Table 2.1.2.2

APPENDIX 2-BA
CANADIAN NIAGARA POWER INC.
FIXED ASSETS CONTINUITY SCHEDULE
December 31, 2014

		COST								ACCUMULATED DEPRECIATION							NBV
OEB ACCT #	ACCOUNT DESCRIPTION	COST BEGINNING OF THE YEAR	ADDITIONS	DISPOSALS	ADJUSTMENTS	COST END OF PERIOD	ALLOCATIONS	ADJUSTED COST END OF PERIOD	USEFUL LIFE	ACC DEP'N BEGINNING OF THE YEAR	ADDITIONS	DISPOSALS	ADJUSTMENTS	ACC DEP'N END OF PERIOD	ALLOCATIONS	ADJUSTED ACC DEP'N END OF PERIOD	
1606	Organization & Rec	-	-	-	-	-	-	-	40	-	-	-	-	-	-	-	-
1608	Franchises & Consents	156,053	-	-	-	156,053	-	156,053	40	(39,013)	(3,901)	-	-	(42,915)	-	(42,915)	113,138
1610	Misc. Intangible Plant	40,576	-	-	-	40,576	-	40,576	40	(4,695)	(1,014)	-	-	(5,709)	-	(5,709)	34,866
1611	GA Comp Software	472,313	325,866	-	-	798,179	-	798,179	5	(195,162)	(87,607)	-	-	(282,769)	-	(282,769)	515,410
1611A	GA Comp Software	9,802,932	597,678	-	-	10,400,610	(6,816,713)	3,583,897	10	(5,959,875)	(600,946)	-	-	(6,560,822)	4,064,612	(2,496,210)	1,087,687
1612	D Land Rights	317,589	3,463	-	-	321,052	-	321,052	40	(92,069)	(6,726)	-	-	(98,795)	-	(98,795)	222,258
1805	D Land	208,084	-	-	-	208,084	-	208,084		-	-	-	-	-	-	-	208,084
1808	D Bldgs & Fixtures	3,966,736	-	-	-	3,966,736	-	3,966,736	50	(1,049,315)	(79,335)	-	-	(1,128,650)	-	(1,128,650)	2,838,087
1820	D Station Equipment < 50KV	10,462,058	68,090	-	-	10,530,148	-	10,530,148	50	(2,940,515)	(200,611)	-	-	(3,141,126)	-	(3,141,126)	7,389,022
1820A	D Station Equipment < 50KV	1,660,109	39,223	-	-	1,699,331	-	1,699,331	40	(247,437)	(40,912)	-	-	(288,349)	-	(288,349)	1,410,982
1830	D Poles,Towers&Fixtures	21,988,722	1,151,613	(22,250)	-	23,118,085	-	23,118,085	45	(9,384,980)	(521,420)	19,027	-	(9,887,373)	-	(9,887,373)	13,230,712
1835	D OH Cond & Devices	27,887,833	1,860,392	(2,660)	-	29,745,565	-	29,745,565	45	(8,543,975)	(644,337)	2,660	-	(9,185,651)	-	(9,185,651)	20,559,913
1840	D UG Conduit & Manholes	1,061,295	7,391	-	-	1,068,685	-	1,068,685	50	(333,843)	(66,352)	-	-	(400,194)	-	(400,194)	668,491
1845	D UG Cond & Devices	7,983,678	514,085	(352)	-	8,497,410	-	8,497,410	40	(1,865,498)	(203,563)	352	-	(2,068,709)	-	(2,068,709)	6,428,701
1850	D Line Transformers	14,044,539	597,714	(0)	-	14,642,253	-	14,642,253	40	(5,310,582)	(405,855)	-	-	(5,716,437)	-	(5,716,437)	8,925,816
1855	D Services	9,752,921	555,334	-	-	10,308,254	-	10,308,254	40	(2,824,555)	(223,790)	-	-	(3,048,345)	-	(3,048,345)	7,259,909
1860	D Meters	471,620	47,380	-	-	519,000	-	519,000	30	(141,169)	(31,848)	-	(49)	(173,065)	-	(173,065)	345,935
1860A	D Meters	5,064,617	115,924	-	-	5,180,541	-	5,180,541	15	(1,364,232)	(399,933)	-	-	(1,764,165)	-	(1,764,165)	3,416,376
1860B	D Meters	549,293	30,064	-	-	579,357	-	579,357	30	(290,747)	(20,050)	-	-	(310,797)	-	(310,797)	268,560
1865	D Other Install on Cust Prem	133,772	166	-	-	133,938	-	133,938	10	(44,075)	(13,433)	-	-	(57,508)	-	(57,508)	76,430
1875	D St Lites & Signal Systems	-	-	-	-	-	-	-	20	-	-	-	-	-	-	-	-
1908	GA Bldgs & Fixtures	890,495	15,885	-	-	906,380	-	906,380	50	(188,167)	(18,004)	-	-	(206,171)	-	(206,171)	700,209
1910	GA Leasehold Improvements	695,250	144,925	-	-	840,175	-	840,175	5	(222,880)	(151,098)	-	-	(373,978)	-	(373,978)	466,198
1915	GA Office Furn & Equipment	1,364,865	66,160	-	-	1,431,024	(352,440)	1,078,584	10	(1,285,200)	(27,878)	-	-	(1,313,078)	323,074	(990,004)	88,580
1920	GA Comp Hardware	3,439,751	272,714	-	-	3,712,465	(2,376,526)	1,335,939	5	(2,471,203)	(379,764)	-	-	(2,850,967)	1,822,644	(1,028,323)	307,616
1930	GA Transportation Equipment	583,101	137,344	(126,116)	-	594,329	-	594,329	5	(371,727)	(94,804)	126,116	-	(340,415)	-	(340,415)	253,914
1930A	GA Transportation Equipment	3,069,874	559,754	(231,596)	-	3,398,031	(760,285)	2,637,747	10	(1,676,362)	(292,107)	221,487	-	(1,746,982)	399,581	(1,347,401)	1,290,345
1935	GA Stores Equip	166,638	-	-	-	166,638	(41,993)	124,645	10	(159,276)	(4,628)	-	-	(163,904)	41,304	(122,600)	2,045
1940	GA tools,shop&garage equip	765,737	60,961	-	-	826,698	(195,519)	631,179	10	(671,124)	(18,491)	-	-	(689,615)	169,163	(520,451)	110,728
1945	GA measure&test equip	478,244	30,926	-	-	509,169	(123,354)	385,816	10	(437,618)	(17,061)	-	-	(454,680)	110,103	(344,577)	41,239
1950	GA power op equip	109,339	-	-	-	109,339	-	109,339	10	(95,321)	(2,414)	-	-	(97,734)	-	(97,734)	11,605
1955	GA Comm Equipment	1,062,865	43,239	-	-	1,106,104	(270,242)	835,862	10	(612,103)	(83,360)	-	-	(695,463)	166,762	(528,701)	307,161
1960	GA Misc. Equip	75,037	-	-	-	75,037	(35,025)	40,012	10	(53,442)	(7,504)	-	-	(60,946)	30,926	(30,020)	9,992
1960A	GA Misc. Equip	67,513	20,900	-	-	88,413	-	88,413	5	(59,515)	(5,455)	-	-	(64,970)	-	(64,970)	23,443
1980	GA System Supv Equip	827,178	7,683	-	-	834,862	(209,834)	625,028	20	(698,224)	(10,656)	-	-	(708,880)	178,086	(530,794)	94,234
1995	Contributions & Grants	(10,785,703)	(1,658,435)	9,035	(8,369)	(12,443,472)	-	(12,443,472)		2,084,067	240,460	(577)	-	2,323,951	-	2,323,951	(10,119,521)
	Total before AUC	118,834,922	5,616,436	(373,939)	(8,369)	124,069,050	(11,181,930)	112,887,119		(47,549,831)	(4,424,397)	369,065	(49)	(51,605,211)	7,306,254	(44,298,957)	68,588,162
2055	Asset Under Construction	3,547,798	1,267,996	-	-	4,815,794	-	4,815,794		-	-	-	-	-	-	-	4,815,794
	Total after AUC	122,382,720	6,884,432	(373,939)	(8,369)	128,884,844	(11,181,930)	117,702,913		(47,549,831)	(4,424,397)	369,065	(49)	(51,605,211)	7,306,254	(44,298,957)	73,403,956

Table 2.1.2.3

APPENDIX 2-BA
CANADIAN NIAGARA POWER INC.
FIXED ASSETS CONTINUITY SCHEDULE
December 31, 2015

		COST								ACCUMULATED DEPRECIATION							NBV
OEB ACCT #	ACCOUNT DESCRIPTION	COST BEGINNING OF THE YEAR	ADDITIONS	DISPOSALS	ADJUSTMENTS	COST END OF PERIOD	ALLOCATIONS	ADJUSTED COST END OF PERIOD	USEFUL LIFE	ACC DEP'N BEGINNING OF THE YEAR	ADDITIONS	DISPOSALS	ADJUSTMENTS	ACC DEP'N END OF PERIOD	ALLOCATIONS	ADJUSTED ACC DEP'N END OF PERIOD	
1606	Organization & Rec	-	-	-	-	-	-	-	40	-	-	-	-	-	-	-	-
1608	Franchises & Consents	156,053	-	-	-	156,053	-	156,053	40	(42,915)	(3,901)	-	-	(46,816)	-	(46,816)	109,237
1610	Misc. Intangible Plant	40,576	-	-	-	40,576	-	40,576	40	(5,709)	(1,014)	-	-	(6,724)	-	(6,724)	33,852
1611	GA Comp Software	798,179	166,492	-	-	964,671	-	964,671	5	(282,769)	(136,487)	-	-	(419,256)	-	(419,256)	545,415
1611A	GA Comp Software	10,400,610	640,815	(900)	-	11,040,525	(7,336,039)	3,704,486	10	(6,560,822)	(644,279)	83	-	(7,205,019)	4,558,255	(2,646,764)	1,057,722
1612	D Land Rights	321,052	4,867	-	-	325,919	-	325,919	40	(98,795)	(6,790)	-	-	(105,585)	-	(105,585)	220,334
1805	D Land	208,084	-	(1,430)	-	206,654	-	206,654		-	-	-	-	-	-	-	206,654
1808	D Bldgs & Fixtures	3,966,736	-	(490,886)	-	3,475,850	-	3,475,850	50	(1,128,650)	(75,244)	134,266	-	(1,069,628)	-	(1,069,628)	2,406,222
1820	D Station Equipment < 50KV	10,530,148	1,182,592	(34,804)	-	11,677,936	-	11,677,936	50	(3,141,126)	(204,091)	17,531	-	(3,327,685)	-	(3,327,685)	8,350,251
1820A	D Station Equipment < 50KV	1,699,331	514,319	-	-	2,213,650	-	2,213,650	40	(288,349)	(42,989)	-	-	(331,338)	-	(331,338)	1,882,312
1830	D Poles,Towers&Fixtures	23,118,085	2,578,593	(29,046)	-	25,667,632	-	25,667,632	45	(9,887,373)	(554,028)	28,110	-	(10,413,291)	-	(10,413,291)	15,254,341
1835	D OH Cond & Devices	29,745,565	2,777,581	(5,641)	-	32,517,505	-	32,517,505	45	(9,185,651)	(692,556)	5,565	-	(9,872,643)	-	(9,872,643)	22,644,862
1840	D UG Conduit & Manholes	1,068,685	104,778	-	-	1,173,463	-	1,173,463	50	(400,194)	(66,672)	-	-	(466,866)	-	(466,866)	706,597
1845	D UG Cond & Devices	8,497,410	765,724	(415)	-	9,262,719	-	9,262,719	40	(2,068,709)	(222,321)	402	-	(2,290,628)	-	(2,290,628)	6,972,090
1850	D Line Transformers	14,642,253	590,514	-	-	15,232,767	-	15,232,767	40	(5,716,437)	(421,231)	-	-	(6,137,668)	-	(6,137,668)	9,095,099
1855	D Services	10,308,254	571,682	(0)	-	10,879,936	-	10,879,936	40	(3,048,345)	(239,197)	-	-	(3,287,542)	-	(3,287,542)	7,592,394
1860	D Meters	519,000	105,091	-	-	624,091	-	624,091	30	(173,065)	(27,924)	-	-	(200,989)	-	(200,989)	423,102
1860A	D Meters	5,180,541	320,626	-	(234,065)	5,267,102	-	5,267,102	15	(1,764,165)	(406,153)	-	7,802	(2,162,516)	-	(2,162,516)	3,104,586
1860B	D Meters	579,357	13,046	-	-	592,403	-	592,403	30	(310,797)	(18,834)	-	-	(329,631)	-	(329,631)	262,772
1865	D Other Install on Cust Prem	133,938	-	-	-	133,938	-	133,938	10	(57,508)	(13,439)	-	-	(70,947)	-	(70,947)	62,991
1875	D St Lites & Signal Systems	-	-	-	-	-	-	-	20	-	-	-	-	-	-	-	-
1908	GA Bldgs & Fixtures	906,380	32,714	(26,574)	-	912,520	-	912,520	50	(206,171)	(17,906)	5,625	-	(218,453)	-	(218,453)	694,067
1910	GA Leasehold Improvements	840,175	44,967	-	-	885,142	-	885,142	5	(373,978)	(172,478)	-	-	(546,456)	-	(546,456)	338,687
1915	GA Office Furn & Equipment	1,431,024	69,642	-	-	1,500,666	(369,990)	1,130,676	10	(1,313,078)	(24,219)	-	-	(1,337,297)	329,023	(1,008,274)	122,403
1920	GA Comp Hardware	3,712,465	79,876	-	-	3,792,341	(2,427,966)	1,364,375	5	(2,850,967)	(336,959)	-	-	(3,187,926)	2,039,181	(1,148,745)	215,629
1930	GA Transportation Equipment	594,329	-	-	-	594,329	-	594,329	5	(340,415)	(92,791)	-	-	(433,206)	-	(433,206)	161,123
1930A	GA Transportation Equipment	3,398,031	125,741	(58,857)	-	3,464,915	(774,834)	2,690,081	10	(1,746,982)	(302,490)	58,692	-	(1,990,779)	457,513	(1,533,267)	1,156,814
1935	GA Stores Equip	166,638	-	-	-	166,638	(41,993)	124,645	10	(163,904)	(2,734)	-	-	(166,638)	41,993	(124,645)	-
1940	GA tools,shop&garage equip	826,698	43,095	-	-	869,792	(205,518)	664,274	10	(689,615)	(21,201)	-	-	(710,816)	173,433	(537,383)	126,891
1945	GA measure&test equip	509,169	6,022	-	-	515,191	(124,871)	390,320	10	(454,680)	(16,986)	-	-	(471,665)	114,063	(357,602)	32,718
1950	GA power op equip	109,339	-	-	-	109,339	-	109,339	10	(97,734)	(2,414)	-	-	(100,148)	-	(100,148)	9,191
1955	GA Comm Equipment	1,106,104	7,223	-	-	1,113,327	(272,062)	841,264	10	(695,463)	(78,899)	-	-	(774,362)	186,643	(587,719)	253,546
1960	GA Misc. Equip	75,037	9,995	-	-	85,031	(37,909)	47,123	10	(60,946)	(6,537)	-	-	(67,483)	33,140	(34,343)	12,780
1960A	GA Misc. Equip	88,413	2,974	-	-	91,387	-	91,387	5	(64,970)	(7,014)	-	-	(71,984)	-	(71,984)	19,403
1980	GA System Supv Equip	834,862	211,954	-	-	1,046,816	(263,246)	783,570	20	(708,880)	(10,738)	-	-	(719,618)	180,792	(538,826)	244,744
1995	Contributions & Grants	(12,443,472)	(1,264,311)	7,158	(7,158)	(13,707,783)	-	(13,707,783)		2,323,951	276,451	(79)	-	2,600,323	-	2,600,323	(11,107,461)
	Total before AUC	124,069,050	9,706,611	(641,396)	(241,223)	132,893,041	(11,854,429)	121,038,612		(51,605,211)	(4,594,065)	250,195	7,802	(55,941,279)	8,114,035	(47,827,244)	73,211,368
2055	Asset Under Construction	4,815,794	(1,677,164)	-	234,065	3,372,695	-	3,372,695		-	-	-	(7,802)	(7,802)	-	(7,802)	3,364,893
	Total after AUC	128,884,844	8,029,447	(641,396)	(7,158)	136,265,736	(11,854,429)	124,411,307		(51,605,211)	(4,594,065)	250,195	-	(55,949,081)	8,114,035	(47,835,046)	76,576,261

Table 2.1.2.4

APPENDIX 2-BA
CANADIAN NIAGARA POWER INC.
FIXED ASSETS CONTINUITY SCHEDULE
December 31, 2016

		COST								ACCUMULATED DEPRECIATION							NBV
OEB ACCT #	ACCOUNT DESCRIPTION	COST BEGINNING OF THE YEAR	ADDITIONS	DISPOSALS	ADJUSTMENTS	COST END OF PERIOD	ALLOCATIONS	ADJUSTED COST END OF PERIOD	USEFUL LIFE	ACC DEP'N BEGINNING OF THE YEAR	ADDITIONS	DISPOSALS	ADJUSTMENTS	ACC DEP'N END OF PERIOD	ALLOCATIONS	ADJUSTED ACC DEP'N END OF PERIOD	
1606	Organization & Rec	-	-	-	-	-	-	-	40	-	-	-	-	-	-	-	-
1608	Franchises & Consents	156,053	-	-	-	156,053	-	156,053	40	(46,816)	(3,901)	-	-	(50,717)	-	(50,717)	105,336
1610	Misc. Intangible Plant	40,576	-	-	-	40,576	-	40,576	40	(6,724)	(1,014)	-	-	(7,738)	-	(7,738)	32,837
1611	GA Comp Software	964,671	679,305	-	-	1,643,976	-	1,643,976	5	(419,256)	(224,456)	-	-	(643,712)	-	(643,712)	1,000,264
1611A	GA Comp Software	11,040,525	889,891	-	4,500	11,934,916	-	11,934,916	10	(7,205,019)	(673,395)	-	(225)	(7,878,639)	-	(7,878,639)	4,056,277
1612	D Land Rights	325,919	20,377	-	-	346,296	-	346,296	40	(105,585)	(7,146)	-	-	(112,730)	-	(112,730)	233,566
1805	D Land	206,654	4,862	-	-	211,516	-	211,516		-	-	-	-	-	-	-	211,516
1808	D Bldgs & Fixtures	3,475,850	233,975	-	-	3,709,825	-	3,709,825	50	(1,069,628)	(71,857)	-	-	(1,141,485)	-	(1,141,485)	2,568,340
1820	D Station Equipment < 50KV	11,677,936	342,800	-	-	12,020,736	-	12,020,736	50	(3,327,685)	(228,543)	-	-	(3,556,228)	-	(3,556,228)	8,464,508
1820A	D Station Equipment < 50KV	2,213,650	1,705,161	-	-	3,918,811	-	3,918,811	40	(331,338)	(76,065)	-	-	(407,403)	-	(407,403)	3,511,408
1830	D Poles,Towers&Fixtures	25,667,632	2,419,593	-	-	28,087,225	-	28,087,225	45	(10,413,291)	(626,414)	-	-	(11,039,705)	-	(11,039,705)	17,047,520
1835	D OH Cond & Devices	32,517,505	1,386,266	-	-	33,903,771	-	33,903,771	45	(9,872,643)	(754,981)	-	-	(10,627,624)	-	(10,627,624)	23,276,147
1840	D UG Conduit & Manholes	1,173,463	208,790	-	-	1,382,253	-	1,382,253	50	(466,866)	(33,948)	-	-	(500,814)	-	(500,814)	881,439
1845	D UG Cond & Devices	9,262,719	212,827	-	-	9,475,545	-	9,475,545	40	(2,290,628)	(229,306)	-	-	(2,519,935)	-	(2,519,935)	6,955,611
1850	D Line Transformers	15,232,767	1,914,937	-	-	17,147,704	-	17,147,704	40	(6,137,668)	(455,236)	-	-	(6,592,904)	-	(6,592,904)	10,554,801
1855	D Services	10,879,936	724,666	-	-	11,604,602	-	11,604,602	40	(3,287,542)	(258,128)	-	-	(3,545,670)	-	(3,545,670)	8,058,932
1860	D Meters	624,091	-	-	-	624,091	-	624,091	30	(200,989)	(19,815)	-	-	(220,805)	-	(220,805)	403,286
1860A	D Meters	5,267,102	228,500	(79,179)	244,865	5,661,288	-	5,661,288	15	(2,162,516)	(432,949)	31,289	(23,767)	(2,587,944)	-	(2,587,944)	3,073,344
1860B	D Meters	592,403	79,807	-	-	672,210	-	672,210	30	(329,631)	(19,360)	-	-	(348,991)	-	(348,991)	323,219
1865	D Other Install on Cust Prem	133,938	-	-	-	133,938	-	133,938	10	(70,947)	(13,394)	-	-	(84,341)	-	(84,341)	49,597
1875	D St Lites & Signal Systems	-	-	-	-	-	-	-	20	-	-	-	-	-	-	-	-
1908	GA Bldgs & Fixtures	912,520	20,000	-	-	932,520	-	932,520	50	(218,453)	(18,450)	-	-	(236,903)	-	(236,903)	695,617
1910	GA Leasehold Improvements	885,142	49,746	-	-	934,889	-	934,889	5	(546,456)	(131,176)	-	-	(677,631)	-	(677,631)	257,257
1915	GA Office Furn & Equipment	1,500,666	23,000	-	-	1,523,666	-	1,523,666	10	(1,337,297)	(24,719)	-	-	(1,362,016)	-	(1,362,016)	161,650
1920	GA Comp Hardware	3,792,341	522,768	-	-	4,315,108	-	4,315,108	5	(3,187,926)	(303,342)	-	-	(3,491,268)	-	(3,491,268)	823,841
1930	GA Transportation Equipment	594,329	72,700	-	-	667,029	-	667,029	5	(433,206)	(75,811)	-	-	(509,017)	-	(509,017)	158,012
1930A	GA Transportation Equipment	3,464,915	294,300	-	-	3,759,215	-	3,759,215	10	(1,990,779)	(302,672)	-	-	(2,293,451)	-	(2,293,451)	1,465,764
1935	GA Stores Equip	166,638	-	-	-	166,638	-	166,638	10	(166,638)	-	-	-	(166,638)	-	(166,638)	-
1940	GA tools,shop&garage equip	869,792	50,000	-	-	919,792	-	919,792	10	(710,816)	(25,395)	-	-	(736,211)	-	(736,211)	183,582
1945	GA measure&test equip	515,191	-	-	-	515,191	-	515,191	10	(471,665)	(12,127)	-	-	(483,792)	-	(483,792)	31,399
1950	GA power op equip	109,339	18,000	-	-	127,339	-	127,339	10	(100,148)	(3,314)	-	-	(103,462)	-	(103,462)	23,878
1955	GA Comm Equipment	1,113,327	35,160	-	-	1,148,487	-	1,148,487	10	(774,362)	(80,212)	-	-	(854,574)	-	(854,574)	293,912
1960	GA Misc. Equip	85,031	-	-	-	85,031	-	85,031	10	(67,483)	(4,358)	-	-	(71,841)	-	(71,841)	13,190
1960A	GA Misc. Equip	91,387	-	-	-	91,387	-	91,387	5	(71,984)	(4,797)	-	-	(76,780)	-	(76,780)	14,606
1980	GA System Supv Equip	1,046,816	-	-	-	1,046,816	-	1,046,816	20	(719,618)	(21,396)	-	-	(741,014)	-	(741,014)	305,802
1995	Contributions & Grants	(13,707,783)	(1,470,207)	-	-	(15,177,990)	-	(15,177,990)		2,600,323	309,718	-	-	2,910,041	-	2,910,041	(12,267,950)
	Total before AUC	132,893,041	10,667,225	(79,179)	249,365	143,730,451	-	143,730,451		(55,941,279)	(4,827,959)	31,289	(23,992)	(60,761,942)	-	(60,761,942)	82,968,510
2055	Asset Under Construction	3,372,695	(1,037,000)	-	(234,065)	2,101,630	-	2,101,630		(7,802)	-	-	7,802	-	-	-	2,101,630
	Total after AUC	136,265,736	9,630,225	(79,179)	15,300	145,832,082	-	145,832,082		(55,949,081)	(4,827,959)	31,289	(16,190)	(60,761,942)	-	(60,761,942)	85,070,140

Table 2.1.2.5

APPENDIX 2-BA
CANADIAN NIAGARA POWER INC.
FIXED ASSETS CONTINUITY SCHEDULE
December 31, 2017

		COST								ACCUMULATED DEPRECIATION							NBV
OEB ACCT #	ACCOUNT DESCRIPTION	COST BEGINNING OF THE YEAR	ADDITIONS	DISPOSALS	ADJUSTMENTS	COST END OF PERIOD	ALLOCATIONS	ADJUSTED COST END OF PERIOD	USEFUL LIFE	ACC DEP'N BEGINNING OF THE YEAR	ADDITIONS	DISPOSALS	ADJUSTMENTS	ACC DEP'N END OF PERIOD	ALLOCATIONS	ADJUSTED ACC DEP'N END OF PERIOD	
1606	Organization & Rec	-	-	-	-	-	-	-	40	-	-	-	-	-	-	-	-
1608	Franchises & Consents	156,053	-	-	-	156,053	-	156,053	40	(50,717)	(3,901)	-	-	(54,619)	-	(54,619)	101,434
1610	Misc. Intangible Plant	40,576	-	-	-	40,576	-	40,576	40	(7,738)	(1,014)	-	-	(8,753)	-	(8,753)	31,823
1611	GA Comp Software	1,643,976	300,531	-	-	1,944,507	-	1,944,507	5	(643,712)	(320,823)	-	-	(964,535)	-	(964,535)	979,972
1611A	GA Comp Software	11,934,916	973,496	-	-	12,908,412	-	12,908,412	10	(7,878,639)	(747,753)	-	-	(8,626,392)	-	(8,626,392)	4,282,021
1612	D Land Rights	346,296	20,517	-	-	366,814	-	366,814	40	(112,730)	(7,657)	-	-	(120,387)	-	(120,387)	246,427
1805	D Land	211,516	123,387	-	-	334,903	-	334,903		-	-	-	-	-	-	-	334,903
1808	D Bldgs & Fixtures	3,709,825	32,472	-	-	3,742,297	-	3,742,297	50	(1,141,485)	(74,521)	-	-	(1,216,006)	-	(1,216,006)	2,526,291
1820	D Station Equipment < 50KV	12,020,736	118,700	-	-	12,139,436	-	12,139,436	50	(3,556,228)	(233,158)	-	-	(3,789,386)	-	(3,789,386)	8,350,051
1820A	D Station Equipment < 50KV	3,918,811	1,350,963	-	-	5,269,774	-	5,269,774	40	(407,403)	(114,267)	-	-	(521,669)	-	(521,669)	4,748,105
1830	D Poles,Towers&Fixtures	28,087,225	2,367,461	-	-	30,454,686	-	30,454,686	45	(11,039,705)	(679,601)	-	-	(11,719,306)	-	(11,719,306)	18,735,380
1835	D OH Cond & Devices	33,903,771	1,347,941	-	-	35,251,712	-	35,251,712	45	(10,627,624)	(784,794)	-	-	(11,412,418)	-	(11,412,418)	23,839,295
1840	D UG Conduit & Manholes	1,382,253	239,209	-	-	1,621,462	-	1,621,462	50	(500,814)	(26,179)	-	-	(526,993)	-	(526,993)	1,094,469
1845	D UG Cond & Devices	9,475,545	226,194	-	-	9,701,740	-	9,701,740	40	(2,519,935)	(232,144)	-	-	(2,752,078)	-	(2,752,078)	6,949,661
1850	D Line Transformers	17,147,704	1,636,697	-	-	18,784,401	-	18,784,401	40	(6,592,904)	(499,631)	-	-	(7,092,535)	-	(7,092,535)	11,691,866
1855	D Services	11,604,602	512,630	-	-	12,117,232	-	12,117,232	40	(3,545,670)	(273,594)	-	-	(3,819,265)	-	(3,819,265)	8,297,968
1860	D Meters	624,091	-	-	-	624,091	-	624,091	30	(220,805)	(19,061)	-	-	(239,865)	-	(239,865)	384,226
1860A	D Meters	5,661,288	196,252	-	-	5,857,540	-	5,857,540	15	(2,587,944)	(457,504)	-	-	(3,045,448)	-	(3,045,448)	2,812,092
1860B	D Meters	672,210	81,202	-	-	753,412	-	753,412	30	(348,991)	(21,123)	-	-	(370,114)	-	(370,114)	383,297
1865	D Other Install on Cust Prem	133,938	-	-	-	133,938	-	133,938	10	(84,341)	(13,394)	-	-	(97,735)	-	(97,735)	36,203
1875	D St Lites & Signal Systems	-	-	-	-	-	-	-	20	-	-	-	-	-	-	-	-
1908	GA Bldgs & Fixtures	932,520	20,000	-	-	952,520	-	952,520	50	(236,903)	(18,850)	-	-	(255,754)	-	(255,754)	696,766
1910	GA Leasehold Improvements	934,889	85,389	-	-	1,020,277	-	1,020,277	5	(677,631)	(114,298)	-	-	(791,929)	-	(791,929)	228,348
1915	GA Office Furn & Equipment	1,523,666	23,500	-	-	1,547,166	-	1,547,166	10	(1,362,016)	(24,964)	-	-	(1,386,980)	-	(1,386,980)	160,187
1920	GA Comp Hardware	4,315,108	354,153	-	-	4,669,261	-	4,669,261	5	(3,491,268)	(320,898)	-	-	(3,812,165)	-	(3,812,165)	857,095
1930	GA Transportation Equipment	667,029	17,500	-	-	684,529	-	684,529	5	(509,017)	(64,417)	-	-	(573,433)	-	(573,433)	111,096
1930A	GA Transportation Equipment	3,759,215	157,500	-	-	3,916,715	-	3,916,715	10	(2,293,451)	(301,571)	-	-	(2,595,022)	-	(2,595,022)	1,321,693
1935	GA Stores Equip	166,638	-	-	-	166,638	-	166,638	10	(166,638)	-	-	-	(166,638)	-	(166,638)	-
1940	GA tools,shop&garage equip	919,792	60,000	-	-	979,792	-	979,792	10	(736,211)	(30,700)	-	-	(766,911)	-	(766,911)	212,882
1945	GA measure&test equip	515,191	-	-	-	515,191	-	515,191	10	(483,792)	(5,282)	-	-	(489,074)	-	(489,074)	26,117
1950	GA power op equip	127,339	18,000	-	-	145,339	-	145,339	10	(103,462)	(5,114)	-	-	(108,575)	-	(108,575)	36,764
1955	GA Comm Equipment	1,148,487	43,463	-	-	1,191,950	-	1,191,950	10	(854,574)	(82,203)	-	-	(936,777)	-	(936,777)	255,172
1960	GA Misc. Equip	85,031	-	-	-	85,031	-	85,031	10	(71,841)	(3,088)	-	-	(74,929)	-	(74,929)	10,102
1960A	GA Misc. Equip	91,387	-	-	-	91,387	-	91,387	5	(76,780)	(4,797)	-	-	(81,577)	-	(81,577)	9,810
1980	GA System Supv Equip	1,046,816	-	-	-	1,046,816	-	1,046,816	20	(741,014)	(21,401)	-	-	(762,415)	-	(762,415)	284,401
1995	Contributions & Grants	(15,177,990)	(550,000)	-	-	(15,727,990)	-	(15,727,990)		2,910,041	332,872	-	-	3,242,913	-	3,242,913	(12,485,078)
	Total before AUC	143,730,451	9,757,158	-	-	153,487,610	-	153,487,610		(60,761,942)	(5,174,828)	-	-	(65,936,769)	-	(65,936,769)	87,550,840
2055	Asset Under Construction	2,101,630	-	-	-	2,101,630	-	2,101,630		-	-	-	-	-	-	-	2,101,630
	Total after AUC	145,832,082	9,757,158	-	-	155,589,240	-	155,589,240		(60,761,942)	(5,174,828)	-	-	(65,936,769)	-	(65,936,769)	89,652,471

GROSS FIXED ASSET TABLE

See Table 2.1.3.1 below for a gross fixed asset table showing year-over-year variances. Totals agree to Asset Continuity Schedules provided in Exhibit 2, Tab 1, Schedule 2.

TABLE 2-1-3-1
CANADIAN NIAGARA POWER INC.
GROSS FIXED ASSETS

OEB Account	Description	2013 Board Approved	2013 Actual	Variance from 2013 EDR	2014 Actual	Variance from 2013 Actual	2015 Actual	Variance from 2014 Actual	2016 Bridge	Variance from 2015 Actual	2017 Test	Variance from 2016 Bridge
	Intangibles											
1606	Organization	-	-	-	-	-	-	-	-	-	-	-
1608	Franchises and Consents	156,053	156,053	-	156,053	-	156,053	-	156,053	-	156,053	-
1610	Miscellaneous Intangible Plant	-	40,576	40,576	40,576	-	40,576	-	40,576	-	40,576	-
1611	Computer Software	4,467,521	4,227,200	(240,321)	4,382,076	154,876	4,669,157	287,081	13,578,892	8,909,735	14,852,919	1,274,027
1612	Land Rights	-	317,589	317,589	321,052	3,463	325,919	4,867	346,296	20,377	366,814	20,517
	Sub Total - Intangibles	**4,623,574**	**4,741,417**	**117,843**	**4,899,757**	**158,340**	**5,191,705**	**291,948**	**14,121,817**	**8,930,112**	**15,416,362**	**1,294,545**
	Land and Buildings											
1805	Land	211,728	208,084	(3,645)	208,084	-	206,654	(1,430)	211,516	4,862	334,903	123,387
1806	Land Rights	390,983		(390,983)		-		-		-		-
1808	Buildings and Fixtures	4,118,304	3,966,736	(151,568)	3,966,736	-	3,475,850	(490,886)	3,709,825	233,975	3,742,297	32,472
	Sub Total - Land and Buildings	**4,721,016**	**4,174,820**	**(546,196)**	**4,174,820**	**-**	**3,682,504**	**(492,316)**	**3,921,341**	**238,837**	**4,077,201**	**155,860**
	DS											
1820	Distribution Station Equipment - Normally Primary below 50 kV	13,150,339	12,122,166	(1,028,173)	12,229,479	107,312	13,891,585	1,662,107	15,939,547	2,047,962	17,409,210	1,469,663
	Sub Total - DS	**13,150,339**	**12,122,166**	**(1,028,173)**	**12,229,479**	**107,312**	**13,891,585**	**1,662,107**	**15,939,547**	**2,047,962**	**17,409,210**	**1,469,663**
	Poles and Wires											
1830	Poles, Towers and Fixtures	22,652,964	21,988,722	(664,242)	23,118,085	1,129,363	25,667,632	2,549,547	28,087,225	2,419,593	30,454,686	2,367,461
1835	Overhead Conductors and Devices	26,489,721	27,887,833	1,398,112	29,745,565	1,857,732	32,517,505	2,771,940	33,903,771	1,386,266	35,251,712	1,347,941
1840	Underground Conduit	1,316,383	1,061,295	(255,088)	1,068,685	7,391	1,173,463	104,778	1,382,253	208,790	1,621,462	239,209
1845	Underground Conductors and Devices	7,590,879	7,983,678	392,799	8,497,410	513,732	9,262,719	765,308	9,475,545	212,827	9,701,740	226,194
	Sub Total - Poles and Wires	**58,049,946**	**58,921,527**	**871,582**	**62,429,745**	**3,508,218**	**68,621,319**	**6,191,573**	**72,848,795**	**4,227,476**	**77,029,600**	**4,180,805**
	Line Transformers											
1850	Line Transformers	14,078,668	14,044,539	(34,130)	14,642,253	597,714	15,232,767	590,514	17,147,704	1,914,937	18,784,401	1,636,697
	Sub Total - Line Transformers	**14,078,668**	**14,044,539**	**(34,130)**	**14,642,253**	**597,714**	**15,232,767**	**590,514**	**17,147,704**	**1,914,937**	**18,784,401**	**1,636,697**
	Services and Meters											
1855	Services	10,347,664	9,752,921	(594,743)	10,308,254	555,334	10,879,936	571,682	11,604,602	724,666	12,117,232	512,630
1860	Meters	6,019,066	6,085,530	66,463	6,278,898	193,368	6,483,596	204,698	6,957,588	473,992	7,235,042	277,454
1865	Other Installations on Customer's Premises	127,878	133,772	5,894	133,938	166	133,938	-	133,938	-	133,938	-
	Sub Total - Services and Meters	**16,494,608**	**15,972,222**	**(522,386)**	**16,721,090**	**748,868**	**17,497,470**	**776,380**	**18,696,129**	**1,198,659**	**19,486,213**	**790,084**
	General Plant											
1908	Buildings and Fixtures	992,660	890,495	(102,165)	906,380	15,885	912,520	6,139	932,520	20,000	952,520	20,000
1910	Leasehold Improvements	471,814	695,250	223,436	840,175	144,925	885,142	44,967	934,889	49,746	1,020,277	85,389
	Sub Total - General Plant	**1,464,474**	**1,585,745**	**121,271**	**1,746,555**	**160,810**	**1,797,662**	**51,107**	**1,867,408**	**69,746**	**1,972,797**	**105,389**
	Equipment											
1915	Office Furniture and Equipment	1,100,462	1,098,382	(2,080)	1,078,584	(19,798)	1,130,676	52,092	1,523,666	392,990	1,547,166	23,500
1930	Transportation Equipment	3,697,222	3,123,754	(573,468)	3,232,075	108,321	3,284,410	52,334	4,426,244	1,141,834	4,601,244	175,000
1935	Stores Equipment	133,408	133,311	(97)	124,645	(8,665)	124,645	-	166,638	41,993	166,638	-
1940	Tools, Shop and Garage Equipment	597,154	620,574	23,419	631,179	10,605	664,274	33,095	919,792	255,518	979,792	60,000
1945	Measurement and Testing Equipment	425,093	386,529	(38,564)	385,816	(713)	390,320	4,504	515,191	124,871	515,191	-
1950	Power Operated Equipment	109,339	109,339	-	109,339	-	109,339	-	127,339	18,000	145,339	18,000
1955	Communication Equipment	895,654	879,432	(16,222)	835,862	(43,570)	841,264	5,403	1,148,487	307,222	1,191,950	43,463
1960	Miscellaneous Equipment	437,969	114,752	(323,217)	128,425	13,673	138,509	10,085	176,418	37,909	176,418	-
	Sub Total - Equipment	**7,396,302**	**6,466,073**	**(930,229)**	**6,525,925**	**59,852**	**6,683,439**	**157,514**	**9,003,776**	**2,320,337**	**9,323,739**	**319,963**
	IT Assets											
1920	Computer Equipment - Hardware	1,340,098	1,300,368	(39,730)	1,335,939	35,570	1,364,375	28,436	4,315,108	2,950,734	4,669,261	354,153
1925	Computer Software	-		-		-		-		-		-
	Sub Total - IT Assets	**1,340,098**	**1,300,368**	**(39,730)**	**1,335,939**	**35,570**	**1,364,375**	**28,436**	**4,315,108**	**2,950,734**	**4,669,261**	**354,153**
	Other Distribution Assets											
1980	System Supervisory Equipment	740,344	662,181	(78,163)	625,028	(37,152)	783,570	158,542	1,046,816	263,246	1,046,816	-
	Sub Total - Other Distribution Assets	**740,344**	**662,181**	**(78,163)**	**625,028**	**(37,152)**	**783,570**	**158,542**	**1,046,816**	**263,246**	**1,046,816**	**-**
	Contributions and Grants											
1995	Contributions and Grants - Credit	(10,216,811)	(10,785,703)	(568,891)	(12,443,472)	(1,657,770)	(13,707,783)	(1,264,311)	(15,177,990)	(1,470,207)	(15,727,990)	(550,000)
	Sub Total - Contributions and Grants	**(10,216,811)**	**(10,785,703)**	**(568,891)**	**(12,443,472)**	**(1,657,770)**	**(13,707,783)**	**(1,264,311)**	**(15,177,990)**	**(1,470,207)**	**(15,727,990)**	**(550,000)**
	GROSS ASSETS TOTAL	**111,842,558**	**109,205,357**	**(2,637,201)**	**112,887,119**	**3,681,763**	**121,038,612**	**8,151,493**	**143,730,451**	**22,691,839**	**153,487,610**	**9,757,158**

OVERVIEW OF ALLOWANCE FOR WORKING CAPITAL

The Working Capital Allowance for CNPI is forecasted to be $5,459,030 for 2017. CNPI has applied the 7.5% default Working Capital Allowance in accordance with the OEB letter dated June 3, 2015, Allowance for Working Capital for Electricity Distribution Rate Applications which states:

“Effective immediately, the OEB is adopting a new default value of 7.5% of the sum of the cost of power and operating, maintenance and administration (OM&A) costs.”

CNPI has provided its calculations by account for each of 2013 Board Approved, 2013 Actuals, 2014 Actuals, 2015 Actuals, 2016 Bridge Year and the 2017 Test Year. Details of the calculations have been provided in Exhibit 2, Tab 1, Schedule 6.

For 2017, the power purchased amount is based on the normalized load forecast as described in Exhibit 3 and the current RPP and Non-RPP commodity estimates of $0.10730/kWh and $0.10850/kWh respectively.

The rates used for the Wholesale Market Service Charge, and the Rural or Remote Rate Protection Charge are the most recently approved by the Board for CNPI; these are:

- Wholesale Market Service Charge $0.0036/kWh, and
- Rural or Remote Rate Protection Charge $0.0013/kWh.

The forecasted costs for the Retail Transmission Service Rates are calculated on the basis of the normalized volumes forecast and the rates generated by the Board’s Retail Transmission Service Rate Workform completed for CNPI in Exhibit 8, Tab 2, Schedule 2.

There are low voltage charges from Hydro One in CNPI’s service territories in Port Colborne and Gananoque. The recovery of these costs is discussed in Exhibit 8, Tab 2, Schedule 7. These Low Voltage Service Charges are included within the Cost of Power calculations in the Allowance for Working Capital.

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7.5% ALLOWANCE APPROACH

CNPI is not proposing to use a lead lag study in order to determine its working capital allowance. CNPI is using the 7.5% allowance approach where the allowance for working capital is calculated to be 7.5% of the sum of the cost of power and controllable expenses.

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CANADIAN NIAGARA POWER INC.
WORKING CAPITAL CALCULATION BY ACCOUNT

	Description	2013 Board Approved	Allowance for Working Capital	2013 Actual	Allowance for Working Capital	2014 Actual	Allowance for Working Capital	2015 Actual	Allowance for Working Capital	2016 Bridge	Allowance for Working Capital	2017 Test	Allowance for Working Capital
Rate Used for Working Capital Allowance			13%		13%		13%		13%		13%		7.5%
Power Supply Expenses													
4705	Power Purchased	42,565,293	5,533,488	30,301,863	3,939,242	33,313,173	4,330,713	32,994,508	4,289,286	53,125,980	6,906,377	52,392,230	3,929,417
4707	Charges-Global Adjustment	-	-	14,577,834	1,895,118	13,625,549	1,771,321	16,418,932	2,134,461	-	-	-	-
4708	Charges-WMS	3,361,894	437,046	2,602,917	338,379	2,898,036	376,745	1,989,046	258,576	2,956,205	384,307	2,915,488	218,662
4714	Charges-NW	3,579,733	465,365	3,462,801	450,164	3,567,475	463,772	3,397,929	441,731	3,686,173	479,202	3,633,726	272,529
4716	Charges-CN	2,834,436	368,477	2,766,655	359,665	2,795,622	363,431	2,742,713	356,553	2,968,325	385,882	2,926,130	219,460
4750	Charges - LV	112,688	14,649	31,809	4,135	23,092	3,002	49,241	6,401	105,494	13,714	103,998	7,800
4751	Charges-Smrt Mtr Charge	-	-	177,596	23,088	267,349	34,755	268,163	34,861	270,047	35,106	270,777	20,308
	Power Supply Expenses Total	**52,454,045**	**6,819,026**	**53,921,476**	**7,009,792**	**56,490,297**	**7,343,739**	**57,860,531**	**7,521,869**	**63,112,224**	**8,204,589**	**62,242,349**	**4,668,176**
Distribution Expenses - Operation													
5005	Operation Supervision and Engineering	151,373	19,679	21,436	2,787	95,309	12,390	70,274	9,136	64,726	8,414	125,073	9,381
5010	Load Dispatching	259,040	33,675	283,868	36,903	272,190	35,385	280,924	36,520	163,129	21,207	201,457	15,109
5012	Station Buildings and Fixtures Expense	146,117	18,995	155,142	20,169	161,605	21,009	152,244	19,792	185,937	24,172	190,156	14,262
5016	Distribution Station Equipment - Operation Labour	88,797	11,544	115,608	15,029	69,685	9,059	93,016	12,092	61,580	8,005	87,186	6,539
5017	Distribution Station Equipment - Operation Supplies and Expenses	14,237	1,851	11,136	1,448	6,193	805	3,435	446	18,540	2,410	12,662	950
5020	Overhead Distribution Lines and Feeders - Operation Labour	73,068	9,499	75,811	9,855	134,742	17,516	86,037	11,185	168,667	21,927	169,185	12,689
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	15,720	2,044	89,712	11,662	40,731	5,295	29,779	3,871	11,620	1,511	11,852	889
5035	Overhead Distribution Transformers- Operation	1,580	205	1,326	172	9,157	1,190	31,728	4,125	30,119	3,915	21,555	1,617
5040	Underground Distribution Lines and Feeders - Operation Labour	163,565	21,263	274,727	35,714	248,649	32,324	155,483	20,213	173,523	22,558	72,891	5,467
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	1,600	208	2,227	289	4,650	604	10,105	1,314	1,200	156	92,907	6,968
5055	Underground Distribution Transformers - Operation	8,168	1,062	-	-	2,356	306	7,581	986	8,160	1,061	4,718	354
5065	Meter Expense	324,504	42,186	289,776	37,671	334,674	43,508	359,287	46,707	405,592	52,727	484,963	36,372
5070	Customer Premises - Operation Labour	47,666	6,197	18,266	2,375	7,320	952	4,289	558	9,214	1,198	-	-
5075	Customer Premises - Materials and Expenses	6,000	780	734	95	3,373	438	4,195	545	-	-	-	-
5085	Miscellaneous Distribution Expense	160,112	20,815	193,872	25,203	299,116	38,885	370,143	48,119	291,095	37,842	318,291	23,872
5090	Underground Distribution Lines and Feeders - Rental Paid	-	-	-	-	-	-	6,926	900	25,000	3,250	15,000	1,125
5095	Overhead Distribution Lines and Feeders - Rental Paid	-	-	-	-	36,993	4,809	37,240	4,841	40,000	5,200	40,000	3,000
5096	Other Rent	3,000	390	-	-	-	-	-	-	-	-	-	-
	Distribution Expenses - Operation Total	**1,464,548**	**190,391**	**1,533,641**	**199,373**	**1,726,744**	**224,477**	**1,702,685**	**221,349**	**1,658,103**	**215,553**	**1,847,897**	**138,592**
Distribution Expenses - Maintenance													
5105	Maintenance Supervision and Engineering	98,183	12,764	123,446	16,048	24,520	3,188	33,812	4,396	10,704	1,392	22,193	1,664
5110	Maintenance of Buildings and Fixtures - Distribution Stations	37,206	4,837	42,585	5,536	42,743	5,557	44,792	5,823	56,339	7,324	26,657	1,999
5114	Maintenance of Distribution Station Equipment	152,233	19,790	91,026	11,833	124,428	16,176	192,235	24,990	145,430	18,906	138,424	10,382
5120	Maintenance of Poles, Towers and Fixtures	61,673	8,018	44,339	5,764	36,462	4,740	85,080	11,060	196,007	25,481	133,260	9,995
5125	Maintenance of Overhead Conductors and Devices	284,197	36,946	253,387	32,940	378,727	49,235	323,489	42,054	398,625	51,821	473,496	35,512
5130	Maintenance of Overhead Services	271,835	35,338	321,373	41,779	304,669	39,607	272,976	35,487	345,917	44,969	253,566	19,017
5135	Overhead Distribution Lines and Feeders - Right of Way	442,990	57,589	430,171	55,922	480,934	62,521	464,165	60,341	505,238	65,681	644,242	48,318
5145	Maintenance of Underground Conduit	-	-	-	-	1,812	236	4,651	605	2,492	324	6,294	472
5150	Maintenance of Underground Conductors and Devices	39,840	5,179	29,668	3,857	12,243	1,592	29,859	3,882	40,508	5,266	42,704	3,203
5155	Maintenance of Underground Services	45,093	5,862	42,128	5,477	43,711	5,682	61,012	7,932	41,350	5,376	54,873	4,115
5160	Maintenance of Line Transformers	95,141	12,368	124,816	16,226	76,671	9,967	31,679	4,118	29,902	3,887	35,141	2,636
5175	Maintenance of Meters	380,487	49,463	431,316	56,071	366,828	47,688	369,007	47,971	411,157	53,450	408,200	30,615
5195	Maintenance of Other Installations on Customer Premises	3,600	468	5,070	659	-	-	115	15	20,000	2,600	20,000	1,500
	Distribution Expenses - Maintenance Total	**1,912,478**	**248,622**	**1,939,325**	**252,112**	**1,893,749**	**246,187**	**1,912,871**	**248,673**	**2,203,670**	**286,477**	**2,259,049**	**169,429**
Billing and Collection													
5305	Supervision	167,557	21,782	148,484	19,303	147,872	19,223	135,935	17,672	158,638	20,623	165,581	12,419
5310	Meter Reading Expense	93,026	12,093	29,114	3,785	98,199	12,766	89,467	11,631	80,288	10,437	87,471	6,560
5315	Customer Billing	556,589	72,357	442,284	57,497	463,319	60,231	468,792	60,943	454,347	59,065	469,679	35,226
5320	Collecting	410,836	53,409	446,610	58,059	367,930	47,831	367,130	47,727	393,414	51,144	410,106	30,758
5335	Bad Debt Expense	252,000	32,760	208,129	27,057	188,227	24,470	218,239	28,371	241,000	31,330	262,000	19,650
5340	Miscellaneous Customer Accounts Expenses	581,045	75,536	600,158	78,021	502,817	65,366	475,044	61,756	546,571	71,054	565,189	42,389
	Billing and Collection Total	**2,061,053**	**267,937**	**1,874,779**	**243,721**	**1,768,363**	**229,887**	**1,754,606**	**228,099**	**1,874,259**	**243,654**	**1,960,026**	**147,002**
Community Relations													
5410	Community Relations - Sundry	-	-	657	85	560	73	46	6	-	-	-	-
5420	Community Safety Program	9,200	1,196	10,680	1,388	2,595	337	1,830	238	2,000	260	16,850	1,264
5425	Miscellaneous Customer Service and Informational Expenses	26,500	3,445	11,348	1,475	11,348	1,475	20,250	2,633	23,300	3,029	23,300	1,747
5660	General Advertising Expenses	5,000	650	3,730	485	2,504	326	12,169	1,582	3,000	390	3,000	225
	Community Relations Total	**40,700**	**5,291**	**26,414**	**3,434**	**17,007**	**2,211**	**34,295**	**4,458**	**28,300**	**3,679**	**43,150**	**3,236**

CANADIAN NIAGARA POWER INC.
WORKING CAPITAL CALCULATION BY ACCOUNT

	Description	2013 Board Approved	Allowance for Working Capital	2013 Actual	Allowance for Working Capital	2014 Actual	Allowance for Working Capital	2015 Actual	Allowance for Working Capital	2016 Bridge	Allowance for Working Capital	2017 Test	Allowance for Working Capital
Rate Used for Working Capital Allowance			13%		13%		13%		13%		13%		7.5%
Administrative and General Expenses													
5615	General Administrative Salaries and Expenses	4,672,729	607,455	4,696,520	610,548	4,188,822	544,547	4,240,805	551,305	4,334,864	563,532	4,421,266	331,595
5620	Office Supplies and Expenses	549,803	71,474	465,355	60,496	542,629	70,542	446,962	58,105	547,049	71,116	568,456	42,634
5625	Administrative Expense Transferred/Credit	(4,714,977)	(612,947)	(5,184,700)	(674,011)	(3,907,414)	(507,964)	(3,965,621)	(515,531)	(3,885,443)	(505,108)	(4,029,548)	(302,216)
5630	Outside Services Employed	460,697	59,891	447,726	58,204	430,877	56,014	480,141	62,418	542,688	70,549	553,334	41,500
5635	Property Insurance	58,000	7,540	77,757	10,108	60,782	7,902	58,797	7,644	63,200	8,216	56,300	4,223
5645	Employee Pensions and Benefits	1,189,718	154,663	1,266,141	164,598	1,119,788	145,572	1,098,811	142,845	1,045,633	135,932	1,107,967	83,098
5655	Regulatory Expenses	320,690	41,690	235,111	30,564	216,055	28,087	232,673	30,248	216,172	28,102	247,407	18,555
5665	Miscellaneous General Expenses	600,246	78,032	308,789	40,143	334,071	43,429	406,703	52,871	369,961	48,095	411,705	30,878
5670	Rent	342,711	44,552	342,711	44,552	335,868	43,663	342,585	44,536	349,437	45,427	342,503	25,688
5672	Lease Payment Expense	-	-	9,910	1,288	16,025	2,083	22,373	2,908	20,000	2,600	22,400	1,680
5675	Maintenance of General Plant	739,768	96,170	648,802	84,344	555,850	72,260	611,871	79,543	619,305	80,510	588,013	44,101
5680	Electrical Safety Authority Fees	-	-	-	-	13,830	1,798	14,385	1,870	17,860	2,322	17,900	1,342
5695	OM&A Contra Account	-	-	50,548	6,571	-	-	-	-	-	-	-	-
6205	Donations	21,099	2,743	22,759	2,959	22,759	2,959	22,759	2,959	22,759	2,959	23,900	1,793
	Administrative and General Expenses Total	**4,240,483**	**551,263**	**3,387,429**	**440,366**	**3,929,942**	**510,893**	**4,013,244**	**521,722**	**4,263,484**	**554,253**	**4,331,601**	**324,870**
Taxes													
6105	Taxes Other Than Income Taxes (Note less capital taxes)	116,700	15,171	102,475	13,322	99,008	12,871	101,233	13,160	103,000	13,390	103,000	7,725
	Taxes Total	**116,700**	**15,171**	**102,475**	**13,322**	**99,008**	**12,871**	**101,233**	**13,160**	**103,000**	**13,390**	**103,000**	**7,725**
Working Capital Allowance Total		**62,290,005**	**8,097,701**	**62,785,539**	**8,162,120**	**65,925,111**	**8,570,264**	**67,379,465**	**8,759,330**	**73,243,040**	**9,521,595**	**72,787,072**	**5,459,030**

CALCULATION OF COST OF POWER

CNPI has calculated the cost of power for the 2016 Bridge Year and the 2017 Test Year based on the forecast discussed in Exhibit 3. The commodity price used to calculate commodity costs were the prices published in the Board's Regulated Price Plan Report – November 1, 2015 to October 31, 2016 dated October 15, 2015. CNPI acknowledges that the Board may revise its Regulated Price Plan Report.

The components of CNPI's cost of power are:

- Commodity (RPP and Non-RPP pricing)
- Wholesale Market Service
- Rural Rate Assistance
- Retail Transmission Service Charge – Network
- Retail Transmission Service Charge – Connection
- Low Voltage Charge
- Smart Meter Entity
- Ontario Electricity Support Program Charge

Commodity Expense

Commodity expenses have been calculated for the 2016 Bridge Year and the 2017 Test Year using the RPP and Non-RPP commodity costs of $0.1073 and $0.1085 per kWh respectively. These values were derived from the Board's Regulated Price Plan Report – November 1, 2015 to October 31, 2016 dated October 15, 2015. Forecasted volumes are taken from the forecast discussed in Exhibit 3 and are adjusted for losses.

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2016 Commodity Expense - RPP				
	kWh	Loss Factor	RPP Price	Amount
Residential	185,566,763	1.0542	0.10730	20,990,507
GS < 50 kW	57,631,679	1.0542	0.10730	6,519,045
GS 50 to 4,999 kW	17,092,945	1.0542	0.10730	1,933,480
Embedded Dx	-	1.0542	0.10730	-
USL	1,478,170	1.0542	0.10730	167,204
Sentinel Lighting	659,331	1.0542	0.10730	74,581
Street Lighting	68,548	1.0542	0.10730	7,754
Total	262,497,435			$ 29,692,571

2017 Commodity Expense - RPP				
	kWh	Loss Factor	RPP Price	Amount
Residential	184,595,984	1.0542	0.10730	20,880,697
GS < 50 kW	57,017,333	1.0542	0.10730	6,449,553
GS 50 to 4,999 kW	16,713,281	1.0542	0.10730	1,890,534
Embedded Dx	-	1.0542	0.10730	-
USL	1,456,709	1.0542	0.10730	164,777
Sentinel Lighting	629,014	1.0542	0.10730	71,151
Street Lighting	59,830	1.0542	0.10730	6,768
Total	260,472,152			$ 29,463,479

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2016 Commodity Expense - Non-RPP				
	kWh	Loss Factor	Non-RPP Price	Amount
Residential	13,552,718	1.0542	0.10850	1,550,169
GS < 50 kW	11,007,336	1.0542	0.10850	1,259,027
GS 50 to 4,999 kW	172,052,511	1.0542	0.10850	19,679,487
Embedded Dx	5,135,041	1.0542	0.10850	587,350
USL	6,141	1.0542	0.10850	702
Sentinel Lighting	-	1.0542	0.10850	-
Street Lighting	3,118,303	1.0542	0.10850	356,674
Total	204,872,050			$ 23,433,408

2017 Commodity Expense - Non-RPP				
	kWh	Loss Factor	Non-RPP Price	Amount
Residential	13,481,818	1.0542	0.10850	1,542,060
GS < 50 kW	10,889,999	1.0542	0.10850	1,245,606
GS 50 to 4,999 kW	168,230,922	1.0542	0.10850	19,242,371
Embedded Dx	5,129,448	1.0542	0.10850	586,710
USL	6,052	1.0542	0.10850	692
Sentinel Lighting	-	1.0542	0.10850	-
Street Lighting	2,721,726	1.0542	0.10850	311,313
Total	200,459,965			$ 22,928,751

Wholesale Market Service Expense

Wholesale Market Service expenses have been calculated for the 2016 Bridge Year and the 2017 Test Year using the currently prescribed rate of $0.0036 per kWh. Forecasted volumes are taken from the forecast discussed in Exhibit 3 and are adjusted for losses.

2016 Wholesale Market Service				
	Volume	Loss Factor	Rate	Amount
Residential	199,119,481	1.0542	0.0036	755,682
GS < 50 kW	68,639,015	1.0542	0.0036	260,493
GS 50 to 4,999 kW	189,145,457	1.0542	0.0036	717,830
Embedded Dx	5,135,041	1.0542	0.0036	19,488
USL	1,484,310	1.0542	0.0036	5,633
Sentinel Lighting	659,331	1.0542	0.0036	2,502
Street Lighting	3,186,850	1.0542	0.0036	12,094
Total	467,369,485			$ 1,773,723

2017 Wholesale Market Service				
	Volume	Loss Factor	Rate	
Residential	198,077,803	1.0542	0.0036	751,729
GS < 50 kW	67,907,332	1.0542	0.0036	257,716
GS 50 to 4,999 kW	184,944,203	1.0542	0.0036	701,885
Embedded Dx	5,129,448	1.0542	0.0036	19,467
USL	1,462,761	1.0542	0.0036	5,551
Sentinel Lighting	629,014	1.0542	0.0036	2,387
Street Lighting	2,781,556	1.0542	0.0036	10,556
Total	460,932,116			$ 1,749,293

Rural Rate Assistance Expense

Rural Rate Assistance expenses have been calculated for the 2016 Bridge Year and the 2017 Test Year using a calculated rate of $0.0013 per kWh. Forecasted volumes are taken from the forecast discussed in Exhibit 3 and are adjusted for losses.

2016 Rural Rate Assistance				
	Volume	Loss Factor	Rate	Amount
Residential	199,119,481	1.0542	0.00130	272,885
GS < 50 kW	68,639,015	1.0542	0.00130	94,067
GS 50 to 4,999 kW	189,145,457	1.0542	0.00130	259,216
Embedded Dx	5,135,041	1.0542	0.00130	7,037
USL	1,484,310	1.0542	0.00130	2,034
Sentinel Lighting	659,331	1.0542	0.00130	904
Street Lighting	3,186,850	1.0542	0.00130	4,367
Total	467,369,485			$ 640,511

2017 Rural Rate Assistance				
	Volume	Loss Factor	Rate	Amount
Residential	198,077,803	1.0542	0.00130	271,458
GS < 50 kW	67,907,332	1.0542	0.00130	93,064
GS 50 to 4,999 kW	184,944,203	1.0542	0.00130	253,459
Embedded Dx	5,129,448	1.0542	0.00130	7,030
USL	1,462,761	1.0542	0.00130	2,005
Sentinel Lighting	629,014	1.0542	0.00130	862
Street Lighting	2,781,556	1.0542	0.00130	3,812
Total	460,932,116			$ 631,689

Transmission Network and Connection Expense

Transmission Network and Connection expenses have been calculated for the 2016 Bridge Year and the 2017 Test Year. The Retail Transmission Service Rates are the most recently Board Approved rates for CNPI. Forecasted volumes are taken from the forecast discussed in Exhibit 3 and are adjusted for losses.

2016 Retail Transmission - Network					
	UOM	Volume	Loss Factor	Rate	Amount
Residential	kWh	199,119,481	1.0542	0.0072	1,511,365
GS < 50 kW	kWh	68,639,015	1.0542	0.0061	441,391
GS 50 to 4,999 kW	kW	606,862	1.0542	2.5966	1,661,186
Embedded Dx	kW	13,732	1.0542	2.5966	37,589
USL	kWh	1,484,310	1.0542	0.0064	10,014
Sentinel Lighting	kW	2,008	1.0542	2.2129	4,685
Street Lighting	kW	9,843	1.0542	1.9219	19,942
Total					$ 3,686,173

2017 Retail Transmission - Network					
	UOM	Volume	Loss Factor	Rate	Amount
Residential	kWh	198,077,803	1.0542	0.0072	1,503,458
GS < 50 kW	kWh	67,907,332	1.0542	0.0061	436,686
GS 50 to 4,999 kW	kW	593,383	1.0542	2.5966	1,624,288
Embedded Dx	kW	13,717	1.0542	2.5966	37,548
USL	kWh	1,462,761	1.0542	0.0064	9,869
Sentinel Lighting	kW	1,916	1.0542	2.2129	4,470
Street Lighting	kW	8,591	1.0542	1.9219	17,406
Total					$ 3,633,726

2016 Retail Transmission - Connection					
	UOM	Volume	Loss Factor	Rate	Amount
Residential	kWh	199,119,481	1.0542	0.0058	1,217,488
GS < 50 kW	kWh	68,639,015	1.0542	0.0050	361,796
GS 50 to 4,999 kW	kW	606,862	1.0542	2.0803	1,330,881
Embedded Dx	kW	13,732	1.0542	2.0803	30,115
USL	kWh	1,484,310	1.0542	0.0051	7,980
Sentinel Lighting	kW	2,008	1.0542	1.6977	3,594
Street Lighting	kW	9,843	1.0542	1.5873	16,471
Total					$ 2,968,325

2017 Retail Transmission - Connection					
	UOM	Volume	Loss Factor	Rate	Amount
Residential	kWh	198,077,803	1.0542	0.0058	1,211,119
GS < 50 kW	kWh	67,907,332	1.0542	0.0050	357,940
GS 50 to 4,999 kW	kW	593,383	1.0542	2.0803	1,301,320
Embedded Dx	kW	13,717	1.0542	2.0803	30,082
USL	kWh	1,462,761	1.0542	0.0051	7,864
Sentinel Lighting	kW	1,916	1.0542	1.6977	3,429
Street Lighting	kW	8,591	1.0542	1.5873	14,376
Total					$ 2,926,130

Low Voltage Charge

Low Voltage expenses have been calculated for the 2016 Bridge Year and the 2017 Test Year using the most recently Board Approved rates for CNPI. Forecasted volumes are taken from the forecast discussed in Exhibit 3.

2016 Low Voltage Charge				
	Volume	Loss Factor	Rate	Amount
Residential	199,119,481	1.0542	0.0002	41,982
GS < 50 kW	68,639,015	1.0542	0.0002	14,472
GS 50 to 4,999 kW	606,862	1.0542	0.0735	47,022
Embedded Dx	13,732	1.0542	0.0735	1,064
USL	1,484,310	1.0542	0.0002	313
Sentinel Lighting	2,008	1.0542	0.0542	115
Street Lighting	9,843	1.0542	0.0507	526
Total	269,875,252			$ 105,494

2017 Low Voltage Charge				
	Volume	Loss Factor	Rate	
Residential	198,077,803	1.0542	0.0002	41,763
GS < 50 kW	67,907,332	1.0542	0.0002	14,318
GS 50 to 4,999 kW	593,383	1.0542	0.0735	45,978
Embedded Dx	13,717	1.0542	0.0735	1,063
USL	1,462,761	1.0542	0.0002	308
Sentinel Lighting	1,916	1.0542	0.0542	109
Street Lighting	8,591	1.0542	0.0507	459
Total	268,065,502			$ 103,998

Smart Metering Entity Expense

Smart Metering Entity expenses have been calculated for the 2016 Bridge Year and the 2017 Test Year using the currently prescribed rate of $0.0079 per applicable customer per month. Forecasted customer counts are taken from the forecast discussed in Exhibit 3.

2016 Smart Meter Entity Charge			
	Volume	Rate	Amount
Residential	25,995	0.79	246,433
GS < 50 kW	2,491	0.79	23,615
GS 50 to 4,999 kW			
Embedded Dx			
USL			
Sentinel Lighting			
Street Lighting			
Total	25,995		$ 270,047

2017 Smart Meter Entity Charge			
	Volume	Rate	
Residential	26,074	0.79	247,182
GS < 50 kW	2,489	0.79	23,596
GS 50 to 4,999 kW			
Embedded Dx			
USL			
Sentinel Lighting			
Street Lighting			
Total	26,074		$ 270,777

Ontario Electricity Support Program Charge

Ontario Electricity Support Program expenses have been calculated for the 2016 Bridge Year and the 2017 Test Year using the most recently Board Approved rates for CNPI. Forecasted volumes are taken from the forecast discussed in Exhibit 3.

2016 Ontario Electricity Support Program Charge				
	Volume	Loss Factor	Rate	Amount
Residential	199,119,481	1.0542	0.0011	230,903
GS < 50 kW	68,639,015	1.0542	0.0011	79,595
GS 50 to 4,999 kW	189,145,457	1.0542	0.0011	219,337
Embedded Dx	5,135,041	1.0542	0.0011	5,955
USL	1,484,310	1.0542	0.0011	1,721
Sentinel Lighting	659,331	1.0542	0.0011	765
Street Lighting	3,186,850	1.0542	0.0011	3,696
Total	467,369,485			$ 541,971

2017 Ontario Electricity Support Program Charge				
	Volume	Loss Factor	Rate	
Residential	198,077,803	1.0542	0.0011	229,695
GS < 50 kW	67,907,332	1.0542	0.0011	78,747
GS 50 to 4,999 kW	184,944,203	1.0542	0.0011	214,465
Embedded Dx	5,129,448	1.0542	0.0011	5,948
USL	1,462,761	1.0542	0.0011	1,696
Sentinel Lighting	629,014	1.0542	0.0011	729
Street Lighting	2,781,556	1.0542	0.0011	3,226
Total	460,932,116			$ 534,506

Power Supply Expense

The resultant power supply expense for the 2016 Bridge Year and the 2017 Test Year are summarized in the following tables.

2016 Cost of Power Expense Summary	
Charge Type	Amount
4705 - Cost of Power	$ 53,125,979
4708 - Charges - WMS	$ 1,773,723
4714 - Charges - NW	$ 3,686,173
4716 - Charges - CN	$ 2,968,325
4750 - Low Voltage Charge	$ 105,494
4730 - Charges - Rural Rate Assistance	$ 640,511
4751 - Charges - IESO SME	$ 270,047
4708 - OESP Charge	$ 541,971
Total	$ 63,112,224

2017 Cost of Power Expense Summary	
Charge Type	Amount
4705 - Cost of Power	$ 52,392,230
4708 - Charges - WMS	$ 1,749,293
4714 - Charges - NW	$ 3,633,726
4716 - Charges - CN	$ 2,926,130
4750 - Low Voltage Charge	$ 103,998
4730 - Charges - Rural Rate Assistance	$ 631,689
4751 - Charges - IESO SME	$ 270,777
4708 - OESP Charge	$ 534,506
Total	$ 62,242,349

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TREATMENT OF STRANDED ASSETS RELATED TO MIST DEPLOYMENT

Background

In 2014 the OEB made amendments to the DSC such that MIST meters were required to be installed for customers that had a monthly peak demand over 50 kW. This implementation was to be completed by August 21, 2020. CNPI commenced and substantially completed its MIST meter installations on 145 customers during 2015. Consequently, 145 meters have been stranded as a result of this implementation.

In the OEB's March 2015 Accounting Procedures Handbook Guidance, the OEB directed distributors to be guided by the various Board documents related to record-keeping and disposition of smart meter costs and these have been referred to below.

On December 15, 2011, the OEB issued Guideline G-2011-0001 "Smart Meter Funding and Cost Recovery – Final Disposition." This guideline included filing instructions related to the recovery of stranded meter costs associated with Smart Metering activities conducted by electricity distributors. The OEB's rules provide that "distributors be held whole with respect to the cost recovery of stranded meters."

In this Application, CNPI is requesting to recover its stranded meter costs, in the form of rate riders, over a five year period, from January 1, 2017 to December 31, 2021. A rate rider of $3.60 per customer per month has been calculated.

The Board's Guideline: Smart Meter Funding and Cost Recovery (G-2008-0002) provides two options to distributors regarding the accounting treatment of stranded meters. Option one was to record them in "Sub-account Stranded Meter Costs" of Account 1555 ("Scenario A"), while option two was to leave them in rate base ("Scenario B"). CNPI has utilized Scenario B.

Scenario B

As meters that were in service were replaced with MIST meters, they continued to be depreciated in CNPI's accounting records, with depreciation expense included in OEB 5705 and accumulated depreciation recorded in OEB 2105. The original capital costs of these stranded meters remained in OEB 1860. For 2016, depreciation expense has also been calculated to allow for a forecasted residual net book value balance as at December 31, 2016. As shown in Table 2.1.8.1 below, the residual net book value of the stranded meters that were taken out of service has been forecasted to be $47,890 as at December 31, 2016. A nominal proceeds amount equivalent roughly to metal scrap value has been forecasted to be recovered.

Table 2.1.8.1

Table 2.1.8.1 Stranded Meter Treatment (Scenario B)
Appendix 2-S
Stranded Meter Treatment

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2007					$ -		$ -
2008					$ -		$ -
2009					$ -		$ -
2010					$ -		$ -
2011					$ -		$ -
2012					$ -		$ -
2013					$ -		$ -
2014					$ -		$ -
2015		$ 79,179	$ 25,361		$ 53,818		$ 53,818
2016	(1)	$ 79,179	$ 31,289		$ 47,890	$ 1,000	$ 46,890

Notes:

(1) *For 2016, the amounts provided are on a forecasted basis*

Disposition Calculation

Table 2.1.8.2 below outlines the rate rider calculated on the Stranded Meter balance of $46,890, over a five year period beginning January 1, 2017. The rate rider was calculated using the average metered customers in the General Service >50 kW rate class for the

2017 Test Year. A five year recovery period was elected so as to calculate a rider that was reasonable within the bill impact models completed in Exhibit 8 of this Application.

Table 2.1.8.2

Table 2.1.8.2 Calculation of Stranded Meter Rate Rider

	Total
Number of Meters Installed (2015):	145
Stranded Meter Costs	
Scenario A	$ -
Scenario B	$ 46,890
	$ 46,890
Average Metered Customers for 2017 Test Year	217
Recovery Period in Months	60
Stranded Meter Disposition Rate Rider	**$ 3.60**

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CAPITAL EXPENDITURES

- Appendix A – Distribution System Plan (DSP)
- Appendix B – Capital Projects (Appendix 2-AA)
- Appendix C – Capital Expenditures (Appendix 2-AB)

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Appendix A
Distribution System Code (DSP)

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2016

Distribution System Plan

Revision: 1.44

Revision Date: April 26, 2016

Print Date: April 27, 2016

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TABLE OF FIGURES

(Note that the above entries are hyperlinked to location of Figure in this document)

5 CNPI Distribution System Plan

This document outlines the current Distribution System Plan (DSP) for Canadian Niagara Power Inc. (CNPI).

It was prepared to conform to the *Ontario Energy Board Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5, Consolidated Distribution System Plan Filing Requirements, March 28, 2013* (“Chapter 5”)

As such, it will often refer to and include aspects of CNPI’s Distribution Asset Management Plan (DAMP), which is a summary document of CNPI’s Asset Management process that was created prior to 2013, but maintained and updated on a regular basis.

5.0 Introduction

5.0.1 Non-Disclosure

This document does not contain private customer information or confidential future business plans.

5.0.2 Executive Summary

Canadian Niagara Power Inc. (CNPI) has prepared its Distribution System Plan (DSP) with a focus on its core values and objectives:

(i) Provide for the growth needs of its customers in the various service territories

(ii) Provide safe, reliable, and high-quality service to all of the customers of CNPI

(iii) Satisfy the first two principles in a sustainable manner which manages the long-term costs to be borne by the ratepayers of CNPI.

This objective is met through the application of thorough and sound planning, prudent and justified budgeting, and ongoing oversight, documentation, and review of all efforts and expenditures while implementing the documented capital and operating plans. CNPI believes that it has met these objectives, as outlined in this DSP.

The main challenges facing CNPI today can be summarized as:

1) Managing our asset life cycles to ensure timely replacement of critical assets as they reach or near the end of their useful lives. CNPI has significant distribution assets that are aged.

2) Elimination of legacy three-wire Delta systems that represent safety and operational concerns. CNPI has been engaged in voltage conversion programs for some time, and this challenge represents a focus for CNPI in its capital program over the entire forecast period of 2016-2021, and beyond.

3) Dealing with the first two challenges in a prudent and sustainable manner that maintains system reliability and customer satisfaction, maximizes operational efficiency, and addresses worker and public safety; all while focusing on the need to manage overall costs and the associated impacts on CNPI's distribution rates.

CNPI capital expenditures over the historical period and estimated capital expenditures during the forecasted period are set out in Figure 5.0.4.2-1.

The proposed capital expenditures of CNPI in the test year and forecast period in each of the investment categories may be summarized as follows:

System Access

System Access (SA) projects fall into two general classes.

The first is in response to customer requests for connections. CNPI must complete requested connections in order to meet customer needs and remain compliant with regulations.

The second class is 3rd party requests to upgrade or relocate portions of the distribution system in response to the needs of Joint Use partners or Municipal roadway authorities. Some of the gross expenditures in the SA category are offset by Contributions In Aid of Construction (CIACs) from the requesting parties as required by the Distribution System Code (DSC), CNPI's Condition of Service, or by directly negotiated agreement.

As projects of this non-discretionary category are driven by external stakeholders, the planning process by CNPI for SA projects must be somewhat reactive in nature.

System Renewal

System Renewal (SR) has historically been CNPI's largest investment category and will remain so throughout the forecast period. There are two main drivers in the SR category throughout the forecast period:

- Managing our asset life cycles to ensure timely replacement of critical assets as they reach or near the end of their useful lives. CNPI has significant distribution assets that are aged. In particular, CNPI is implementing a targeted pole replacement program to address the need to develop a sustainable pole asset lifecycle process.
- Renewal support for the program to eliminate the legacy three-wire delta systems at CNPI. Much of these three-wire systems have assets that are also in aged or deteriorated condition, necessitating SR projects to supplement the voltage conversion projects, which are themselves of the System Service category.

System Service

CNPI has been implementing a long-term voltage conversion program to eliminate its three-wire 4.8kV and 26.4kV delta systems, for reasons of safety, capacity, and distribution loss reduction. In many cases, this also allows for the elimination of deteriorated plant at the same time (See SR above).

In conjunction with this voltage conversion program, CNPI will be constructing new Distribution Substation facilities that are expected to:

- replace legacy end-of-life asset,
- establish 8.3kV(wye) and 27.6kV(wye) sources for legacy delta system conversions,
- improve reliability and facilitate improved control and data collection.

General Plant

General plant expenditures account for spending on such things as Fleet, Facilities, and Information Technologies. CNPI employs long-term strategies in each of these areas to ensure that assets are renewed or replaced as they reach the end of their useful lives, when they are rendered technically obsolete, or when they must be upgraded to meet changing stakeholder or regulatory needs.

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated

First year of Forecast Period: *2017*

CATEGORY	Historical Period (previous plan[1] & actual)								Bridge Year	Test Year	Forecast Period (planned)			
	2012		2013		2014		2015		2016	2017	2018	2019	2020	2021
	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual						
	$ '000		*$ '000*		*$ '000*		*$ '000*		*$ '000*					
System Access	(1)	699,501	(1)	664,857	(1)	332,934	(1)	984,532	352,898	908,897	536,611	547,343	559,940	571,139
System Renewal	(1)	2,997,112	(1)	8,847,242	(1)	4,033,193	(1)	4,920,766	6,036,707	4,990,817	5,939,120	5,496,072	5,460,618	7,043,601
System Service	(1)	635,926	(1)	554,267	(1)	863,147	(1)	884,275	722,488	1,841,678	1,064,435	1,504,806	1,179,108	835,558
General Plant	(1)	5,779,708	(1)	3,248,525	(1)	1,655,157	(1)	1,239,874	2,518,132	2,015,766	1,825,260	1,621,293	2,477,611	2,073,684
TOTAL EXPENDITURE		**10,112,247**		**13,314,890**		**6,884,432**	-	**8,029,447**	**9,630,225**	**9,757,158**	**9,365,426**	**9,169,514**	**9,677,278**	**10,523,982**
System O&M		$ 3,341,251		$ 3,472,966		$ 3,620,493		$ 3,615,556	$ 3,861,773	$ 4,106,946	$ 4,189,085	$ 4,272,867	$ 4,358,324	$ 4,445,490

Notes to the Table:

(1) This is Canadian Niagara Power's first Distribution System Plan and as such planned expenditures were not allocated to Chapter 5 Investment Categories.

Figure 5.0.2.4-1: Capital Expenditure Summary

{Also referred to as Appendix 2AB in CNPI 2017 Cost of Service Application (EB-2016-0061)}

5.0.3 General Introduction and System Overview

Section 3 of CNPI's Distribution System Asset Management Plan (DAMP) provides a much more detailed description of CNPI's distribution systems. The following is a brief summary.

Canadian Niagara Power Inc. (CNPI) is a Licensed Local Distribution Company (LDC) in Ontario, and supplies electricity to over 25,200 customers in Town of Fort Erie (FE) and City of Port Colborne (PC) and over 3,600 customers in the Town of Gananoque and surrounding areas.

CNPI operates as Eastern Ontario Power (EOP) for the portion of its service territory in and around Gananoque.

5.0.3.1 CNPI Service Territory

The following three figures indicate the service territories of CNPI. More detailed maps may be found in Appendix A. The first is an overview, and the next two show the two distinct operating areas:

Figure 5.0.3-1: Overview of Service Territory for CNPI

Figure 5.0.3.1-2: CNPI Service Territory in the Municipality of Fort Erie and Port Colborne

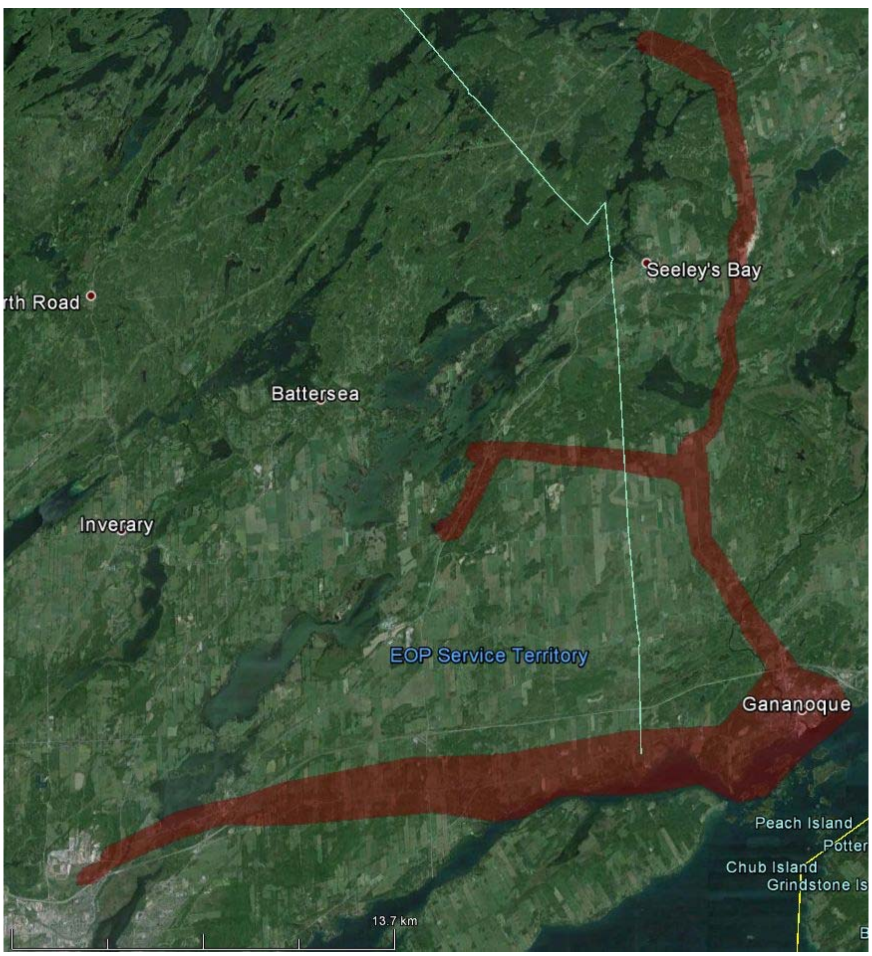


Figure 5.0.3.1-3: CNPI Service Territory for Gananoque (EOP)

5.0.3.2 Service Territory Features

5.0.3.2(a) Town of Fort Erie (FE)

The Town of Fort Erie is normally supplied by a single 115kV transmission line (Line 2) owned by CNPI Transmission. Line 2 originates from Murray Transmission Station (TS) owned by Hydro One Network Inc. (HONI). In 2015, the total system load was approximately 35MW. Two transmission substations (Station 17 and Station 18) supply total ten (10) 34.5kV (wye) distribution feeders (4 from Station 17 and 6 from Station 18). With the proper feeder switching arrangements, either TS can supply entire load of Fort Erie. There are three (3) major lower distribution voltages: 4.16kV (wye), 4.8kV (delta), and 8.3kV (wye).

The major challenges affecting the Fort Erie distribution system are aging assets and elimination of the 4.8kV delta configuration.

5.0.3.2(b) City of Port Colborne (PC)

The majority of City of Port Colborne load is supplied by a single 115kV transmission line (C2P) and a dual elements Port Colborne TS owned by HONI. In 2015, the total system load was approximately 37MW. The four (4) 27.6kV (wye) feeders originated from PC TS can back up each other via a number of intertie switching points and provide some operating flexibilities. A small portion of the load is supplied from a 27.6kV feeder originated from Crowland TS located in the City of Welland. 4.16kV is the lower voltage which serves distribution load in much of the urban areas of Port Colborne.

The major challenges affecting the Port Colborne distribution system are aging distribution substations and lines.

5.0.3.2(c) Gananoque and surrounding areas (EOP)

As an embedded distributor, EOP is supplied by a single 44 kV sub-transmission line (M8) originated from Frontenac substation owned by HONI. In 2015, the system peak load was approximately 12MW. The EOP owned Main Substation transform the 44 kV to a legacy 26.4kV (delta) voltage, which supplies only distribution substations, ratio banks, and a few customer owned substations for large industrial loads and embedded generating plants. There are few distributed loads connected to the 26.4kV system due to the delta configuration. Almost all distribution loads are connected to 4.16kV system.

The major challenges affecting the EOP distribution system are aging assets and elimination of the 26.4kV delta configuration.

5.0.3.3 Summary of Key Statistics

The following table summarizes some key statistics for the three operating areas that comprise CNPI as of December of 2015:

	Niagara Area Operating as CNPI	Gananoque Area Operating as EOP	Total
Customers			
Residential	22,836	3,144	25,980
General Service	2,276	419	2,695
Distribution Line Assets			
Poles, owned by CNPI	19,918	2,954	22,872
Distribution Transformers	5,282	886	6,168
Service Area (km^2)	292	65	357
Total Overhead Line (km)	775	172	947
Total Underground Line (km)	69	11	80
Ratio (step-down) banks	36	3	39
Distribution Substations	8	4	12
power transformers	14	6	20
circuit breakers	54	20	74
distribution feeders	43	17	60

Figure 5.0.3.3-1: Summary of Key Statistics

5.1 General and Administrative Matters

The form and the content of these filing requirements reflect the Board's conclusions in relation to distribution infrastructure planning. These filing requirements introduce a standard approach to a distributor's filings of asset management and capital expenditure plan information in support of a rate application. As detailed in section 5.2, distributors filing a corporate 'Asset Management Plan' are expected to include and clearly identify in their filings the information set out in these filing requirements, and to use the terminology and formats set out in these filing requirements.

CNPI has prepared this Distribution System Plan (DSP) in expectation of filing it as an exhibit in a Cost of Service Application.

As much as possible, the DSP utilizes the headings, terminology, and the formats set out in "*Ontario Energy Board Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5, Consolidated Distribution System Plan Filing Requirements, March 28, 2013*", hereafter referred to as "Chapter 5".

Text shown in blue italics throughout the DSP are excerpts from Chapter 5 and shown herein for reference.

Some additional sections have been added to this DSP. The table of contents, beginning on Page 3, outlines all sections, including any additional sections.

CNPI has prepared and maintains separate documentation for its Distribution Asset Management Plan (DAMP). CNPI intends to file its DAMP as Appendix M of this DSP.

5.1.1 Investment Categories

A distributor's investment projects and activities should be grouped for filing purposes into one of the four investment categories listed below, based on the 'trigger' driver of the expenditure, examples of which are provided on Table 1.

- *System access investments are modifications (including asset relocation) to a distributor's distribution system a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system*
- *System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services.*
- *System service investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements*
- *General plant investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities*

A project or activity involving two or more 'drivers' associated with different categories should be placed in the category corresponding to the 'trigger' driver. For example, a project triggered by the need to replace end of service life components in a distribution station should be considered a 'system renewal investment, even if in anticipation of future system requirements (a 'system service' driver) the project includes assets rated for a higher voltage and/or capable of handling reverse flows. Note, however (as detailed in section 5.4.5), information on all drivers of a given project or activity should be used to justify proposed capital investments.

Since 2014, CNPI has matched its internal capital project Categories, Drivers and "Project Triggers" to conform to those described the Ontario Energy Board (OEB) document *Chapter 5 Consolidated Distribution System Plan Filing Requirements* ("Chapter 5")

These are summarized in the table on the following page.

Table 1 from "Chapter 5":

Table 1 – Investment Categories & Example Drivers and Projects/Activities

	Example Drivers	Example Projects / Activities
system access	customer service requests	– new customer connections – modifications to existing customer connections – expansions for customer connections or property development
system access	other 3rd party infrastructure development requirements	– system modifications for property or infrastructure development (e.g. relocating pole lines for road widening)
system access	mandated service obligations (DSC; Cond. of Serv.; etc.)	– metering – Long term load transfer
system renewal	assets/asset systems at end of service life due to: – failure – failure risk – substandard performance – high performance risk – functional obsolescence	– programs to refurbish/replace assets or asset systems; e.g: batteries; cable (by type); cable splices; civil works; conductor; elbows & inserts; insulators; poles (by type); physical plant; relays; switchgear; transformers (by type); other equipment (by type)
system service	expected changes in load that will constrain the ability of the system to provide consistent service delivery	– property acquisition – capacity upgrade (by type); e.g. phases; circuits; conductor; voltage; transformation; regulation – line extensions
system service	system operational objectives: – safety – reliability – power quality – system efficiency – other performance/functionality	– protection & control upgrade; e.g. reclosers; tap changer controls/relays; transfer trip – automation (new/upgrades) by device type/function – SCADA – distribution loss reduction
general plant[1]	– system capital investment support – system maintenance support – business operations efficiency – non-system physical plant	– land acquisition – structures & depreciable improvements – equipment and tools – supplies – finance/admin/billing software & systems – rolling stock – intangibles (e.g. land rights; capital contributions to other utilities)

Figure 5.1.1-1 Investment Categories

5.1.2 Investments Related to Renewable Energy Generation (REG)

Under the renewed regulatory framework, a distributor's investments to accommodate and connect renewable energy generation (i.e. REG investments) are integral to its DS Plan, which includes all costs to connect renewable generation facilities that will be the responsibility of the distributor under the DSC, and are therefore eligible for recovery through the provincial cost recovery mechanism set out in section 79.1 of the OEB Act.

5.1.2.1 Historical Investments related to REG

CNPI has made no material distribution system investments in the past five years specifically to accommodate and/or connect Renewable Energy Generation (REG) investments.

5.1.2.2 Forecasted Investments related to REG

At the time of preparation of this DSP, CNPI has no plans to make any REG investments in the period from 2016 to 2021.

As outlined in 5.4.3.4, there are constraints for the connection of new REG projects to the CNPI distribution system in the Niagara region.

To date, CNPI has not received any applications from a Distributed Generation (DG) proponent served by its Eastern Ontario Power (EOP) operating region to connect a DG larger than 500kW.

Based on historical demand, CNPI does not intend to make any pre-emptive REG investments in its system to allow for additional large (i.e. greater than 10 kW) DG projects unless and until one or more DG applications are received that would require such an expansion.

CNPI would require an analysis of the impact on its system of any such proposed project via a Connection Impact Assessment (CIA). If the results of the CIA demonstrate the need for CNPI to enhance any portion of its distribution system to accommodate a large DG project, CNPI would undertake to do so, upon commitment by the DG proponent, on a case-by-case basis.

5.1.3 Timing of Filing

All distributors are required to file a DS Plan as specified here when filing a cost of service application for the rebasing of their rates under the 4th Generation IR or a Custom IR application. Distributors proposing to use the 'Annual IR Index' method for 2014 rates are not required to use Chapter 5 when filing an application. However, any distributor using the 'Annual IR Index' method must make a Chapter 5 filing within five years of the date of the most recent Board decision approving their rates in a cost of service proceeding; and is required to do so at five year intervals thereafter while using the Annual IR Index method. The Board may also require a DS Plan to be filed in relation to leave to construct, Incremental Capital Module or Z-factor applications.

This DSP has been updated in the first quarter of 2016, in anticipation of inclusion in a Cost of Service application to be filed in April of 2016.

5.1.4 Planning in Consultation with Third Parties

5.1.4.1 Regional Planning and Consultations

Prior to filing a DS Plan and at a time and in a manner to be determined in consultation with the participants in a Regional Planning Process, a distributor must:

1. *Provide regionally interconnected distributors (including host and/or embedded where applicable), the transmitter to which the distributor is connected and the OPA (where applicable) with information on:*
    - *forecast load at existing (and proposed, if any) points of interconnection;*
    - *forecast renewable generation connections and any planned network investments to accommodate the connections;*
    - *investments involving smart grid equipment and/or systems that could have an impact on the operation of assets serving the regionally interconnected utilities; and*
    - *the results of projects or activities involving the study or demonstration of innovative processes, services, business models, or technologies; and on the projects or activities of this nature planned by the distributor over the forecast period.*
2. *Consult with regionally interconnected distributors (including host and embedded where applicable) and transmitter(s) to which the distributor is connected in preparing their DS Plan.*

Port Colborne and Fort Erie lie in the region of the Province of Ontario designated at the 'Niagara Region' by Hydro One Networks Inc (HONI) and the Independent Electricity System Operator (IESO) for Regional Planning purposes.

In the fourth quarter of 2015, the Regional Planning process was initiated for Niagara Region. Along with other stakeholders, CNPI has participated in this process to-date. As of March 2016, the process is at the stage of "Needs Assessment". CNPI will continue to participate in this Regional Planning process as required until its completion.

Refer to Appendix B for a copy of a letter received from HONI outlining the participation of CNPI in the Niagara Region Planning Process to-date.

Eastern Ontario Power (EOP) lies in the Regional Planning district designated as 'Peterborough to Kingston'. EOP is a wholly embedded distributor, supplied by Hydro One Networks (HONI) via a 44kV connection. CNPI has reviewed the documentation prepared for this region by HONI and the other stakeholders. To date, no requests have been made by HONI to EOP to furnish information. CNPI is prepared to promptly respond to any such requests if and when they shall be made.

Refer to Appendix C for a copy of a letter received from HONI outlining the participation of CNPI in the Peterborough Planning process to-date.

5.1.4.2 Renewable Energy Generation Investments

Prior to filing a DS Plan, a distributor must:

1. *Not less than 60 days (where REG investments are contemplated; 30 days otherwise) in advance of the date the distributor needs to receive the OPA letter for inclusion in an application, a distributor must submit information to the OPA in relation to the REG investments identified in their DS Plan and request in writing that the OPA provide a letter commenting on the information by a date that conforms to the distributor's filing timetable.*
2. *The Board expects that the OPA comment letter will include:*
    - *the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;*
    - *whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;*
    - *the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and*
    - *whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan. The Board may postpone processing an application where a comment letter from the OPA has not been filed in accordance with this requirement.*

The Board may postpone processing an application where a comment letter from the OPA has not been filed in accordance with this requirement

It is mandated by the OEB that all distributors submit information to the IESO in relation to the REG investments identified in their DSP and request in writing that the IESO provide a letter commenting on the REG Plan, no less than 30 days in advance of filing the DSP where the distributor is not requesting investments related to REG projects.

CNPI has followed these instructions from the OEB by preparing and submitting to the IESO a preliminary version of this DSP that detailed the following:

- Existing Distributed Generation Connections;
- Anticipated Distributed Generation Connections; and
- Investments to facilitate Renewable Energy Generation.

The IESO has reviewed the REG investment plan and their comments are set out in a letter that appears as Appendix D of this DSP.

5.1.5 Performance Reporting

A distributor is to provide information on its performance in relation to its DS Plan as set out in section 5.2.3, including information on the achievement of the operational or other objectives targeted by investments the costs for which were approved in a previous application(s). Through its RRR filing, a distributor is also required to report annually on its performance, including in relation to reliability and any Performance Scorecard metrics established by the Board, including metrics related to asset management and capital expenditure planning as applicable.

To facilitate performance monitoring and utility benchmarking, the OEB employs a balanced scorecard approach that translates the four Renewed Regulatory Framework for Electricity (RRFE) performance outcomes into a set of measures that can be monitored and compared.

CNPI utilizes the performance scorecard metrics shown in Section 5.2.3 of this document, as established by the OEB, to continuously monitor its achievement in relation to the four performance outcomes and reports its performance to the OEB as required

Please refer to Appendix E of this DSP for a copy of the most recent (2014) Scorecard for CNPI.

5.2 Distribution System Plans

5.2.1 Distribution System Plan Overview

This section provides the Board and stakeholders with a high level overview of the information filed in the DSP. Prior to filing, care should be taken to ensure that summary information is consistent with the detailed information filed in the following sections and elsewhere in the application.

Key elements of the DS Plan that affect its rates proposal, especially prospective business conditions driving the size and mix of capital investments needed to achieve planning objectives

a) the sources of cost savings expected to be achieved over the forecast period through good planning and DS Plan execution

b) the period covered by the DS Plan (historical and forecast years);

c) an indication of the vintage of the information on investment 'drivers' used to justify investments identified in the application (i.e. the information should be considered "current" as of what date?);

d) where applicable, an indication of important changes to the distributor's asset management process (e.g. enhanced asset data quality or scope; improved analytic tools; process refinements; etc.) since the last DS Plan filing;

e) aspects of the DS Plan that relate to or are contingent upon the outcome of ongoing activities or future events, the nature of the activity (e.g. Regional Planning Process) or event (Board decision on LTLT) and the expected dates by which such outcomes are expected or will be known.

CNPI's DSP is a collection of information with inputs from numerous sources starting from our core business objectives, asset management objectives and performance evaluation, and consultations with major stakeholders.

The drivers are addressed under the headings of System Access, System Renewal, System Services and General Plant. The planning objectives and processes are explored in detail in Section 5.4.2.1, but in summary include:

1) Ensure proper allocation of investments to meet regulatory obligations;
2) Ensure adequate level of investment in the renewal of distribution system assets;
3) Determine the acceptable level of expenditures required to meet existing and future demand levels; and

4) Ensure proper allocation of investments in general plant assets.

The output of this process is a sustainable, five-year capital plan for the forecast period, with expenditures levelized as much as possible from year to year within the limits of resource management and good utility practices. CNPI's DSP was developed with the objective to not only address the identified near-term needs on the distribution system, but also to prepare for foreseeable future changes and requirements on the system to achieve sound and effective financial planning in the long term.

5.2.1.1 Key Elements of the DSP

Canadian Niagara Power Inc. (CNPI) has prepared its Distribution System Plan (DSP) with a focus on its core values and objectives:

(i) Provide for the growth needs of its customers in the various service territories

(ii) Provide safe, reliable, and high-quality service to all of the customers of CNPI

(iii) Satisfy the first two principles in a sustainable manner which minimizes the long-term costs to be borne by the ratepayers of CNPI.

CNPI believes that it has met these objectives, as outlined in this DSP.

CNPI has engaged in regular consultations with municipal staff in its service areas to discuss growth issues. As a result of economic conditions in each of its service areas, and the trending in actual and forecast system load, CNPI is projecting little if any commercial growth in the forecast period. Industrial and residential growth is expected to be very limited, and associated demand-reduction initiatives (such as CDM) are expected to offset any such organic growth.

As a result, CNPI does not intend to make significant or material investments to meet growth targets (although one or more 'un-forecasted' industrial loads would require a revision to this).

Instead, the CNPI investment plan will be focusing on addressing issues with its legacy distribution system. These are discussed in some detail in the CNPI Distribution Asset Management Plan (DAMP), included as Appendix M of this DSP.

The main challenges facing CNPI today can be summarized as:

1) Managing our asset life cycles to ensure timely replacement of critical assets as they reach or near the end of their useful lives. CNPI has significant distribution assets that are aged.
2) Elimination of legacy three-wire delta systems that represent safety and operational concerns. CNPI has been engaged in voltage conversion programs for some time, and this challenge represents a focus for CNPI in its capital program over the entire forecast period and beyond.
3) Dealing with the first two challenges in a prudent and sustainable manner that maintains system reliability and customer satisfaction, maximizes operational efficiency, and addresses worker and public safety, all while focusing on the need to manage overall costs and the associated impacts on CNPI's distribution rates.

The CNPI Capital Plan from 2016 to 2021 will be targeted towards overcoming these challenges.

5.2.1.2 Sources of Cost Savings Expected

Over the previous cycle, CNPI has undertaken many procedural and policy improvements to improve efficiency in the operation of the system that are expected to show positive results with respect to cost savings and efficiencies.

CNPI has identified the following sources of cost savings and efficiencies expected to be achieved over the forecast period:

5.2.1.2(a) Targeted Asset Replacement Programs

These proactive programs are more cost-effective when compared to a traditional reactive approach, where individual poles are changed as the need arises. CNPI is currently conducting a multi-year pole testing program (see section 6.3.2 of DAMP) to determine the present condition of all poles. This is expected to identify those poles that might require replacement, and is further assessing these results to determine their probable remaining useful lives. CNPI has incorporated these results in its capital program planning to ensure that as many problematic poles are addressed at CNPI carries out its various programs.

5.2.1.2(b) Distribution Automation (DA)

DA has a clear impact on reliability statistics, but is also a labour savings option when applied on protection and switching devices that are remote from the service centre.

5.2.1.2(c) Standardized Designs

Standard Designs save money both by reducing the engineering costs of the project as well as reducing installation costs and material stock costs. CNPI is part of the Utilities Standard Forum (USF) group, which has standardized installation drawings for use in the projects in this DSP.

5.2.1.2(d) Mobile Computing

Devices such as portable computing devices to replace paper-based data collection and processes will improve operational efficiency, reduce the possibility of data translation errors, and provide cost savings at the time of collection, and the time of data entry.

CNPI is using or presently deploying mobile technology to

- Provide automatically-updated digital maps sourced from its Geospatial Information System (GIS) system to ensure all operating staff have up-to-date information about the CNPI distribution system at a reduced cost. These cost reductions are due to reduced labor in map production, and significant reductions in paper and ink.
- Provide a 'Mobile Document Library' to ensure that field staff have complete and up-to-date access to documents like Standards, Procedures, Policies, and 3rd party documents from the Ministry of Labour (MOL) and Ministry of Transport – Ontario (MTO).
- Provide an engineering field tool for on-site design and data capture of proposed projects. This tool is fully integrated with the CNPI GIS and Enterprise SAP systems to reduce repeated input error and improve response and reply times when other stakeholders, such as customers, are involved.

5.2.1.2(e) Distribution System Line-Loss Reduction

Distribution System Losses are being improved through renewal and voltage conversion projects. Among its other benefits, Voltage Conversion usually results in distribution lines operating at higher nominal voltages. This results in correspondingly lower line currents, which directly impacts the resulting line-losses.

Specifically, in addition to a number of smaller projects to upgrade distribution lines and operate them at a higher system voltage, CNPI has some multi-year projects underway that will significantly reduce system losses:

- Fort Erie North 4.8kV Delta to 8.3kV Wye Conversion Program

- Fort Erie Ridgeway 4.8kV Delta to 8.3kV Wye Conversion Program
- EOP West Line 4.16kV to 27.6kV Wye Voltage Conversion Program

CNPI has identified other focus areas that are to be converted in the period beyond 2021.

These projects are described in greater detail in section 5.4.6 of this DSP.

5.2.1.3 Period Covered by the DSP

The period of this DSP conforms to the historical and forecast period of the CNPI Cost of Service Application to be filed in April of 2016.

The historical period covers the years from 2012 to 2015.

The forecast period covers the current budget year 2016 and the future period from 2017 to 2021.

Certain analyses looked further into the future when evaluating long term impacts of capital project prioritization during this period, such as long-term tangible benefits and costs associated with reduction of line-losses.

5.2.1.4 Vintage of the Information on Investment 'Drivers'

CNPI understands the value of using the most up-to date information possible when assessing and prioritizing projects.

CNPI always uses its most recent information available from reliability results, periodic inspections and maintenance programs. Whenever a new inspection cycle is complete, CNPI reviews any 'committed' projects to ensure that all inputs and assumptions used in project selection are still valid.

CNPI inspects its Distribution substations on a monthly basis. At the time of preparing this document, the most recent substation inspections were done in February of 2016.

In accordance with Appendix C of the Distribution System Code, CNPI inspects all of the lines in Fort Erie, Port Colborne, and the Town of Gananoque every three years. The most recent line inspection cycle was completed in 2015/Q2. The oldest such information was collected in 2013.

In 2016, CNPI has initiated a comprehensive pole testing program that is expected to obtain an empirical assessment of each of its distribution poles that meet the necessary age criterion. To manage costs, this program is planned to take place over six years. In 2010/11, CNPI tested a large sample of more than ten percent (>10%) of its poles to ascertain the overall condition of its pole assets.

5.2.1.5 Important Changes to the AM Process

This is the first documented comprehensive Distribution System Plan (DSP) for CNPI.

In 2011, CNPI prepared its first consolidated Distribution Asset Management Plan (DAMP) to describe and document its Asset Management strategies.

Prior to its creation, as described in the DAMP, CNPI relied on various asset management and planning tools to perform its project planning, prioritizing, and decision making processes.

Please refer to section 2 (and its subsections) of the DAMP for information on the CNPI Asset Management Process.

5.2.1.6 Aspects contingent upon the outcome of ongoing activities

While the overall DSP spending program itself is contingent upon the OEB approval of the rates as applied for, a select few investments described in the DSP are contingent upon the outcome of ongoing activities or future events.

Specifically, the level of actual investments within the System Access category may be altered slightly year-to-year from the proposed investment levels, depending upon the number of customer requests for new services connections, the ongoing needs of our Joint Use (JU) partners, and line relocation requests by municipal and provincial land owners.

These capital expenditures are highly dependent on external drivers and the level may deviate significantly during the next five years. However, best efforts are made to understand the level of investment needed by meeting with planning agencies within the municipality and utilizing historic trends and regular consultations with our JU partners.

In addition, Renewable Energy Generation (REG) projects for Fort Erie and Port Colborne have been greatly constrained by the need for HONI to upgrade Allenburg TS (now completed) and to complete the construction of the Niagara-Caledonia-Middleport transmission line. If and when these constraints are removed, CNPI expects an increase in applications from REG proponents, which would have a direct impact on the CNPI 5-year capital program. The future timing for this is not known at the time of preparation of this report.

At an Integrated Regional Resource Planning (IRRP) Meeting for Niagara Region held on April 15, 2016, it was confirmed by staff from HONI and IESO that this REG connection constraint imposed by the incomplete Niagara-Caledonia-Middleport transmission line will be remaining in place for the foreseeable future.

5.2.2 Coordinated Planning with Third Parties

To demonstrate that a distributor has met the Board's expectations in relation to coordinating infrastructure planning with customers, the transmitter, other distributors and/or the OPA or other third parties where appropriate, a distributor must provide:

a) *a description of the consultation(s), including*
   - *the purpose of the consultation (e.g. Regional Planning Process);*
   - *whether the distributor initiated the consultation or was invited to participate in it;*
   - *the other participants in the consultation process (e.g. customers; transmitter; OPA);*
   - *the nature and prospective timing of the final deliverables (if any) that are expected to result from or otherwise be informed by the consultation(s) (e.g. Regional Infrastructure Plan; Integrated Regional Resource Plan); and*
   - *an indication of whether the consultation(s) have or are expected to affect the distributor's DS Plan as filed and if so, a brief explanation as to how.*

b) *where a final deliverable of the Regional Planning Process is available, the final deliverable; where a final deliverable is expected but not available at the time of filing, information indicating:*
   - *the role of the distributor in the consultation;*
   - *the status of the consultation process; and*
   - *where applicable the expected date(s) on which final deliverables are expected to be issued.*

c) *the comment letter provided by the OPA in relation to REG investments included in the distributor's DS Plan (see 5.2.4.2), along with any written response to the letter from the distributor, if applicable.*

The following section describes the coordination between CNPI and other agencies. Please refer to section 5.4.1.6 for a description of customer engagement and consultations.

5.2.2.1 Regional Planning - Niagara Region

Port Colborne and Fort Erie lie in the region of the Province of Ontario designated at the ‘Niagara Region’ by Hydro One Networks Inc (HONI) and the IESO for Regional Planning purposes.

In the fourth quarter of 2015, the Regional Planning process was initiated for Niagara Region. Along with other stakeholders, CNPI has participated in this process to-date. As of March 2016, the process is at the stage of “Needs Assessment”. CNPI will continue to participate in this Regional Planning process as required until its completion.

Refer to Appendix B for a copy of a letter received from HONI outlining the participation of CNPI in this process to-date.

5.2.2.2 Regional Planning - Peterborough to Kingston Region

Eastern Ontario Power (EOP) lies in the Regional Planning district designated as ‘Peterborough to Kingston’. EOP is a wholly embedded distributor, supplied by Hydro One Networks (HONI) via a 44kV connection. To date, no requests have been made by EOP to furnish information of any kind to HONI. CNPI is prepared to promptly respond to any such requests if and when they shall be made. CNPI has reviewed the documentation prepared by HONI and the other stakeholders.

Refer to Appendix C for a copy of a letter received from HONI outlining the participation of CNPI in this process to-date.

5.2.2.3 Comment letter from IESO (formally OPA)

It is mandated by the OEB that all distributors submit information to the IESO in relation to the REG investments identified in their DSP and request in writing that the IESO provide a letter commenting on the REG Plan, no less than 30 days in advance of filing the DSP where the distributor is not requesting investments related to REG projects.

CNPI has followed these instructions from the OEB by preparing and submitting to the IESO a REG Investment Plan that details the following:

- Existing Distributed Generation Connections;
- Anticipated Distributed Generation Connections; and
- Investments to facilitate Renewable Energy Generation.

The IESO has reviewed the REG investment plan and the IESO comments are set out in Appendix D of this DSP.

5.2.3 Performance Measurement for Continuous Improvement

As mentioned in section 5.0, good distributor planning is an essential element of the Board's performance-based rate-setting approaches. The Board understands that distributors often use certain qualitative assessments and/or quantitative metrics to monitor the quality of their planning process, the efficiency with which their plans are implemented, and/or the extent to which their planning objectives are met. The Board expects that this information is used to improve continuously a distributor's asset management and capital expenditure planning processes.

5.2.3.1 Metrics to Monitor DSP Process Performance

Identify and define the methods and measures (metrics) used to monitor distribution system planning process performance, providing for each a brief description of its purpose, form (e.g. formula if quantitative metric) and motivation (e.g. consumer, legislative, regulatory, corporate). These measures and metrics are expected to address, but need not be limited to:

- *customer oriented performance (e.g. consumer bill impacts; reliability; power quality);*
- *cost efficiency and effectiveness with respect to planning quality and DS Plan implementation (e.g. physical and financial progress vs. plan; actual vs. planned cost of work completed); and*
- asset and/*or system* operations performance.

CNPI uses a set of performance measures to continuously monitor and evaluate its achievement with respect to the four performance outcomes established by the OEB particularly in respect of the Electricity Distributers Scorecard (Scorecard). The most recent scorecard for CNPI (2014) may be found in Appendix E of this DSP.

Most of these measurements are required by the OEB for the DSP filing, while some are not. Regardless of requirement, these measurements are recorded as they are considered meaningful in the case of CNPI. There are also a few additional metrics contemplated in the Filing Requirements. In aggregate, these measures not only allow CNPI to capture deviations in its own performance from year to year, but also provide a means for CNPI to compare its performance with other Local Distribution Companies (LDC's) in Ontario.

Five of the performance measures reported in the Scorecard were added by the OEB in May 2014 to capture performance in value to customers, effective planning, and asset management.

Not all of these measures have been historically tracked by CNPI and, therefore, it is not possible to report on trends for all metrics at this time. The baseline data and the actuals will be included in future fillings.

5.2.3.1(a) Customer Focus

CNPI has consistently met and exceeded the mandated targets for Service Quality and Customer Satisfaction. CNPI has been performing an annual customer satisfaction survey for 17 years to measure its performance and to identify areas of importance and concern for its residential and general customers.

CNPI has used these results to guide its efforts in providing customer service programs, and investing prudently in reliability-enhancing distribution system upgrades. For a number of years, CNPI lacked the ability to benchmark these results against other local LDCs.

In recent years, the OEB mandated that all LDCs in Ontario must perform such surveys.

In 2015, CNPI changed survey consultants in order to employ UtilityPulse. This was done because this organization was now providing this service for many other Ontario LDC's, and CNPI felt that this would provide more meaningful and comparable results.

CNPI's survey results for 2015 were favorable. Our overall Customer Satisfaction result was 94%, compared to an average score of 88% for other LDC's in the province of Ontario.

5.2.3.1(b) Operational Effectiveness

CNPI has consistently been compliant with the requirements of O. Reg 22/04.

Our recent System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) indices for 2014, as reported on the Scorecard were almost identical with CNPI's average values over the five years ending in 2014. Our 2015 reliability index values were somewhat better. This was in large part due to better-than-typical overall weather during 2015. In-depth analysis of CNPI reliability may be found in section 9 of the CNPI DAMP.

CNPI interprets this trend to mean that the reliability-driven investments being made are at a prudent level, with gradual improvements being made over time. There does not seem to be any need to make a general increase in the level of such investments, nor are there indicators that CNPI should reduce or cease such investments.

Two Cost Control factors are reported; Cost per Customer and Cost per km of line. CNPI has one of the lowest customer densities (i.e. Customers per km of line) in southern Ontario, indicating that it needs more poles, and more length of conductor per customer, compared to the average. This would lead to the conclusion that it would be unreasonable to expect CNPI to be able to deliver high-quality electricity at a lower-than-average cost. Therefore, CNPI has always focused on its own internal trend. Between 2010 and 2014, the two Cost Factors increased, but at a rate less than inflation (Stats-Can CPI).

5.2.3.1(c) Public Policy Responsiveness

CNPI recognizes that the following public-policy driven programs could have a material impact on CNPI's capital investment strategy:

Conservation and Demand Management:

CNPI had been challenged in its efforts to meet the assigned target due to a significant reduction in customer demand and energy consumption, in 2011, which has continued into 2014 with a decline in customer demand coupled with customer closures. This resulted in significant adverse economic impacts affecting the entire service territory. Due to these negative economic impacts, a lack of growth and a decline in the larger customer base, the CNPI service territories have seen a dramatic overall decline in energy throughput and system demand since 2008, the year that was used as the base year to set the mandated targets.

Connection of Renewable Generation:

As outlined elsewhere in this DSP (section 5.4.3), there are constraints that have limited the number of REG projects to be connected by CNPI. Nevertheless, CNPI has met and exceeded the OEB-mandated requirements for timely connections of REG projects (e.g. MicroFIT and FIT).

5.2.3.1(d) Financial Performance

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC on behalf of the OEB to produce a single efficiency ranking. The electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs. The model developed by Pacific Economics Group to predict a distributor's costs relies on a data set that includes all distributors in Ontario. For 2014, CNPI was placed in Group 4 indicating that actual costs are within +/- 25% of predicted costs.

5.2.3.2 Summary of Performance over the Historical Period

Provide a summary of performance and performance trends over the historical period using the methods and measures (metrics/targets) identified and described above. This summary must include historical period data on:

1) *all interruptions; and*
2) *all interruptions excluding 'loss of supply' for a) the distribution system average interruption frequency index; b) system average interruption duration index; and c) customer average interruption duration index.*

Where performance assessments indicate marked adverse deviations from trend or targets (including any established in a previously filed DS Plan), provide a brief explanation and refer to these instances individually when responding to provision 'c)' below.

Please refer to section 9 of the CNPI DAMP for information on the reliability performance of the CNPI distribution system.

5.2.3.3 Effect on the DSP

Explain how this information has affected the DS Plan (e.g. objectives; investment priorities; expected outcomes) and has been used to continuously improve the asset management and capital expenditure planning process

Through reviews and analyses of the information outlined in the previous sections, CNPI has determined several key factors:

- Customers want reliable power. They wish the number and frequency of outages to be lower. However, they do not want their electricity bills to rise by any excessive amount to achieve this.
- Customers want the delivery of their electricity to be done at the lowest possible cost. They also do not want large changes in these costs.
- The long term reliability that has been achieved by CNPI is reasonable, given the levels of exposure to inclement weather found throughout our systems. The year-over-year performance is quite stable, indicating that our reliability-driven investment levels are prudent.
- CNPI has endeavored to maintain increases in costs of its capital investment profile, and its operating and maintenance programs, to values at or below inflationary levels. In recent years, it has introduced new test programs, such as systematic pole testing and also introduced new capital spending programs intended to address specific safety or asset condition concerns. It has attempted to do so in a manner which avoids large changes in costs on a year-over-year basis.
- The majority of CNPI's capital investment is focused on SR projects. These projects will systematically replace end of useful live assets and maintain system reliability.
- CNPI will invest approximately $1.7 million between 2016 and 2021 in Distribution Automation (DA) related projects which will identify forced outages faster, closely identify outage location, and reduce response time. Over time, these investments will improve system reliability.
- To sustain its reliability goals, CNPI will continue its expenditure in vegetation management effort, even though it is considered an Operating and Maintenance (O&M) cost. Starting in 2017, CNPI will initiate an Emerald Ash Borer (EAB) program to manage the impact of EAB as described in section 5.2.4.2 of the CNPI DAMP.

5.3 Asset Management Process

As noted in the Introduction, a distributor's asset management process is the systematic approach used to plan and optimize ongoing capital and operating and maintenance expenditures on its distribution system and general plant. The purpose of the information requirements set out in this section 5.3 is to provide the Board and stakeholders with an understanding of the distributor's asset management process, and the direct links between the process and the expenditure decisions that comprise the distributor's capital investment plan.

Please refer to section 2 of the CNPI DAMP for this information.

It is included in this DSP as Appendix M.

5.3.1 Asset Management Process Overview

This section provides the Board and stakeholders with a high level overview of the information filed on a distributor's asset management process, including key elements of the process that have informed the preparation of the distributor's capital expenditure plan and therefore are referred to in response to requirements for more detailed information supporting the overall capital expenditure plan, budget allocations to categories of investments, or material projects/activities proposed for recovery in rates.

Please refer to section 2 of the CNPI Distribution Asset management Plan (DAMP) for more extensive description of the CNPI Asset Management Process.

It is included in this DSP as Appendix M.

5.3.1.1 **Asset Management Strategy**

(This information may also be found in section 2.1 of the CNPI DAMP)

Prudent and timely planning lies at the core of any sustainable asset management program. At CNPI, planning is a continuous and evolving process designed to meet the present and changing needs of a variety of stakeholders.

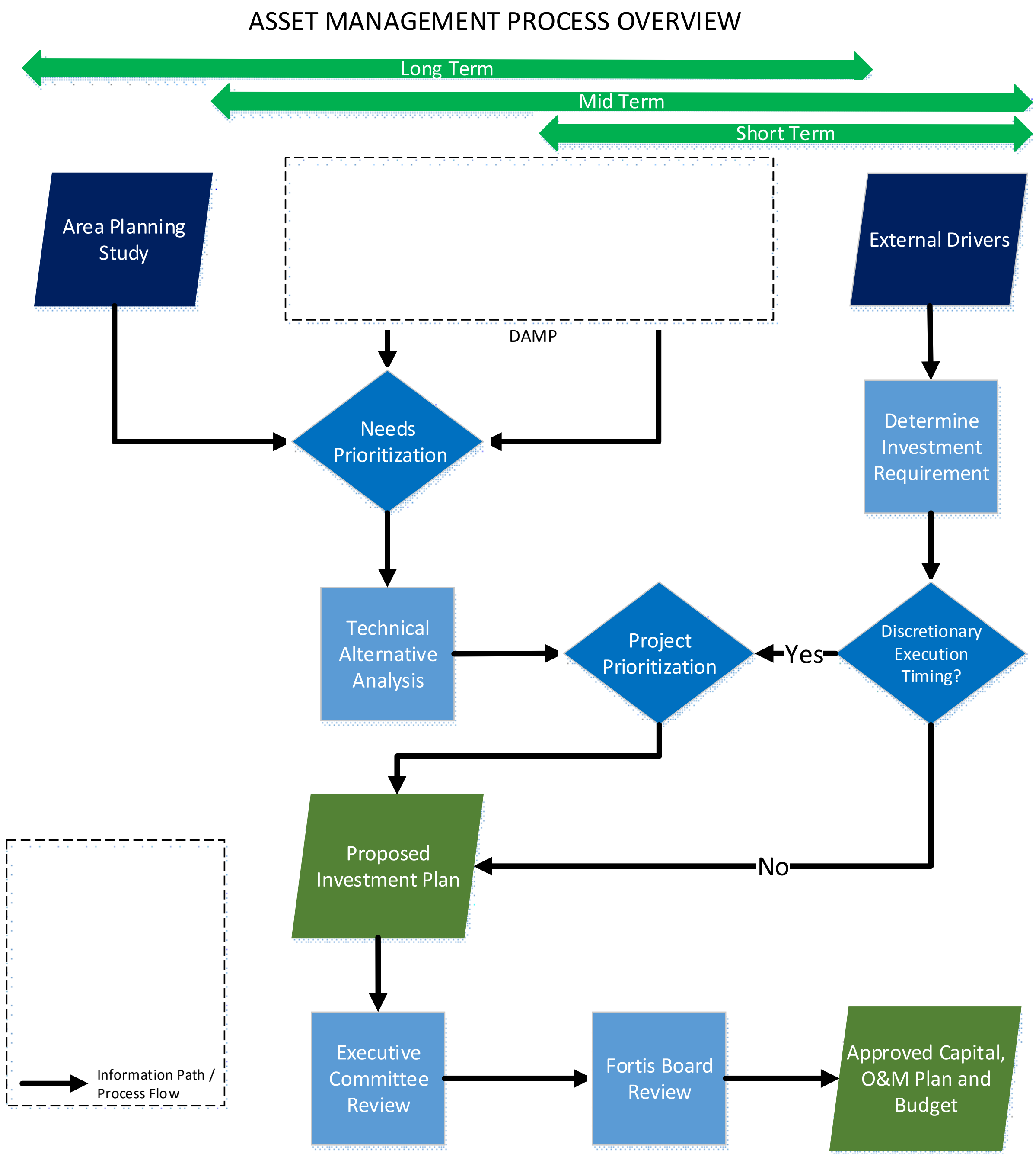


Figure 5.3.1.1-1: Asset Management Process Overview

At CNPI, planning is divided into three general categories, with ongoing interaction between all three.

5.3.1.1(a) Long Term Planning (Forecast Horizon Typically 10 Years)

Long range planning at CNPI is generally performed through the preparation and periodic review of Area Planning Studies (APS), load growth projections, governmental initiatives, and changes to standards, guidelines, and codes.

The APS analyzes the existing distribution system and anticipated customer load (and generation) changes over a planning horizon of ten years.

A long-term load (and distributed generation) forecast is prepared, using the best information available at the time of the study. Input is sought from all relevant stakeholders, including customers and developers, municipalities, internal corporate departments, and various Provincial organizations.

Technical issues like component capacities, ability to operate within voltage requirements, and basic contingency analysis are reviewed, and system deficiencies (present and predicted through the load forecast period) are identified.

Various alternatives and solutions are proposed, and then analyzed to ensure that they address all predicted deficiencies. Recommendations are then made based on a Least-Cost Cumulative Present-Worth methodology.

Where these recommendations impact on non-LDC assets (such as a Transmission Substation), these are integrated with the Transmitter Asset Management Plan (TAMP) of the transmitter

APS' do not attempt to identify or address all asset condition issues, as these concerns are more immediate in nature and are resolved through a 5-year (medium term) budget planning process. However, if some distribution assets are known to be approaching the end of their useful lives, this information is taken into account when proposing alternative solutions.

Generally, a complete APS for each region of CNPI will be performed at regular intervals of several years, with periodic reviews to ensure that the information and conclusions in each study are still reasonably accurate and valid as more-recent data becomes available.

Major unforeseen events may require a shorter interval between studies. For example, a request for service from a large load or generation customer may trigger the need for a comprehensive study, if the proposed change is outside the parameters of the most recent full study.

5.3.1.1(b) Medium Term Planning (5 Year Planning Horizon)

CNPI uses results from its strategic planning and other reports, such as asset condition reports, to perform 'tactical' planning which covers a five-year period.

Medium-Term planning is performed each year, to incorporate new information that may arise, such as new regulations, longer-term individual customer needs, or updated asset condition reports. Typical inputs to medium term planning include:

- Customer-driven needs
- Municipal-driven needs
- Regulatory requirements
- Reliability analysis
- Asset evaluation and renewal requirements
- Expansion requirements identified through long-term planning
- Extraordinary initiatives, such as FIT, Smart-Grid and Smart Meters

The results of this medium term planning set priorities, goals and targets to define optimal and sustainable levels of activity in all areas of the LDC.

The outcomes of tactical planning contribute directly to the corporate five-year fiscal plan.

5.3.1.1(c) Short Term Planning (One Year Planning Horizon)

Short term or operational planning involves developing specific plans to implement the projects defined in next year's budget as well as operate the distribution system(s) in a safe and reliable manner.

It also addresses short-term needs, such as connection of a customer that was not identified previously during medium term planning, or reaction to external events such as a severe ice storm. Typical inputs to the short term planning process include:

- Next Year Budget and Project Design Based on the Investment Plan
- Known Customer-Driven Asset Development
- Known Municipal and Developer-Driven Asset Development
- Other Short-term Projects

The general process followed in the Short Term Planning Horizon is depicted in Figure 5.3.1.1-2:

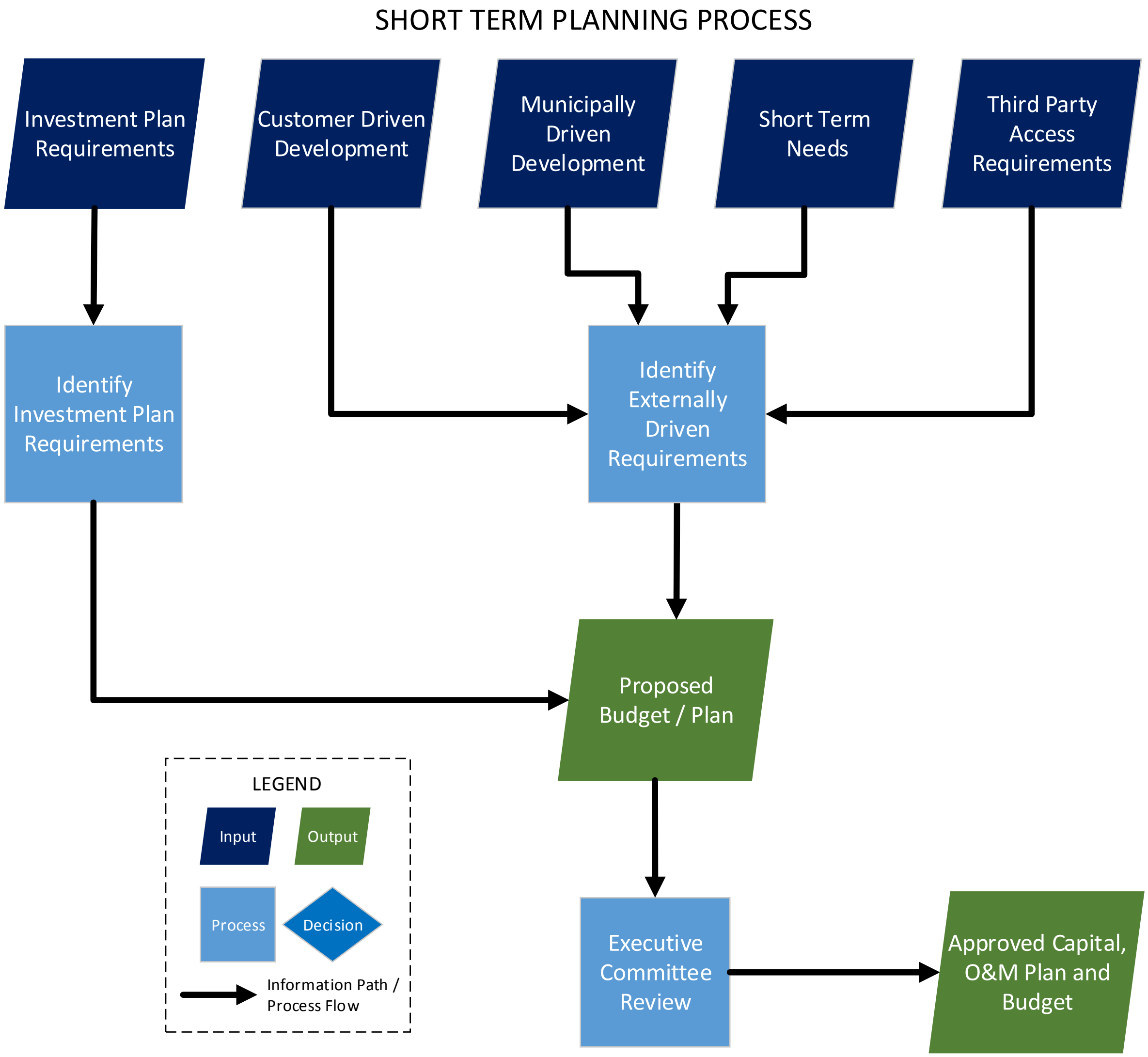


Figure 5.3.1.1-2: Short Term Planning Process

5.3.1.2 Asset Management Objectives

A description of the distributor's asset management objectives and related corporate goals, and the relationships between them; where applicable, show and explain how the distributor ranks asset management objectives for the purpose of prioritizing investments;

The table below illustrates how the asset management objectives and principles identified in the CNPI DAMP (section 1.2), as well as CNPI's core values, relate to each other and to the Renewed Regulatory Framework for Electricity (RRFE) performance outcomes established by the Board.

Performance Outcome	Asset Management Objective	Core Values
Customer Focus	• Provide for growth needs of customers • Provide safe, reliable, and high-quality service • manage costs borne by ratepayers	• Customer Service • Respect for People • Community Involvement • Safety and the Environment
Operational Effectiveness	• *Prudently and efficiently* manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement of all distribution assets in a sustainable manner in accordance with standards, codes, and good utility practices	• Customer Service • Productivity
Public Policy Responsiveness	• Principles are derived from safety considerations; *acts, regulations, codes and guidelines*	• Safety and the Environment
Financial Performance	• Prudently and efficiently manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement *of all distribution assets in a sustainable manner*	• Productivity • Financial Success

Figure 5.3.1.2-1: Asset Management Objectives in Relation to Performance Outcomes

5.3.1.3 Asset Management Strategy

Information regarding the components (inputs/outputs) of the asset management process used to prepare a capital expenditure plan, identify and briefly explain the data sets, primary process steps, and information flows used by the distributor to identify, select, prioritize and/or pace investments; e.g.

- *asset register*

Refer to DAMP section 4 for a description of CNPI's Managed Assets.

- *asset condition assessment*

Refer to DAMP section 6 for asset condition assessment information.

- *asset capacity utilization/constraint assessment*

Refer to DAMP section 7 for Asset Utilization assessments.

- *historical period data on customer interruptions caused by equipment failure*
- *reliability-based 'worst performing feeder' information and analysis*
- *reliability risk/consequence of failure analyses.*

Refer to DAMP section 9 for this information

Use of a flowchart illustration accompanied by explanatory text is recommended.

Refer to DAMP section 2 for this information

5.3.2 Overview of Assets Managed

Appropriate regulatory assessment of DS Plans requires an understanding of the scope and depth of the assets managed by a distributor. Distributors vary in terms of the types of assets managed (e.g. some own high voltage equipment; others do not). Detailed characteristics and data on the assets covered by the asset management process are to be filed.

5.3.2.1 Features of the Distribution Service Area

A description and explanation of the features of the distribution service area (e.g. urban/rural; temperate/extreme weather; underground/overhead; fast/slow economic growth) pertinent for asset management purposes, highlighting where applicable expectations for the evolution of these features over the forecast period that have affected elements of the DS Plan.

Please refer to CNPI DAMP (section 3.2) for this information.

5.3.2.2 System Configuration

A summary description of the system configuration, including length (km) of underground and overhead systems; number and length of circuits by voltage level; number and capacity of transformer stations;

Please refer to CNPI DAMP (section 3) for this information.

A summary table may be found in section 3.6 of the CNPI DAMP

5.3.2.3 Asset Condition

Information (in tables and/or figures) by asset type (where available) on the quantity/years in service profile and condition of the distributor's system assets, including the date(s) the data was compiled.

Please refer to CNPI DAMP (section 6) for this information.

5.3.2.4 Asset Utilization

An assessment of the degree to which the capacity of existing system assets is utilized relative to planning criteria, referencing the distributor's asset related objectives and targets.

Where cited as a 'driver' of a material investment(s) included in the capital expenditure plan, provide a level of detail sufficient to understand the influence of this factor on the scope and value of the investment.

Please refer to CNPI DAMP (section 7) for this information.

5.3.3 Asset Lifecycle Optimization Policies and Practices

An understanding of a distributor's asset lifecycle optimization policies and practices will support the regulatory assessment of system renewal investments and decisions to refurbish rather than replace system assets. Information provided should be sufficient to show the trade-off between spending on new capital (i.e. replacement) and life- extending refurbishment.

5.3.3.1 Asset Lifecycle Optimization Policies and Practices

A description of asset lifecycle optimization policies and practices, including but not necessarily limited to:

- *a description of asset replacement and refurbishment policies, including an explanation of how (e.g. processes; tools) system renewal program spending is optimized, prioritized and scheduled to align with budget envelopes; and how the impact of system renewal investments on routine system O&M is assessed;*
- *a description of maintenance planning criteria and assumptions; and a description of routine and preventative inspection and maintenance policies, practices and programmes (can include references to the DSC).*

Please refer to CNPI DAMP (section 8) for this information.

5.3.3.2 Asset Life Cycle Risk Management Policies and Practices

A description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation, including but not necessarily limited to the methods used; types of information inputs and outputs; and how conclusions of risk analyses are used to select and prioritize capital expenditures.

Please refer to CNPI DAMP (section 8) for this information.

5.4 Capital Expenditure Plan

A distributor's DS Plan details the programme of system investment decisions developed on the basis of information derived from its asset management and capital expenditure planning process. It is critical that investments, whether identified by category or by specific project, be justified in whole or in part by reference to specific aspects of that process.

As noted above, a DS Plan must include information on prospective investments over a minimum five year forecast period, beginning with the test year (or initial test year if Customer IR filing), as well as information on investments – planned and actual – over the five year period prior to the initial year of the forecast period.

5.4.1 Summary

This section elicits key information about a distributor's capital expenditure plan including, by category (see section 5.1.1), significant projects and activities to be undertaken and their respective key drivers; the relationship between investments in each category and a distributor's objectives and targets; and the primary factors affecting the timing of investment in each category (or of projects within each category, if significant).

The following information should be provided:

a) *Information on the capability of the distributor's system to connect new load or generation customers in sufficient detail to convey the basis for the scope and quantum of investments related to this 'driver'.*

b) *Total annual capital expenditures over the forecast period, by investment category (see section 5.4)*

c) *A brief description of how for each category of investment, the outputs of the distributor's asset management and capital expenditure planning process have affected capital expenditures in that category and the allocation of the capital budget among categories.*

d) *A list and brief description including total capital cost (table format recommended) of material capital expenditure projects/activities, sorted by category;*

e) *Information related to a Regional Planning Process or contained in a Regional Infrastructure Plan that had a material impact on the distributor's capital expenditure plan, with a brief explanation as to how the information is reflected in the plan.*

f) A brief description of customer engagement activities to obtain information on their preferences and how the results of assessing this information are reflected in the plan.

g) A brief description of how the distributor expects its system to develop over the next five years, including in relation to load and customer growth, smart grid development and/or the accommodation of forecasted renewable energy generation projects.

h) A list and brief description including where applicable total capital cost (table format recommended) of projects/activities planned:

- *in response to customer preferences (e.g., data access and visibility; participation in distributed generation; load management);*
- *to take advantage of technology-based opportunities to improve operational efficiency, asset management and the integration of distributed generation and complex loads; and*
- *to study or demonstrate innovative processes, services, business models, or technologies.*

5.4.1.1 Summary

A summary of CNPI's expenditures for the proposed capital investments in the test year and forecast period in each of the investment categories are briefly discussed below:

5.4.1.1(a) System Access

System Access (SA) projects fall into two general classes.

The first is in response to customer requests for connections. CNPI must complete requested connections in order to meet customer needs and remain compliant with regulations.

The second class is 3rd party requests to upgrade or relocate portions of the distribution system in response to the needs of Joint Use partners or Municipal roadway authorities. Some of the gross expenditures in the SA category are offset by Contributions In Aid of Construction (CIACs) from the requesting parties as required by the Distribution System Code (DSC), CNPI's Condition of Service, or by directly negotiated agreement.

As projects of this non-discretionary category are driven by external stakeholders, the planning process by CNPI for SA projects must be somewhat reactive in nature.

5.4.1.1(b) **System Renewal**

System Renewal (SR) has historically been CNPI's largest investment category and will remain so throughout the forecast period. There are two main drivers in the SR category throughout the forecast period:

- Managing our asset life cycles to ensure timely replacement of critical assets as they reach or near the end of their useful lives. CNPI has significant distribution assets that are aged. In particular, CNPI is implementing a targeted pole replacement program to address the need to develop a sustainable pole asset lifecycle process.
- Renewal support for the program to eliminate the legacy three-wire delta systems at CNPI. Much of these three-wire systems have assets that are also in aged or deteriorated condition, necessitating SR projects to supplement the voltage conversion projects, which are themselves of the System Service category.

5.4.1.1(c) **System Service**

The CNPI has been implementing a long-term voltage conversion program to eliminate its three-wire 4.8kV and 26.4kV delta systems, for reasons of safety, capacity, and distribution loss reduction. In many cases, this also allows for the elimination of deteriorated plant at the same time (See SR above).

In conjunction with this voltage conversion program, CNPI will be constructing new Distribution Substation facilities that are expected to replace legacy end-of-life asset, establish 8.3kV(wye) and 27.6kV(wye) sources for legacy delta system conversions, and improve reliability and facilitate improved control and data collection.

5.4.1.1(d) **General Plant**

General plant expenditures account for spending on such things as Fleet, Facilities, and Information Technologies. CNPI employs long-term strategies in each of these areas to ensure that assets are renewed or replaced as they reach the end of their useful lives, when they are rendered technically obsolete, or when they must be upgraded to meet changing stakeholder or regulatory needs.

5.4.1.2 System Capability to Connect New Load or Generation

As covered in much more detail in section 7 of the CNPI DAMP, the CNPI distribution system generally possesses sufficient capacity in its higher-voltage systems (34.5kV and 27.6kV) to connect all reasonably foreseeable new loads into its system. In some cases, CNPI would need to perform an expansion to extend a circuit at this higher voltage to the site of the new load.

In Fort Erie, there is also adequate Transmission Station capacity to accommodate all such loads.

However, in Port Colborne, Transmission Station capacity constraints at Port Colborne TS has historically forced at least one large customer to seek a direct connection to the IESO-controlled grid to meet its load expansion needs. It is expected that the ongoing HONI-led Niagara Region Planning (i.e. the IRPP/RIP process) initiative will address such foreseeable new needs in the future.

As outlined in section 5.4.3, there are significant constraints to connection of new REG loads.

5.4.1.3 Summary of Annual Capital Expenditures

Please refer to section 5.4.4 of this DSP for a graph and a table that summarizes the total anticipated invested to be made by CNPI during the forecast period, broken down by category.

The information in this table is the same as that provided by Appendix 2AB of the CNPI 2017 Cost of Service application.

5.4.1.4 Material Capital Expenditure Projects

Please refer Figure 5.4.5.2-1 for a listing of material projects.

Section 5.4.6 contains more detailed descriptions for each project in this listing.

5.4.1.5 Material Impact of IRRP/RIP on the DSP

Integrated Regional Resource Planning (IRRP) for the area designated as ‘Niagara Region’ is still at the ‘Needs Assessment’ phase, as documented in a recent letter from HONI attached as Appendix B herein. At this time, there is no published Regional Infrastructure Plan (RIP).

If and when this process identifies constraints or other factors that have a material impact on the CNPI Capital Expenditure Plan, that plan (and this section of this document) will be modified accordingly.

It is likely that CNPI as an LDC will not be impacted by the Niagara Region IRRP, and will not likely have to make any investments as a result.

This is because:

- CNPI has experienced low load growth. This is expected to continue throughout the planning period
- CNPI is at an 'edge' or 'corner' of Ontario, normally served via a radial connection to the HONI-owned and IESO-controlled grid.

5.4.1.6 Customer Preferences

The following is a summary of the Customer Engagement Activities of CNPI:

5.4.1.6(a) Large Customer Direct Consultations

CNPI engages in ongoing direct consultation with subdivision developers, commercial customers, and major industrial customers on their needs and business plans, if any.

Some of these consultations are reactive, as when the external stakeholder approaches CNPI with a new need or a quality concern.

Some are proactive, where CNPI seeks out information regarding their future plans, undertakes CDM initiatives, or asks them about their legacy services. For example, in developing Fort Erie North voltage conversion program, CNPI consulted a large spot load served by the legacy 4.8kV delta system (a manufacturer located in the Fort Erie), for their supply options and incorporate their requirements in the program design.

5.4.1.6(b) Developer information sessions

CNPI has engaged in multiple directed information sessions many with its third-party stakeholders, such as:

- Subdivision developers and their design agencies
- Electricians and electrical design companies that service the CNPI areas
- Large industries interested in CDM.
- Municipal planning staff

CNPI described its OEB-mandated processes and sought comments from these stakeholders on ways to improve these processes as well as project communications.

Appendix F show samples of presentations made during these sessions

5.4.1.6(c) Niagara Region Coordinating meetings

CNPI attends all Niagara Region Interagency Regional Planning meetings (not to be confused with IESO-directed Regional Planning) to meet with other agencies such as road authorities and joint use partners to coordinate ongoing efforts and to maximize any synergies that may be obtained from mutual design and coordination of intended construction activities.

5.4.1.6(d) Municipal Economic Development & Tourism Corporation

CNPI meets with municipal planning and development entities at both the town/city and regional levels to ensure maximum coordination of activities, and also to find out what significant projects may require the active participation of CNPI, as well as assist CNPI in forecasting load growths.

5.4.1.6(e) Annual Customer Surveys and Special Focus Groups

In response to the Board's Filing Requirements to engage customers on the specific proposals contained in this application, in addition to the annual customer survey, in January 2016 CNPI retained UtilityPULSE to design, collect feedback and provide detailed information on customer feedback (which is contained in Appendix G). In March, 2016, two residential focus groups were held with a total of 32 participants and two general service focus group sessions with a total of 25 participants. The goal of the focus group session was to engage customers in dialogue to gain a better understanding of the findings from the telephone interviews from the annual survey referred to in the section (A) and to capture their thoughts and ideas on the company's rate application process and Distribution System Plan.

Each of the focus group sessions followed a prescribed format where a CNPI executive and the UtilityPULSE moderator welcomed attendees followed by the CNPI executive providing about a 15-20 minute overview (see Appendix H for a copy of the Executive presentation) of the organization and the DSP.

Focus Group participants were provided an opportunity to ask questions. CNPI personnel left the room once questions (if any) were answered. The moderator facilitated each session by sequencing the questions consistently in each session. In addition, every participant was given the opportunity to voluntarily complete a brief paper-based questionnaire and/or to provide written comments.

The results of these focus groups were compared with CNPI's investment strategies and specific plans outlined elsewhere in this DSP. CNPI determined that there was a good 'match' between the customers expressed needs and the CNPI plans, with one notable exception; some CNPI customers expressed a desire to have no rate increases, which conflicts with the need of CNPI to make sustainable investments in its distribution system.

5.4.1.7 Expected System Development over the Planning Horizon

5.4.1.7(a) Load and Customer Growth

CNPI does not expect any significant load growth in the forecast period, although that is subject to change if and when a new proponent commits to locating in our service territory. Although there have been several discussions with such proponents, nothing has approached the level of commitment required for formal inclusion in this DSP.

For example, there is a well-known proposal in Fort Erie, the Canadian Motor Speedway (CMS), which has been well-publicized and has a high probability of proceeding in 2017 or 2018. If this project were to proceed, the campus of new facilities would add about 5 to 8MW of new load, and would require a significant net capital investment by CNPI and a subsequent re-structuring of CNPI's capital development plan to accommodate the needs of this group of external stakeholders.

As a result of projected low organic load growth in the forecast period, the CNPI capital plan has focused on dealing with its two most critical internal needs:

1) The need to eliminate its extensive three wire delta systems
2) The need to replace or refurbish the portion of its distribution system that has reached or is nearing the end of its useful life.

These issues have been described in several other section of this DSP, as well as in the CNPI DAMP.

5.4.1.7(b) Smart Grid development

CNPI will continue to invest in the following technology-driven Smart Grid programs that are already underway at CNPI:

1) Distribution automation through the targeted installation of reclosers, automated switches and fault indicators. CNPI intends to continue with its efforts to integrate such facilities with its SCADA and Outage Management System (OMS) applications
2) Substation Protection Upgrades – CNPI will continue with its program to replace legacy fuse protection with relay-controlled reclosers to improve reliability and protection, and improve SCADA controllability of its feeders.

3) GIS / OMS – CNPI will continue to make select investments in its GIS and OMS systems to meet the needs of its external and internal stakeholders. The focus will be on improved operational efficiencies and improved customer communications.

5.4.1.7(c) Renewable Energy Generation (REG) projects

As outlined in section 5.4.3 of this DSP, CNPI has limited need to allow for the connection of any REG project over 10kW during the forecast period. If the constraints that cause this should change, CNPI will review and revise its plans as necessary.

5.4.1.8 Customer Preferences, Technology and Innovation Projects

5.4.1.8(a) Automated Collections

In 2014 collections enhancements streamlined the process by which customers are notified of overdue accounts. The replacement of mailed reminder notices with an automated telephone call has resulted in a savings of approximately $12,000. This allows customers to be notified in a more timely fashion of overdue amounts on their hydro accounts.

As well, technology enhancements have reduced the manual processing through automations with Canada Post Xpress post software to more efficiently issue final collection notices to customers. As well, regulatory requirements are tracked with the capability of the software to identify where the collection notice is in the delivery cycle.

5.4.1.8(b) Power Outage Automated Customer Communications

In response to customer satisfaction survey results, where 60% of residential customers and 58% of general service customers indicated a preference to receive information about outages via a recorded message, CNPI has developed a process to pro-actively identify customers affected by power interruptions resulting from system repairs/upgrades. Automated phone calls via OnecallNow.com are generated prior to the outage giving customers the opportunity to make any necessary arrangements for their electrical service.

5.4.1.8(c) UtilAssist

Customers identified proactive outage communications as the most important item they were willing to pay more for each month and thus an important area where CNPI could improve overall service levels. CNPI has entered into a project to provide enhanced call answer services to its customers. Leveraging the services of UtilAssist (PowerAssist) customers will have more access to a live Customer Service Representatives (CSR) through an increased number of after business hours inbound telephone lines. Current providers have a limited number of inbound telephone lines which can result in busy signals when customers are trying to contact CNPI. PowerAssist CSR's have access to customer data to provide a higher level of customer interaction during the call. This service will be expanded in late 2016 for all inbound power outage calls.

5.4.1.8(d) MyHydroEye (Smart Meter customer portal)

Customers have indicated that they want access to their time-of-use (TOU) and interval data to help them make informed decisions about their energy usage. As such CNPI has provided all TOU customers the MyHydroEye on-line resource which allows customers to review usage data. This allows customers to make adjustment to their consumption patterns to influence electricity bill amount, as well as forecast bill results in the event they enrolled on a retailer contract.

5.4.1.8(e) Utility SettlementManager

For large users UtiliSmart SettlementManager is available which provides more detailed and individualized data around the composition of the customers' invoice as well load information. In 2016 customers with MIST meters will also be able to access the SettlementManager to review their usage data and assist them in managing their electricity costs by providing usage data.

5.4.1.8(f) GIS / OMS / EA

CNPI has implemented an integrated Geographical Information System /Outage Management System / Outage Management System / Engineering Analysis (GIS/OMS/EA) enterprise system to enhance most aspects of recordkeeping, planning, outage management, and engineering analysis of the Operations department.

5.4.1.8(g) Mobile computing

CNPI has been working to deliver mobile computing to its field staff since 2015. During 2016, CNPI intends to deliver a number of features that will improve efficiencies:

1) Mobile mapping with automated updates
2) Field engineering and staking software
3) Mobile library of essential corporate and 3rd party documents
4) Automated Metering recordkeeping software

5.4.1.8(h) Coordination with Transmitter in Fort Erie

CNPI operates as both an LDC (which is the main focus of this DSP) and as a Transmitter (CNPI Tx), as it owns and operates both of the Customer Delivery Points (CDP) in Fort Erie. That has allowed for very close coordination of efforts to maximize LDC customer needs.

Since 2012, at the request and urging of CNPI LDC, CNPI Tx has optimized its protection and control asset renewal program to ensure that all ten (10) of its CDP feeders will be equipped with modern multifunction electronic relays that allow for improved reliability performance and provide new functionality. CNPI Tx expects to complete this modernization program by 2016/Q2.

5.4.1.8(i) Distribution Automation

For a number of years, CNPI has been engaged in a Distribution Automation program that leverages its investments in SCADA, GIS and Outage Management systems (OMS) to improve operational efficiencies and improve reliability. Some of these investments can be characterized in recent years as 'Smart Grid' investments.

These include:

1) Automated line reclosers complete with SCADA
2) Automated three-phase load-break switches, complete with SCADA
3) Fault Indicators that help in identifying the location of faults to the CNPI distribution system. CNPI is investigating the suitability of SCADA-able units.
4) Integration of Smart Meters with OMS to provide near-real-time identification of system outages at the consumer level.

5.4.1.8(j) Social media

In 2014, CNPI introduced social media as a means to further interact and communicate with its customers. Currently, approximately 10 per cent of customers surveyed in 2014 preferred to receive communications via social media channels, this number is expected to grow. As a result of the customers' feedback, CNPI launched both Facebook and Twitter. CNPI's social media following has continued to increase since the launch. Contests were held to promote the new communication channels and utilization continues to grow. Currently, CNPI is using social media for larger outages affecting many customers, but not for some outages of lesser scope. Future initiatives will involve after hours monitoring of social media by a third party to keep customers informed during all power outages. This will be implemented in June, 2016.

5.4.2 Capital Expenditure Planning Process Overview

5.4.2.1 Description of the CNPI Capital Expenditure Planning Objectives

A description of the distributor's capital expenditure planning objectives, planning criteria and assumptions used, explaining relationships with asset management objectives, and including where applicable its outlook and objectives for accommodating the connection of renewable generation facilities;

The fundamental objective of the CNPI DSP is to prudently and efficiently manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement of all distribution assets in a sustainable manner that maximizes safety and customer reliability, which minimizes costs, in the short and long terms.

This objective is met through the application of thorough and sound planning, prudent and justified budgeting, and ongoing oversight, documentation, and review of all efforts and expenditures while implementing the documented capital and operating plans.

CNPI will maintain a comprehensive Distribution Asset Management Program (DAMP) and DSP which outlines the operating and capital processes, activities, and expenditures that are necessary to ensure that CNPI continues to provide the safe, reliable, and efficient distribution of electricity to its customers.

There are three key principles that are integral to the CNPI DSP/DAMP

- Provide for the growth needs of the customers in the various service territories
- Provide safe, reliable, and high-quality service to all of the customers of CNPI
- Satisfy the first two principles in a sustainable manner which manages the long-term costs to be borne by the ratepayers of CNPI.

These key principles are derived from safety considerations; acts, regulations, codes and guidelines; Good utility practice; and Customer expectations.

These are reviewed annually and adjustments to the plan are made based on changes in legislation, system performance reviews, safety assessments, infrastructure studies, and customer feedback.

5.4.2.2 Non-Distribution System Alternatives to Relieve System Capacity

If not otherwise specified in (a), the distributor's policy on and procedure whereby non-distribution system alternatives to relieving system capacity or operational constraints are considered, including the role of Regional Planning Processes in identifying and assessing alternatives;

A large portion of the CNPI Eastern Ontario Power (EOP) distribution system is represented by the 'North Line'. This 38km section of three phase 26.4 (delta) line runs an extensive distance through challenging terrain to feed a total of three long-term REG-type customers and two small load customers. This line runs outside of CNPI EOP's intrinsic service area to reach these customers, and these five customers are therefore described explicitly on CNPI's distribution license.

The existence of this line and its connection to EOP is an historic artifact of the system dating back many years, long before the re-regulation period of the 1990s and 2000s.

Much of this line is nearing or has reached the end of its useful technical life. CNPI has been evaluating alternatives to simply rebuilding this line 'in place'.

One such option would be to embed these legacy loads into nearby HONI facilities, as HONI does have the electrical franchise in the area where these five customers lie.

Section 5.4.6.15 of this DSP outlines the costs associated with this option, which would be Non-distribution (from CNPI's perspective) if pursued.

5.4.2.3 Project Prioritization Tools and Methods

A description of the process(es), tools and methods (including where relevant linkages to the distributor's asset management process) used to identify, select, prioritize and pace the execution of projects in each investment category (e.g. analysis of impact of planned capital expenditures on customer bills);

(This information may also be found in section 2.4 of the CNPI DAMP)

5.4.2.3(a) Prioritization

Capital investments are selected for execution based on priority. Projects or programs developed to address a need stemming from an external driver are prioritized based on execution timing requirements and resource availability. These projects are typically customer, municipally / regionally, or third party driven. In order to meet the regulatory requirements associated with these types of projects, these investments are considered to be non-discretionary.

Internally driven projects and programs based on asset condition analysis are typically non-discretionary in nature. For these projects the prioritization focuses on asset replacement timing based on risk of asset failure and the customer impact associated with the potential loss of service.

Projects or programs stemming from internal drivers are prioritized based on the identified benefit vs. cost of execution and alignment with asset management objectives. The benefit of a given project or program execution is evaluated based on the adherence to CNPI's project justification criteria. CNPI identifies a primary "trigger" or driver for selected project alternatives but also, identifies the applicable justification criteria.

The justification criteria identifies whether the project positively impacts:

- Safety
- Customer Value
- Operational Efficiency
- Reliability
- Coordination / Interoperability
- Economic Development
- Cyber-Security / Privacy
- Environmental Objectives

Use of these criteria promotes project selection that provides a balanced approach toward meeting CNPI's asset management objectives. Projects and programs directed at replacement of end-of-life assets in advance of failure are given higher priority due to impact on safety and reliability. CNPI's long and medium term planning processes identify program based system renewal investments aimed at levelizing year over year expenditure maximizing the efficient use of resources.

Investments with primary drivers related to the system service category are typically discretionary. The discretionary nature of these types of investments tends to rank associated projects and programs with lower priority compared to system access and system renewal based investments. The selection criteria for discretionary projects are based on incremental analysis. CNPI's historical and forecast investment profile indicates that system service based projects tend to account for a small component of annual expenditure

5.4.2.3(b) Investment Plan

CNPI produces a five year investment plan based on the prioritized registry of projects and programs. This investment plan is updated on an annual basis. The five year investment plan is reviewed by the Executive Committee of CNPI to ensure alignment with asset management objectives as they relate to the performance outcomes identified above. The Executive Committee also ensures that appropriate risk mitigation strategies are deployed within the investment portfolio.

On an annual basis, the five year plan is also reviewed and approved by the Board of Directors of CNPI to ensure alignment with strategic goals and to benchmark against historical investments.

CNPI derives an annual budget as part of its short term planning process. The annual budget is derived from the five year investment plan but also takes into account any new and previously unforeseen requirements. These are typically externally driven such as:

- Customer Requirements
- Regulatory Changes
- Municipal / Regional Initiatives
- Third Party Access Requests
- Reliability Driven Requirements

The annual budget is reviewed and approved by the Executive Committee to ensure adherence and alignment with long and medium term investment plan requirements.

5.4.2.4 Mechanisms Used to engage Customers

If not otherwise included in c) above, details of the mechanisms used by the distributor to engage customers for the purpose of identifying their needs, priorities and preferences (e.g. surveys, system data analytics, and analyses – by rate class – of customer feedback, inquiries, and complaints); the stages of the planning process at which this information is used; and the aspects of the DS Plan that have been particularly affected by consideration of this information

5.4.2.4(a) Large Customer Direct Consultations

CNPI engages in continuous direct consultation with subdivision developers, commercial customers, major industrial customers on their needs and business plans, if any.

Some of these consultations are reactive, as when the external stakeholder approaches CNPI with a new need or a quality concern.

Some are proactive, where CNPI seeks out information regarding their future plans, undertakes CDM initiatives, or asks them about their legacy services.

5.4.2.4(b) Developer information sessions

CNPI has engaged in multiple directed information sessions many with its third-party stakeholders, such as:

- Subdivision developers and their design agencies
- Electricians and electrical design companies that service the CNPI areas
- Large industries interested in CDM.
- Municipal planning staff

CNPI described its OEB-mandated processes and sought comments from these stakeholders on ways to improve these processes as well as project communications.

Appendix F show samples of presentations made during these sessions.

5.4.2.4(c) Niagara Region Coordinating meetings

CNPI attends all Niagara Region Interagency Regional Planning meetings (not to be confused with IESO-directed Regional Planning) to meet with other agencies such as road authorities and joint use partners to coordinate ongoing efforts and to maximize any synergies that may be obtained from mutual design and coordination of intended construction activities.

5.4.2.4(d) Municipal Economic Development & Tourism Corporation

CNPI meets with municipal planning and development entities at both the town/city and regional levels to ensure maximum coordination of activities, and also to find out what significant projects may require the active participation of CNPI.

5.4.2.4(e) Annual Customer Surveys and Special Focus Groups

In response to the Board's Filing Requirements to engage customers on the specific proposals contained in this application, in addition to the annual customer survey, in January 2016 CNPI retained UtilityPULSE to design, collect feedback and provide detailed information on customer feedback (included as Appendix G). In March, 2016, two residential focus groups were held with total of 32 participants and two general service focus group sessions with a total of 25 participants. The goal of the focus group session was to engage customers in dialogue to gain a better understanding of the findings from the telephone interviews from the annual survey referred to in the section 5.4.2.4(a) and to capture their thoughts and ideas on the company's rate application process and Distribution System Plan (DSP).

Each of the focus group sessions followed a prescribed format where a CNPI executive and the UtilityPULSE moderator welcomed attendees followed by the CNPI executive providing about a 15-20 minute overview (see Appendix H for a copy of the Executive presentation) of the organization and the Distribution System Plan (DSP).

Focus Group participants were provided an opportunity to ask questions. CNPI personnel left the room once questions (if any) were answered. The moderator facilitated each session by sequencing the questions consistently in each session. In addition, every participant was given the opportunity to voluntarily complete a brief paper-based questionnaire and/or to provide written comments.

The results of these focus groups were compared with CNPI's investment strategies and specific plans outlined elsewhere in this DSP. CNPI determined that there was a good 'match' between the customers expressed needs and the CNPI plans, with one notable exception; some CNPI customers expressed a desire to have no rate increases, which conflicts with the need of CNPI to make sustainable investments in its distribution system.

5.4.2.5 Method and Criteria Used to Prioritize REG Investments

If different from that described above, the method and criteria used to prioritise REG investments in accordance with the planned development of the system, including the impact if any of the distributor's plans to connect distributor-owned renewable generation project(s).

5.4.2.5(a) Historical Investments related to REG

CNPI has made no material distribution system investments in the past five years specifically to accommodate and/or connect Renewable Energy Generation (REG) investments.

5.4.2.5(b) Forecasted Investments related to REG

Based on historical demand, at the time of preparation of this DSP, CNPI has no plans to make any system expansions specifically as "REG investments" in the period from 2016 to 2021.

As outlined in 5.4.3.4, there are constraints for the connection of new REG projects to the CNPI distribution system in the Niagara region.

To date, CNPI has not received any applications from a DG proponent served by its Eastern Ontario Power (EOP) operating region to connect a DG larger than 500kW.

CNPI does not intend to make any pre-emptive REG investments in its system to allow for large (i.e. greater than 500 kW) DG projects unless and until one or more DG applications are received that would require such an expansion.

CNPI would require an analysis of the impact on its system of any such proposed project via a Connection Impact Assessment (CIA). If the results of the CIA demonstrate the need for CNPI to enhance any portion of its distribution system to accommodate a large DG project, CNPI would undertake to do so, upon commitment by the DG proponent, on a case-by-case basis.

5.4.2.5(c) Prioritization of REG Investments

As there is no likelihood of new large REG projects in the forecast period that would generate resource conflicts for CNPI, at this time CNPI has no need to define a prioritization strategy for them.

5.4.3 System Capability Assessment for Renewable Energy Generation

This section provides information on the capability of a distributor's distribution system to accommodate REG, including a summary of the distributor's load and renewable energy generation connection forecast by feeder/substation (where applicable); and information identifying specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected renewable generation capacity.

a) Applications from renewable generators for connection in the distributor's service area;

b) The number and the capacity (in MW) of renewable generation connections anticipated over the forecast period based on existing connection applications, information available from the OPA and any other information the distributor has about the potential for renewable generation in its service area (where a distributor has a large service area, or two or more non-contiguous regions included in its service area, a regional breakdown should be provided);

c) The capacity (MW) of the distributor's distribution system to connect renewable energy generation located within the distributor's service area;

d) Constraints related to the connection of renewable generation, either within the distributor's system or upstream system (host distributor and/or transmitter):

e) Constraints for an embedded distributor that may result from the connections.

5.4.3.1 Applications from Renewable Generators

5.4.3.1(a) Connections up to 10kVA

As of February 29, 2016, CNPI had connected 137 MicroFIT projects representing 1279 kW of nameplate capacity[1].

CNPI currently has received several such applications and is in the process of connecting them.

[1] For reasons of privacy, no further project details are provided in this DSP.

5.4.3.1(b) Connections over 10KVA

Historically, CNPI have connected a total of three (3) REG projects under FIT with a total nameplate capacity of 1068kVA.

CNPI currently has no new such applications which have progressed to the commitment stage where they have a FIT contract from IESO and are awaiting connection.

There have been several expressions of interest and requests for preliminary consultation, but no proponent has committed to a connection.

5.4.3.2 Anticipated REG Connections over the Forecast Period

As outlined in 5.4.3.4, there are constraints for the connection of new REG projects to much of the CNPI distribution system.

In areas outside of these constraints, there has been very limited historical interest in connecting REG projects.

At this time CNPI does not anticipate any significant quantity of REG connection, larger than 10kVA, over the forecast period.

As outlined in section 5.4.3.3, CNPI can accommodate a reasonable number of REG projects if they do develop, and would deal with them on a case-by-case basis.

5.4.3.3 System Capacity for REG Connections

5.4.3.3(a) CNPI System Capacity

As shown in Table 5.4.3.4-1 (in section 5.4.3.4(c)), CNPI operates its distribution system at two primary voltages for a given general area.

Any proposed FIT or other REG project with a nameplate capacity of 300kVA or larger must be supplied by the higher voltage system.

5.4.3.3(b) Feeder Capacity for REG Projects

CNPI does have capacity on each of its main feeders (i.e. those operating at 27.6kV and 34.5kV) to allow for the connection of several small (i.e. less than 500 kW) DG projects without significant investments in distribution system enhancements, other than site-specific extensions of these feeders to reach proposed locations of REG projects.

The transmitter-owned Customer Delivery Points (CDP) are expected to be able to match this capacity.

In any case, the connection of any such project would be subject to fulfilling any and all requirements identified in a CNPI Connection Impact Assessment (CIA).

5.4.3.4 Constraints Related to the Connection of Renewable Generation

As previously outlined in section 5.1.2 of this DSP, there are constraints on new REG projects in the Niagara peninsula that have limited the size and number of REG projects to-date, and will continue to do so in the forecast period.

5.4.3.4(a) Upstream System Constraints

Port Colborne and Fort Erie lie in the region of the Province of Ontario designated as the 'Niagara Region' by the IESO for Regional planning purposes. For some time, the ability to connect new large Distributed Generation (DG) projects of any kind (including REG projects such as those included in the FIT Program) have been constrained by the Transmitter and IESO-controlled Grid, for technical reasons. This impacts any proposed project with a nameplate capacity over 500kVA.

Until 2014, short-circuit constraints at HONI Allenburg TS restricted connections of REG projects. These constraints have now been addressed.

There is another constraint of REG project connections caused by the need by HONI to complete the construction of a transmission line designated as the Niagara-Caledonia-Middleport line. This construction project is presently on-hold, and will remain so until a lands-rights issue is resolved. Until this line is completed and in-service, there is a limited ability to export additional generation out of the area under certain scenarios. This has prevented the connection of any new large REG projects (>500kW) and restricted the ability to connect smaller REG projects to very small numbers.

- At an IRRP Meeting for Niagara Region held on April 15, 2016, it was confirmed by staff from HONI and IESO that the REG connection constraint imposed by the incomplete Niagara-Caledonia-Middleport transmission line will be remaining in place for the foreseeable future.

5.4.3.4(b) FIT Program Constraints

In addition to the System Constraints described in 5.4.3.4(a), there may be FIT constraints imposed by the IESO or the government of Ontario that prevent the connection of some FIT projects with a nameplate rating larger than 10KVA. This would tend to reduce the total number of committed projects to be connected by CNPI.

5.4.3.4(c) CNPI System Capacity / Constraints

In each of its service territories, CNPI operates its distribution system at two groups of primary voltages as follows:

Area	Higher Voltage ("Trunk")	Lower Voltage ("Legacy")
Fort Erie	34.5kV (Y)	4.16kV(Y), 4.8kV(∆), 8.3kV(Y)
Port Colborne	27.6kV (Y)	4.16kV (Y)
EOP (Gananoque)	26.4kV (∆)	4.16kV (Y)

Figure 5.4.3.4-1: CNPI Distribution Voltages by Area

The "legacy" system was constructed many years ago. The higher voltage system was added/converted when capacity requirements made it necessary. These higher voltage systems serve as a 'trunk' or backbone system to:

- supply distribution stepdown stations, which in turn supply the lower voltage systems.
- supply large spot loads/generators (typically anything over 300kVA).
- supply areas of newer development where the legacy system was not already present.

This means that any FIT or other REG project 300kVA or larger must be supplied by the higher voltage system. In some cases, this would require a distribution expansion of 1.0 km or more. In many cases, the resulting project costs would exceed the *renewable energy expansion cost cap* and require a capital contribution from the REG proponent.

5.4.3.4(d) Feeder Capacity for REG Projects

CNPI does have capacity on each of its main feeders (i.e. those operating at 27.6kV and 34.5kV) to allow for the connection of several small (i.e. less than 500 kW) DG projects without significant investments in distribution system enhancements, other than site-specific extensions of these feeders to reach proposed locations of REG projects.

5.4.3.4(e) Constraints imposed by a Connection Impact Assessment

The connection of any REG project would be subject to fulfilling any requirements identified in a CNPI Connection Impact Assessment (CIA). This would depend on the specifics of the applicant's project.

5.4.3.5 Constraints for an embedded distributor

As previously outlined in section 5.1.2 of this DSP, there are constraints on new REG projects in the Niagara peninsula that have limited the number of REG projects to-date, and will continue to do so in the forecast period.

Port Colborne and Fort Erie lie in the region of the Province of Ontario designated at the ‘Niagara Region’ by the IESO for Regional planning purposes. For some time, the ability to connect new Distributed Generation (DG) projects of any kind (including REG projects such as those included in the FIT Program) have been constrained by the Transmitter and IESO-controlled Grid, for technical reasons.

These same constraints will apply to CNPI’s sole embedded distributor, HONI. A small portion of HONI’s distribution system is supplied via CNPI feeder 43M-13, which in turn is embedded distribution in HONI’s feeder 43M-13, supplied from Crowland TS.

The CNPI distribution system would impose no additional or unusual constraints, other than those typically associated with supporting a REG project to be connected to a 27.6kV distribution feeder.

5.4.4 Capital Expenditure Summary

The purpose of the information filed under this section is to provide the Board and stakeholders with a 'snapshot' of a distributor's capital expenditures over a 10 year period, including five historical years and five forecast years. Note that where a distributor's internal investment planning framework does not align with the investment categories defined here, best efforts are expected to 'map' investments to these categories.

Despite the 'multi-purpose' character of a project or activity, for 'summary' purposes the entire costs of individual projects or activities are to be allocated to one of the four investment categories on the basis of the primary (i.e. initial or 'trigger') driver of the investment. Note, however, that for material projects, a distributor must estimate and allocate costs to the relevant investment categories when providing information to justify the investment, as this assists in understanding the relationship between the costs and benefits attributable to each driver underlying the investment. In any event, the categorization of an individual project or activity for the purposes of these filing requirements should not in any way affect the proper apportionment of project costs as per the DSC.

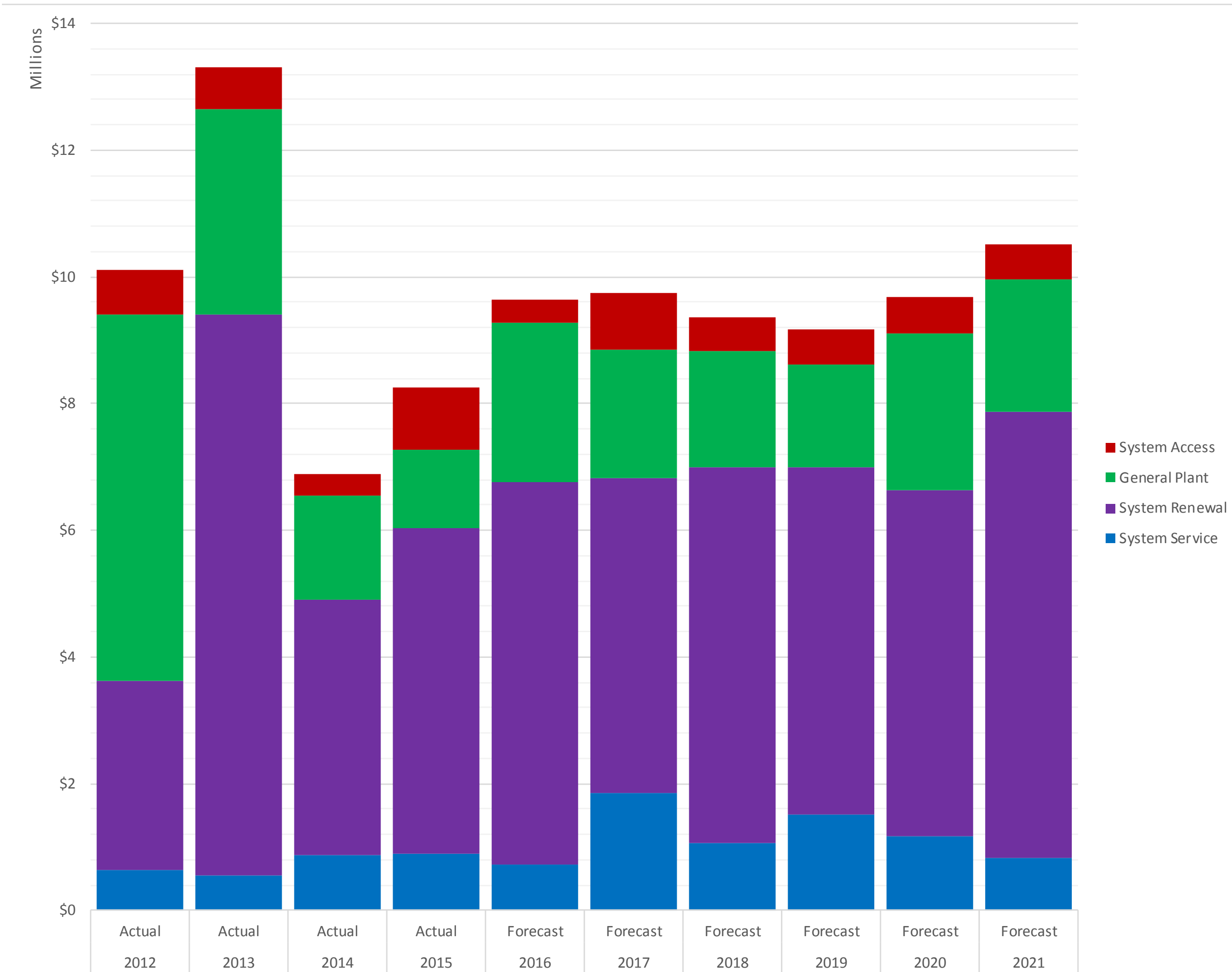
Table 2 illustrates how information filed under this section includes a distributor's actual and forecast (i.e. proposed) capital expenditures over the historical and forecast periods. System operations and maintenance (O&M) costs are also shown to reflect the potential impact, if any, of capital expenditures on routine system O&M. Note that 'Plan' expenditures over the historical period refer to a distributor's previous plan for capital expenditures after adjustments (if any) occasioned by the Board's decision on the relevant prior application.

Brief explanatory notes should be provided to explain the factor(s) and/or circumstances underlying marked changes in the share of total investment represented by a given investment category over the forecast period relative to 'actual' spending over the historical period. For example, a large expenditure over a relatively short period for a 'one-off' project (e.g. a distribution station) can cause a temporary 'step change' in category C spending compared to the trend in actual expenditures over the historical period.

While year over year 'Plan vs. Actual' variances for individual investment categories are expected, explanatory notes should be provided where

- *for any given year "Total" 'Plan' vs. 'Actual' variances over the historical period are markedly positive or negative; or*
- *a trend for variances in a given investment category is markedly positive or negative over the historical period.*

The graph and table below outline the total new investments made by CNPI over the previous five years, as well as the proposed investments CNPI intends to make in the 2016 to 2021 forecast period, a period of 10 years altogether.



Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Status	Actual	Actual	Actual	Actual	Forecast (Bridge Year)	Forecast (Test Year)	Forecast	Forecast	Forecast	Forecast
System Access (SA)	$ 700	$ 665	$ 333	$ 985	$ 353	$ 909	$ 537	$ 547	$ 560	$ 571
System Renewal (SR)	2,997	8,847	4,033	5,155	6,037	4,991	5,939	5,496	5,461	7,044
System Service (SS)	636	554	863	884	722	1,842	1,064	1,505	1,179	836
General Plant (GP)	5,780	3,249	1,655	1,240	2,518	2,016	1,825	1,621	2,478	2,074
Total	**$10,112**	**$13,315**	**$ 6,884**	**$ 8,264**	**$ 9,630**	**$ 9,757**	**$ 9,365**	**$ 9,170**	**$ 9,677**	**$10,524**

Figure 5.4.4-1: 10 year Capital Investment Summary (Historic and Forecast)

The information shown above is the same as that shown in Appendix 2AB of the CNPI 2017 COS application (EB-2016-0061).

5.4.4.1 Historical Variance of Year-over-Year Investments, by Category.

(Includes 2017 Test year)

Please note that the information provided in the following section may also be found in Exhibit 2, Tab 2, Schedule 2 of the CNPI 2017 Cost of Service Application (EB-2016-0061).

Please also note that much of these investments were made prior to the introduction of 'Chapter 5' Investment Categories in 2013. CNPI has made its best effort to retroactively assign all historical investments to an appropriate Category.

5.4.4.1(a) 2012 Actual vs. 2013 Actual

Category	*2012 Actual*	*2013 Actual*	*Variance from 2012 Actual*
System Access	699,501	664,857	-34,644
System Renewal	2,997,112	8,847,242	5,850,130
System Service	635,926	554,267	-81,659
General Plant	5,779,708	3,248,525	-2,531,183
Total Capital Expenditures	**$ 10,112,247**	**$ 13,314,890**	**$ 3,202,643**

System Access (SA) - Variance – 2013 Actual $34,644 less than 2012 Actual

This variance is within the normal variability of expenditures in this category and below the materiality threshold level.

System Renewal (SR) – Variance – 2013 Actual $5,850,130 more than 2012 Actual

Approximately $4,900,000 of Smart Meter assets were capitalized during 2013, resulting in a $4,500,000 increase over 2012 Smart Meter investments.

2013 storm rebuilds stemming from major weather events in July and November contributed a $175,000 increase to the variance.

Replacement of end of life assets within the Gananoque service territory during 2013 resulted in approximately $640,000 increase to System Renewal expenditures.

System Service (SS) – Variance – 2013 Actual $81,659 less than 2012 Actual

This variance is within the normal variability of expenditures in this category and below the materiality threshold level.

General Plant (GP) – Variance – 2013 Actual $2,531,183 less than 2012 Actual

2013 General Plant expenditures do not include any costs pertaining to the acquisition of Port Colborne Hydro assets, or General Expense Capital charges. The absence of these costs results in decreases to 2013 expenditures of $2,700,000 and $1,100,000 respectively when compared to previous year expenditures.

Additionally, there were no large vehicle purchases in 2013. As part of CNPI's Fleet Asset Management Replacement Schedule, a large vehicle was purchased the previous year. The absence of a large vehicle purchase in 2013 provides approximately $330,000 in decreased costs.

During 2013 approximately $800,000 of technology costs associated with the completion of the Smart Meter project were realized. These costs included SAP specific development such as programmatic updates, net new interfacing with external systems and minor external consulting. These charges resulted in an $800,000 increase to General Plant expenditures when compared to the prior year.

Leasehold improvement projects totalling approximately $360,000 occurred during 2013 at the Fort Erie Service Centre. These improvements were largely a result of the consolidation of the Port Colborne and Fort Erie service centres and accommodation of current staffing levels through the construction of additional office space.

In 2013, internal and external efforts pertaining to a newly developed Environment Health and Safety applications resulted in approximately $110,000 of increased General Plant expenditures.

-$2,700,000	Port Colborne Hydro Assets
-$1,100,000	General Expense Capital
-$330,000	Fleet Purchase
+$800,000	Smart Meter Technology
+$360,000	Leasehold Improvements
+$345,000	Software Development
+$110,000	Health, Safety & Environment Software
-$2,515,000	**Net Variance Explanation**

5.4.4.1(b) 2013 Actual vs. 2014 Actual

Category	2013 Actual	2014 Actual	Variance from 2013 Actual
System Access	664,857	332,934	-331,923
System Renewal	8,847,242	4,033,193	-4,814,049
System Service	554,267	863,147	308,880
General Plant	3,248,525	1,655,157	-1,593,368
Total Capital Expenditures	**$ 13,314,890**	**$ 6,884,432**	**-$ 6,430,458**

System Access (SA) – Variance - 2014 Actual $331,923 less than 2013 Actual

System Access investments and third party contributions are entirely based on the needs of external stakeholders such as customers, and joint use partners. These needs fluctuate from year to year. There is no reason to expect that the total amounts to be consistent from year to year.

System Renewal (SR) – Variance – 2014 Actual $4,814,049 less than 2013 Actual

2014 System Renewal expenditures do not include any costs related to the capitalization of Smart Meter assets or the M11 Line Rebuild, resulting in a decreases of approximately $4,900,000 and $218,000 respectively.

Replacement of end of life assets within the Gananoque service territory during 2014 decreased significantly, resulting in a $500,000 decrease within the System Renewal expenditure category.

During 2014 the Barrick Conversion and Rebuild was initiated, contributing a $645,000 increase towards the variance.

Additionally, Rebuilding of the 5/8 Line commenced during 2014, providing a $220,000 increase towards 2014 System Renewal expenditures.

-$4,900,000	Smart Meter assets
-$ 218,000	M11 Line Rebuild
-$500,000	End of life asset replacements – Gananoque
+$645,000	Barrick Conversion & Rebuild
+$220,000	5/8 Line Rebuild
-$4,753,000	**Net Variance Explanation**

System Service (SS) – Variance – 2014 Actual $308,880 more than 2013 Actual

2014 Delta to Wye Conversion efforts were captured under the 18L10 Line Extension project. Construction efforts for 18L10 Line Extension project resulted in approximately a $350,000 increase to 2014 System Service expenditures.

2014 System Service expenditures do not include any costs related to the Station 18 New Feeder Configuration Project, resulting in a decrease of approximately $100,000.

General Plant (GP) – Variance – 2014 Actual $1,593,368 less than 2013 Actual

During 2014, no costs associated with the completion of the Smart Meter project, leasehold improvements or acquisition of Port Colborne Hydro assets were realized. The absence of these costs resulted in decreases of approximately $800,000, $360,000 and $190,000 respectively, within the General Plant expenditure category when compared to the prior year.

Additionally, 2014 software development costs decreased approximately $170,000 when compared to the prior year. This decrease is offset partially through the firewall hardware replacement during 2014. The replacement resulted in a $120,000 increase within the General Plant expenditure category over the previous year.

-$800,000	Smart Meter assets
-$360,000	Leasehold Improvements
-$190,000	Port Colborne Hydro Assets
-$170,000	IT Software Development
+$120,000	IT Firewall Replacement
-$1,400,000	**Net Variance Explanation**

5.4.4.1(c) 2014 Actual vs. 2015 Actual

Category	2014 Actual	2015 Actual	Variance from 2014 Actual
System Access	332,934	984,532	651,598
System Renewal	4,033,193	4,920,766	887,573
System Service	863,147	884,275	21,128
General Plant	1,655,157	1,239,874	- 415,283
Total Capital Expenditures	**$ 6,884,432**	**$ 8,029,447**	**$ 1,145,015**

System Access (SA) – Variance – 2015 Actual $651,598 more than 2014 Actual

System Access investments and third party contributions are entirely based on the needs of external stakeholders such as customers, and joint use partners. These needs fluctuate from year to year. There is no reason to expect that the total amounts to be consistent from year to year.

System Renewal (SR) – Variance – 2015 Actual $887,573 more than 2014 Actual

Construction of a new distribution substation, Gilmore DS, was initiated in 2015. This resulted in a $135,000 increase to 2015 System Renewal expenditures.

$234,000 in MIST Meter assets were capitalized during 2015, completing regulatory requirements in this area.

During 2015, an $185,000 increase to System Renewal expenditures occurred stemming for a rebuild of the Canal Risers on Forks Road.

Targeted replacement of end-of-life assets during 2015 in the Gananoque service territory resulted in a $240,000 expenditure increase from previous year. This investment was directed at achieving sustainable end of life pole replacement levels.

$100,000 of increased efforts pertaining to the Barrick Conversion and Rebuild project were also realized during 2015.

+$135,000	Gilmore DS
+$234,000	MIST Meter assets
+$185,000	Canal Riser Rebuild
+$240,000	End of life asset replacements – Gananoque
+$100,000	Barrick Conversion & Rebuild
+$894,000	**Net Variance Explanation**

System Service (SS) – Variance – 2015 Actual $21,128 more than 2014 Actual

This variance is within the normal variability of expenditures in this category and below the materiality threshold level.

General Plant (GP) – Variance – 2015 Actual $415,283 less than 2014 Actual

2015 General Plant expenditures do not include the purchase of a bucket truck. As part of CNPI's Fleet Asset Management Replacement Schedule, a large vehicle was purchased the previous year. The absence of a large vehicle purchase in 2015 provides approximately $250,000 in decreased costs.

Additionally, during 2015 there were no replacements to firewall hardware within the General Plant expenditure category. A replacement had occurred the previous year, resulting in a $120,000 decrease in 2015 expenditures.

5.4.4.1(d) 2015 Actual vs. 2016 Forecast

Category	2015 Actual	2016 Forecast	Variance from 2015 Actual
System Access	984,532	352,898	-631,634
System Renewal	4,920,766	6,036,707	1,115,941
System Service	884,275	722,488	-161,787
General Plant	1,239,874	2,518,132	1,278,258
Total Capital Expenditures	**$ 8,029,447**	**$ 9,630,225**	**$ 1,600,778**

System Access (SA) – Variance – 2016 Forecast $631,634 less than 2015 Actual

System Access investments and third party contributions are entirely based on the needs of external stakeholders such as customers, and joint use partners. These needs fluctuate from year to year. There is no reason to expect that the total amounts to be consistent from year to year.

System Renewal (SR) – Variance – 2016 Forecast $1,115,941 more than 2015 Actual

As a result of the need to construct the new Gilmore distribution substation in 2016, net increases totaling $1.35 million relating to substation projects over the prior year have been forecasted.

There are no forecasted costs associated with MIST Meter assets or the Forks Road Canal Riser Rebuild in 2016. Absence of these costs results in decreases to 2016 System Renewal expenditures of approximately $234,000 and $185,000 respectively.

System Service (SS) – Variance – 2016 Forecast $161,787 less than 2015 Actual

There are no forecasted costs associated with the 18L10 Line Extension Project in 2016, resulting in a $150,000 decrease of System Service expenditures.

General Plant (GP) – Variance - 2016 Forecast $1,278,258 more than 2015 Actual

As part of CNPI's Fleet Asset Management Replacement Schedule, a large bucket truck vehicle is forecasted for purchase during 2016 resulting in a net $210,000 increase to the General Plant expenditure category.

Approximately $470,000 of SAP software improvements are scheduled to occur in 2016, resulting in an increase over the prior year. These improvements include SAP Work Manager mobile application, asset management integration, bill print enhancements and business process improvements.

During 2016, CNPI's SAP server and associated storage system are scheduled for replacement at a cost of approximately $385,000. This contributes as an increase to the General Plant expenditure category.

Additionally, within Information Technology there are several costs captured in miscellaneous including Adobe software upgrades, a complete upgrade to the existing SharePoint intranet and the introduction PowerAssist call management. These costs result in a $170,000 increase within the 2016 General Plant expenditure category.

+$210,000	Fleet purchase
+$470,000	SAP Software Improvements
+$385,000	SAP Server & Storage System Replacement
+$170,000	Misc. IT General Plant
+$1,235,000	**Net Variance Explanation**

5.4.4.1(e) 2016 Forecast vs. 2017 Forecast

Category	2016 Forecast	2017 Forecast	Variance from 2016 Forecast
System Access	352,898	908,897	555,999
System Renewal	6,036,707	4,990,817	-1,045,890
System Service	722,488	1,841,678	1,119,190
General Plant	2,518,132	2,015,766	-502,366
Total Capital Expenditures	**$ 9,630,225**	**$ 9,757,158**	**$ 126,933**

System Access (SA) – Variance – 2017 Forecast $555,999 more than 2016 Forecast

System Access investments and third party contributions are entirely based on the needs of external stakeholders such as customers, and joint use partners. These needs fluctuate from year to year. There is no reason to expect that the total amounts to be consistent from year to year.

System Renewal (SR) – Variance – 2017 Forecast $1,045,890 less than 2016 Forecast

A net decreases totaling $1.7 million relating to substation projects over the prior year have been forecasted in 2017. This decrease results from the completion of the new Gilmore substation project during 2016.

Increased system rebuilds are forecasted for 2017 within the CNPI service territories, resulting in a $315,000 increase within the System Renewal expenditure category. These forecasted increases are detailed in section 5.4.6.1.

During 2017, improvements at Station 19 are scheduled to occur. These improvements total $350,000 and result in an increase within the System Renewal expenditure category. This is detailed in section 5.4.6.13.

System Service (SS) - Variance - 2017 Forecast $1,119,190 more than 2016 Forecast

An increase of Delta to Wye system conversion efforts is forecasted to occur during 2017 across all CNPI service territories. The conversions projects totaling approximately $1 million result in an increase to the System Service expenditure category when compared to the previous year. This is detailed in sections 5.4.6.2, 5.4.6.4, and 5.4.6.9.

General Plant (GP) – Variance – 2017 Forecast $502,366 less than 2016 Forecast

In 2017, there are less significant lifecycle related IT hardware replacements scheduled as well as reduced IT based software costs, resulting in a $473,000 decrease in General Plant expenditures.

5.4.4.2 Selected Forecast Period Variances, by Category

5.4.4.2(a) 2017 Test Year vs. 2018 Forecast

Category	*2017 Forecast*	*2018 Forecast*	*Variance from 2017 Forecast*
System Access	908,897	536,611	-372,286
System Renewal	4,990,817	5,939,120	948,302
System Service	1,841,678	1,064,435	-777,243
General Plant	2,015,766	1,825,260	-190,506
Total Capital Expenditures	**$ 9,757,158**	**$ 9,365,426**	**$ -391,733**

System Access (SA) – Variance – 2018 Forecast $372,286 less than 2017 Forecast

System Access investments and third party contributions are entirely based on the needs of external stakeholders such as customers, and joint use partners. These needs fluctuate from year to year. There is no reason to expect that the total amounts to be consistent from year to year. At the time of this filing, CNPI is forecasting an 'average' volume of such work with an 'average' volume of offsetting Contributions In Aid of Construction (CIAC's).

System Renewal (SR) – Variance – 2018 Forecast $948,302 more than 2017 Forecast

CNPI plans to construct a new Distribution Substation (DS) in Port Colborne to allow for the retirement of two other DS's that are at or near the end of their useful lives. The net impact of the new DS construction will be an increase in SR investments for substations of $906,000 in 2018 over 2017.

System Service (SS)) – Variance – 2018 Forecast $777,243 less than 2017 Forecast

In 2017, projected investments include $ 750,000 in System Service expenditures to support delta to Wye conversion efforts in the Gananoque service territory. In 2018, no such investment is planned, reducing net SS investments by $750,000.

General Plant (GP)

Within 2017 there is a scheduled replacement of the non-SAP host servers and associated storage system as part of the lifecycle management process. This generates an additional $200,000 increase for the year when compared to 2018.

5.4.4.2(b) 2018 Forecast vs. 2021 Forecast

Category	*2018 Forecast*	*2019 Forecast*	*2020 Forecast*	*2021 Forecast*	*2021 Variance from 2018 Forecast*
System Access	*536,611*	*547,343*	*559,940*	*571,139*	*34,528*
System Renewal	*5,939,120*	*4,746,072*	*5,496,072*	*5,460,618*	*1,104,482*
System Service	*1,064,435*	*1,504,806*	*1,179,108*	*918,380*	*228,877*
General Plant	*1,825,260*	*1,621,293*	*2,477,611*	*2,073,684*	*248,424*
Total Capital Expenditures	***$9,365,426***	***$8,419,514***	***$9,169,514***	***$9,677,278***	***$1,158,556***

2018 to 2021 System Access (SA) – Variance – 2021 Forecast $34,528 more than 2018 Forecast

System Access investments and third party contributions are entirely based on the needs of external stakeholders such as customers, and joint use partners. These needs fluctuate from year to year. There is no reason to expect that the total amounts to be consistent from year to year. At the time of this filing, CNPI is forecasting an 'average' volume of such work with an 'average' volume of offsetting CIAC's. Since overall SA investments are impossible to forecast with any certainty, CNPI has assumed an average year-over-year growth of 2% from 2018 to 2021.

2018 to 2021 System Renewal (SR) – Variance – 2021 Forecast $1,104,482 more than 2018 Forecast

In 2021, CNPI Intends to build a new Distribution Station (DS) in the south eastern area of Fort Erie. This station is anticipated to require $550,000 more investments in substations than in 2018.

CNPI will be engaged in significant efforts to eliminate its legacy delta systems throughout the forecast period. Some of this work is straight voltage conversion, attributed to System Service (SS), and some of this work requires accompanying refurbishment or replacement of legacy line, attributed to System Renewal (SR). In 2021, CNPI expects a change in the relative mix of these two types of work, contributing to a net increase in SR of $470,000.

2018 to 2021 System Service (SS) – Variance – 2021 Forecast $228,877 less than 2018 Forecast

CNPI will be engaged in significant efforts to eliminate its legacy delta systems throughout the forecast period. Some of this work is straight voltage conversion, attributed to System Service (SS), and some of this work required accompanying refurbishment or replacement of legacy line, attributed to System Renewal (SR). In 2021, CNPI expects a change in the relative mix of these two types of work, contributing to a net decrease in SS of $229,000.

2018 to 2021 General Plant (GP) – Variance – 2021 Forecast $248,424 more than 2018 Forecast

The summary below represents the three primary areas of focus in respect of technology related capital improvements. In general, the year over year allocation to these areas remain consistent with the exception of hardware. The hardware variances are attributed to significant replacement of systems that are at the end of their lifecycle. Such systems include but are not limited to host servers, storage systems and associated network gear.

Please note that amounts shown are thousands of dollars:

	2016	2017	2018	2019	2020	2021
Hardware	600	354	250	200	200	400
Software	1,491	1,274	1,004	1,000	1,000	1,000
	$2,091	$1,628	$1,254	$1,200	$1,200	$1,400

5.4.5 Justifying Capital Expenditures

As indicated in Chapter 1, the onus is on a distributor to provide the data, information and analyses necessary to support the capital-related costs upon which the distributor's rate proposal is based. Filings must enable the Board to assess whether and how a distributor's DS Plan delivers value to customers, including by controlling costs in relation to its proposed investments through appropriate optimization, prioritization and pacing of capital-related expenditures.

5.4.5.1 Overall Plan

The Board's assessment of DS Plans includes the costs of material projects/activities included in the DS Plan, as well as the costs represented by the respective shares of the overall DS Plan budget allocated to each of the four investment categories. Information to be provided in this section pertains to the latter; the former is addressed in section 5.4.5.2.

To support the overall quantum of investments included in a DS Plan by category, a distributor should include information on:

- *comparative expenditures by category over the historical period;*
- *the forecast impact of system investment on system O&M costs, including on the direction and timing of expected impacts;*
- *the 'drivers' of investments by category (referencing information provided in response to sections 5.3 and 5.4), including historical trend and expected evolution of each driver over the forecast period (e.g. information on the distributor's asset- related performance and performance targets relevant for each category, referencing information provided in section 5.2.3);*
- *information related to the distributor's system capability assessment (see section 5.4.3)*

CNPI has prepared its Capital Plan with a focus on its core values and objectives:

(i) Provide for the growth needs of its customers in the various service territories

(ii) Provide safe, reliable, and high-quality service to all of the customers of CNPI

(iii) Satisfy the first two principles in a sustainable manner which minimizes the long-term costs to be borne by the ratepayers of CNPI.

These objectives have been met through the application of thorough and sound planning, prudent and justified budgeting, and ongoing oversight, documentation, and review of all efforts and expenditures while implementing the documented capital and operating plans. CNPI believes that it has met these objectives, as outlined in this Distribution System Plan.

As stated previously, the main challenges facing CNPI today can be summarized as:

1) Managing our asset life cycles to ensure timely replacement of critical assets as they reach or near the end of their useful lives. CNPI has significant distribution assets that are aged.
2) Elimination of legacy three-wire delta systems that represent safety and operational concerns. CNPI has been engaged in voltage conversion programs for some time, and this challenge represents a focus for CNPI in its capital program over the entire forecast period of 2016-2021, and beyond.
3) Dealing with the first two challenges in a prudent and sustainable manner that maintains system reliability and customer satisfaction, maximizes operational efficiency, and addresses worker and public safety; all while focusing on the need to manage overall costs and the associated impacts on CNPI's distribution rates.

CNPI capital expenditures over the historical period and estimated capital expenditures during the forecasted period were previously described in section 5.4.4.1

A summary of CNPI's forward-looking expenditures for the proposed capital investments in the test year and forecast period in each of the investment categories was discussed previously, in section 5.4.1.1.

5.4.5.2 Summary of Material Investments

The focus of this section is on projects/activities that meet the materiality threshold set out in Chapter 2 of the Filing Requirements for Electricity Transmission and Distribution Applications. However, distributors are encouraged in all instances to consider the applicability of these requirements to ensure that all investments proposed for recovery in rates, including those deemed by the applicant to be distinct for any other reason (e.g. unique characteristics; marked divergence from previous trend) are supported by evidence that enables the Board's assessment according to the evaluation criteria set out below. The level of detail characterizing the evidence filed by a distributor to support a given investment project/activity should be proportional to the materiality of the investment.

A. General Information on the Project/Activity

The following information is to be provided for any material project in order to facilitate and understanding of the quantum of the expenditure, timing, and contingencies associated with the project:

- *total capital and where applicable, (non-capitalized) O&M costs proposed for recovery in rates*
- *related customer attachments and load, as applicable*
- *start date, in-service date and expenditure timing over the planning horizon*
- *the risks to the completion of the project or activity as planned and the manner in which such risks will be mitigated*
- *if not evident from Table 2, comparative information on expenditures for equivalent projects/activities over the historical period, where available*
- *information on total capital and OM&A costs associated with REG investment, if any, included in a project/activity; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities*
- *where a proposed project requires Leave to Construct approval under Section 92 of the OEB Act, with construction commencing in the test year, the applicant must provide a summary of the evidence for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular)*

B. Evaluation criteria and information requirements for each project/activity

The Board's evaluation of material investments aligns with the outcomes set out in section 5.0.4. Efficiency, customer value, reliability and safety are the primary *criteria for evaluating any material investment; other criteria pertaining specifically to grid modernization will be applied where applicable.*

The Board's investment evaluation criteria and the qualitative or quantitative evidence that a distributor can use to demonstrate that an investment is consistent with these criteria are set out below.

1. *Efficiency, Customer Value, Reliability*

    a. *identify the main 'driver' ('trigger') of the project/activity, and where applicable any secondary 'drivers'; related objectives and/or performance targets; and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment*

    b. *indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing and pacing projects in each investment category described in response to section 5.4.2(c) using, where applicable, quantitative and/or qualitative analyses of the project and project alternatives involving design, scheduling, funding and/or ownership options (e.g. whole or part ownership solely by or jointly with 3rd parties)*

        - *explain the effect of the investment on system operation efficiency and cost-effectiveness*
        - *the net benefits accruing to customers as a result of the investment*
        - *the impact of the investment on reliability performance including on the frequency and duration of outages*

    Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the imputed value of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives.

    Where a distributor's choices as to technical design, component characteristics, how the work is carried out, etc. have been affected by a decision to configure a project to meet both a 'trigger' driver and one or more other drivers in a manner that affects cost as well as benefits, these effects should be highlighted.

2. *Safety*

    Provide information on the effect of the investment on health and safety protections and performance

3. *Cyber-security, Privacy*

Where applicable, provide information showing that the investment conforms to all applicable laws, standards and best utility practices pertaining to customer privacy, cyber-security and grid protection

4. *Co-ordination, Interoperability*

    a. *where applicable, explain how the investment applies recognized standards, referencing co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.*

    b. *describe how the investment potentially enables future technological functionality and/or addresses future operational requirements*

5. *Economic Development*

    Where applicable, describe the effect of the investment on Ontario economic growth and job creation

6. *Environmental Benefits:*

    Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies

C. *Category-specific requirements for each project/activity*

As set out below, category-specific information and analyses should also be used to support a project/activity (or elements thereof as applicable).

a) *System access – projects/activities in this category are driven by statutory, regulatory or other obligations on the part of the distributor to provide customers with access to their distribution system. Most frequently, investments relate to requests by customers for connections or connection modifications, but also include requests from municipal authorities for a distributor to relocate system assets in order to accommodate infrastructure development or modifications. Consequently, investment budgets for this category can vary from one DS Plan to the next depending on business conditions. In the event that the project involves replacing a distributor's system assets, there may also be asset life-cycle related considerations to the extent that infrastructure is taken out of service prior to the end of its service life and new infrastructure is commissioned. Information bearing on these issues should therefore be included in a distributor's justification of a project/activity in this category, including (where applicable) but not restricted to:*

- *factors affecting the timing/priority of implementing the project*
- *factors relating to customer preferences or input from customers and other third parties*

- *factors affecting the final cost of the project*
- *how controllable costs have been minimized*
- *whether other planning objectives are met by the project or have intentionally been combined into the project and if so, which objectives and why*
- *whether technically feasible project design and/or implementation options exist, whether these options were considered and if not, why not*
- *where such options were considered and project decision support tools and methods described in response to section 5.4.2 (c) were used to help identify the proposed option, provide a summary of the results of the analysis, including where applicable:*
  - *the least cost option: a comparison of the life cycle cost of all options considered (including the proposed project) – over the service life of the proposed project*
  - *the cost efficient option: a comparison of net project benefits and costs over the service life of the proposed project including:*
    - *I. a project configured solely to meet the obligation; and*
    - *II. the proposed project and where considered, technically feasible options to the proposed project that meet the same objectives.*
- *where applicable, the results of the 'final economic evaluation' carried out as per section 3.2 of the DSC*
- *where applicable (e.g. REG investment), information on the nature and magnitude of the system impacts of the project, the costs of any system modifications required to accommodate these impacts and the means by which these costs are to be recovered*

b) System renewal – projects/activities in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. "failure"). Generally, the lower the *former and/or higher the latter, the more important it becomes to replace or refurbish the asset(s) sooner rather than later.*

Hence, a distributor's discretion over the timing and priority of projects in this category may lessen over time, such as where assets with high consequence of failure are consistently operating outside applicable operating limits. On the other hand, a distributor may have considerable discretion over timing and priority where deteriorating asset condition has little or no impact on performance and the consequences in terms of the number of customers and criticality of service potentially affected by an asset failure are relatively low.

Information bearing on these issues should therefore be included in a distributor's justification of each sustainment project/activity, including (where applicable) but not restricted to:

- *a description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to*
    - *the distributor's asset performance-related operational targets and asset lifecycle optimization policies and practices (i.e. filings in relation to sections 5.2.3 and 5.3.3)*
    - *information on the condition of the assets relative to their typical life-cycle;*
    - *and performance record of the assets targeted by the project*
    - *the number of customers in each customer class potentially affected by a failure of the assets included in the project*
    - *quantitative customer impacts (e.g. frequency or duration of interruptions or number of customers affected) with associated risk level(s)*
    - *qualitative customer impacts (e.g. customer satisfaction; customer migration)*
    - *with associated risk level(s)*
    - *the value of customer impact (e.g. high, medium, low) in terms of the characteristics of customers potentially affected by failure that have a bearing on the criticality and/or cost of failure (e.g. customer classes; customer access to backup service)*
- *other factors that may affect the timing of the proposed project, including the rate at which assets are replaced over the forecast*

period (i.e. investment intensity), where applicable; priority relative to other projects (this and other categories)

- *identify the consequences for system O&M costs, including the implications for system O&M of not implementing the project*
- *identification of reliability and or safety factors that may have played a role*
- *where applicable and reasonable variation and/or uncertainty in the above factors exists, provide – using the tools and methods described in response to section 5.4.2 (c) – an analysis of project benefits and costs comparing alternatives to the timing of the proposed project, highlighting the trade-offs between rate of expenditure and mitigation of the consequences of asset performance deterioration. Where the ranking of the proposed project relative to the alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, these should be described and explained in relation to the proposed project and all alternatives.*
- *where the proposed project meets the requirement for 'like for like' renewal and has been configured at extra cost to address other distributor planning objectives (e.g. development related objectives), provide – using the tools and methods described in response to section 5.4.2 (c) – an analysis of project benefits and costs comparing a) a project configured solely to meet the requirement; b) the proposed project; and c) technically feasible alternatives to the proposed project that meet the same objectives as the proposed project. Where the ranking of the proposed project relative to alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, these should be described and explained in relation to the proposed project and all alternatives.*

c) *System service – projects/activities in this category are driven by the distributor's expectations that evolving customer use of the system may occasion the creation of system capacity constraints or otherwise adversely impact operations in a manner that challenges the distributor's service delivery standards or objectives. Distributor discretion in relation to investments in this category can be relatively high in terms of both* *initiating a project and determining the priority and timing of project-related expenditures.*

- *Information used by a distributor to justify projects/activities in this category should include, but need not be restricted to:*
- *where measurable, an assessment of the benefits of the project for customers in relation to the achievement of the objectives of the investment; express the result (including where value is in the form of an avoided cost) in terms of cost impact to customers where practicable*
- *where applicable, information on regional electricity infrastructure requirements identified in a regional planning process that affected the initiation or final configuration of the project; and on the corresponding distribution of the benefits and responsibility for project costs*
- *description of how advanced technology has been incorporated into the project (if applicable) and including how standards relating to interoperability and cybersecurity have been met.*
- *identification of any reliability, efficiency, safety and coordination benefits or affects the project will have on the distributor's system*
- *identifying and explaining the factors affecting implementation timing/priority*
- *providing, where applicable and using the tools and methods described in response to section 5.4.2 (c), an analysis of project benefits and costs comparing the proposed project to a) doing nothing; and b) technically feasible alternatives to the proposed project considered that meet the same objectives as the proposed project.*
- *Where the ranking of the proposed project relative to alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, information should be provided that describes these 'qualitative' factors in relation to the proposed project and all alternatives, and that explains whether and how these factors affected the selection of the proposed project.*

d) <u>General plant</u> – projects/activities in this category are driven by the distributor's evolving requirements for capital to support day to day business and operations activities. Distributor discretion in relation to *investments in this category can be relatively high in terms of both initiating a project and determining the priority and timing of project-related expenditures. Information used by a distributor to justify material projects/activities in this category should include but need not be restricted to:*

- *the results of quantitative and qualitative analyses (using the tools and methods described in response to section 5.4.2 (c) where applicable) of the proposed project/activity, including assessments of financially feasible options to the proposed project (including the 'do nothing option' where applicable), identifying the (net) benefits of the proposed investment in monetary terms where practicable;*
- *For projects the capital cost of which substantially exceed the materiality threshold, (e.g. CIS, GIS, new office building) the distributor shall file a thorough business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).*

Figure 5.4.5.2-1 on the following page lists major (or material) projects for the period from 2016 to 2021. This covers the current fiscal year (2016) and a five-year forecast period from 2017 to 2021.The table lists those projects with a gross expected investment level of $100,000 or more.

Note that there are several potential projects, triggered by needs of customer and/or third party joint-use partner of a material nature that MAY occur in the forecast period (all of which would be SA if constructed). At the time of the latest revision of this document, no such project has reached a state where there has been customer commitment or payments received, so they are not included.

If and when such a project is committed, then CNPI will meet its obligation to serve and make the necessary investments. In such a case, it may prove necessary to exceed the 'Sundry SA' forecasted amounts in the SA category to accommodate the needs of these stakeholders, and could result in adjustments to investments in other categories if it is necessary to reassign significant resources.

A more detailed description for each of these projects can be found in section 5.4.6 of this DSP.

CNPI Major Projects (Investments exceeding $100,000) - 2016-2021

DSP ID	Area	Project	Main Category	Annual Material Investment ($ 000's)						
				2016	2017	2018	2019	2020	2021	Total
1	FE	Construct New Gilmore DS	SR	2,124	-	-	-	-	-	2,124
2	FE	QEW North 4.8Δ to 8.3Y Voltage Conversion SS	SS	-	209	209	209	209	-	836
3	FE	QEW North 4.8Δ to 8.3Y Rebuild & Conversion SR	SR	751	832	832	832	832	-	4,079
4	FE	Ridgeway - 4.8Δ to 8.3Y Voltage Conversion SS	SS	330	410	295	241	396	-	1,672
5	FE	Ridgeway - 4.8Δ to 8.3Y Rebuild & Conversion SR	SR	620	95	450	368	506	-	2,039
6	FE	5/8 Line 34.5kV Distribution Line Rebuild	SR	250	250	-	-	-	-	500
7	EOP	Construct Herbert DS to Gananoque DS 4.16kV Intertie	SR	380	-	-	-	-	-	380
8	CNPI	Distribution Automation & Reliability Improvements Program	SS	308	311	260	265	271	276	1,691
9	FE	4.8kV Delta to 8.3 Wye Voltage Conversion Program	SS	-	104	163	169	171	542	1,149
10	PC	Distribution System Upgrade Program	SR	120	231	226	553	525	584	2,239
11	FE	Distribution System Upgrade Program	SR	225	442	677	1,209	1,126	2,497	6,176
12	EOP	Distribution System Upgrade Program	SR	132	512	545	553	561	569	2,872
13	FE	Station 19 DS Protection Upgrade & Arc Flash Hardening	SS	-	348	-	-	-	-	348
14	PC	Construct new substation - Port Colborne South DS	SR		409	1,250				1,659
15	EOP	North Line - Rebuild 9.8km	SR	-	257	280	240	180	160	1,117
16	EOP	Main Substation - Delta to Wye Conversion	SS	-	750	-	-	-	-	750
17	CNPI	Targeted Pole Replacement Program	SR	870	981	997	1,014	1,031	1,048	5,941
18	PC	Killaly DS - Upgrade Protection and Redundant Source	SS	-	-	-	410	-	-	410
19	FE	New South DS - Acquire Land	GP	-	-	-	-	250	-	250
20	FE	New South DS - Construct new substation	SR	-	-	-	-	-	1,700	1,700
21	CNPI	Fleet Management Program GP	GP	327	175	385	75	775	418	2,155
22	CNPI	Information Technology - Hardware GP	GP	600	354	250	200	200	400	2,004
23	CNPI	Information Technology - Software GP	GP	1,491	1,274	1,004	1,000	1,000	1,000	6,769

Figure 5.4.5.2-1: CNPI Material Projects in the Forecast Period

5.4.6 Material Projects

This section describes each major (defined as having a gross cost of $100,000 or greater) project at CNPI, as shown on the Figure 5.4.5.2-1 in section 5.4.5.2

5.4.6.1 FE - Construct New Gilmore DS

(Project 1 in Figure 5.4.5.2-1)

5.4.6.1(a) Justification for three material projects:

Please note that the justification described in sections 5.4.6.1(b) through 5.4.6.1(g) hereafter apply to three distinct Material Projects of this DSP:

- Project 1: FE Construct New Gilmore DS
- Project 2: FE - QEW North 4.8Δ to 8.3Y Rebuild & Conversion SS
- Project 3: FE - QEW North 4.8Δ to 8.3Y Rebuild & Conversion SR

5.4.6.1(b) Challenges with Existing System in the 'North QEW' Area

5kV Aerial Cable nearing the end of useful life

Approximately 4.0km of the main 4.8 delta feeder lines in the North QEW area is composed of aged cable mounted aerially on poles. As outlined in the CNPI DAMP Section 6.1.2 and DAMP Appendix J, recent 3rd party testing by Kinetrics has confirmed this cable has a projected life of only 5 to 10 more years. This cable was installed over a fairly narrow timeframe in the past, so it is likely that cable failures caused by deterioration may become frequent once they begin.

CNPI needs a plan to begin to address the removal of this cable in a timely and effective manner. Resource restrictions require a multi-year approach, as CNPI wishes to ensure sufficient planning and construction effort-hours are available to complete this work.

Aged Distribution Substation Equipment

As described in DAMP sections 6.1.2 and 6.1.3, Station 12 and Station 15 contain many assets that are nearing or have reached the end of their useful lives.

Delta 4.8kV System

As outlined in the CNPI DAMP (Section 3.2) and section 5.4.4.1 of this DSP, CNPI is in the process of eliminating its legacy 4.8kV delta three wire system for reasons of safety and efficiency. As discussed in 5.4.6.1(d) herein, CNPI can create material annual long term reductions in distribution operating losses by introducing a higher voltage system to replace the 4.8 delta system.

In addition, much of the 4.8kV delta system is aged, and will require investments in asset renewal even if voltage conversions are not carried out.

Vulnerable Legacy Supply from south side of QEW

As outlined in the DAMP (section 6.1.2), most of the 4.8 delta feeders supplying the North QEW area originate at Station 12 and supply the North QEW area via underground feeder exits that cross under the QEW, a 400-series highway that passes through Fort Erie. There are only two corridors for these exits, and several of these feeder exits are composed of legacy underground cables that have been in service for an extended time. The location and type of these underground circuits make their replacement costs very high.

5.4.6.1(c) Alternative Analysis:

CNPI performed a detailed alternative analysis utilizing the integrated Engineering Analysis (EA) module of its Milsoft GIS system to analyze the Fort Erie distribution system, including the 'North QEW' area. This load-flow analysis revealed several items of concern over a ten-year planning horizon. This software was then used to evaluate a number of possible alternatives to address all of the problems identified in 5.4.6.1(b).

Factors considered during these analyses included:

- Overloaded conductors and other equipment
- Substandard voltages and voltage balance
- Fault levels exceeding design parameters
- Predicted reliability
- N-1 Contingency analysis
- Safety concerns, such as delta systems or Arc hazard identification
- Distribution loss savings
- Retirement of aged assets

The three major alternatives identified to address the problems were as follows:

Alternative A - Maintain Status Quo, Replace Deteriorated Assets, Delay Conversion

- Replace all assets where-is and in-kind as they reach the end of their useful lives. As each portion of line is rebuilt, use higher voltage standard in construction, and convert to 8.3kV or 34.5kV in future when possible.

- This option DOES NOT address the concerns of the presence of the delta system nor does it result in any line-loss savings for a longer period of time.
- Once all identified conversions for this option are performed (by 2035), the expected reduction in peak line-losses would be about 185kW. After applying appropriate values for Load Factor (LF) and Line-Loss Factor (LLF), this would be an annual reduction in wasted energy of 550MWh, worth about $77,100 in 2016.

Alternative B - Construct Gilmore DS, Convert 4.8 Delta to 8.3kV Wye

- Decommission Station 15 immediately, retiring rather than replacing 4.8kV substation delta assets in-kind.
- Build a new duel-element 8.3kV DS at Gilmore road, leveraging the property and facilities already present at Station 18 and Station 15.
- Construct a double-circuit loop in the North QEW (see 5.4.6.3) and convert all of the legacy 4.8kV delta in the North QEW area (most to 8.3kV wye) over a five year period. Increase capital investments in years 2016-2020 to complete this in a timely manner.
- Some of the legacy 4.8kV delta would be converted to 19.9kV, as there is some 19.9/34.5kV distribution lines in the north potion of this area of concern.
- Frees up 4.8kV capacity needs at Station 12 by 2020, allowing retirement of one of the aging power transformers rather than replacement.
- Once all identified conversions for this option are performed (by 2020), the expected reduction in peak line-losses would be about 256kW. After applying appropriate values for Load Factor (LF) and Line-Loss Factor (LLF), this would be an annual reduction in wasted energy of 763MWh, worth about $106,800 in annual savings in 2016.

Alternative C – Construct Central DS, Convert 4.8 Delta to 8.3kV Wye

- Decommission Station 15 within 2 years, retiring rather than replacing 4.8kV delta assets in-kind.
- Similar to Alternative B, except that the proposed DS would be built on a green-field site near to the load center of the area to be converted. This

option would require the purchase of land for a suitable site, and an expansion of the 34.5kV system to act as the source for this station.

- This option would free up 4.8kV capacity needs at Station 12 by 2020, allowing retirement of one of the aging power transformers rather than replacement.
- Once all identified conversions for this option are performed (by 2020), the expected reduction in peak line-losses would be about 371kW. After applying appropriate values for Load Factor (LF) and Line-Loss Factor (LLF), this would be an annual reduction in wasted energy of 1,106MWh, worth about $154,800 in annual savings in 2016.

5.4.6.1(d) NPV Evaluation

Economic Assumptions and Parameters:

- All costs were estimated using 2016 equivalent amounts.
- Future Value (FV) amounts were derived assuming all costs of all types would increase with a constant 2.00%/annum as a deemed inflation factor.
- Present Value (PV) amounts were discounted from future values using CNPI's present Weighted Average Cost of Capital (WACC) as a constant discount factor. For 2016, this value is 7.18%/annum.
- For economic comparison of alternatives, all cash flows, expense and capital, were deemed to be equivalent and fully occurring in the year in which they were spent/invested. This 'simple cash flow' evaluation does not factor in cash flows arising from depreciation or taxes.
- Savings arising from system loss reductions were deemed to be equal in value to other costs incurred or avoided. A 25-year cost recovery period was used for study purposes.

The three alternatives were subjected to a Net-Present-Value (NPV) evaluation and the results can be seen in the following cash-flow table and graph:

	Alt A: Status Quo, Replace Deteriorated Assets, Delayed Conversion			Alt B: Construct Gilmore DS, Convert 4.8kV ∆ to 8.3kV Y			Alt C: Construct Central DS, Convert 4.8kV ∆ to 8.3kV Y		
Year	FV Cost	PV Cost	Cumulative NPV Cost	FV Cost	PV Cost	Cumulative NPV Cost	FV Cost	PV Cost	Cumulative NPV Cost
2016	$ 488,333	$ 488,333	$ 488,333	$2,864,313	$2,864,313	$2,864,313	$3,798,520	$3,798,520	$3,798,520
2017	671,500	626,516	1,114,849	1,034,398	965,104	3,829,417	960,126	895,807	4,694,327
2018	570,486	496,612	1,611,462	1,027,290	894,264	4,723,681	939,065	817,463	5,511,790
2019	1,091,276	886,325	2,497,787	1,019,484	828,016	5,551,697	916,778	744,599	6,256,390
2020	441,993	334,935	2,832,722	1,010,954	766,084	6,317,781	893,223	676,869	6,933,259
2021	644,047	455,354	3,288,076	- 117,991	- 83,422	6,234,359	- 170,912	- 120,838	6,812,421
2022	527,419	347,915	3,635,991	- 120,351	- 79,390	6,154,969	- 174,330	- 114,998	6,697,423
2023	469,047	288,682	3,924,673	- 122,758	- 75,553	6,079,416	- 177,817	- 109,440	6,587,983
2024	771,342	442,932	4,367,605	- 125,213	- 71,902	6,007,515	- 181,373	- 104,151	6,483,833
2025	411,366	220,396	4,588,002	- 127,717	- 68,427	5,939,088	- 185,000	- 99,117	6,384,715
2026	1,333,839	666,754	5,254,756	- 130,271	- 65,120	5,873,968	- 188,700	- 94,327	6,290,389
2027	427,985	199,608	5,454,364	- 132,877	- 61,972	5,811,996	- 192,474	- 89,768	6,200,621
2028	- 81,321	- 35,386	5,418,978	- 135,534	- 58,977	5,753,019	- 196,324	- 85,430	6,115,191
2029	- 99,536	- 40,411	5,378,566	- 138,245	- 56,127	5,696,892	- 200,250	- 81,301	6,033,890
2030	954,056	361,394	5,739,961	- 141,010	- 53,414	5,643,478	- 204,255	- 77,371	5,956,519
2031	- 103,558	- 36,600	5,703,361	- 143,830	- 50,833	5,592,645	- 208,340	- 73,632	5,882,887
2032	512,125	168,871	5,872,232	- 146,707	- 48,376	5,544,269	- 212,507	- 70,073	5,812,813
2033	- 107,741	- 33,147	5,839,085	- 149,641	- 46,038	5,498,231	- 216,757	- 66,687	5,746,126
2034	- 109,896	- 31,545	5,807,540	- 152,634	- 43,813	5,454,418	- 221,093	- 63,464	5,682,662
2035	- 134,513	- 36,025	5,771,515	- 155,686	- 41,695	5,412,723	- 225,514	- 60,397	5,622,266
2036	- 137,203	- 34,284	5,737,231	- 158,800	- 39,680	5,373,042	- 230,025	- 57,478	5,564,788
2037	- 139,947	- 32,627	5,704,604	- 161,976	- 37,763	5,335,280	- 234,625	- 54,700	5,510,088
2038	- 165,216	- 35,938	5,668,666	- 165,216	- 35,938	5,299,342	- 239,318	- 52,056	5,458,032
2039	- 168,520	- 34,201	5,634,466	- 168,520	- 34,201	5,265,142	- 244,104	- 49,540	5,408,492
2040	- 171,890	- 32,548	5,601,918	- 171,890	- 32,548	5,232,594	- 248,986	- 47,146	5,361,346
2041	- 175,328	- 30,975	5,570,943	- 175,328	- 30,975	5,201,619	- 253,966	- 44,867	5,316,478

Figure 5.4.6.1-1: Net Present Value Comparison of Alternatives for Projects 1, 2 and 3

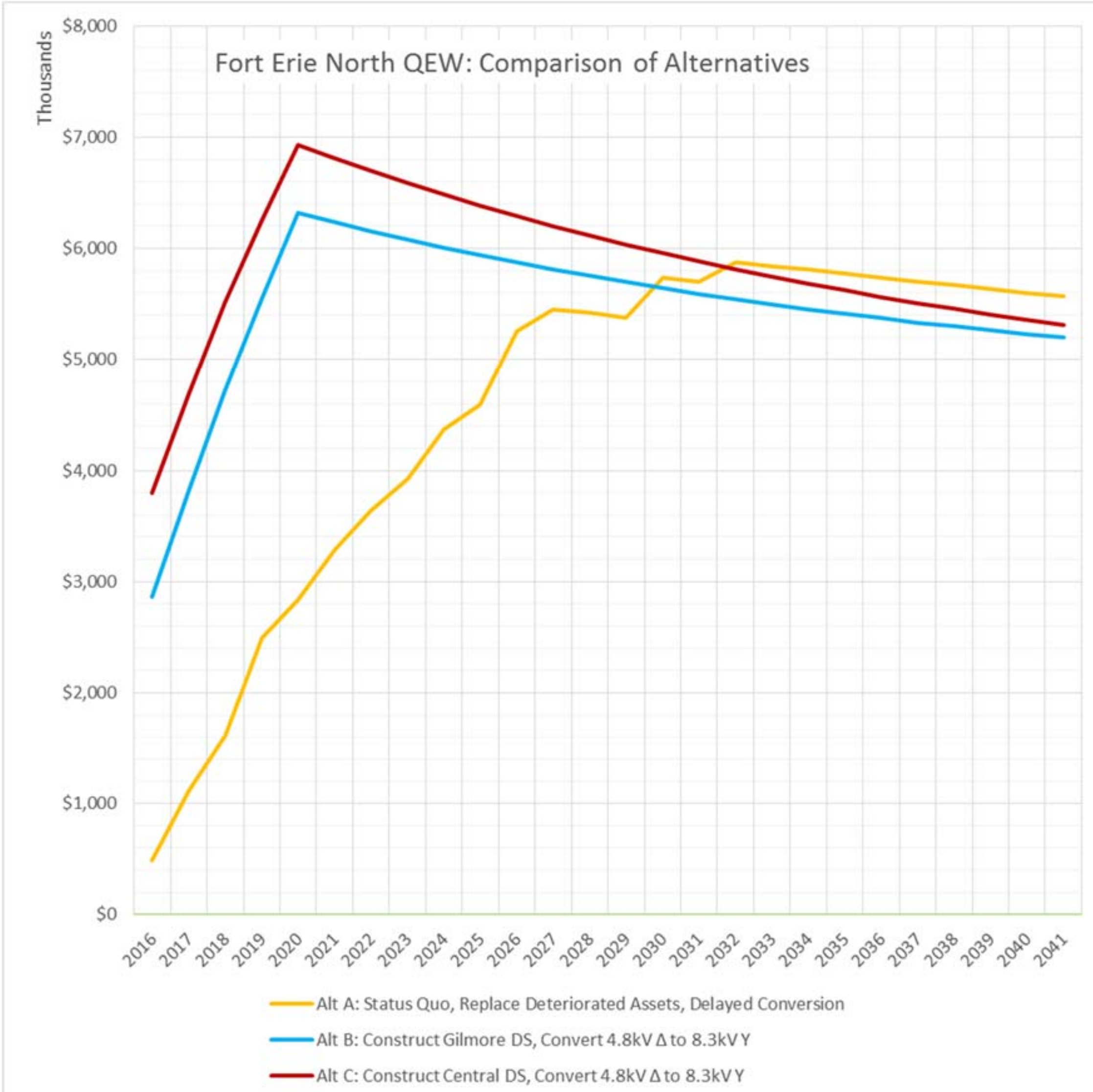


Figure 5.4.6.1-2 Comparison of Alternatives for QEW North

5.4.6.1(e) Comparison of Alternative NPV Costs:

Alternative A does not have as much ‘up-front’ capital costs as the other options. This alternative requires more overall capital investments over time, as delta supply transformers at Station15 and Station 12 would need to be eventually replaced in-kind rather than simply retired. Additional substation refurbishments will be required to sustain these two DS’s beyond their intended service lives. Distribution line-loss savings are reduced compared to the other alternatives, and occur further into the future. *This alternative DOES NOT address the safety concerns regarding the CNPI delta system in a timely fashion.*

Alternative B has higher initial construction costs when compared to Alternative A. It has lower capital investments overall, as major substation legacy assets are retired rather than replaced. This alternative results in more attractive line-loss reductions when compared to Alternative A, and they are realized much sooner.

Alternative C has higher initial construction costs compared to Alternative B. Its location nearer the QEW North 'load center' results in the best overall line-loss savings, but these long-term savings do not fully offset the initial capital cost differences. In addition, this alternative carries more Project Risk than Alternative B. This is due to the need to seek out a suitable site and perform a full Environmental Assessment of the suitability for this proposed location to house a Distribution Substation

5.4.6.1(f) Recommendation

Alternative B is recommended, as it not only addresses the safety and operational concerns related to the legacy delta systems in a timely manner, but Alternative B also results in the lowest long-term NPV costs and offers the most effective means of dealing with all of the identified challenges.

5.4.6.1(g) Spending profile for recommended solution:

(Note that the costs shown below include all costs associated with Projects 1, 2 and 3 in this DSP. They are shown together in the following table as they were all part of the alternative analysis)

DSP ID	Area	Project	Main Category	Annual Material Investment ($ 000's)						
				2016	2017	2018	2019	2020	2021	**Total**
1	FE	Construct New Gilmore DS	SR	2,124	-	-	-	-	-	**2,124**
2	FE	QEW North 4.8Δ to 8.3Y Voltage Conversion SS	SS	-	209	209	209	209	-	**836**
3	FE	QEW North 4.8Δ to 8.3Y Rebuild & Conversion SR	SR	751	832	832	832	832	-	**4,079**
		TOTAL		**2,875**	**1,041**	**1,041**	**1,041**	**1,041**	**-**	**7,039**

5.4.6.1(h) Project 1 Description – Construct Gilmore DS:

This project provides for the construction of a new 34.5:8.3kV substation at Gilmore Road with a projected in-service date in 2016/Q4. It is being done to provide an 8.3kV grounded-wye source in the north-eastern area of Fort Erie to allow for the start of a 5-year project to convert a major section of the legacy delta three-wire system.

Substation Design

Gilmore DS will be constructed on the site of a legacy distribution substation (Station 15 DS) within a fenced enclosure that also contains CNPI Station 18 TS. It will be located on a CNPI-owned parcel of land near the intersection of Thompson Rd. and Gilmore Rd. as shown below:

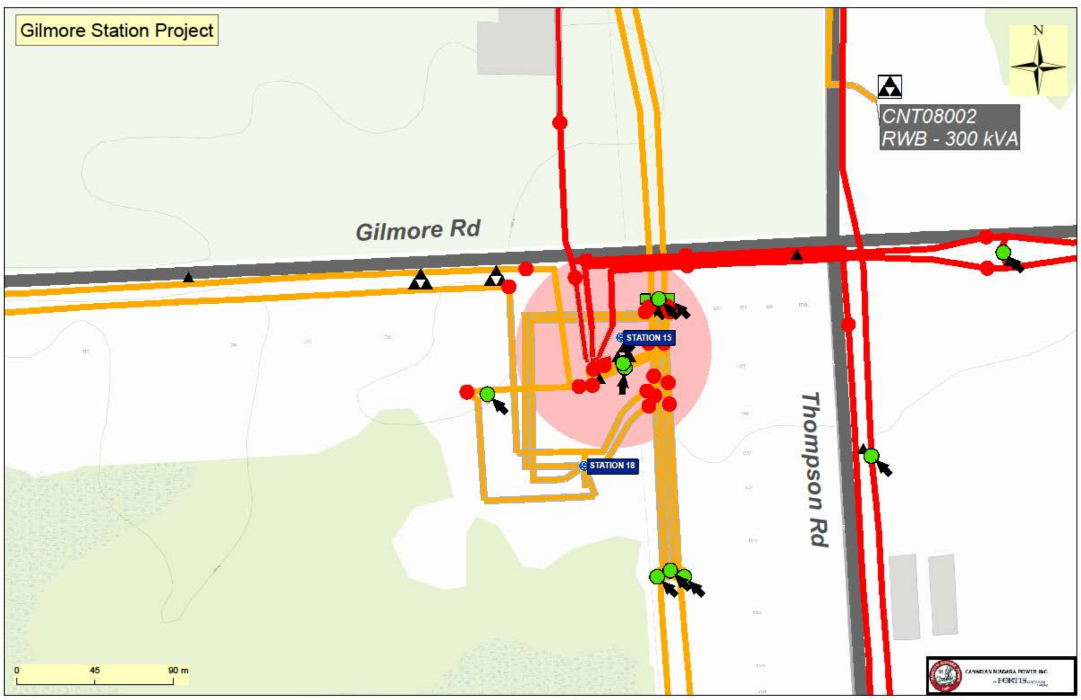


Figure 5.4.6.1-3 Proposed Location for Gilmore DS

Gilmore DS will share facilities with the existing Station 18 TS to reduce construction costs:

- Property, fencing, and driveway
- Grounding and lightning protection
- Control building c/w ancillary equipment like lighting, AC and DC panels, and battery banks.

The station will be an aerial 'bare-wire' design, using pole-mounted equipment similar to many other components to be found throughout the CNPI distribution system, reducing the need to develop new expertise or stocking of new major equipment.

The station will consist of:

- Two 7.5MVA 34.5:8.3kV (Y-Gnd) power transformers
- Two high-side pole-mount 38kV G&W Viper^{tm} reclosers serving as transformer high-side breakers.
- Two low-side pole-mount G&W Viper^{tm} reclosers serving as transformer low-side breakers.
- Four low-side G&W Viper^{tm} reclosers serving as feeder breakers, with provision for two more if needed in the future.
- Two distinct low-side (8.3kV wye) busses, constructed as overhead strain-busses using single-pole cross-arm supporting structures
- An underground-cable connection between the two 8.3kV busses, c/w one G&W Viper^{tm} recloser, acting as a tie point between the two busses.
- Sundry ducting and cabling, including conduit to the road to provide for an ultimate design of six feeders. Only four sets of feeder exit cables will be constructed in 2016 to meet present load needs.

A conceptual drawing and a one-line AC elementary drawing are shown in Figure 5.4.6.1-4 and 5.4.6.1-5:

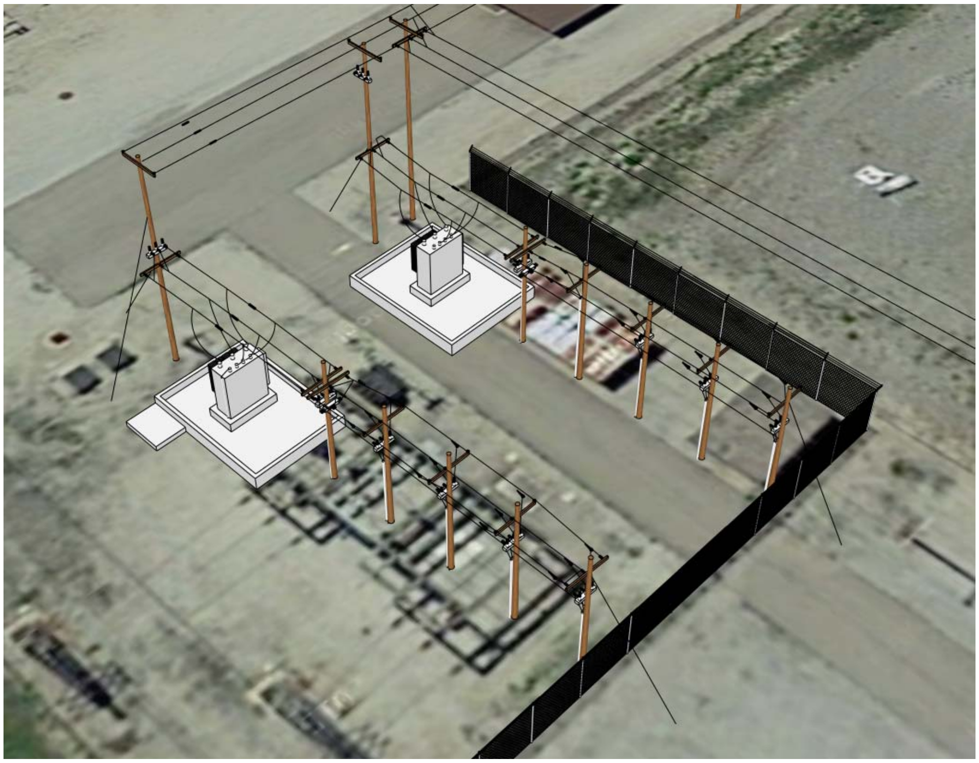


Figure 5.4.6.1-4 Conceptual Drawing of Gilmore DS

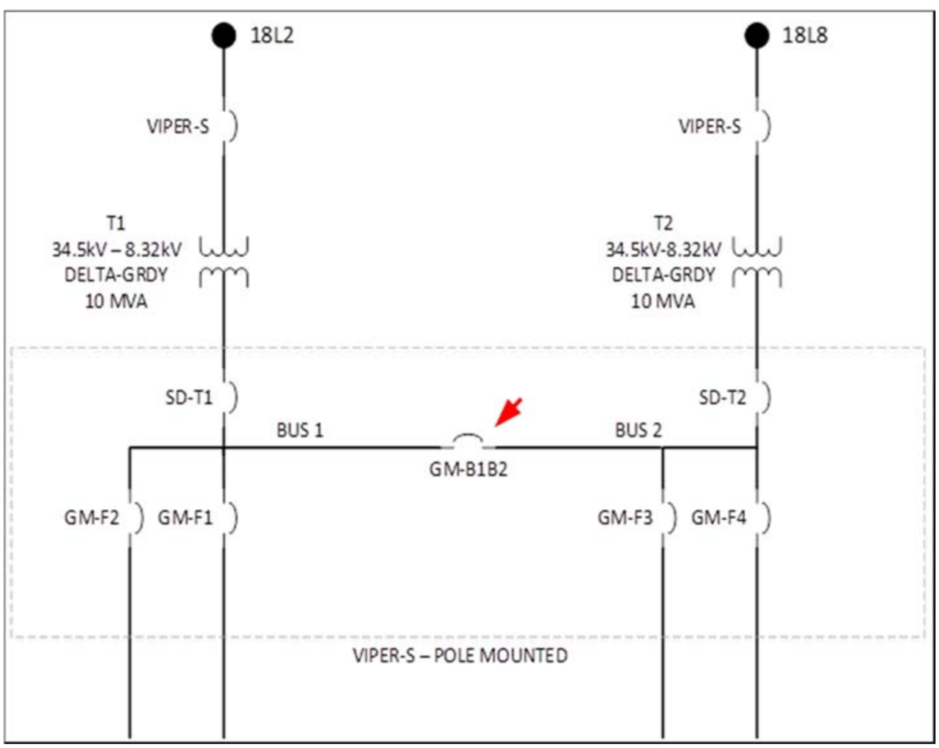


Figure 5.4.6.1-5 Elementary AC One-Line for Gilmore DS

5.4.6.1(i) Cost Estimate:

The cost estimate for Gilmore DS is as follows:

Item	Description	Quantity	Unit Cost	Total Cost
1	Power Transformer	1	$ 200,000.00	$ 200,000.00
4	Pole Work	10	$ 12,000.00	$ 120,000.00
5	Low Side Viper-S / Breaker	7	$ 30,000.00	$ 210,000.00
6	High Side Viper-S / Breaker	2	$ 30,000.00	$ 60,000.00
7	1000 kcmil 33% CN 15kV Cable	1200	$ 50.00	$ 60,000.00
8	Terminations	54	$ 100.00	$ 5,400.00
9	Relay Panels	1	$ 140,000.00	$ 140,000.00
10	Civil	1	$ 448,400.00	$ 448,400.00
11	Feeder Exits (separate OEB acct)	1	$ 490,000.00	$ 490,000.00
12	Internal Labour	1600	$ 73.00	$ 116,800.00
13	Engineering	1	$ 80,000.00	$ 80,000.00
Total Estimate				$ 1,930,600.00
Total Estimate w/ Contingency				**$ 2,123,660.00**

Figure 5.4.6.1-6 Cost Estimate Breakdown for Gilmore DS

5.4.6.2 FE - QEW North 4.8Δ to 8.3Y Voltage Conversion SS

(Project 2 in Figure 5.4.5.2-1)

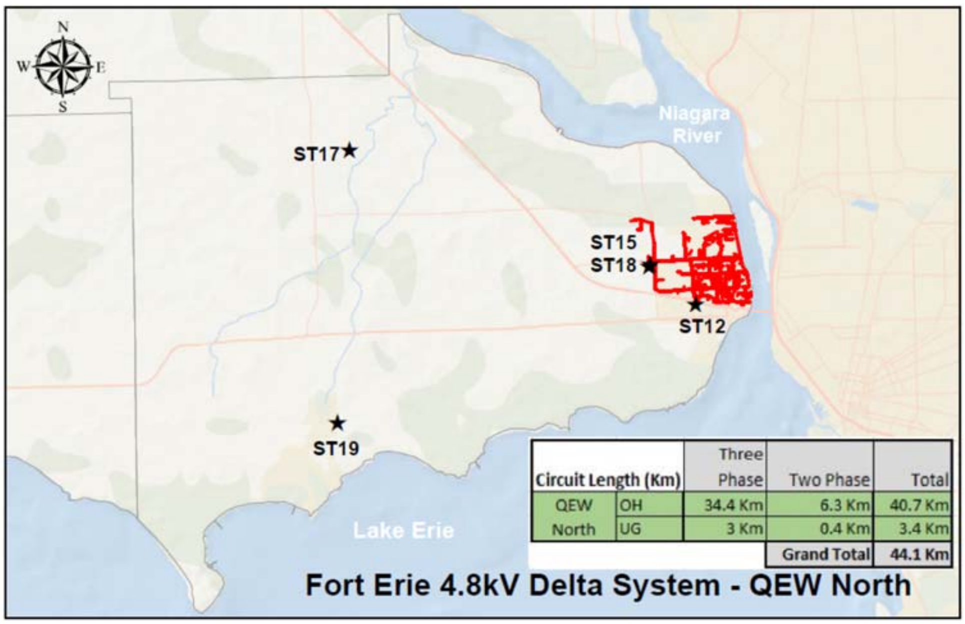
5.4.6.2(a) Justification and Alternative Analysis

Please refer to sections 5.4.6.1(a) through 5.4.6.1(g) of this DSP.

5.4.6.2(b) Project Description

This project is the voltage conversion (System Service) portion of the line work described in section 5.4.6.1 of this DSP. There is a closely-related System Renewal (SR) project (5.4.6.3) that provides for replacement of deteriorated assets in the same area on some of the same distribution lines.

This area has been designated as 'QEW North' and is shown in the following map:



Circuit Length (Km)		Three Phase	Two Phase	Total
QEW North	OH	34.4 Km	6.3 Km	40.7 Km
	UG	3 Km	0.4 Km	3.4 Km
			Grand Total	44.1 Km

Figure 5.4.6.2-1: Map showing QEW North area

This area, north of the QEW, contains approximately 44 circuit-km of the total 191 circuit-km of 4.8kV delta lines within the FE distribution system. In order to eliminate the delta system in this area, CNPI estimates the following effort will be required:

Effort	Line Length (km)
Line Rebuild	19.7
Line Refurbishment	8
Line Conversion	12.5

Figure 5.4.6.2-2: Estimated Effort – Elimination of QEW North Delta System

CNPI plans to eliminate the delta system in the QEW North area by 2020.

This capital project covers the conversion portion of item 2 in the table where both conversion and asset replacement is planned, and covers all of item 3, on legacy lines where 'pure' conversions with a minimum of asset replacement will be done.

Once this project is complete in 2020, the Fort Erie system should then be configured as shown in Figure 5.4.6.2-3:

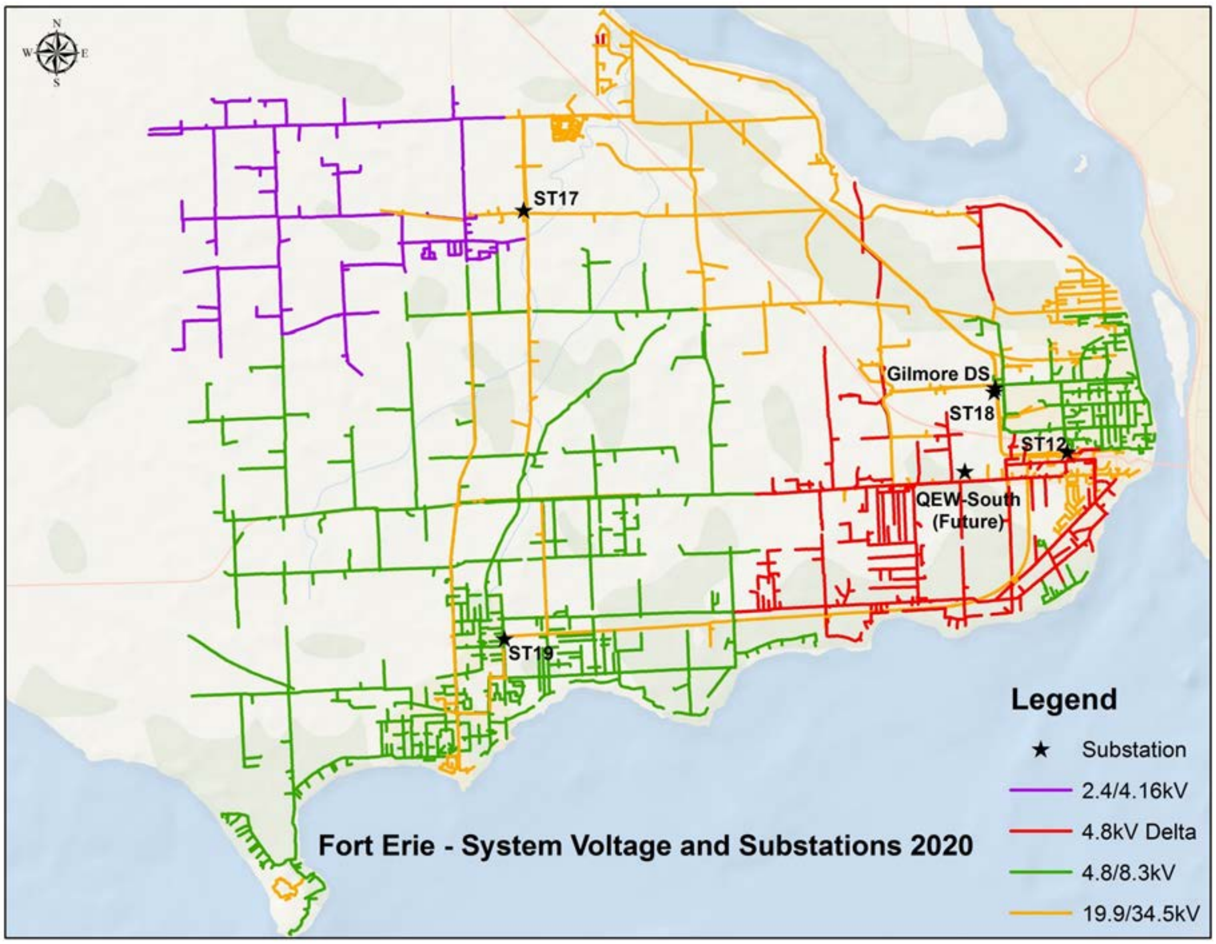


Figure 5.4.6.2-3: FE System Voltage and Substations by 2020

The annual spending profile during the forecast period is as follows:

DSP ID	Area	Project	Main Category	Annual Material Investment ($ 000's)						
				2016	2017	2018	2019	2020	2021	Total
2	FE	QEW North 4.8Δ to 8.3Y Voltage Conversion SS	SS	-	209	209	209	209	-	836

5.4.6.3 FE - QEW North 4.8∆ to 8.3Y Rebuild & Conversion SR

(Project 3 in Figure 5.4.5.2-1)

5.4.6.3(a) Justification and Alternative Analysis

Please refer to sections 5.4.6.1(a) through 5.4.6.1(g) of this DSP.

5.4.6.3(b) Project Description

This project is the System Renewal portion of the work described in section 5.4.6.1 of this DSP. It covers those investments that are driven by the need to renew old assets that are near or have reached the end of their useful service lives. This work is required due to the deteriorated condition of these assets.

The timing of these projects will be synchronized to any Voltage Conversion projects taking place in the same general area (see 5.4.6.2) to ensure that all of these works are done efficiently and with a minimum of project delays.

This item also provides for the construction, starting in 2016, of a double-circuit 336 AAC 8.3kV ‘backbone’ loop to serve as the main trunks of the four feeders to be established from the new substation (Gilmore DS) described in section 5.4.6.1. Portions of this route were specifically selected by CNPI to replace some of the aerial cables of concern described in section 5.4.6.1(c).

The approximate routing of this ‘loop’ will be as shown in Figure 5.4.6.3-1:

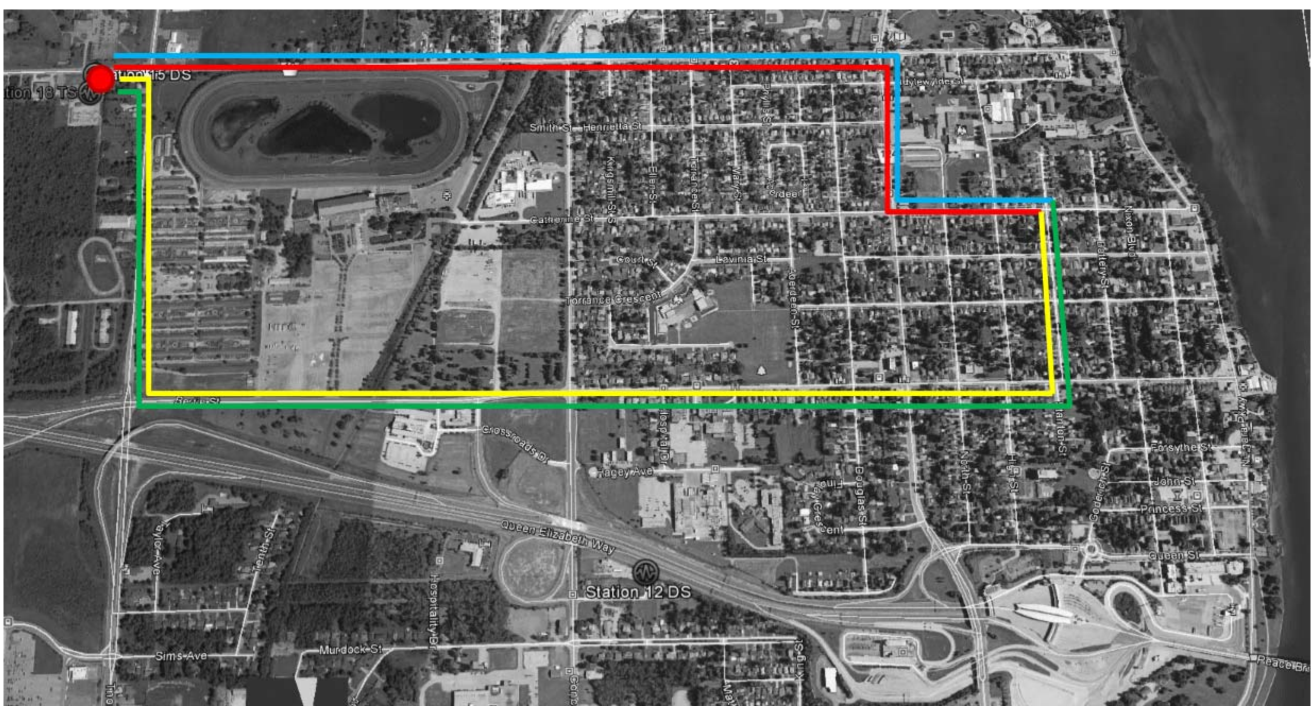


Figure 5.4.6.3-1: Gilmore DS and QEW-North Conversion – Conceptual Backbone Design

Much of this rebuild work will be in the replacement of aged poles. Based on the schedule for conversion in this area for the period 2016 through to 2020, CNPI estimates the following annual pole replacements in this area:

Year	2016	2017	2018	2019	2020
Est. Pole Count	106	117	117	117	117

The annual spending profile during the forecast period for this SR work is as follows:

DSP ID	Area	Project	Main Category	Annual Material Investment ($ 000's)						
				2016	2017	2018	2019	2020	2021	Total
3	FE	QEW North 4.8Δ to 8.3Y Rebuild & Conversion SR	SR	751	832	832	832	832	-	4,079

5.4.6.4 FE – Ridgeway – 4.8∆ to 8.3Y Voltage Conversion SS

(Project 4 in Figure 5.4.5.2-1)

5.4.6.4(a) Justification and Alternative Analysis

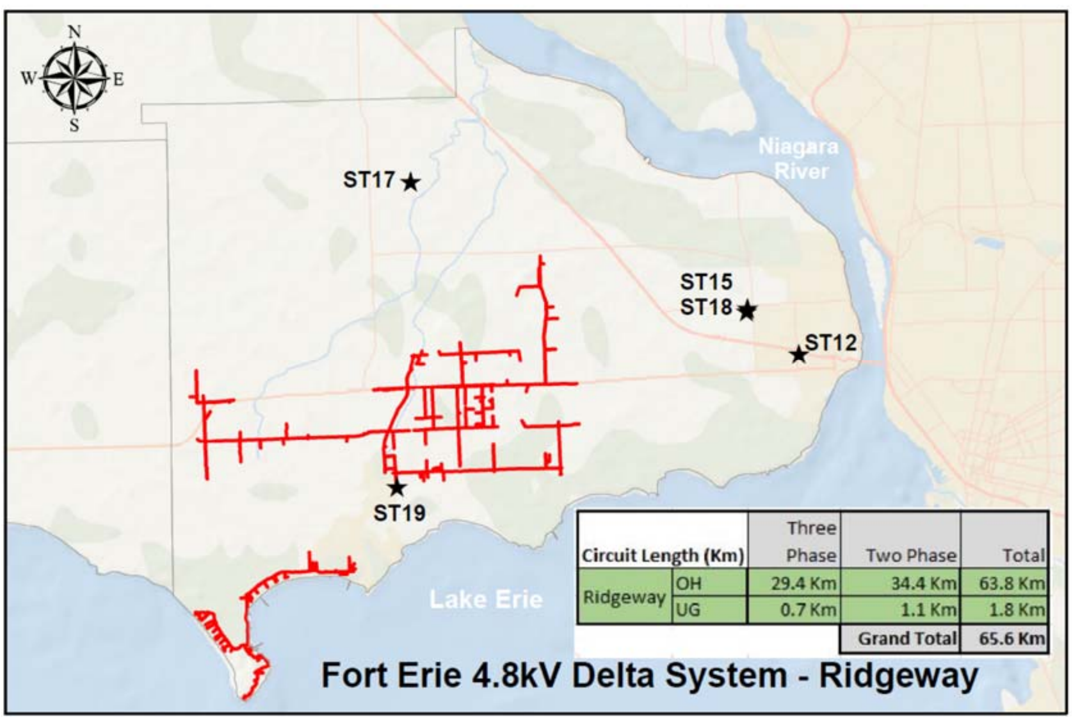
This project is necessary in order for CNPI address safety and operating concerns associated with its legacy 4.8kV delta system, as per DAMP, sections 3.3.2 and 6.2.1.

Other than the non-discretionary project described in 5.4.6.4(b), there were no other alternatives identified that resolved these concerns without requiring considerably larger capital investments.

5.4.6.4(b) Project Description

The introduction of the wye configured Station 19 in 2001 was a major step towards elimination of the delta primary system in the Ridgeway area. Although this source was introduced, a significant portion of the area remains delta distribution. These areas are supplied via structure mounted ratio bank transformers that have delta connected secondary.

The ratio bank transformers have contributed to a decline in reliability during lightning events. The transformers are susceptible to impulse related failures due to their high impedance characteristic. Figure 5.4.6.4-1 illustrates the remaining delta distribution system in the Ridgeway area:



Circuit Length (Km)		Three Phase	Two Phase	Total
Ridgeway	OH	29.4 Km	34.4 Km	63.8 Km
	UG	0.7 Km	1.1 Km	1.8 Km
			Grand Total	65.6 Km

Figure 5.4.6.4-1: Ridgeway Delta Distribution System

The Ridgeway area contains approximately 66 circuit-km of the total 191 circuit-km of 4.8kV delta lines within the FE distribution system. A portion of this area has already been rebuilt during the historical investment period to support a wye connected configuration. In order to eliminate the delta system in this area, CNPI estimates the following effort will be required:

Effort	Line Length (km)
Line Rebuild	8.2
Line Refurbishment	13.8
Line Conversion	41.8

In principle, CNPI targets a line for holistic **rebuild** whenever spot replacement of deteriorated assets would cost more than 60% to 70% of the costs to simply rebuild the entire line.

Sections of line would be **refurbished** if fewer assets require spot replacement, resulting in a cost less than 60% of the equivalent rebuild cost.

Line **conversion** is simply the replacement of minor components (such as arresters, switches, etc.), in order to connect the section to a wye source.

In reality, each project is analyzed technically, operationally, and financially in design stage to determine whether a line section should be rebuilt, refurbished, or converted to achieve maximum cost effectiveness.

Based on the schedule for conversion in this area for the period 2016 through to 2020, CNPI estimates the following annual pole replacements:

Year	2016	2017	2018	2019	2020
Est. Pole Count	94	14	68	56	77

CNPI plans to eliminate the Delta system in the Ridgeway area by the end of 2020.

5.4.6.4(c) Line-Losses – Savings due to Voltage Conversion

Distribution line-losses were calculated, assuming no conversion of the Ridgeway area, and then recalculated assuming conversion of the Ridgeway area, all using the CNPI GIS/EA software.

Once all of the Ridgeway conversions are complete in 2020, peak line-losses are expected to be reduced by about 190kW. Applying appropriate load factors and line-loss factors, these annual savings in losses has been calculated to be 566MWh per year.

This represents an annual savings (assuming 2016 equivalent values) of $79,000 per year. Over the 25 years of the evaluation period, the NPV of the cash-flows arising from these loss savings is approximately $1,036,000.

The perpetual savings would have a NPV of approximately $1,560,000.

5.4.6.4(d) Cost Breakdown

A breakdown of total spending for this project over its five years is as follows:

FE - Ridgeway 4.8Δ to 8.3Y Voltage Conversion 2016-2020

		km	unit cost	extended	SR Split	SS Split	SR	SS	TOTAL
Station 19 - New feeder exit		n/a	$ 55,000	$ 55,000	100%	0%	$ 55,000	$ -	**$ 55,000**
10RT5	3ph rebuild	1.20	$ 160,000	$ 192,000	100%	0%	$ 192,000	$ -	**$ 192,000**
10RT5	3ph convert	7.70	$ 5,000	$ 38,500	0%	100%	$ -	$ 38,500	**$ 38,500**
10RT5	2ph->1ph convert	2.00	$ 40,000	$ 80,000	0%	100%	$ -	$ 80,000	**$ 80,000**
10RT5	2ph->1ph refurbish	7.70	$ 75,000	$ 577,500	65%	35%	$ 375,375	$ 202,125	**$ 577,500**
10RT5	1ph->1ph convert	4.00	$ 5,000	$ 20,000	0%	100%	$ -	$ 20,000	**$ 20,000**
2016		**22.60**					$ 622,375	$ 340,625	**$ 963,000**
10RT3	3ph convert	3.60	$ 50,000	$ 180,000	0%	100%	$ -	$ 180,000	**$ 180,000**
10RT3	2ph->1ph convert	2.60	$ 40,000	$ 104,000	0%	100%	$ -	$ 104,000	**$ 104,000**
10RT3	2ph->1ph refurbish	1.50	$ 75,000	$ 112,500	47%	53%	$ 52,875	$ 59,625	**$ 112,500**
10RT4	3ph reconductor only	1.00	$ 85,000	$ 85,000	50%	50%	$ 42,500	$ 42,500	**$ 85,000**
10RT4	2ph->1ph convert	0.60	$ 40,000	$ 24,000	0%	100%	$ -	$ 24,000	**$ 24,000**
2017		**9.30**					**$ 95,375**	**$ 410,125**	**$ 505,500**
9RT2	3ph Rebuild	2.00	$ 180,000	$ 360,000	100%	0%	$ 360,000	$ -	**$ 360,000**
9RT2	3 ph convert	2.00	$ 10,000	$ 20,000	0%	100%	$ -	$ 20,000	**$ 20,000**
9RT2	2ph->1ph convert	10.00	$ 40,000	$ 400,000	0%	100%	$ -	$ 400,000	**$ 400,000**
9RT2	3ph convert	4.00	$ 50,000	$ 200,000	0%	100%	$ -	$ 200,000	**$ 200,000**
9RT2	2ph->1ph refurbish	5.00	$ 75,000	$ 375,000	47%	53%	$ 176,250	$ 198,750	**$ 375,000**
2018-2019		**23.00**					**$ 536,250**	**$ 818,750**	**$ 1,355,000**
2018							$ 294,938	$ 450,313	**$ 745,250**
2019							$ 241,313	$ 368,438	**$ 609,750**
67RT3	3ph rebuild	1.50	$ 180,000	$ 270,000	100%	0%	$ 270,000	$ -	**$ 270,000**
67RT3	3ph refurbish	1.00	$ 90,000	$ 90,000	50%	50%	$ 45,000	$ 45,000	**$ 90,000**
67RT3	3ph convert	5.00	$ 50,000	$ 250,000	0%	100%	$ -	$ 250,000	**$ 250,000**
67RT3	2ph->1ph convert	3.00	$ 40,000	$ 120,000	0%	100%	$ -	$ 120,000	**$ 120,000**
67RT3	2ph->1ph refurbish	2.30	$ 75,000	$ 172,500	47%	53%	$ 81,075	$ 91,425	**$ 172,500**
2020		**12.80**					**$ 396,075**	**$ 506,425**	**$ 902,500**
TOTAL		**54.10**					**$ 1,650,075**	**$ 2,075,925**	**$ 3,726,000**

Figure 5.4.6.4-2: Cost Breakdown for Ridgeway Conversion

The annual spending profile for the SS portion during the forecast period is as follows:

DSP ID	Area	Project	Main Category	Annual Material Investment ($ 000's)						
				2016	2017	2018	2019	2020	2021	Total
4	FE	Ridgeway - 4.8Δ to 8.3Y Voltage Conversion SS	SS	330	410	295	241	396	-	1,672

5.4.6.5 FE - Ridgeway - 4.8∆ to 8.3Y Rebuild & Conversion SR

(Project 5 in Figure 5.4.5.2-1)

5.4.6.5(a) Justification and Alternative Analysis

This project is necessary in order for CNPI address asset condition concerns in this area of Fort Erie. Replacing assets before they become operational and safety hazards is a non-discretionary obligation for CNPI.

Other than the non-discretionary project described in 5.4.6.5(b), there were no other alternatives identified that resolved these concerns without requiring considerably larger capital investments.

5.4.6.5(b) Project Description

This project is the System Renewal (SR) portion of the work described in section 5.4.6.4 of this DSP. It covers those investments that are driven by the need to renew old assets that are near or have reached the end of their useful service lives. This work is required due to the deteriorated condition of these assets.

The timing of these projects will be synchronized to any Voltage Conversion projects taking place in the same general area (see 5.4.6.4) to ensure that all of these works are done efficiently and with a minimum of project delays.

The annual spending profile during the forecast period is as follows:

DSP ID	Area	Project	Main Category	Annual Material Investment ($ 000's)						
				2016	2017	2018	2019	2020	2021	Total
5	FE	Ridgeway - 4.8Δ to 8.3Y Rebuild & Conversion SR	SR	620	95	450	368	506	-	2,039

5.4.6.6 FE - 5/8 Line 34.5kV Distribution Line Rebuild

(Project 6 in Figure 5.4.5.2-1)

5.4.6.6(a) Justification and Alternative Analysis

This project is necessary in order for CNPI address asset condition concerns. Replacing assets before they become operational and safety hazards is a non-discretionary obligation for CNPI.

Other than the project described in 5.4.6.6(b), there were no other alternatives identified that resolved these concerns without requiring considerably larger capital investments.

5.4.6.6(b) Project Description

For some time, CNPI has been engaged in replacing this 100-year old line. It is being replaced with a single-pole wooden line, constructed to modern standards in accordance with O. Reg 22/04.

Figure 5.4.6.6-1 Legacy 5/8 Line

The legacy line was originally built to carry 25Hz power from the Rankine Generating plant to Buffalo, New York. CNPI has since re-purposed this line to serve as a 34.5kV 60Hz distribution line, but the structures have reached the end of their useful lives.

This project also provides for reclamation of the off-road Right-of-Way (ROW) to ensure that the new line is free of vegetation hazards and to ensure all-season accessibility to the new line.

The annual spending profile during the forecast period is as follows:

DSP ID	Area	Project	Main Category	Annual Material Investment ($ 000's)						
				2016	2017	2018	2019	2020	2021	Total
6	FE	5/8 Line 34.5kV Distribution Line Rebuild	SR	250	250	-	-	-	-	500

5.4.6.7 EOP - Construct Herbert DS to Gananoque DS 4.16kV Intertie

(Project 7 in Figure 5.4.5.2-1)

The 4.16kV system in Gananoque is a traditional 4.16Y/2.4kV grounded-wye system that serves mostly residential loads in the urban and rural areas. At present, there is a limitation on the capacity of feeder interties in the urban 4.16kV distribution system. Consequently, there is insufficient capability to supply the full load of one of the downtown distribution stations (Gananoque or Herbert Street) should the second distribution substation be offline under planned or emergency circumstances.

With the aged infrastructure in the urban distribution, EOP has taken advantage of system renewal projects (e.g. Oak Alley Rebuild, 2013) to increase the capacity on portions of the 4.16kV feeder interties.

These improvements will increase operating flexibility and improve system capacity and reliability. In continuation with system rebuilds along Oak Alley, EOP will complete the rebuild of the 4.16kV interties between Herbert Street and Gananoque distribution substations in 2016.

5.4.6.7(a) Alternative Analysis

Three (3) alternatives were developed to deal with the capacity limitations of the urban 4.16kV distribution in Gananoque and these alternatives are detailed below.

Alternative A – Refurbish Interties – Upgrade Primary Conductors

The existing 4.16kV interties are at the end of their useful life and the assets are in poor condition. Construction clearances are compromised in many situations posing risks to both the public and EOP line crews. The primary conductors cannot be replaced without replacing/upgrading all of the assets along these interties. For that reason, this alternative is not acceptable.

Alternative B – Rebuild Interties

This alternative would involve the rebuild of approximately 410m of single circuit distribution line along Coopers Alley and the rebuild of an additional 300m of double circuit line along Pine Street. The Pine street portion would involve some additional work to relocate the line out of some difficult to access rear-lot properties. The estimated cost of rebuilding these interties as described would be as follows.

- Coopers Alley: $125,000
- Pine Street: $155,000

Alternative C – Rebuild Interties with overbuilt 26.4kV circuit

Herbert Street DS is currently radially fed from a 26.4kV tap off of the 'Town Loop'. This alternative takes advantage of the rebuild projects along Pine Street and Coopers Alley to complete a 26.4kV loop between Herbert Street and Gananoque Substations providing redundancy in the 26.4kV supply to Herbert Street DS. This new loop will also allow EOP to retire approximately 150m of 26.4kV end-of-life rear lot construction. The estimated savings of the avoided cost of rebuilding this line is $50,000.

Along with the rebuilds detailed in Alternative B, an overbuilt 26.4kV circuit would be added to the pole-line to create this loop. In addition to the 410m along Coopers Alley, approximately 215m of 26.4kV circuit would have to be extended up Herbert Street in an overbuilt construction. The existing infrastructure along Herbert Street was constructed to accept this extension as part of previous projects. The estimated cost of this alternative is as follows.

- Coopers Alley: $180,000
- Pine Street: $200,000

5.4.6.7(b) Summary and Recommendations

Alternative A is not feasible due to the aged infrastructure along Pine Street and Coopers Alley. The condition of the existing pole lines requires complete line rebuilds and therefore, this option is not recommended.

Alternative B solves the immediate issue of aged infrastructure along Pine Street and Coopers Alley and at the same time upgrades will be made to the conductors to improve the capacity of these interties. Herbert Street substation would remain radially fed on the 26.4kV distribution. The total cost of this alternative would be $330,000, including approximately $50,000 required in the very near future to replace aged 26.4kV infrastructure.

Alternative C builds upon Alternative B to complete a 26.4kV loop between Herbert and Gananoque DS. The total cost of this alternative is estimated at $380,000.

Alternative C is recommended, even though it is not the lowest cost alternative. Alternative C provides much better operating flexibility and is expected to improve system reliability by completing the 26.4kV loop supplying Herbert DS.

The annual spending profile during the forecast period is as follows:

DSP ID	Area	Project	Main Category	Annual Material Investment ($ 000's)						
				2016	2017	2018	2019	2020	2021	Total
7	EOP	Construct Herbert DS to Gananoque DS 4.16kV Intertie	SR	380	-	-	-	-	-	380

5.4.6.8 CNPI – Distribution Automation & Reliability Improvements

(Project 8 in Figure 5.4.5.2-1)

This multi-year program is aimed at the introduction of field based automated switching and protection devices. Based on analysis of reliability data, CNPI targets sections of feeders with poor performance and implements automation designed to decrease outage frequency and duration and to improve overall response time. Section 9 of CNPI's DAMP contains an analysis of feeder performance for the Fort Erie, Port Colborne and Gananoque service areas. The results of this type of analysis have historically been utilized to target feeder sections for implementation of automated devices.

The installations typically consist of a motor operated switch or recloser coupled with protective relaying and control devices. The resulting installation is capable of remote interrogation and operation via CNPI's SCADA system.

The figure below is an example of an installation of a SCADA controlled recloser. This device was implemented on the mid-point of the 18L10 feeder in an effort to limit the section of line impacted by downstream faults. This location also serves as a strategic sectionalizing point, allowing restoration of the majority of customers upstream of this location from an adjacent circuit when required.

Figure 5.4.6.x-1 SCADA Controlled Recloser Installation

CNPI's current fleet of field based automated devices includes 26 installations. Each of these incorporates SCADA control with remote connectivity to CNPI's control room.

Although CNPI's SAIDI and SAIFI trending is positive over the historical period, feeder level analysis still indicates that there is room for improvement on specific line sections. Investments in the forecast period target poorly performing feeders with the automation improvements at a rate of three to four units per year. Locations are prioritized based on the impact of the anticipated reduction in feeder exposure to downstream faults.

The annual spending profile during the forecast period is as follows:

DSP ID	Area	Project	Main Category	Annual Material Investment ($ 000's)						
				2016	2017	2018	2019	2020	2021	**Total**
8	CNPI	Distribution Automation & Reliability Improvements Program	SS	308	311	260	265	271	276	**1,691**

5.4.6.9 FE - 4.8kV Delta to 8.3 Wye Voltage Conversion Program

(Project 9 in Figure 5.4.5.2-1)

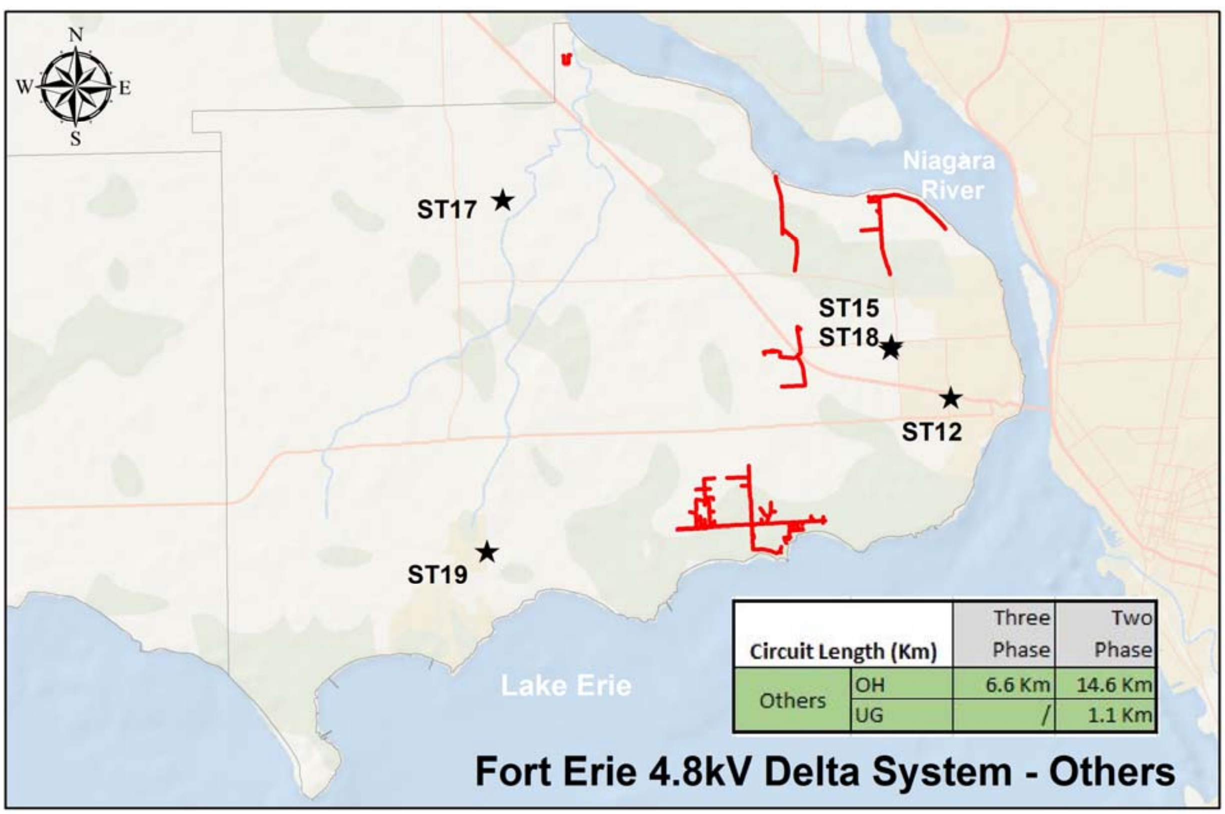
5.4.6.9(a) Justification and Alternative Analysis

This project is necessary in order for CNPI address safety and operating concerns associated with its legacy 4.8kV delta system, as per DAMP, sections 3.3.2 and 6.2.1.

Other than the non-discretionary project described in 5.4.6.9(b), there were no other alternatives identified that resolved these concerns without requiring considerably larger capital investments.

5.4.6.9(b) Project Description

The specific areas of concern for this "System Service (SS)" material project is described in DAMP 6.2.1.4. A map of these areas is also shown in Figure 5.4.6.9-1 for reference:



Circuit Length (Km)		Three Phase	Two Phase
Others	OH	6.6 Km	14.6 Km
	UG	/	1.1 Km

Figure 5.4.6.9-1: Remaining 4.8kV delta with Aerial Stepdown as Source

This area consists of ancillary delta load supplied by ratio banks connected to the CNPI 34.5kV distribution system. These are structure mounted ratio bank transformers that have delta connected secondary. The ratio transformers are susceptible to impulse related failures due to their high impedance characteristic.

These areas contain approximately 22 circuit-km of the total 191 circuit-km of 4.8kV delta lines within the FE distribution system.

5.4.6.9(c) **2016-2021 Conversion Project:**

CNPI has been in the process of addressing its concerns with its legacy 4.8 delta distribution system for some time. The rationale and justification for this effort can be found in sections 3.3.2 and 6.2 of the CNPI Distribution Asset Management Plan (DAMP).

The ongoing CNPI voltage conversion program will complete the conversion of these areas in the period from 2016 to 2021. The majority of this area requires only line conversion efforts. CNPI has allotted investment for conversion of these sections between 2016 and 2021.

In 2021, there will be some conversion required in the southern portion of this area, involving legacy pole replacements. CNPI estimates the following effort to complete conversion in these areas:

Effort	Line Length (km)
Line Rebuild	1.4
Line Refurbishment	2.4
Line Conversion	17.4

Approximately 55 pole replacements will be required due to rebuild and refurbishment in 2021 based on currently available condition data.

Due to the focus on the conversion of other 4.8kV delta areas described in sections 5.4.6.2 through 5.4.6.5 of this DSP in 2016 to 2020, there will be limited resources available to complete much of this work until 2021.

The annual spending profile during the forecast period is as follows:

DSP ID	Area	Project	Main Category	Annual Material Investment ($ 000's)						
				2016	2017	2018	2019	2020	2021	Total
9	FE	4.8kV Delta to 8.3 Wye Voltage Conversion Program	SS	-	104	163	169	171	542	1,149

In addition, associated pole replacements will be done on these same lines. This related work is part of the work outlined in section 5.1.1.11 of this DSP.

5.4.6.10 PC - Distribution System Upgrade Program SR

(Project 10 in Figure 5.4.5.2-1)

5.4.6.10(a) Justification

This program is necessary in order for CNPI address asset condition concerns. Replacing assets before they become operational and safety hazards is a non-discretionary obligation for CNPI.

5.4.6.10(b) Program Description

This SR program represents all of the tasks, projects, and capital asset replacement efforts in the City of Port Colborne with a scope of less than $100,000 and so not otherwise captured by a material project in this DSP.

As can be seen in the spending profile, most of the SR capital budget relates to projects that support CNPI's focus on asset renewal in such areas as the southern 4.16kV area of Port Colborne, so there is a reduced amount of additional funding set aside for other more modest projects.

One specific set of small projects that will be done over the 2016 to 2019 period will be to upgrade sections of legacy small conductors in the southern 4.16kV area of Port Colborne to better act as main feeder routes for the new DS described in section 5.4.6.14. These projects were triggered by the need to upgrade or retire two DS's (Jefferson DS and Catharine DS), so these investments were attributed to the SR category.

The annual spending profile during the forecast period is as follows:

DSP ID	Area	Project	Main Category	Annual Material Investment ($ 000's)						
				2016	2017	2018	2019	2020	2021	Total
10	PC	Distribution System Upgrade Program	SR	120	231	226	553	525	584	2,239

5.4.6.11 FE - Distribution System Upgrade Program SR

(Project 11 in Figure 5.4.5.2-1)

5.4.6.11(a) Justification

This program is necessary in order for CNPI address asset condition concerns. Replacing assets before they become operational and safety hazards is a non-discretionary obligation for CNPI.

5.4.6.11(b) Program Description

This SR program represents all of the tasks, projects, and capital asset replacement efforts in the Town of Fort Erie with a scope of less than $100,000 and so not otherwise captured as a material project in this DSP.

As can be seen in the spending profile, most of the SR capital budget earlier in the forecast period relates to projects that support CNPI's focus on voltage conversion and asset renewal in such areas as North QEW and Ridgeway, so there is only a reduced amount of additional funding set aside for other more modest projects.

In 2021, there is a greater funding allowance as the larger projects are projected to be completed by 2020. Ongoing engineering and design reviews are likely to identify some material projects (i.e. exceeding $100k) before the CNPI 2021 capital budget is prepared, reviewed, and approved at some point during 2020.

The annual spending profile during the forecast period is as follows:

DSP ID	Area	Project	Main Category	Annual Material Investment ($ 000's)						
				2016	2017	2018	2019	2020	2021	Total
11	FE	Distribution System Upgrade Program	SR	225	442	677	1,209	1,126	2,497	6,176

5.4.6.12 EOP - Distribution System Upgrade Program

(Project 12 in Figure 5.4.5.2-1)

5.4.6.12(a) Background Information

EOP's distribution system serves more than 3,500 customers within its service territory. The service territory includes an area of approximately 65 square kilometers with approximately 172km of overhead distribution circuits occupying approximately 145 kilometers of pole lines, and 11 kilometers of underground distribution. There are 670 distribution transformer installations.

In operating its distribution systems in Gananoque, CNPI's primary objectives are to optimize asset performance in a cost-effective manner, promote employee and public safety, maintain high standards of reliability, meet customer demand, and protect the environment.

CNPI makes prudent capital investments in system renewal projects to replace/upgrade end-of-useful-life infrastructure to meet these objectives.

Geographically, EOP's distribution system can be broken down into three distinct areas. Each of these areas have their own unique characteristics as described below.

Geographical Breakdown of EOP's Distribution System

Area	# of Customers	# of Distribution Transformers	Pole Km of Overhead Line	Average Span Length	Km of Underground Lines
Town of Gananoque	2825	319	34	39m	5
West Line	750	348	73	53m	6
North Line	6	3	38	59m	0

Given the extensive scope of the North Line, upgrades to it are being treated as special projects outside of the scope of EOP's normal distribution system upgrade program as detailed in section 5.4.6.15 of this DSP.

The scope of EOP's distribution system upgrade program deals entirely with the distribution system within the town of Gananoque (~40km) and along the West line (~80km).

In order to meet its asset management sustainment goals, EOP must make capital investments towards rebuilding an average of 0.8km in town and 1.6km along the West Line per year in order to keep up with aging infrastructure.

Although the downtown distribution represents a smaller geographic area in comparison to the West Line, its added complexity requires that resources be shared equally between the two. In reality, investments may be focused more in one area than another depending on where the most aged infrastructure is. Presently, the most deteriorated infrastructure is located in the downtown core of Gananoque which is where the majority of capital investments will be made over the next five years as detailed below.

5.4.6.12(b) Downtown Rebuild/Voltage Conversion

Much of the downtown core contains assets at or near the end of their useful lives. Significant capital investments will be required over the next few years to replace/rebuild these assets.

The existing 4.16kV system presents some challenges in itself and is inefficient in several ways. One challenge is the limited capacity on any given feeder due to constraints on voltage drop and conductor size. This poses challenges when connecting large loads and typically requires an extension of the 26.4kV system (depending on location) in order to connect these loads. Obvious inefficiencies can be seen on the 4.16kV system as the lower system voltage results in high line-losses. In addition, other inefficiencies exist due to the increased complexity of the system.

Upon conversion of the 26.4kV delta distribution to a 27.6Y/16.0kV system, EOP would take advantage of this by converting end-of-useful-life 4.16kV assets to the 27.6kV system at their time of replacement with the intent of eventually eliminating most of the 4.16kV distribution system in the town of Gananoque.

Additional conversions may take place ahead of end-of-life if the payback can be justified. The following alternatives were developed to evaluate the feasibility of a voltage conversion of the downtown distribution system.

5.4.6.12(c) Alternative Analysis of Downtown Rebuild

Two (2) alternatives were developed to address the aged infrastructure within the town of Gananoque as detailed below.

Alternative A – Maintain Status Quo

This alternative would keep the 4.16kV distribution system ‘as-is’. The end-of-useful-life assets would be rebuilt in an essentially like-for-like fashion. Minor improvements would be made through conductor replacements to improve capacity and reduce line-losses.

Looking at total life cycle cost analysis, the cumulative net present value cost of this alternative would be $5,300,000.

Alternative B – Voltage conversion of Downtown Distribution

This alternative would piggyback on EOP's initiative to convert the 26.4kV delta distribution to a 16/27.6kV grounded wye system by the end of 2017. As part of system renewal projects within the downtown core, the lines would be rebuilt and insulated to 28kV.

The new lines could then be converted to 27.6kV. There would be little added cost to these conversions compared to rebuilding them on the 4.16kV distribution system as the only real incremental cost is a small premium for 28kV insulators and distribution transformers.

There are two major economic returns supporting this conversion. One is in loss savings of reduced primary conductor line-losses. The other major contributor to the savings is the avoided cost of having to upgrade/replace major pieces of equipment (transformers, breakers, relaying) within Herbert Street DS and Gananoque DS.

By transferring load over to the 27.6kV distribution system, EOP could gradually retire these distributions stations.

Over the next five years, conversions will be focused in the downtown core in conjunction with system renewal projects. It is estimated that the peak load on the 4.16kV distribution system can be reduced from 10.6MVA to 5MVA through these conversions and the addition of one small ratio bank.

This would allow EOP to retire an end-of-life station transformer in Gananoque DS while maintaining N-1 contingencies on the 4.16kV system without the need to replace this asset in-kind, due to reduced load levels.

The estimated cumulative NPV cost of this alternative, net of line-loss savings, is $5,000,000.

5.4.6.12(d) Summary and Recommendations

Alternative A addresses the immediate need to replace the aging infrastructure in the downtown core of Gananoque's distribution system. However, it does not benefit from the long term savings of reduced line-losses and the avoided costs of replacing major pieces of equipment in Herbert DS and Gananoque DS resulting in a higher life cycle cost in comparison to Alternative B.

Alternative B addresses the immediate need to replace the aging infrastructure in the downtown core but takes advantage of these system renewal projects to insulate the new lines to 28kV and transfer them to the 27.6kV distribution. The major return on this alternative is the savings in primary line-losses and the avoided costs of replacing/upgrading distribution stations.

For these reasons, Alternative B is recommended.

The annual spending profile during the forecast period is as follows:

DSP ID	Area	Project	Main Category	Annual Material Investment ($ 000's)						
				2016	2017	2018	2019	2020	2021	Total
12	EOP	Distribution System Upgrade Program	SR	132	512	545	553	561	569	2,872

5.4.6.13 FE - Station 19 DS Protection Upgrade & Arc Flash Hardening

(Project 13 in Figure 5.4.5.2-1)

This Distribution Substation was described in section 3.3.3.3 of the CNPI DAMP. Some issues were discussed in section 6.1.4 of that document.

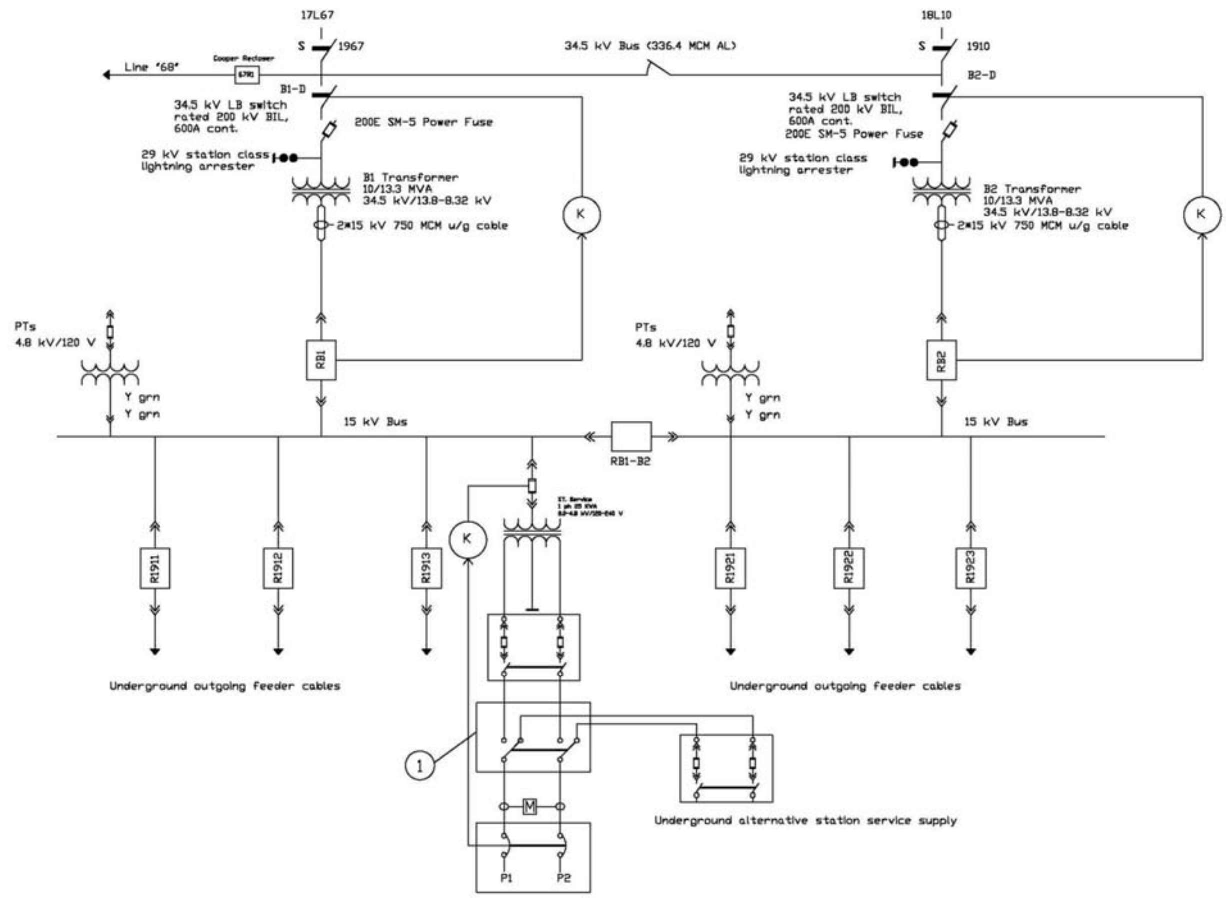


Figure 5.4.6.13-1: Station 19 DS - Elementary One-Line Diagram

5.4.6.13(a) Issues with Existing Distribution Substation

Arc Hazard Risk

Station 19 was constructed in 2001. At the time, the safety risks to personnel and equipment as a result of worst-case arc-flashes was not as well understood as they are today. As a result, the legacy design for station 19 did not take arc-flash risk into account as a formal part of its construction.

All of this station's low-side (8.3kV) equipment is housed in a single metal-clad enclosure. This can be seen as the large grey building in the photographs of figure 5.4.6.13-2. This includes all feeder circuit breakers, metering, and protection & control (including SCADA).

Figure 5.4.6.13-2: Street and Overhead View of Station 19 DS

At this time, it is possible that a single worst-case arc flash event could disrupt the ability of this switchgear to deliver any supply to the 8.3kV customers in its supply area. As outlined in section 3.3.1.3 of the DAMP, this is the only such source available. Some failure modes could disrupt delivery of power for several months.

For this reason, CNPI has always been careful to ensure that a high quality maintenance and inspection program is employed. Although the probability of such an arc-flash event is extremely low, this probability is not zero.

Legacy Protection and Control Equipment

This station was built 15 years ago. Many of the protection relays have reached the end of their useful lives and require replacement. They are also considered obsolete by today's standards.

In addition, the original design only called for supply-side (34.5) primary fuses to protect the supply ingress points and the two 10/13.3MVA power transformers.

These transformers are expensive to replace, and require very long lead times to acquire and install. If one of these transformers required replacement, it might take as long as 32 weeks to replace.

Power fuses can be effective protective devices, but they are not as effective as relay-controlled circuit breakers, complete with current transformers (CT's), in detecting and clearing system faults while minimizing damage to the protected components.

5.4.6.13(b) Capital Project Description

This capital project provides for two key things:

Arc Hazard Hardening

CNPI will be making changes to the secondary (8.3kV) configuration such that no single contingency can cause component loss in a manner that prevents delivery from at least one power transformer. Supplemented by external sources, this should remove the 8.3kV service territory around Station 19 from the contingency load-at-risk category.

After 2021, once CNPI has commissioned the new South FE DS described in 5.4.6.20, there could be additional source relief to this service territory, further reducing the chance for a long-term outage to these customers.

Modernization of Protection and Control

This project also provides for:

- Replacement of the legacy high-side primary fuses with two relay-controlled Viper^{tm} reclosers
- Replacement of legacy relaying with modern Schweitzer Engineering Laboratory (SEL) relays, including modernization of the SCADA Remote Terminal Unit (RTU).
- Improvements to the protection schema at this station to include more sensitive fault detection, transformer differential protection, and faster clearing of low-current faults often associated with developing arc-flash conditions.

The annual spending profile during the forecast period is as follows:

DSP ID	Area	Project	Main Category	Annual Material Investment ($ 000's)						
				2016	2017	2018	2019	2020	2021	Total
13	FE	Station 19 DS Protection Upgrade & Arc Flash Hardening	SS	-	348	-	-	-	-	348

5.4.6.14 PC - Port Colborne South DS - Construct New Substation

(Project 14 in Figure 5.4.5.2-1)

5.4.6.14(a) Issues with Existing Distribution System and Substations

This project is intended to address several different problems in the 4.16kV-supplied area of Port Colborne:

Jefferson DS

As described in the CNPI DAMP (sections 3.4.2 and 6.1.7) there are issues with this station:

- It was constructed in 1952 and much of the major equipment is now 64 years old, including the power transformer and 4.16kV switchgear. This equipment is now beyond the age at which it would normally be considered to be reaching end-of-life.
- There is no longer any source for spare parts for the power transformer or switchgear. For some time, CNPI staff have had to custom-make some parts to keep this equipment fully operational.
    - In 2015, CNPI decommissioned another DS (Barrack DS) that used some of the same equipment. This provided a limited supply of additional spare parts, but this equipment was also of similar vintage and in similar condition. Many of its parts were worn out in the same fashion as at Jefferson.
- There is no provision for oil collection in the event of a major power transformer oil leak. The fundamental design of this substation does not lend itself to retrofitting to correct this.
- This DS has only power fuses to protect the supply ingress point and the power transformer.
    - This transformer would be expensive to replace, and require very long lead times to acquire and install. If one of these transformers required replacement, it might take up to 32 weeks to replace.
    - Power fuses can be effective protective devices, but they are not as effective as relay-controlled circuit breakers, complete with current transformers (CT’s), in detecting and clearing system faults while minimizing damage to the protected components.

Catharine DS

As described in the CNPI DAMP (sections 3.4.2, 3.4.2.2, and 6.15), there are concerns with this station:

- It was constructed in 1975 and much of the major equipment is now 46 years old, including the power transformer and 4.16kV switchgear. This equipment is beginning to reach its originally forecasted end-of-life.
- There is no provision for oil collection in the event of a major power transformer oil leak.
- This DS has only power fuses to protect the supply ingress point and the power transformer.
    - o This transformers would be expensive to replace, and require very long lead times to acquire and install. If one of these transformers required replacement, it might take up to 32 weeks to replace.
    - o Power fuses can be effective protective devices, but they are not as effective as relay-controlled circuit breakers, complete with current transformers (CT's), in detecting and clearing system faults while minimizing damage to the protected components

There is no automation at this station.

Contingency

Please refer to Figure 5.4.6.14-1 for a map showing the general location of the Distribution Substations discussed in this section.

In 2015, CNPI expanded the capacity of Fielden DS in central Port Colborne and added a second power transformer element to address contingency-based reliability concerns. This expansion allowed the retirement of Barrack DS (not shown), an aged substation which otherwise would have required extensive refurbishments to remain in service.

However, as described previously, Jefferson DS and Catherine DS each have issues which make their long-term viability doubtful without extensive on-site reconstruction efforts.

Using its GIS/EA software, CNPI has performed contingency analysis on the Port Colborne 4.16kV system. From the results of this analysis, it is clear that the needs of this system cannot be met if both Jefferson DS and Catherine DS become unavailable. There would be significant issues with overloaded conductors and substandard delivery voltages if Fielden DS (even after its expansion) were the only 4.16kV source available on the west bank of the Welland Canal.

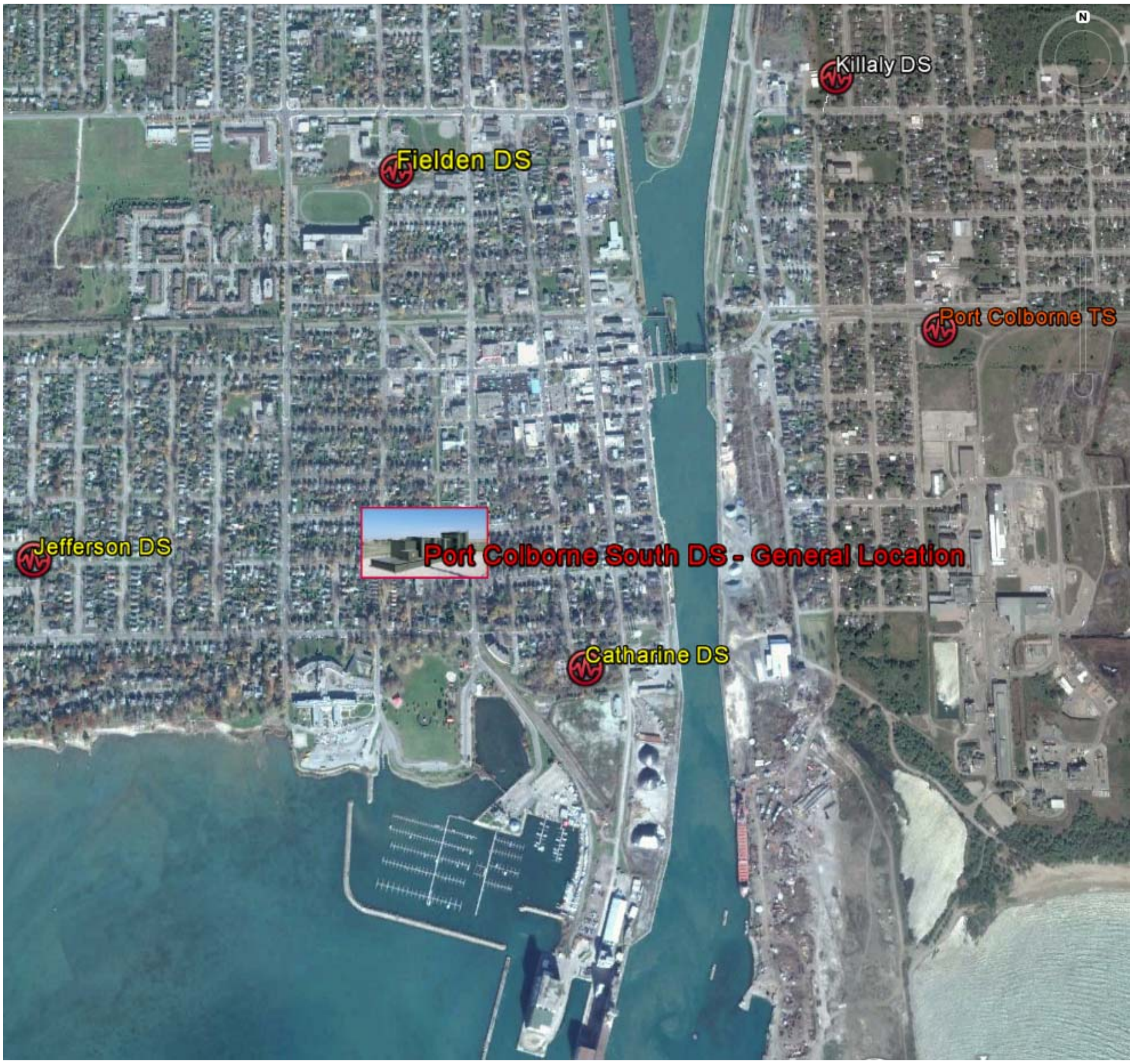


Figure 5.4.6.14-1: South-western Port Colborne, with locations of existing and proposed DS's

5.4.6.14(b) New Distribution Station Design and Location

At the time of preparation of this DSP, CNPI has not carried out a detailed design or high-accuracy cost estimate for this project.

CNPI has not yet determined the exact geographical location for the substation, but has narrowed the optimal areas for it to be located, given the constraints of its future service territory and existing land use in the general area where this station needs to be located.

It is expected that this new DS will need to be located in an area that will have mixed-used properties around it, but composed mostly of residential streets (see Figure 5.4.6.14-1).

For this reason, it may be desirable to create a quiet, low-profile, dead-front design that makes efficient use of land to minimize environmental impacts and maximize the ability of occupants of neighboring properties to enjoy the use of their land.

At this time, CNPI is planning on the construction of a compact station, with three or four 4.16kV feeders, complete with all necessary ancillary equipment.

One possible design would be as pictured below.

Figure 5.4.6.14-2: Photograph of Initial Concept for new Port Colborne South DS

The annual spending profile for this project during the forecast period is estimated to be as follows:

DSP ID	Area	Project	Main Category	Annual Material Investment ($ 000's)						
				2016	2017	2018	2019	2020	2021	Total
14	PC	Port Colborne South DS - Construct New Substation	SR	-	419	1,250	-	-	-	1,669

5.4.6.15 EOP – North Line - Rebuild 9.8km Project

(Project 15 in Figure 5.4.5.2-1)

5.4.6.15(a) Background Information

The North Line is a 38.5-kilometre long radial 26.4kV distribution line that runs from EOP's Main Substation North to three embedded hydro-electric generating plants, one residential customer and one general service customer, as shown on the following map:

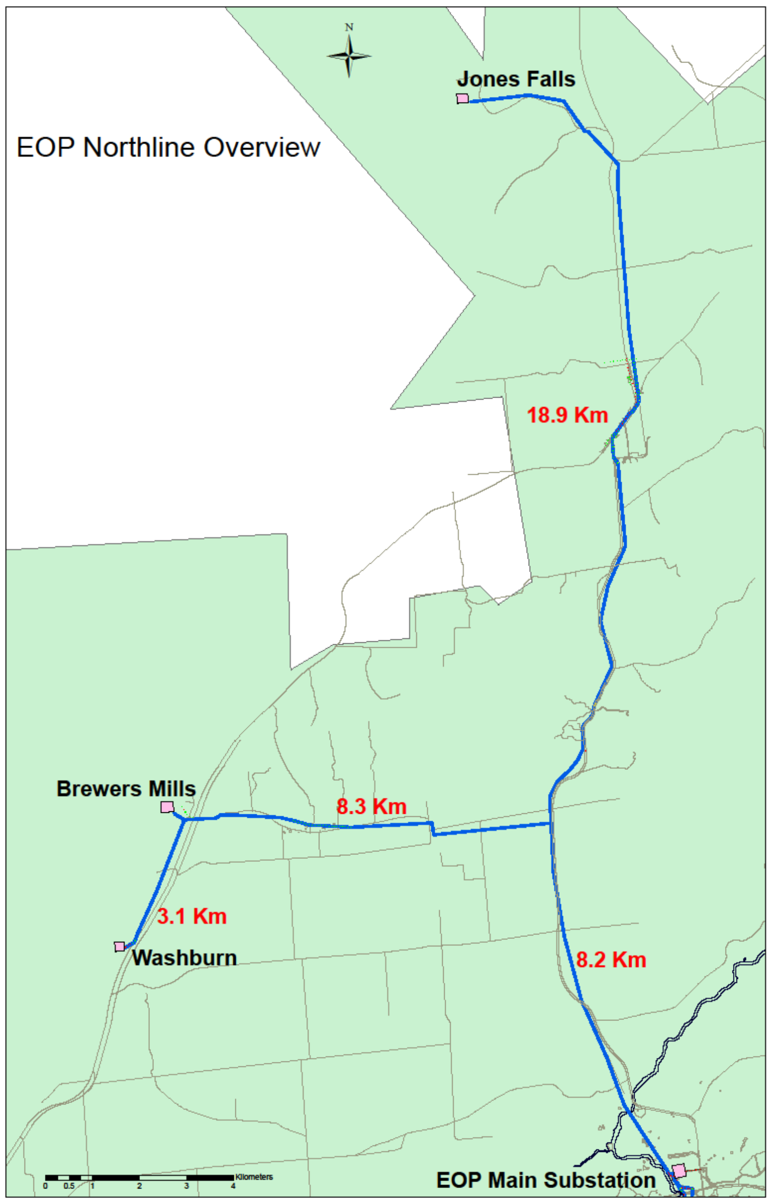


Figure 5.4.6.15-1: Map showing location of EOP North Line

Most of this line was constructed in the 1940's and the conductor size over the majority of this line is #2 copper that is in deteriorating condition. Of the 38-

kilometres of line, there is only about 7.5km (20%) of line located along the roadside. The remainder of the pole line is generally well away from the road, running cross-country through fields and forested areas. Therefore, much of the line is inaccessible by vehicular traffic, which raises operational challenges. The inaccessibility of the line and the forested environment for much of its length creates challenges to its ongoing operation and maintenance.

With the line being a radial configuration with no interties to other feeders, faults must be isolated and repaired before power can be restored to customers located downstream of the fault.

The following table represents historical outage statistics for the North Line in comparison to EOP's distribution system as a whole.

North Line - Historical Outage Statistics 2011-2015

	SAIFI		SAIDI	
YEAR	**North Line**	**System**	**North Line**	**System**
2011	**7.67**	1.51	**24.86**	1.99
2012	**6.33**	4.39	**25.45**	4.78
2013	**10.33**	1.86	**46.14**	2.53
2014	**13.00**	2.05	**46.06**	1.55
2015	**3.83**	0.59	**7.79**	1.01
Average	**8.23**	2.08	**30.06**	2.37

Figure 5.4.6.15-2: North Line Reliability

From the SAIFI figures above, it is apparent that the North Line experiences customer outages at a substantially higher frequency than the rest of EOP's distribution system. The majority of these outages are caused by tree contacts during storms and high wind events.

The lack of line truck access to the majority of the line also leads to additional outages when repairs are required as these repairs must be made by climbing poles or with the use of non-insulated off-road equipment.

From the SAIDI figures above, the average duration of these outages are also substantially higher than the system average. However, these statistics are skewed due to an understanding with the owners of the embedded generation in which EOP can delay repairs to the North Line when generation is not active.

EOP crews experience major challenges when patrolling the off-road portions of the line after dark due to poor visibility and difficult terrain. Faults will be sectionalized if possible to restore power to the healthy portion of the line and dealt with during the daylight hours.

5.4.6.15(b) Alternative Analysis for the North Line

Three (3) alternatives were developed to replace the obsolete assets and improve the reliability to the customers connected to the North Line. These alternatives are detailed below.

Alternative A – Maintain Status Quo

The North Line is at the end of its useful life and the assets are in poor conditions. Leaving it status quo will only make the poor reliability to the customers even worse over time. For that reason, this alternative is not acceptable.

Alternative B – Embed the Customers into the Nearby HONI Distribution System

The customers served by the North Line are surrounded by HONI's distribution systems. This alternative explores the opportunities to transfer these customers to HONI's distribution systems.

In 2013, CNPI filed three CIA applications to HONI. HONI issued Detailed Technical Connection Agreements (DTCA's) for Brewers Mills and Washburn generating plants including Class C Cost Estimates for these projects (See Appendix K) in June, 2013. According to these assessments, these generating plants could be connected to the local distribution system.

Since HONI's local distribution voltage (12.47kV) is different from the generating substation voltage (26.4kV), significant substation upgrade costs ($813,050) are required for the two generating plants. Based on the Class C Cost Estimates from HONI, HONI requires a total of $908,267 contribution from CNPI to connect these two generating plants to HONI's distribution system, including distribution line upgrades, connection costs, and transmission substation upgrades.

CNPI rate payers have to pay $1,721,317 to get these two station embedded into HONI distribution system. In addition to this amount, HONI will spend $630,000 of Renewable Enabling Improvement costs for these projects. The total cost of embedding these two stations is over $2.35 million which would allow 11.3 km of the North Line to be retired.

Figure 5.4.6.15-3 summarizes the estimated cost of connecting these generating plants to HONI's distribution system.

	Washburn		Brewers Mills		Grand Total	
Generation Capacity (MW)		0.1875		0.9		1.0875
Total Substation Upgrade Cost	$	226,550	$	586,500	$	813,050
Contribution Required by HONI	$	63,000	$	845,267	$	908,267
HONI Renewable Enabling Improvement	$	27,000	$	603,000	$	630,000
Total Project Cost	$	316,550	$	2,034,767	$	2,351,317

Figure 5.4.6.15-3: Estimated Cost to Embed Generators in HONI Distribution System

In December 2013, HONI issued an Ineligibility Letter for the 2.3MW Johns Falls generation plant to the 8.3kV feeder F2 from Elgin DS stating the following reasons (See Appendix L for a copy of the Letter):

1) The largest project size connecting to a voltage less than or equal to 13.8kV is 1MW. Your project is 2.3MW which exceeds this limit.
2) There is insufficient thermal capacity in the upstream Crosby TS DESN1 to accommodate your 2.3MW project.

Alternative C – Rebuild the North Line to replace the end-of-useful-life assets

This alternative involves rebuilding most of the 38 km of North Line. The line will be relocated to the road allowance whenever possible. In some cases, joint use lines with HONI or Bell Canada will be considered to share the cost. For budgetary purposes, $120,000/km is used as the average construction cost for this project and based on 38km of line, the total estimated project cost is $4.56 million. During the next 5 years, CNPI will invest approximately $1.1 million to rebuild 9.3km of the North Line. The primary focus of these investments will be to relocate the most vulnerable portions of the line to the road allowance with the following investment profile.

		Investments by Year ('000$)				
Project	Length (km)	2017	2018	2019	2020	2021
Main Station to Taylor Road	4.5	257	280			
Morton to Jones Falls	4.8			240	180	160

Figure 5.4.6.15-4: North Line - Capital Investments 2017-2021

Main Station to Taylor Rd

This 8.7 km line runs from EOP's Main substation, north to Taylor Rd where it splits to feed Brewers Mills and Washburn generating plants to the West and

Jones Falls generating plant to the North (see attached map). The first 5.7 km along its route traverses off-road through dense bush, swamp, and fields. The line makes its way to Hwy 32 where it remains in the road allowance for the remaining 3km. Faults within this section of the line will result in outages to all three generating plants. EOP will make capital investments in years 2017 and 2018 to build approximately 4.5 km of line within the road allowance to replace the off-road portions of this line.

Town of Morton to Jones Falls

This project will cover the replacement of a 4.3 km stretch of line running from the town of Morton, North to Jones Falls generating plant. This section of the line runs through dense bush and is a source of many tree contacts. Re-building this portion of the line along the road side will result in a slightly longer route (4.8 km) however, the ease of access will make construction and maintenance much easier. It will also limit the lines exposure to tree contacts to improve reliability. EOP will make capital investments during 2019-2021 to build approximately 4.8km of line within the road allowance to replace the off-road portions of this line.

5.4.6.15(c) Summary and Recommendations

Alternative A does not replace the end-of-useful-life assets and will result in worsened reliability to the customers over time. Therefore it is not recommended.

Alternative B involves embedding the customers connected to the North Line into HONI's distribution systems and retiring the North Line. Upon a technical review from HONI, it was determined that only Brewers Mills and Washburn generation qualified for embedment in HONI's local distribution system at an estimated cost of $2.35 million. Since Jones Falls generating plant cannot be connected to the HONI local distribution system due to HONI system capacity limitation, EOP would only be able to retire the 11.3km line feeding Brewers Mills and Washburn. At an estimated cost of $120,000/km, the cost to rebuild this 11.3km section of line would be $1.36 million. This alternative also requires CNPI to make clustered investments at the beginning of the project (contribution to Hydro and substation upgrades), which would have a bigger impact to the rates. For these reasons, Alternative B is not recommended.

Alternative C will see gradual investments to rebuild the line over a longer period of time which will result in improvement in reliability to the customers.

Alternative C is recommended.

5.4.6.16 EOP - Main Substation - Delta to Wye Conversion

(Project 16 in Figure 5.4.5.2-1)

5.4.6.16(a) Introduction

A delta system is a 3-wire, ungrounded system in which there is no neutral present. There are inherent disadvantages to the delta system because the absence of a system neutral presents challenges to effective protection and control of the distribution lines. Single-phase-to-ground faults will be sustained, as they cannot be detected by protection equipment as there is no path (neutral/ground) for the fault current to return to the source. The system will remain in operation until there is a second fault on another phase, leading to a higher magnitude phase-to-phase fault.

For this reason, delta distributions system have been widely accepted as being unsafe in comparison to a grounded wye distribution system in which single-phase to ground faults can be easily detected by protection equipment and cleared as quickly as possible.

A delta distribution system also presents technical challenges when connecting single phase loads as equipment must be connected phase-to-phase and insulated accordingly, which leads to additional equipment costs for these installations. For this reason, the 26.4kV delta system in EOP has been limited to being used as a sub-transmission system where it supplies distribution substations, ratio banks, larger three-phase loads and also serves as an intertie to four embedded hydro-electric generation plants.

Converting this system to a 16/27.6kV grounded wye distribution would greatly simplify and reduce the cost of eliminating the 'lossy' 2.4/4.16kV distribution by converting this load to 27.6kV. This would result in significant line-loss savings as well reduced system complexity as detailed in section 5.4.6.12.

The 26.4kV delta system in Gananoque originates from EOP's Main Substation where it is transformed from Hydro One's 44kV supply. The current substation consists of two power transformers operating as one main (TB2) and one spare (TB1). Although TB2 (2006) has a 27.6kV wye secondary, TB1 (1980) has a 26.4kV delta secondary and the system must remain 26.4kV delta to maintain n-1 transformer contingency.

The differing winding configurations (i.e. delta-delta vs. delta-wye) also prevents parallel operation of the two transformers. This leads to a requirement to take a system wide outage when switch from one transformer to the other for maintenance purposes.

5.4.6.16(b) Alternative Analysis

Three (3) alternatives were developed to deal with the 26.4kV delta system in Gananoque and these alternatives are detailed below.

Alternative A – Maintain Status Quo

TB1 was built in 1980 (now 36 years old). Typically, power transformers are expected to last 50 years, so this unit might be expected to have 15 years of useful life remaining. However, this transformer is believed to be in poorer-than-typical condition, based on indicators revealed in multiple Dissolved Gas Analysis (DGA) tests (see DAMP section 6.2.2). Keeping TB1 in service until its end of useful life will result in the lowest alternative cost (estimated PV of $357,000) however, it will delay the conversion of the delta system.

EOP is unwilling to accept the safety hazards that go along with the delta system and as such, additional costs incurred to convert the delta distribution system immediately (Alternatives B and C) will be treated as a 'safety' premium. This alternative will also delay any conversion projects of EOP's 2.4/4.16kV distribution system and in turn, delay the line-loss savings from these conversions.

Alternative B – Replace TB1

This alternative would involve the replacement of TB1 with a new 15-20MVA power transformer with a 27.6kV wye secondary winding. This would be a permanent solution to converting the delta system to grounded wye. It would also have an advantage over Alternative C as both TB1 and TB2 would have delta-wye (DY11) windings allowing them to operate in parallel and eliminate the need to take a system wide outage when switching between transformers for maintenance.

The immediate cost of this alternative will be approximately $750,000 as detailed below.

Item	Cost
Internal Labour	$ 50,000
External Labour	$ 25,000
Planning/Engineering	$ 25,000
Material	$ 650,000
Total	**$ 750,000**

Figure 5.4.6.16-1: Cost Breakdown to replace EOP Main Substation TB1

Alternative C – Install Grounding Transformer

A grounding transformer is a device that can be installed on a delta system which would provide a ground reference and a return path for ground faults and unbalanced neutral current. This alternative is a temporary solution in which a grounding transformer would be installed on the secondary bus of TB1 avoiding the replacement of TB1 before its end-of-life. This alternative would still have a limitation in which TB1 and TB2 could not operate in parallel and so system wide outages would be required when switching between the two.

EOP is currently investigating the reliability and operating limitations of grounding transformers and determining the specifications for this type of installation however, the PV of a suitable grounding transformer is unknown at this time.

5.4.6.16(c) Summary and Recommendations

Alternative A is the least expensive alternative from a present value perspective at $357,000 however the delta distribution system must remain in service for an additional 15 years. EOP is unwilling to accept the risk of leaving the delta system in service due to the safety hazards associated with it.

Alternative B involves the conversion of the delta system to a grounded wye distribution through the replacement of TB1. At $750,000, the PV of this alternative is higher than that of Alternative A. However, this additional cost will be treated as the 'safety' premium required to eliminate the delta system.

Alternative C involves the installation of a grounding transformer in the Main substation allowing TB1 to remain in service until its end of useful life. The cost and feasibility of a grounding transformer is unknown at this time however, given the drawback of not being able to operate TB1 and TB2 in parallel with this arrangement, the PV of this alternative would have to be significantly less than alternative B to be justified.

Alternative B is recommended

The annual spending profile during the forecast period is as follows:

DSP ID	Area	Project	Main Category	Annual Material Investment ($ 000's)						
				2016	2017	2018	2019	2020	2021	Total
16	EOP	Main Substation - Delta to Wye Conversion	SS	-	750	-	-	-	-	750

5.4.6.17 CNPI - Targeted Pole Replacement Program

(Project 17 in Figure 5.4.5.2-1)

5.4.6.17(a) Justification

This program is necessary in order for CNPI address asset condition concerns. Replacing assets before they become operational and safety hazards is a non-discretionary obligation for CNPI.

5.4.6.17(b) Program Description

Starting in 2016, CNPI is implementing a Detailed Pole Inspection and Testing Program. All poles owned by CNPI and older than 15 years of age will be tested. The resulting condition data made available from this program allow CNPI to improve the overall understanding of pole asset health. The availability of condition data on individual poles will allow CNPI to prioritize pole replacements based on a risk assessment approach.

In CNPI's DAMP, Section 6, an assessment of the current condition of CNPI's pole population is provided. Currently available condition data demonstrates that over the next 5 years, over 1750 poles are due for replacement. CNPI's investment plan includes the replacement of many of these poles under other rebuild programs such as the delta to wye conversion based programs. However, outside of the areas covered under these programs, a number of poles exist that are at or approaching end of useful life.

CNPI has historically changed an average of 252 poles per year based on the last five years of activity shown in Figure 5.4.6.17-1 (Also, see DAMP Table 20):

Year	Quantity	2.25% Sustainment Level	Surplus (Deficit)
2011	*132*	508	(376)
2012	276	508	(232)
2013	338	508	(170)
2014	195	508	(313)
2015	320	508	(188)

Figure 5.4.6.17-1: CNPI Historical Pole Replacements

As indicated in the above table, historically CNPI has been well below sustainable levels of pole replacements required to maintain required asset health.

CNPI anticipates that a number of pole replacements will occur though other programs such as voltage conversions and upgrades and expansions as outlined in the Figure 5.4.6.17-2 below.

CNPI should be replacing approximately 508 poles per year to achieve sustainment, based on an average life of 45 years. From the two programs cited above, there would be deficits in the number of pole replacements over the forecast period.

CNPI's Targeted Pole Replacement program is intended to move to a more sustainable approach to its management of distribution poles. In the forecast period, CNPI anticipates changing approximately 138 poles per year under this program based on available resources and incorporating a levelized approach.

Year	2016	2017	2018	2019	2020	2021
Conversion-Based Replacements	200	131	185	173	194	55
Upgrades and Expansions	41	102	124	196	187	225
Targeted Pole Replacements, Forecast	138	138	138	138	138	138
TOTAL Pole Replacements, Forecast	**379**	**371**	**447**	**507**	**519**	**418**

Figure 5.4.6.17-2: CNPI Forecasted Pole Replacements

The total number of poles forecasted to be replaced is less than the 508 poles suggested by the targeted sustainment level of 2.25% for some years, as investment resources are otherwise dedicated to substation SR projects and voltage conversion efforts in some years.

CNPI anticipates that as annual delta to wye conversion investment requirements reduce in the years beyond the forecast period, more emphasis and resources will be placed on the targeted pole replacement strategy to maintain pole asset health without further increases in SR investment levels.

The annual spending profile during the forecast period is as follows:

DSP ID	Area	Project	Main Category	Annual Material Investment ($ 000's)						
				2016	2017	2018	2019	2020	2021	Total
17	CNPI	Targeted Pole Replacement Program	SR	870	981	997	1,014	1,031	1,048	5,941

5.4.6.18 PC - Killaly DS - Upgrade Protection and Redundant Source

(Project 18 in Figure 5.4.5.2-1)

5.4.6.18(a) Challenges with Existing Configuration

There are several existing issues with this Distribution Substation, as described in the CNPI DAMP, sections 3.4.2.1 and 6.1.8 and summarized below. Please refer to the one-line diagram of Figure 5.4.6.18-1 for reference.

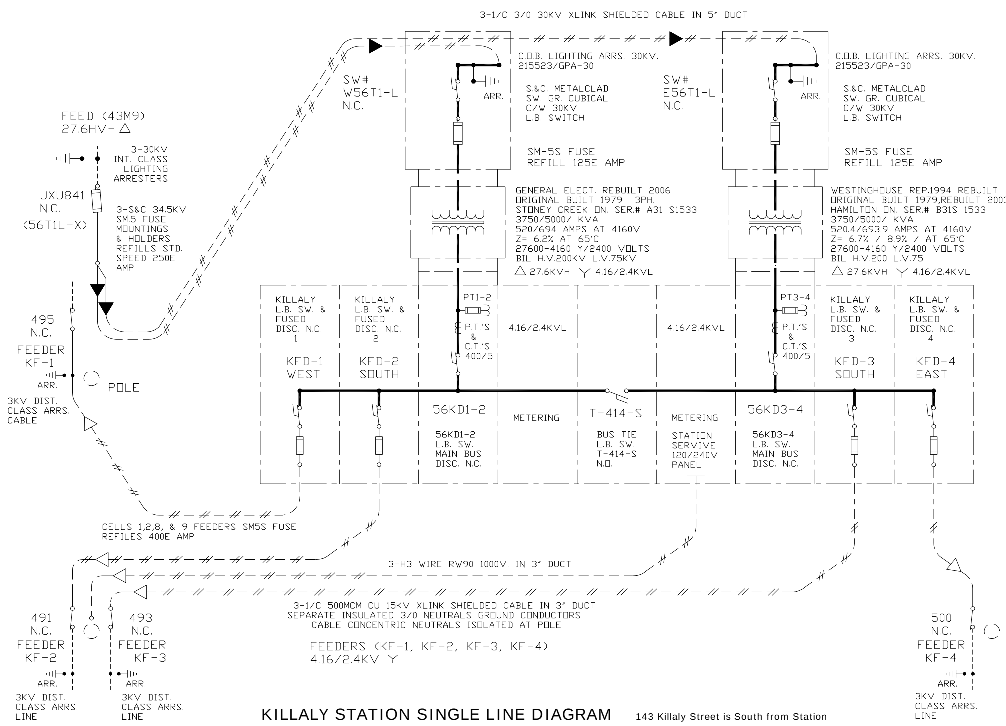


Figure 5.4.6.18-1: Killaly DS – Elementary One-Line Diagram

Load-at-Risk

Killaly DS is isolated from the rest of the 'urban' 4.16kV substation sources by the Welland Canal. There are no other DS that can supply the load of this station if it were to become unavailable. There is a single three-phase set of submarine cables that is installed under the canal, and a few small pole-mounted ratio banks, but they are insufficient to supply all of the extra load represented by Killaly DS.

There is only a single overhead 27.6kV high-side supply to this DS. It splits into two sets of underground cables to supply each of the two power transformers, but both of these cable 'risers' are installed on a common pole. Some outage scenarios would result in no power to many of CNPI's customers for a prolonged period, well in excess of the 8-hour standard used at CNPI and throughout the industry.

The station also incorporates a double-ended 4.16kV switchgear. The switchgear presents another single point of failure for which significantly limits restoration options under contingency.

Protection

This DS has only power fuses to protect the supply ingress point and the power transformer.

- These transformers would be expensive to replace, and require very long lead times to acquire and install. If one of these transformers required replacement, it might take up to 32 weeks to replace.
- Power fuses can be effective protective devices, but they are not as effective as relay-controlled circuit breakers, complete with current transformers (CT's), in detecting and clearing system faults while minimizing damage to the protected components.

5.4.6.18(b) Alternative Analysis

Other than the project proposal described section 5.4.6.18(c), no creditable alternatives were identified that addressed the challenges of section 5.4.6.18(a) without incurring much greater capital costs.

5.4.6.18(c) Project Description

To address all of these issues, this project will consist of:

- Installation of a second 27.6kV supply, tapped from the overhead 27.6kV feeder on Killaly St E.
- Installation of two sets of new 28kV station ingress cables with the cable risers on separate poles. The legacy supply cables will also be replaced during this process.
- Replacement of the 27.6kV primary fuses with pole-mount Viper^{tm} reclosers[2]

[2] In early 2016, a failure to one of the underground 27.6kV ingress cables described in section (a) required the partial replacement of the incoming source. CNPI is taking advantage of this unscheduled event to pre-install the two Viper reclosers in the current year rather than in 2019. The cost of these reclosers has been deducted from the 2019 project costs.

- Replacement of the low-side (4.16kV) feeder-breaker switchgear with a combination of dead-front equipment like S&C PME switchgear and G&W Viper[tm] padmounted reclosers
- Replacement of the vintage protection and control equipment with modern SEL relaying and SCADA modules.
- Complete review and updating of the protection schema to leverage the capabilities of the new relays.

A conceptual one-line diagram can be found in figure 5.4.6.18-2:

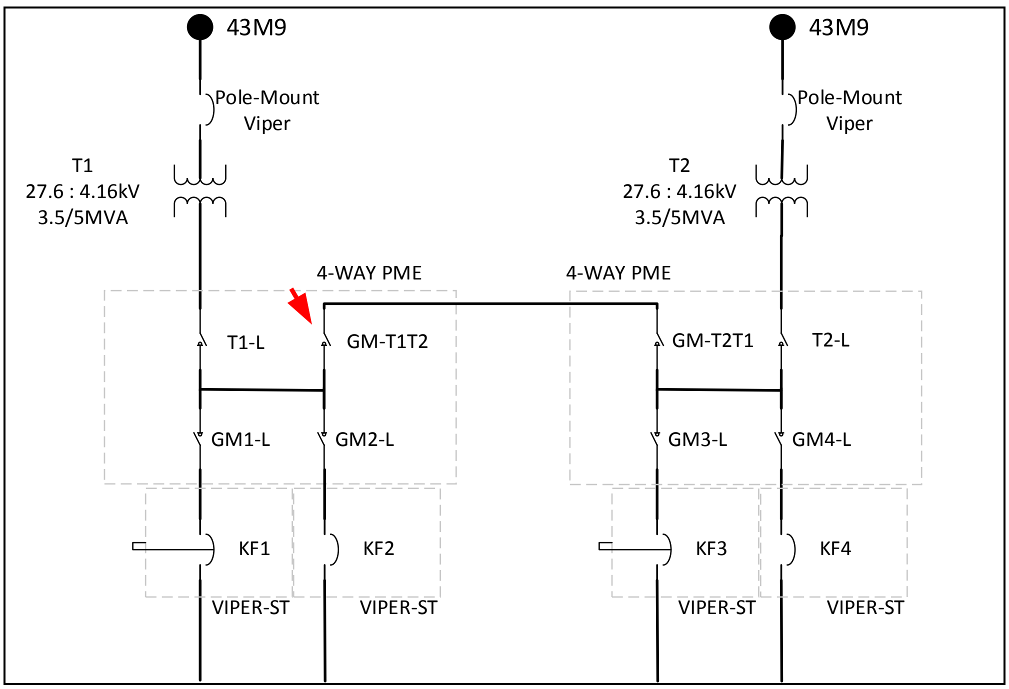


Figure 5.4.6.18-2: Conceptual One-Line for Killaly 2019

The annual spending profile during the forecast period is as follows:

DSP ID	Area	Project	Main Category	Annual Material Investment ($ 000's)						
				2016	2017	2018	2019	2020	2021	**Total**
18	PC	Killaly DS - Upgrade Protection and Redundant Source	SS	-	-	-	410	-	-	**410**

5.4.6.19 FE - New South DS - Acquire Land

(Project 19 in Figure 5.4.5.2-1)

This material project forms an integral part of *Project 5.4.6.20 – FE New South DS – Construct Substation.*

It has been separated as the acquisition of land settles into different accounts and belongs to a distinct investment category (General Plant, or GP).

This specific item provides for the selection and purchase of a plot of land of a suitable size and in a suitable location in the south-eastern portion of Fort Erie to allow for the construction of a dead-front 34.5:8.3kV(wye) distribution substation.

It includes all associated legal fees. The estimated cost in 2020 to acquire this land is approximately $250,000. The actual cost will depend on the specific location chosen, subject to availability and realty market conditions at the time of purchase.

Although CNPI would prefer to delay this purchase until 2020 to minimize the NPV cost of this project, the acquisition could take place sooner if the right opportunity arises to purchase a suitable parcel of land in an attractive location.

Please refer to section 5.4.6.20 for overall substation project description and justification.

The annual spending profile during the forecast period is as follows:

DSP ID	Area	Project	Main Category	Annual Material Investment ($ 000's)						
				2016	2017	2018	2019	2020	2021	**Total**
19	FE	New South DS - Acquire Land	GP	-	-	-	-	250	-	**250**
20	FE	New South DS - Construct new substation	SR	-	-	-	-	-	1,700	**1,700**

5.4.6.20 FE – New South DS – Construct Substation

(Project 20 in Figure 5.4.5.2-1)

5.4.6.20(a) Justification and Alternative Analysis

This project is necessary in order for CNPI address safety and operating concerns associated with its legacy 4.8kV delta system, as per DAMP, sections 3.3.2 and 6.2.1.

Other than the non-discretionary project described in the remainder of 5.4.6.9, there were no other alternatives identified that resolved these concerns without requiring considerably larger capital investments.

5.4.6.20(b) Background Information

The CNPI DAMP (section 6.2.1) discusses the need to eliminate the last remnants of the CNPI delta system in Fort Erie. By 2020, after completion of other material projects in this SP, CNPI anticipates that its Fort Erie distribution system should be as shown in the following map:

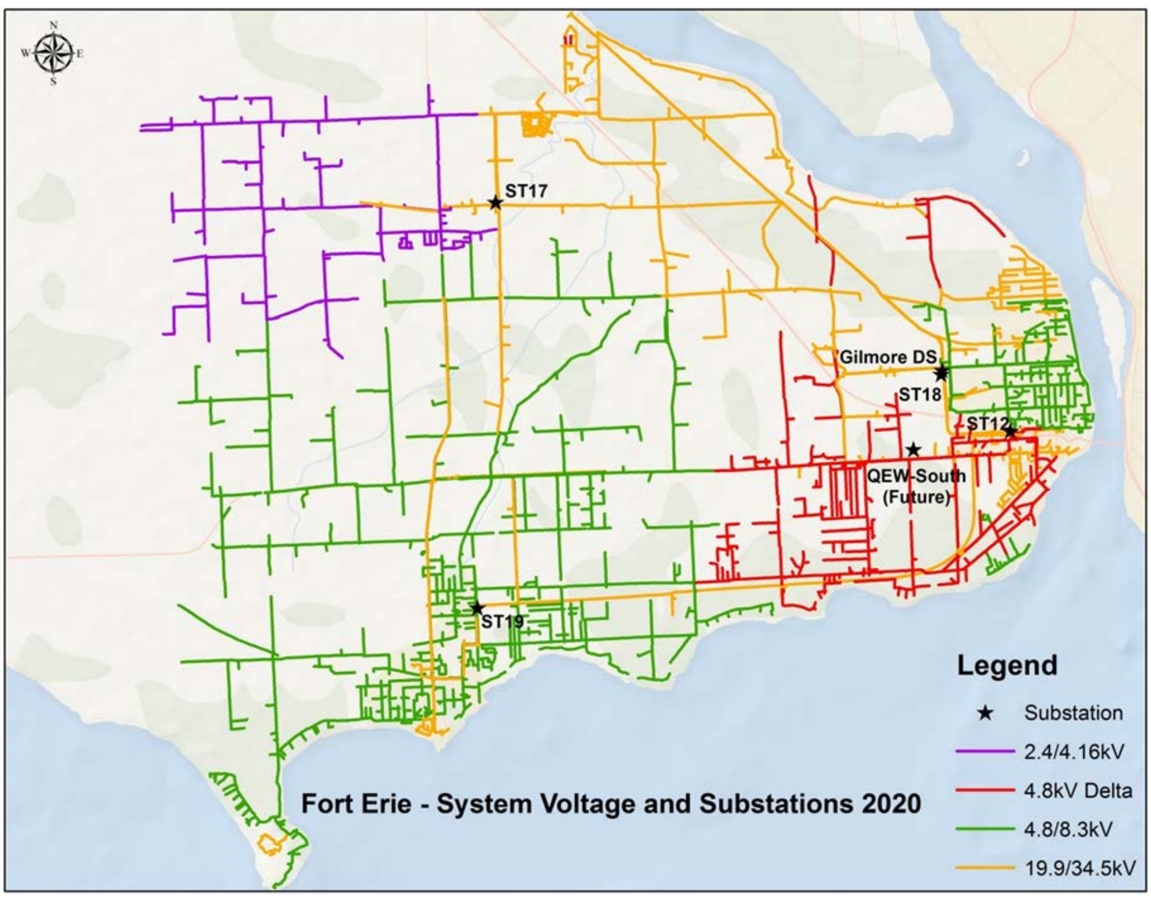


Figure 5.4.6.20-1: FE System by 2020 depicting possible location of new FE South DS

There will still be a large ‘residual’ area on the south side of the QEW area served by Station 12 DS at 4.8kV (delta). Some of the load in this area may be suitable for conversion to 34.5kV, but the majority will have to be converted to 8.3kV (wye) due to spacing constraints with the legacy distribution lines and availability of 34.5kV distribution lines.

The effort to convert this area is scheduled to begin in 2022 (beyond the forecast period of this DSP). In order to start this portion of the CNPI Voltage conversion program, it will first be necessary to create a new 34.5:8.3kV (wye) source on the south side of the QEW, which can be relieved by Gilmore DS (see section 5.4.6.1) in the event of a forced contingency event.

Distribution Substation Design

At the time of preparation of this DSP, CNPI has not carried out a detailed design or high-accuracy cost estimate for this project.

CNPI has not yet determined the geographical location for the substation (see 5.6.4.19), but has narrowed the optimal areas for it to be located, given the constraints of its future load service territory and existing locations of the present CNPI distribution system.

It is expected that this new DS will need to be located in an area that will have mixed-use properties around it, including existing and proposed new residential streets and/or subdivisions.

For this reason, it may be desirable to create a quiet, low-profile, dead-front design that makes efficient use of land to minimize environmental impacts and maximize the ability of occupants of neighboring properties to enjoy the use of their land.

At this time, CNPI is planning on the construction of a compact station, with three or four 8.3kV feeders, complete with all necessary ancillary equipment.

One possible design would be as pictured below:

Figure 5.4.6.20-2: Photograph of Initial Concept for new FE South DS

The estimated annual spending profile during the forecast period is as follows:

DSP ID	Area	Project	Main Category	Annual Material Investment ($ 000's)						
				2016	2017	2018	2019	2020	2021	**Total**
19	FE	New South DS - Acquire Land	GP	-	-	-	-	250	-	**250**
20	FE	New South DS - Construct new substation	SR	-	-	-	-	-	1,700	**1,700**

5.4.6.21 CNPI - Fleet Management Program GP

(Project 21 in Figure 5.4.5.2-1)

CNPI operates a variety of vehicles including passenger vehicles, bucket trucks, and digger derricks. Currently CNPI has a fleet of 53 vehicles that range in age from 1999 to 2015.

Generally, CNPI maintains its fleet of vehicles in accordance with manufacturer's guidelines.

CNPI considers a number of asset condition factors to determine a schedule for replacement of vehicles. Some of these factors are:

- Vehicle age
- Mileage
- Engine hours
- Power Take Off (PTO) hours
- Chassis condition
- Body condition
- Boom condition
- Technical assessment

The annual spending profile during the forecast period is as follows:

DSP ID	Area	Project	Main Category	Annual Material Investment ($ 000's)						
				2016	2017	2018	2019	2020	2021	**Total**
21	CNPI	Fleet Management Program GP	GP	327	175	385	75	775	418	**2,155**

5.4.6.22 CNPI - Information Technology - Hardware GP

(Project 22 in Figure 5.4.5.2-1)

Information Technology Projects

5.4.6.22(a) Overview

CNPI IT assets include hardware and software. The main components of the IT hardware include servers, switches, network equipment, and workstations (desktops and laptops). The software that is used in conjunction with this hardware includes: email applications, file/print services, and the SAP ERP. There are other specific software applications that are used within CNPI that are unique to departmental needs. The strategy for delivering the hardware and software is discussed within Exhibit 2, Tab 2, Schedule 2.

For the purpose of this document, CNPI has determined the total expenditures for the FortisOntario business units and has reported the IT projects on an aggregate basis. For the purpose of rates, the aggregate amounts have been allocated to each business units based on the approved allocation methodology in the BDR Report - Exhibit 4, Tab 5, Schedule 2, Appendix B.

Information Technology Capital Projects (000's)						
	2016	2017	2018	2019	2020	2021
Hardware	600	354	250	200	200	400
Software	1,491	1,274	1,004	1,000	1,000	1,000
	$2,091	$1,628	$1,254	$1,200	$1,200	$1,400

5.4.6.22(b) Hardware

The following discussion relates to IT hardware specific assets.

Workstations

CNPI maintains approximately 135 workstations (both desktops and laptops) allocated to CNPI distribution. The lifecycle of these assets has been set at five years, which coincides with the warranty coverage and useful life of the assets.

The annual cost to replace the workstations has remained relatively consistent using the five-year lifecycle.

Servers

The server assets are also managed using a five-year lifecycle which coincides with the warranty period and useful life. CNPI maintains approximately 73 servers. The annual schedule of replacing CNPI servers is based on the lifecycle (i.e. 20% replacement per year).

The following sub-table summarizes the allocation of hardware based costs for the years 2016 – 2021. Material, labour and overhead are included in these costs.

Project	Annual Investment ($ 000's)						
	2016	2017	2018	2019	2020	2021	Total
Workstation Replacement	75	73	90	80	70	65	453
SAP Host Server/Storage Replacement	386	-	-	-	-	330	716
Non- SAP Host Server/Storage Replacement	-	246	-	-	-	-	246
Data Centre Upgrade	-	-	-	120	-	-	120
Phone System Upgrade	-	-	100	-	-	-	100
Miscellaneous	139	35	60	-	130	5	369
Information Technology - Hardware GP	**600**	**354**	**250**	**200**	**200**	**400**	**2,004**

2016 – 2021 Hardware Allocation

During this period, the following hardware will be replaced or upgraded in respect of lifecycle management frequency or business requirements:

- Replacement of workstations: This is generally separated into two classes; desktops and laptops
- Replacement of corporate servers and storage systems. The replacement program is generally consistent year over year with the exception of the following:
    - 2016: The SAP hardware landscape is being replaced as it is at end of life (five years). Both front-end host servers and the back-end storage system is included.
    - 2017: The non-SAP hardware landscape is being replaced as it is at end of life. This consists of but not limited to email, file/print and utility based servers all residing within a virtualized hardware environment. Both front-end host servers and the back-end storage system is included.
    - 2021: The SAP hardware landscape is being replaced as it is at end of life (five years). Both front-end host servers and the back-end storage system is included.
- Data Centre specific upgrades which include replacement of batteries, cooling system or security based functions.

- Phone System Upgrade which will include minor updates/replacements of various components as well as a full replacement scheduled for 2018.
- Miscellaneous improvements:
    - Wireless technology which provides secure untethered access to corporate systems and data
    - Network switches which provides the physical connectivity of all servers and workstations within the organization
    - Network printers

5.4.6.23 CNPI - Information Technology - Software GP

(Project 23 in table 5.4.5.1)

Please refer to section 5.4.6.22 for overview of this investment program.

Software

Computer software encompasses all applications that are installed and run on workstations and/or servers. This includes the following:

- Operating system
  - Microsoft Windows (workstation)
  - Microsoft Windows Server (server)

- Client specific office productivity
  - Microsoft Office
  - Adobe Acrobat – pdf creation and viewing application
  - WinZip – file compression application
  - SnagIt – screen capture application

- Server specific application
  - Microsoft SQL Server
  - Microsoft SharePoint Server
  - VMware vSphere Virtualization Application
  - Commvault Data Protection
  - Citrix Remote VPN Access
  - Checkpoint Firewall Suite

- Function specific
  - ADP HR Resource Partner
  - ADP Payroll
  - Environment Health & Safety (Compliance Science)

- o Computer-based engineering analysis, outage management, planning/staking, and mapping/geographical information system applications
- o Z-Option (Excel/SAP interface application)
- o SAP
- o Microsoft
- o Adobe
- o Commvault (Backup Software)

Generally, CNPI's software is replaced in conjunction with the vendor's maintenance schedule and lifecycle schedule. Updates and upgrades of software are normally implemented in support of business improvements and consistent with industry standards. Costs associated with software encompasses license specific purchases and/or the development of business process through the use of software.

The following sub-table summarizes the major IT projects for the years 2017 – 2021. Material, labour and overhead are included in these costs.

Project	Annual Investment ($ 000's)						
	2016	2017	2018	2019	2020	2021	Total
SAP Specific							
Business Process Improvements	194	70	-	136	100	100	600
Bill Print Enhancements	106	100	100	100	61	100	567
New G/L Upgrade	-	-	-	-	-	50	50
Mobile Platform Development	214	60	100	100	100	100	674
Security Model Redesign	-	-	150	40	-	-	190
Customer Self-Serve mobile platform	-	60	70	50		10	190
Process Orchestration	72	-	-	-	-	-	72
Business Intelligence					100	100	200
Regulatory Specific	155	85	75	100	75	75	565
GIS/OMS Development	163	300	100	100	100	100	863
Software - Licensing	214	214	214	214	214	214	1,284
Software - Additions	-	-	35	20	10	10	75
Information Security Project	-	50	50	10	10	10	130
SharePoint Upgrade	-	-	-	-	20	-	20
Service Desk Upgrade	-	95	-	20	-	10	125
Environment Health & Safety	90	100	-	-	100	10	300
Vegetation Management	-	20	10	10	10	10	60
Miscellaneous	283	120	100	100	100	100	803
Information Technology - Software GP	**1,491**	**1,274**	**1,004**	**1,000**	**1,000**	**1,000**	**6,769**

2016 – 2021 Software Allocation

During this period the following software will be replaced or upgraded in respect of lifecycle management frequency or business requirements:

- SAP specific
    - Business process improvements
    - Bill Print Enhancements
    - Regulatory specific improvements
    - Security Model Redesign
    - New functional improvements
    - New G/L (General Ledger) upgrade
- GIS/OMS specific
    - Integration with ERP/CIS
    - Automation of manual specific processes
    - General business process improvements
- Environment Health & Safety Specific
    - Collection, tracking and reporting of all HSE data from multiple departments or locations.
    - Leading indicators: observation, inspection, HSE meetings, safety equipment maintenance, and all associated action items including responsibility assignment at each level of the organizational structure.
    - Lagging indicators: Incident reporting company, public and contractor with all associated action items including responsibility assignment at each level of the organizational structure.
    - Compliance and legal requirement management
    - Audit and inspection management
    - Document control and training management
- Vegetation Management Software Specific
    - Facilitate workload forecasting throughout the year, creating schedules in advance.
    - Provide better data and historical information to assist with the budgetary planning process.

  - Establish a consistent and repeatable process to be used by multiple users.
  - Facilitate compliance with regulatory requirements
  - Provide consistent, more accurate record keeping method
  - Create/maintain metrics for various work activities, cost types, and other criteria currently not being captured
- Service Desk Application Replacement
  - Incident response/management
  - Change management
  - Patch management
  - Reporting tools
- Information Security Project
  - Review current environment
  - Agree to new control model
  - Define gap analysis
  - Execute new plan
  - Report on outcomes
- Miscellaneous
  - SharePoint - intranet upgrade/improvements
  - Two factor authentication
  - Mobile device management software
  - Security certificate software
  - External file share software
  - PowerAssist Call Management

5.5 List of Appendices

Appendix	Description
A	Maps of CNPI System
B	Letter from Hydro One Networks for CNPI participation in Regional Planning – Niagara
C	Letter from Hydro One Networks for CNPI participation in Regional Planning – Peterborough to Kingston
D	Comment Letter from IESO regarding CNPI REG Investment Plan
E	CNPI 2014 OEB Performance Scorecard
F	CNPI – Presentations to Customers and Stakeholders
G	2016 Customer Satisfaction Survey
H	Executive Presentation of Customer DSP Focus Groups
I	CNPI Capital Expenditure Approval Forms 2012-2017
J	CNPI Capital Expenditure Approval Forms 2018-2021
K	CIA Applications from CNPI to HONI re. North Line
L	Letter from HONI regarding Jones Falls
M	CNPI Distribution Asset Management Plan (DAMP)

Figure 5.5-1: List of Appendices

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Appendix A.
Maps of CNPI System

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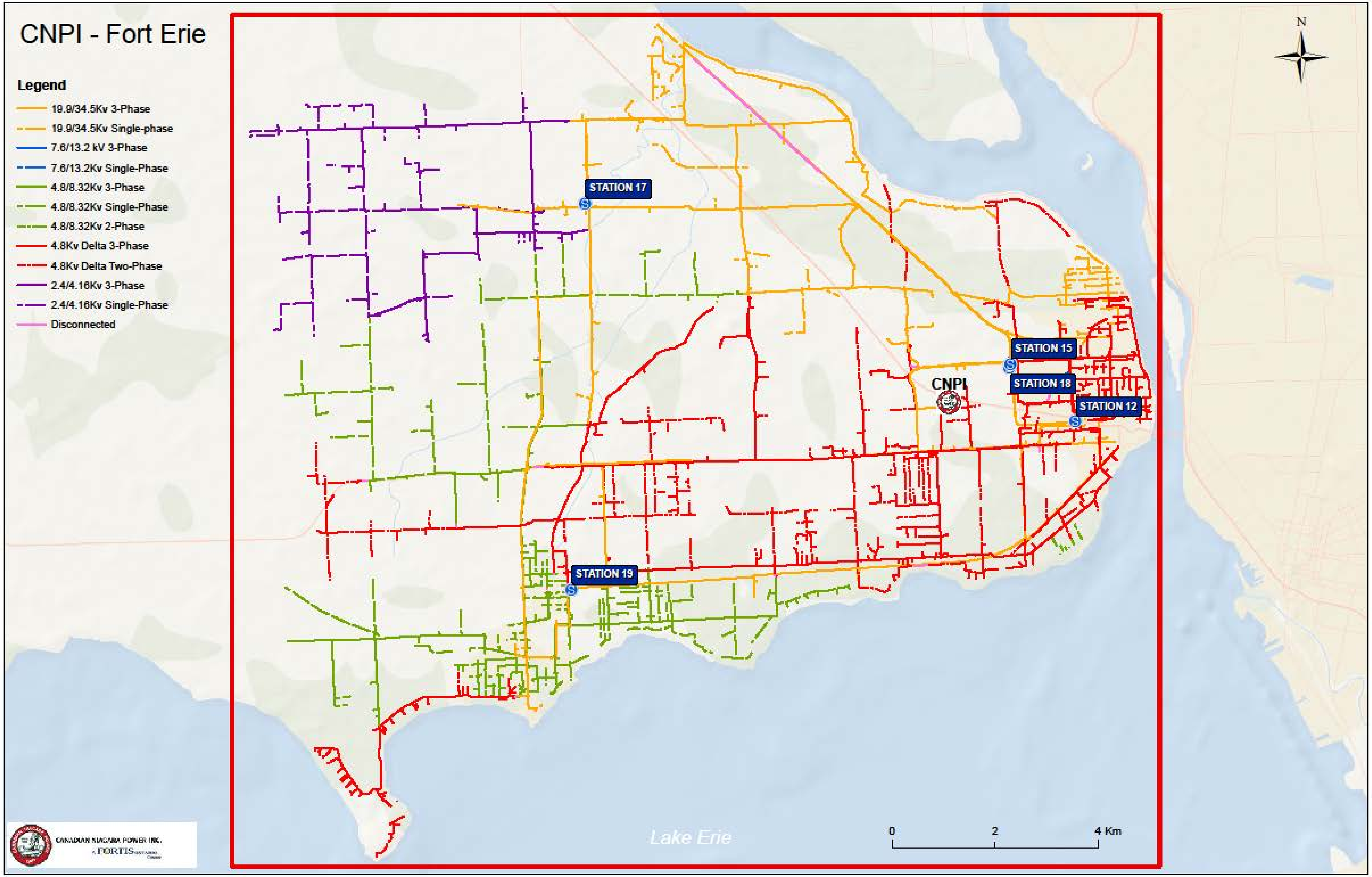
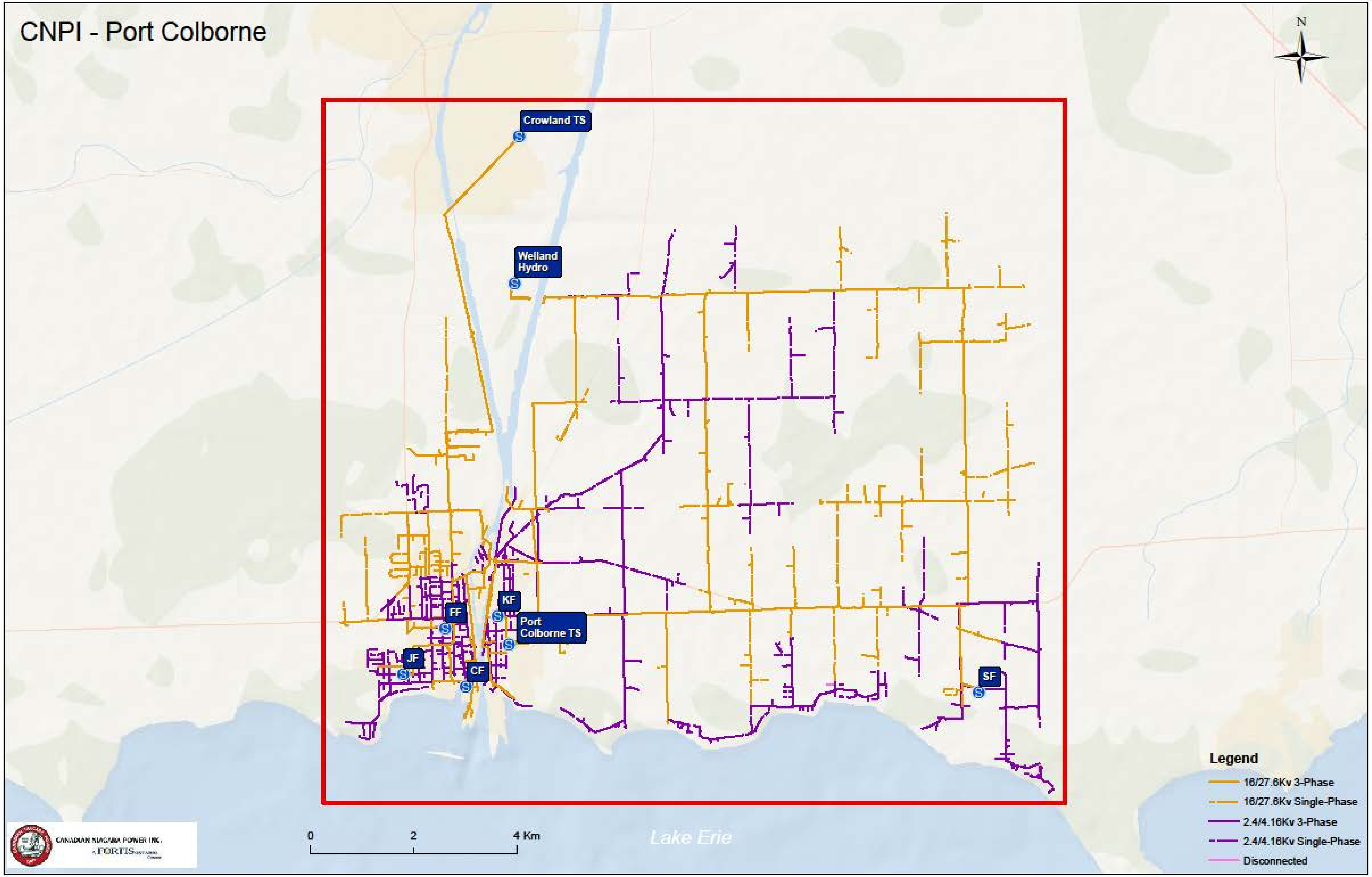
Appendix A. Maps of CNPI Regions

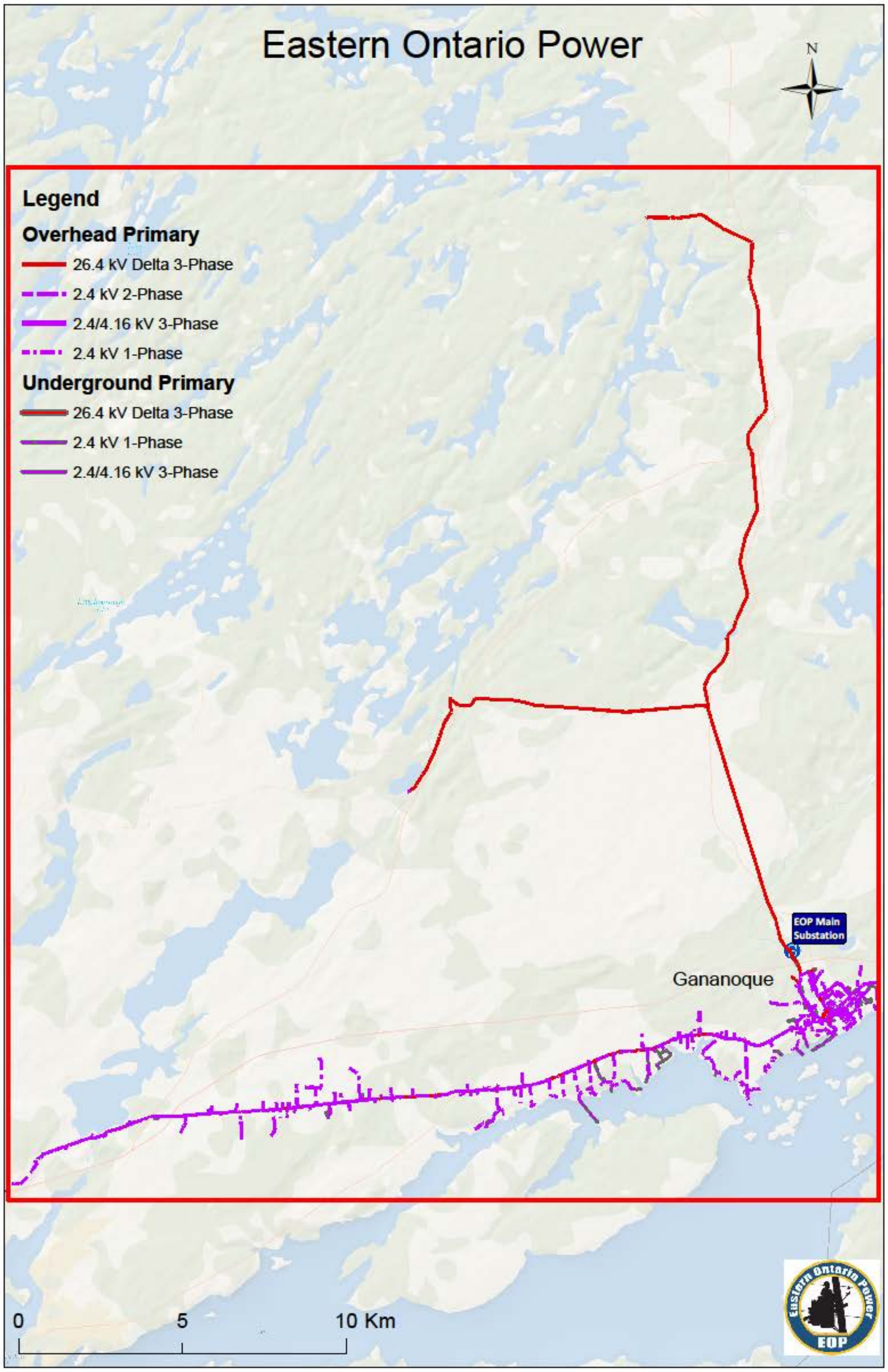
A1. Fort Erie



A2. Port Colborne



A3. EOP (Gananoque)



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Appendix B.

Letter from Hydro One Networks for CNPI participation in Regional Planning - Niagara

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Hydro One Networks Inc.
483 Bay Street
13th Floor, North Tower
Toronto, ON, M5G 2P5
www.HydroOne.com

Tel: (416) 345-5420
Fax: (416) 345-4141
ajay.garg@HydroOne.com

February 26th 2016

Kevin Kilfoil
Technical Services Manager
Canadian Niagara Power Inc.
1130 Bertie St., P.O. Box 1218
Fort Erie, Ontario, L2A 5Y2

Dear Mr. Kilfoil:

Subject: Regional Planning Status

In reference to your request for a regional planning status letter, please note that your Local Distribution Company (LDC) belongs to the Niagara Region, which is in Group 3. A map showing details with respect to the 21 Regions/Groups and a list of LDCs in each Region is attached in Appendix A and B respectively.

Canadian Niagara Power Inc. is currently participating in the Needs Assessment phase of the process for the Niagara Region. It is expected that the Needs Assessment phase for the Niagara Region will be completed by the end of Q2 2016. Further steps of the regional planning process will be undertaken based on the needs and recommendations in the Needs Assessment report. Accordingly, it is premature at this time for Hydro One to comment on any potential investments that would impact Canadian Niagara Power Inc. investment plan.

Hydro One looks forward to continue working with Canadian Niagara Power Inc. in executing the regional planning process. If you have any further questions, please feel free to contact me.

Sincerely,

Ajay Garg, Manager – Regional Planning Coordination
Hydro One Networks Inc.

Appendix A: Map of Ontario's Planning Regions

Northern Ontario

Southern Ontario

Greater Toronto Area (GTA)

Group 1	Group 2	Group 3
Burlington to Nanticoke	East Lake Superior	Chatham/Lambton/Sarnia
Greater Ottawa	London area	Greater Bruce/Huron
GTA East	Peterborough to Kingston	Niagara
GTA North	South Georgian Bay/Muskoka	North of Moosonee
GTA West	Sudbury/Algoma	North/East of Sudbury
Kitchener- Waterloo-Cambridge-Guelph (“KWCG”)		Renfrew
Metro Toronto		St. Lawrence
Northwest Ontario		
Windsor-Essex		

<u>Appendix B</u>: <u>List of LDCs for Each Region</u>

[Hydro One as Upstream Transmitter]

Region	LDCs
1. Burlington to Nanticoke	• Brant County Power Inc. • Brantford Power Inc. • Burlington Hydro Inc. • Haldimand County Hydro Inc. • Horizon Utilities Corporation • Hydro One Networks Inc. • Norfolk Power Distribution Inc. • Oakville Hydro Electricity Distribution Inc.
2. Greater Ottawa	• Hydro 2000 Inc. • Hydro Hawkesbury Inc. • Hydro One Networks Inc. • Hydro Ottawa Limited • Ottawa River Power Corporation • Renfrew Hydro Inc.
3. GTA North	• Enersource Hydro Mississauga Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Newmarket-Tay Power Distribution Ltd. • PowerStream Inc. • PowerStream Inc. [Barrie] • Toronto Hydro Electric System Limited • Veridian Connections Inc.
4. GTA West	• Burlington Hydro Inc. • Enersource Hydro Mississauga Inc. • Halton Hills Hydro Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Milton Hydro Distribution Inc. • Oakville Hydro Electricity Distribution Inc.

5. Kitchener- Waterloo-Cambridge-Guelph (“KWCG”)	• Cambridge and North Dumfries Hydro Inc. • Centre Wellington Hydro Ltd. • Guelph Hydro Electric System - Rockwood Division • Guelph Hydro Electric Systems Inc. • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Kitchener-Wilmot Hydro Inc. • Milton Hydro Distribution Inc. • Waterloo North Hydro Inc. • Wellington North Power Inc.
6. Metro Toronto	• Enersource Hydro Mississauga Inc. • Hydro One Networks Inc. • PowerStream Inc. • Toronto Hydro Electric System Limited • Veridian Connections Inc.
7. Northwest Ontario	• Atikokan Hydro Inc. • Chapleau Public Utilities Corporation • Fort Frances Power Corporation • Hydro One Networks Inc. • Kenora Hydro Electric Corporation Ltd. • Sioux Lookout Hydro Inc. • Thunder Bay Hydro Electricity Distribution Inc.
8. Windsor-Essex	• E.L.K. Energy Inc. • Entegrus Power Lines Inc. [Chatham-Kent] • EnWin Utilities Ltd. • Essex Powerlines Corporation • Hydro One Networks Inc.
9. East Lake Superior	N/A → This region is not within Hydro One’s territory

10. GTA East	• Hydro One Networks Inc. • Oshawa PUC Networks Inc. • Veridian Connections Inc. • Whitby Hydro Electric Corporation
11. London area	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Hydro One Networks Inc. • London Hydro Inc. • Norfolk Power Distribution Inc. • St. Thomas Energy Inc. • Tillsonburg Hydro Inc. • Woodstock Hydro Services Inc.
12. Peterborough to Kingston	• Eastern Ontario Power Inc. • Hydro One Networks Inc. • Kingston Hydro Corporation • Lakefront Utilities Inc. • Peterborough Distribution Inc. • Veridian Connections Inc.
13. South Georgian Bay/Muskoka	• Collingwood PowerStream Utility Services Corp. (COLLUS PowerStream Corp.) • Hydro One Networks Inc. • Innisfil Hydro Distribution Systems Limited • Lakeland Power Distribution Ltd. • Midland Power Utility Corporation • Orangeville Hydro Limited • Orillia Power Distribution Corporation • Parry Sound Power Corp. • Powerstream Inc. [Barrie] • Tay Power • Veridian Connections Inc. • Veridian-Gravenhurst Hydro Electric Inc. • Wasaga Distribution Inc.

14. Sudbury/Algoma	• Espanola Regional Hydro Distribution Corp. • Greater Sudbury Hydro Inc. • Hydro One Networks Inc.
15. Chatham/Lambton/Sarnia	• Bluewater Power Distribution Corporation • Entegrus Power Lines Inc. [Chatham-Kent] • Hydro One Networks Inc.
16. Greater Bruce/Huron	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Festival Hydro Inc. • Hydro One Networks Inc. • Wellington North Power Inc. • West Coast Huron Energy Inc. • Westario Power Inc.
17. Niagara	• Canadian Niagara Power Inc. [Port Colborne] • Grimsby Power Inc. • Haldimand County Hydro Inc.* • Horizon Utilities Corporation • Hydro One Networks Inc. • Niagara Peninsula Energy Inc. • Niagara-On-The-Lake Hydro Inc. • Welland Hydro-Electric System Corp. • Niagara West Transformation Corporation* *Changes to the May 17, 2013 OEB Planning Process Working Group Report
18. North of Moosonee	N/A → This region is not within Hydro One's territory

19. North/East of Sudbury	• Greater Sudbury Hydro Inc. • Hearst Power Distribution Company Limited • Hydro One Networks Inc. • North Bay Hydro Distribution Ltd. • Northern Ontario Wires Inc.
20. Renfrew	• Hydro One Networks Inc. • Ottawa River Power Corporation • Renfrew Hydro Inc.
21. St. Lawrence	• Cooperative Hydro Embrun Inc. • Hydro One Networks Inc. • Rideau St. Lawrence Distribution Inc.

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Appendix C.

Letter from Hydro One Networks for CNPI participation in Regional Planning – Peterborough to Kingston

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Hydro One Networks Inc.
483 Bay Street
13th Floor, North Tower
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Fax: (416) 345-4141
ajay.garg@HydroOne.com

March 18th 2016

Kevin Kilfoil
Technical Services Manager
Canadian Niagara Power Inc.
1130 Bertie St., P.O. Box 1218
Fort Erie, Ontario, L2A 5Y2

Dear Mr. Kilfoil:

Subject: Regional Planning Status for Eastern Ontario Power

In reference to your request for a regional planning status letter, please note that Eastern Ontario Power (EOP) belongs to the Peterborough to Kingston Region, which is in Group 2. A map showing details with respect to the 21 Regions/Groups and a list of Local Distribution Companies (LDCs) in each Region is attached in Appendix A and B respectively.

EOP is an embedded LDC supplied via a radial 44kV line from Frontenac TS, operating under the Canadian Niagara Power Inc. (CNPI) distribution license. Although EOP serves customers in both Peterborough to Kingston and St. Lawrence Regions, for regional planning purposes, EOP belongs to the Peterborough to Kingston Region on the basis of supply station location.

The Needs Assessment report for the Peterborough to Kingston Region was completed in February 2015. None of the needs identified in the report directly impacts EOP. In brief, the report concluded that no further coordinated regional planning is required to address any of the needs identified, and they can be addressed directly by Hydro One and the relevant LDCs. A copy of the report is published on the Hydro One Regional Planning Website.

Hydro One looks forward to continue working with EOP in executing the regional planning process. If you have any further questions, please feel free to contact me.

Sincerely,

Ajay Garg, Manager – Regional Planning Coordination
Hydro One Networks Inc.

Appendix A: Map of Ontario's Planning Regions

Northern Ontario

Southern Ontario

Greater Toronto Area (GTA)

Group 1	Group 2	Group 3
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Appendix B: List of LDCs for Each Region

[Hydro One as Upstream Transmitter]

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Appendix D.

Comment Letter from IESO regarding CNPI REG Investment Plan

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IESO Letter of Comment

Canadian Niagara Power Inc.

Distribution System Plan

April 7, 2016

Independent Electricity System Operator

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Introduction

On March 28, 2013, the Ontario Energy Board ("the OEB" or "Board") issued its Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377). Chapter 5 implements the Board's policy direction on 'an integrated approach to distribution network planning', outlined in the Board's October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority[1] ("OPA") comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the Renewable Energy Generation ("REG") investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

Canadian Niagara Power Inc. – Distribution System Plan

On March 16, 2016, the IESO received the Distribution System Plan ("Plan") of Canadian Niagara Power Inc. ("CNPI") containing REG information, all of which will be filed with the OEB when CNPI files its 2017 Rate Application. The IESO has reviewed the Plan and provides the following comments.

OPA FIT/microFIT Applications Received

The Plan shows that as of February 11, 2016, CNPI has connected 137 microFIT projects representing 1279 kW of capacity, and 3 FIT projects totalling 1068 kW of capacity to its distribution system.

According to the IESO's information, as of February 29, 2016, the IESO has offered contracts to 141 microFIT projects totalling 1311 kW of capacity, and 3 FIT projects totalling 1068 kW of capacity - all of which are connected to CNPI's (or EOP's) distribution system. The renewable energy generation connections information in CNPI'S Plan is therefore consistent with that of the IESO.

[1] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

Independent Electricity System Operator
1600 – 120 Adelaide Street West, Toronto, ON M5H 1T1
t 416 967-7474 f 416 967-1947 toll free 1-800-797-9604 customer.relations@ieso.ca www.ieso.ca

Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with Regional Plans

For regional planning purposes, CNPI is part of the both the Niagara Region (Group 3) and, as Eastern Ontario Power ("EOP"), the Peterborough to Kingston Region (Group 2). For the latter region, EOP is an embedded utility within Hydro One Networks Inc. ("Hydro One") distribution system. Under the new regional planning process endorsed by the OEB in August 2013, while the host distributor is required to gather information from their respective embedded LDCs, it is not required that embedded LDCs be directly involved.

Niagara Region

For the Niagara Region, the Needs Assessment process is still underway. CNPI has participated in the information gathering process for the Needs Assessment, providing required data, including load forecast information to Hydro One. The IESO looks forward to continuing to work with CNPI in the Niagara Region.

Peterborough to Kingston Region

Eastern Ontario Power is an embedded LDC operating under the CNPI distribution licence. Regional Planning for the Peterborough to Kingston Region commenced in December 2014 and was complete with the publishing of the Needs Assessment Report by Hydro One on February 10, 2015. As the host LDC to EOP, Hydro One Distribution provided information for the Needs Assessment. As determined by the Needs Assessment study team, no further regional coordination is required for the Peterborough to Kingston Region. Specifically, no needs impacting EOP were identified, and the report concluded that needs would be addressed between the transmitter and the impacted LDC. Therefore, the regional planning process for this region is complete and will be undertaken again when the next 5-year review cycle commences, unless there is sufficient load growth or an event that triggers the requirement to initiate the regional planning process before then.

The IESO appreciates the opportunity to comment on the Renewable Energy Generation Information provided as part of Canadian Niagara Power Inc.'s Distribution System Plan at this time.

Independent Electricity System Operator
1600 – 120 Adelaide Street West, Toronto, ON M5H 1T1
t 416 967-7474 f 416 967-1947 toll free 1-800-797-9604 customer.relations@ieso.ca www.ieso.ca

Appendix E.

CNPI 2014 OEB Performance Scorecard

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Scorecard - Canadian Niagara Power Inc.

9/28/2015

Performance Outcomes	Performance Categories	Measures		2010	2011	2012	2013	2014	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		94.70%	97.70%	95.70%	93.10%	96.00%		90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Telephone Calls Answered On Time		85.10%	83.40%	84.60%	82.60%	78.20%		65.00%	
	Customer Satisfaction	First Contact Resolution						99.9%			
		Billing Accuracy						99.92%		98.00%	
		Customer Satisfaction Survey Results					80.84%	79.59%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public awareness [measure to be determined]									
		Level of Compliance with Ontario Regulation 22/04		NI	C	C	C	C			C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	1			0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.978			0.137
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted		0.90	1.82	1.89	3.22	1.95			at least within 0.90 - 3.22
		Average Number of Times that Power to a Customer is Interrupted		1.27	1.63	2.21	2.72	2.07			at least within 1.27 - 2.72
	Asset Management	Distribution System Plan Implementation Progress						Completed			
	Cost Control	Efficiency Assessment				4	4	4			
		Total Cost per Customer [1]		$715	$727	$679	$726	$749			
		Total Cost per Km of Line [1]		$19,893	$20,204	$18,790	$20,275	$21,202			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Annual Peak Demand Savings (Percent of target achieved) [2]			8.06%	14.05%	37.28%	54.56%			4.07MW
		Net Cumulative Energy Savings (Percent of target achieved)			30.41%	46.13%	64.52%	82.55%			15.81GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time					0.00%				
		New Micro-embedded Generation Facilities Connected On Time					97.78%	95.65%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.77	0.65	0.33	0.34	0.33			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		2.68	2.97	2.53	2.30	2.02			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)		8.01%	8.01%	8.93%	8.93%			
			Achieved		7.21%	9.42%	6.71%	8.31%			

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 include any persisting peak demand savings from the previous years.

Legend: up down flat target met target not met

Appendix A – 2014 Scorecard Management Discussion and Analysis ("2014 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2014 Scorecard MD&A:

http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

In 2014, CNPI met or exceeded 83% of all performance targets.

In 2015, CNPI expects to continue to improve its overall scorecard performance results as compared to previous years. These performance improvements are expected as a result of enhanced system reliability due to CNPI's investment in its distribution system and continued responsiveness to customer feedback.

Service Quality

- **New Residential/Small Business Services Connected on Time**

In 2014, CNPI connected 96% of the 150 new eligible low-voltage residential and small business customers within the Ontario Energy Board's prescribed five day timeline. Since 2010, CNPI has consistently met the Ontario Energy Board's target and continues to trend upwards.

- **Scheduled Appointments Met On Time**

CNPI continues to exceed the Ontario Energy Board standard of meeting customers as requested within the prescribed timelines set out by the Ontario Energy Board.

- **Telephone Calls Answered On Time**

In 2014, customer service representatives answered 78.20% of its 42,361 calls within 30 seconds. This exceeds the Ontario Energy Board's mandated 65% target. 2014 results are slightly lower than previous years. CNPI continues to offer and promote self-serve options and utilizes social media to engage and inform customers in an effort to offer customers additional channels to interact with the Company.

Customer Satisfaction

- **First Contact Resolution**

CNPI measured First Contact Resolution by tracking the number of escalated calls as a percentage of total calls taken by the customer contact center from July 1, 2014 to December 31, 2014. For this period, less than one percent of calls were escalated.

- **Billing Accuracy**

For the period from October 1, 2014 – December 31, 2014, CNPI issued approximately than 87,000 invoices and 99.9% were accurate. This is above the industry standard of 98%.

- **Customer Satisfaction Survey Results**

CNPI utilizes a third party to conduct a telephone survey for its residential customers. The survey includes questions regarding the quality of service, safety, billing, customer communications and information on the industry. The results cited on the scorecard represent customers who indicated that they were 'completely' and 'mostly' satisfied with the overall quality of service. To date, CNPI has not included responses of being 'somewhat' satisfied in the scorecard result. 2014 results were slightly lower than 2013 which is consistent with lower 2014 industry results. This reduction may be attributable to well published events in the industry as a whole, such as the Ombudsman's report on electricity billing and the increasing cost of energy. However, within the survey, customers continue to rate CNPI very high for the safe and reliable delivery of service and providing timely and accurate bills at 90% and 91%, respectively.

The survey provides useful information to better meet the needs of CNPI's customers and is incorporated into the distribution system plan, capital planning and overall company objectives.

Safety

- **Public Safety**

  - **Component A – Public Awareness of Electrical Safety**

CNPI has a number of internal initiatives to communicate Public Awareness of Electrical Safety to our customers. Additionally, CNPI partners with ESA in promoting ESA provincial wide public safety campaigns.

  - **Component B – Compliance with Ontario Regulation 22/04**

This component includes the results of an Annual Audit, Declaration of Compliance, Due Diligence Inspections, Public Safety Concerns and Compliance Investigations. All the elements are evaluated as a whole and determine the status of compliance (Non-Compliant, Needs Improvement, or Compliant).

Results provided by ESA, CNPI's status for 2014 is Compliant.

  - **Component C – Serious Electrical Incident Index**

"Serious electrical incidents", as defined by Regulation 22/04, make up Component C. The metric details the number of and rate of "serious electrical incidents" occurring on a distributor's assets and is normalized per 10, 100 or 1,000 km of line (10km for total lines under 100km, 1000km for total lines over 1000km, and 100km for all the others).

Results provided by ESA, CNPI had one incident in 2014.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**

CNPI's customers experienced a decrease in the average duration of electrical service disruptions in 2014 over the previous year. CNPI continues to invest in grid modernization in order to gain visibility on the state of the distribution system and improve overall response and restoration times. Grid modernization initiatives include the deployment of automated devices and implementation of an outage management system. CNPI understands that reliability of electrical service is a high priority for its customers and continues to invest in replacement of end-of-life assets as well as vegetation management.

- **Average Number of Times that Power to a Customer is Interrupted**

CNPI's customers have experienced a reduction in the average number of electrical service disruptions in 2014 over the previous year. CNPI has deployed several initiatives aimed at reducing the number of electrical service interruptions such as the vegetation management program and cyclical asset preventative maintenance programs.

CNPI reviews outage statistics on a monthly basis to identify areas of poor distribution system performance. This process indicates any trends in poor performance and identifies opportunities to improve reliability. CNPI has also completed an asset condition assessment to identify assets that present a risk of impacting system reliability. CNPI uses reliability indicators and asset condition assessment data as key drivers into the system planning process.

Asset Management

- **Distribution System Plan Implementation Progress**

CNPI currently follows an internally developed five year capital planning process for expenditures on the distribution system. CNPI is in the process of aligning its internally developed process with the requirements outlined in the Chapter 5 Consolidated Distribution System Plan Filing guideline, including the Distribution System Plan. CNPI will be filing a formal Distribution System Plan in accordance with Chapter 5 in 2016 as part of evidence for its next cost of service application.

Cost Control

- **Efficiency Assessment**

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC on behalf of the Ontario Energy Board to produce a single efficiency ranking. The electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs. The model developed by Pacific Economics Group to predict a distributor's costs relies on a data set that includes all distributors in Ontario. For 2014, CNPI was placed in Group 4 indicating that actual costs are within +/- 25% of predicted costs.

However, CNPI uses industry-standard budgeting and accounting practices to predict and track its costs. The actual costs incurred each year by CNPI to deliver all of its programs generally compare favorably to the costs predicted by these practices. For 2014, these actual costs were within 5% of predicted (budgeted) costs. CNPI believes that this variance is minimal and indicative of sound performance from its distribution system planning process. CNPI's forward looking goal is that this efficiency performance will not decline in future years.

- **Total Cost per Customer**

Total cost is calculated as the sum of CNPI's OM&A costs, including depreciation and financing costs. This amount is then divided by the total number of customers that CNPI serves to determine Total Cost per Customer. The cost performance result for 2014 is $749 /customer which is a 3.2% increase over 2013. However, CNPI's Total Cost per Customer has increased on average by only 1.3% per annum over the period 2010 through 2014. This compares favorably with the Consumers Price Index (CPI) over the same period.

Historical cost measures are reflective of the fact that 80% of CNPI's service territory is located in rural areas, subject to more severe weather due to its location on the shore of Lake Erie (Lake Ontario for Eastern Ontario Power's service territory) with its prevailing winds and lake effect precipitation, and the operation and maintenance of several distribution substations. CNPI performs a comprehensive series of programs to meet all legal and regulatory requirements, with special emphasis on public safety, optimizing reliability, meeting customers' needs, and general cost control.

CNPI will continue to replace distribution assets proactively along a carefully managed timeframe in a manner that balances system risks and customer rate impacts. CNPI will continue to seek and implement productivity and system reliability improvement initiatives to help offset some of the costs associated with future system enhancements. Customer engagement initiatives will continue in order to ensure customers have an opportunity to share their viewpoint on CNPI's capital spending plans.

- **Total Cost per Km of Line**

This measure uses the same total cost that is used in the Cost per Customer calculation above. The total cost is divided by the total kilometers of line that CNPI operates to serve its customers. CNPI's 2014 rate is $21,202 per km of line, a 4.6% increase over 2013. However, CNPI's Total Cost per Customer has increased on average by only 1.8% per annum over the period 2010 through 2014. This compares favorably with the CPI over the same period.

As outlined on Total Cost per Customer above, historical cost measures are reflective of the fact that 80% of CNPI's service territory is located in rural areas, subject to more severe weather due to its location on the shore of Lake Erie (Lake Ontario for Eastern Ontario Power's service territory) with its prevailing winds and lake effect precipitation, and the operation and maintenance of several distribution substations. . CNPI performs a comprehensive series of programs to meet all legal and regulatory requirements, with special emphasis on public safety, optimizing reliability, meeting customers' needs, and general cost control.

As outlined on Total Cost per Customer above, CNPI will continue to replace distribution assets proactively along a carefully managed timeframe in a manner that balances system risks and customer rate impacts. CNPI will continue to seek and implement productivity and system reliability improvement initiatives to help offset some of the costs associated with future system enhancements. Customer engagement initiatives will continue in order to ensure customers have an opportunity to share their viewpoint on CNPI's capital spending plans.

Conservation & Demand Management

- **Net Annual Peak Demand Savings (Percent of target achieved)**

On the basis of the IESO's "2011 – 2014 Final Results Report" issued on September 1, 2015, CNPI achieved 54.6% of its Net Annual Peak Demand Savings. CNPI fully leveraged the suite of Independent Electricity System Operator ("IESO") province-wide demand management programs and placed emphasis on supporting the conservation efforts of large commercial, industrial and institutional customers.

CNPI had been challenged in its efforts to meet the assigned target due to a significant reduction in customer demand and energy consumption, in 2011, which has continued into 2014 with a decline in customer demand coupled with customer closures. This resulted in significant adverse economic impacts affecting the entire service territory. Due to these negative economic impacts, a lack of growth and decline in the larger customer base, the CNPI service territories have seen a dramatic overall decline in energy throughput and system

demand since 2008; the year that was used as the base year to set the mandated targets.

- **Net Cumulative Energy Savings (Percent of target achieved)**

On the basis of the IESO's "2011 – 2014 Final Results Report" issued on September 1, 2015, CNPI achieved 82.6% of its Net Energy Savings. CNPI fully leveraged the suite of Independent Electricity System Operator ("IESO") province-wide demand management programs and placed emphasis on supporting the conservation efforts of large commercial, industrial and institutional customers.

CNPI had been challenged in its efforts to meet the assigned target due to a significant reduction in customer demand and energy consumption, in 2011, which has continued into 2014 with a decline in customer demand coupled with customer closures. This resulted in significant adverse economic impacts affecting the entire service territory. Due to these negative economic impacts, a lack of growth and decline in the larger customer base, the CNPI service territories have seen a dramatic overall decline in energy throughput and system demand since 2008; the year that was used as the base year to set the mandated targets.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**

CNPI did not receive any requests for a renewable generation connections in 2014.

- **New Micro-embedded Generation Facilities Connected On Time**

In 2014, CNPI connected twenty-three (23) new micro-embedded generation facilities (microFIT projects of less than 10 kW). All but one facilities were connected within the prescribed time frame of five business days. Only one facility was connected on the sixth day. The minimum acceptable performance level for this measure is 90% of the time. CNPI works closely with its customers and their contractors to make the connection process as streamlined and transparent as possible.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

The Scorecard reports the current ratio for CNPI's segmented distribution business. On a consolidated basis, the 2014 liquidity current

ratio based on CNPI's audited financial statements is 1.59 (2013 1.22). The liquidity ratio has remained relatively unchanged over the past several years and going forward it is expected to, at a minimum, be held relatively constant. CNPI has consistently shown a liquidity ratio greater than 1.0, which is an indication that CNPI is appropriately leveraged.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**

The Ontario Energy Board uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5.

The Scorecard reports the total debt to equity ratio for CNPI's segmented distribution business. On a consolidated basis, the 2014 leverage debt to equity ratio based on CNPI's audited financial statements is 1.27. The leverage ratio has remained relatively unchanged over the past several years and going forward it is expected to be held relatively constant.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**

CNPI's 2014 distribution rates were approved by the Ontario Energy Board as part of its last Cost of Service application for rates effective January 1, 2013 and this included an expected (deemed) regulatory return on equity of 8.93%. The Ontario Energy Board allows a distributor to earn within +/- 3% of the expected return on equity.

- **Profitability: Regulatory Return on Equity – Achieved**

CNPI's return achieved in 2014 was 8.31%, which is within the +/- 3% range allowed by the Ontario Energy Board. CNPI achieved returns are higher in 2014 as compared to 2013 due to a higher adjusted regulated net income, as a result of decreased expenses offset by a decline in distribution revenue.

Note to Readers of 2014 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgement on the reporting date of the performance scorecard, and could be markedly different in the future.

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Appendix F.

CNPI – Presentations to Customers and Stakeholders

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Connecting New or Upgrading Services

Process and Timeline

Types of Projects

- Subdivisions
- Primary Service
  - Overhead
  - Underground
- Secondary Service
  - Overhead
  - Underground

- CNPI schedules ALL projects on a '**First-Commit, First-Done**' basis

Note: Some projects WILL require upgrades to the CNPI system, which could mean higher connection costs and longer lead times!

Types of Projects

- Subdivisions
- Primary Service
  - Overhead
  - Underground
- Secondary Service
  - Overhead
  - Underground

Note: Some projects WILL require upgrades to the CNPI system, which could mean higher connection costs and longer lead times!

CNPI - SUBDIVISION Construction Timeline (Revised on 2015-11-26)

1) Project Developer contacts CNPI

2) CNPI waits for Developer to pay Design Fee *
- Currently $10,000
- Any unused portion credited to CIAC

3) Project Placed in CNPI Design Queue
- Currently about 3 weeks

4) Developer provides required information
- Subdivision layout / R-Plan
- Load Forecast
  - House Build SCHEDULE and types

5) CNPI creates electrical design for subdivision
- Typically about 3 weeks
- Requires prompt developer feedback to avoid delays

6) CNPI provides design and cost information
- Discount-Cash-Flow evaluation
- CIAC and Deposit determined to complete project by CNPI

7) CNPI waits for Developer to pay CIAC and Deposit *
- Developer may provide CNPI civil works as 'payment in kind' for portion of CIAC
- Material Orders wait as well

8) Project placed in CNPI Construction Queue
- Currently about 8-10 weeks
- May also be waiting for padmount transformer delivery (currently 18-20 weeks)

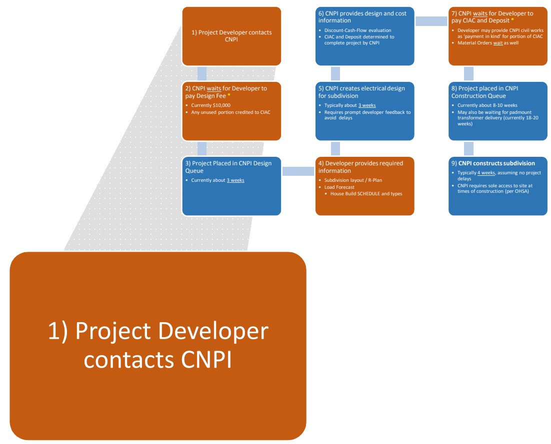
9) **CNPI constructs subdivision**
- Typically 4 weeks, assuming no project delays
- CNPI requires sole access to site at times of construction (per OHSA)

* Developer can prepay for padmount transformers to reduce transformer delivery delays

TOTAL Project Time = 30 weeks + any Developer delays.
Can be reduced to 22-24 weeks if transformers are prepaid.

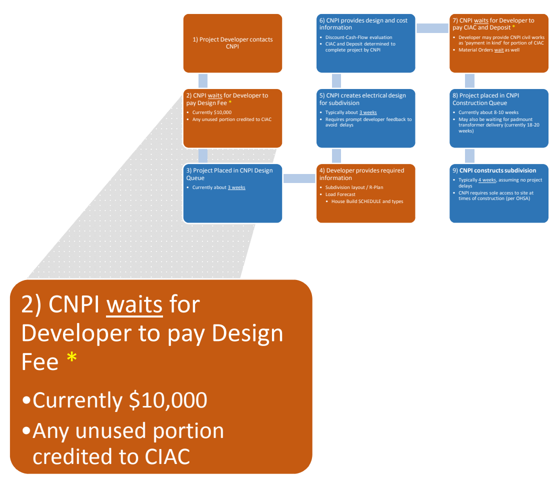
Step 1: Developer contacts CNPI

- Developer contacts CNPI and shares preliminary information:
  - Where is it?
  - How big is it?
  - When do they ***want*** it ready?
  - Contacts for consultants, builders, etc
- CNPI will take no significant action until design fee is paid!



Step 2: CNPI waits for Developer Commitment

- CNPI waits for Developer <u>commitment</u> to proceed.
  - Design Fee: currently $10k unless job is very large or has special challenges
  - Any unused amounts are applied to construction costs or refunded if project does not proceed
- Developer may want to prepay a transformer deposit
  - CNPI will then order subdivision's distribution transformers
  - Recent delivery lead times are 18-20 weeks, on average
- CNPI will take no significant action until design fee is paid!

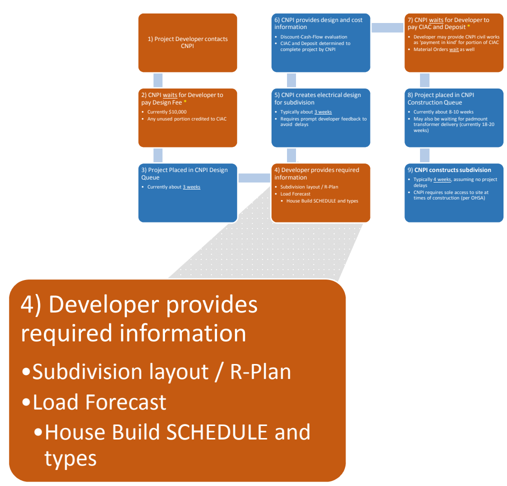


Step 3: CNPI puts project in Design Queue

- Once committed, the project is scheduled by CNPI for detailed design
- Assigned to next available Planner
  - Wait time for design to start can depend on volume of other projects that are already committed
  - Typical waiting period is 3 weeks

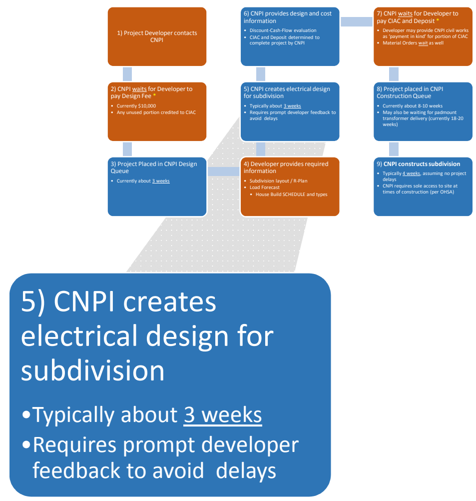
Step 4: Developer provides detailed project information

- Developer must provide project information to CNPI
  - This can (and should) be done during Design Queue waiting period
- Information includes:
  - R-Plan
  - Housing Types and Quantities
  - 5-year Load Forecast
  - Layout details:
    - street lighting



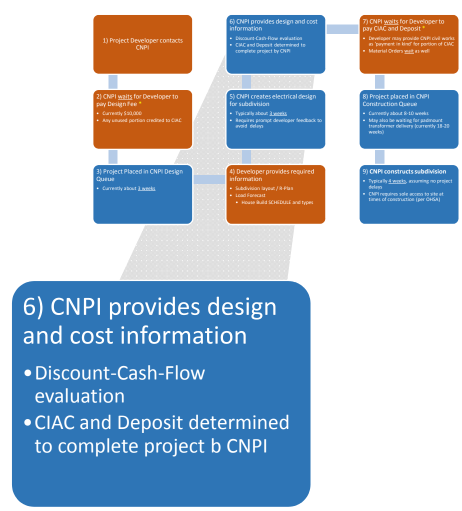
Step 5: CNPI creates electrical design

- CNPI creates electrical design
- This often involves discussion with developer
  - Prompt feedback ensures no unnecessary delays
- Typical design requires <u>3 weeks </u>to complete
- More complicated designs may require more time
  - E.g.: Location of proposed subdivision requires expansion of CNPI system



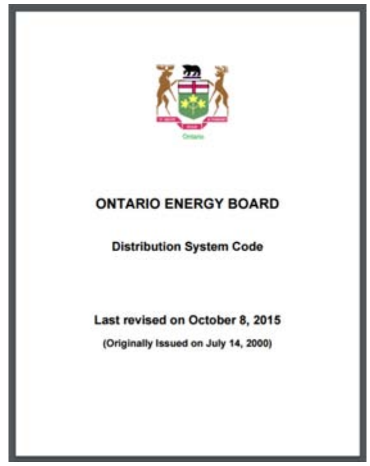
Step 6: CNPI provides design and cost information

- CNPI submits design to developer
- CNPI also provides cost information:
  - Contribution In Aid of Construction (CIAC)
    - 'up-front' Payment to CNPI
    - Represents the total project cost of CNPI *<u>less a credit</u>* for future net revenues
      - Credit based on Net-Present-Value of Discount Cash Flow evaluation
  - Surety (guarantee) for the CNPI future revenue credit:
    - "What if promised load doesn't appear?"
    - Usually in the form of a Letter-of-Credit
    - Held for 5 years, but reviewed annually.



Discount-Cash-Flow? Net-Present-Value? CIAC? What does all THAT mean !?

- CNPI follows process defined in our main Regulatory document:
  - OEB Distribution System Code
- Goal:
  - Over the Planning Horizon (e.g. 25 years), all of the 'legacy' Ratepayers of CNPI are to be 'held whole'
  - CNPI calculates the Contribution In Aid of Construction (CIAC) that it must collect from each new project that results in exactly ZERO net revenue to CNPI
  - CIAC CAN be zero if a project provides enough revenue !


ONTARIO ENERGY BOARD

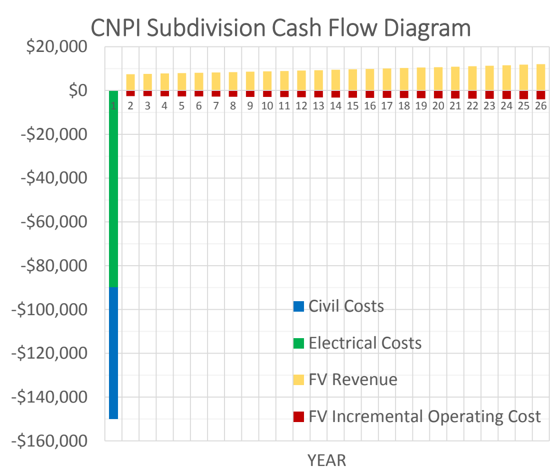
Distribution System Code

Last revised on October 8, 2015

(Originally Issued on July 14, 2000)

Discount-Cash-Flow? Net-Present-Value? CIAC? What does all THAT mean !? ...continued

- CNPI uses estimates for:
  - Cost of Civil Works
    - trenching, conduit, transformer pads, etc
  - Cost of Electrical Works
    - poles, primary cables, distribution transformers, labor and expenses, etc
  - Future Operating Costs
    - Every new addition to CNPI system must be Operated and Maintained
  - Future Revenues to CNPI
    - Based on Developer's Forecast!
    - Every new load provides ongoing revenue to CNPI



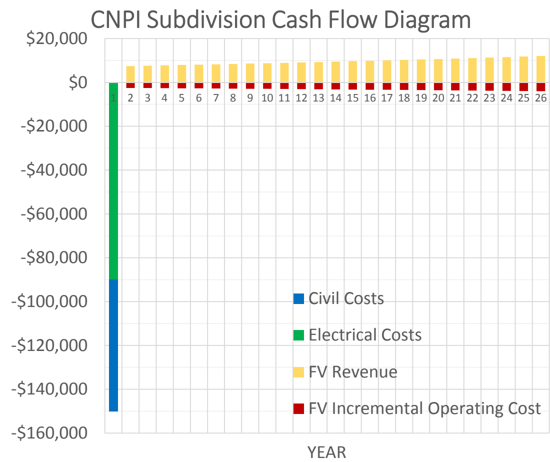
Example Calculation (Simplified):

- Up-front Costs to CNPI:
  - Civil Costs: $60,000
  - Electrical Costs: $90,000

- Ongoing:

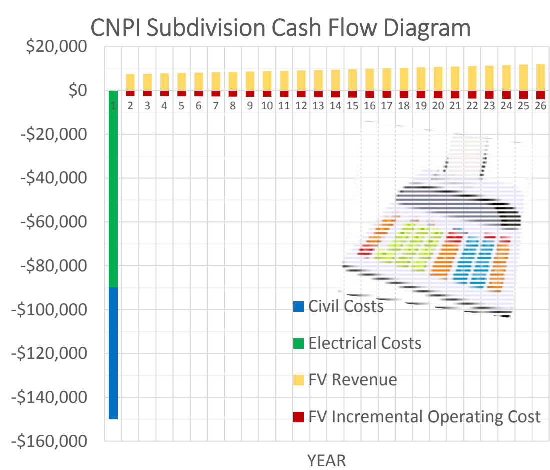
  (amounts shown for year 2, increasing over time, due to inflation)
  - Annual Sales Revenue: $7,500
  - Annual new O&M Cost: $2,500

  - Net Revenue: $5,000



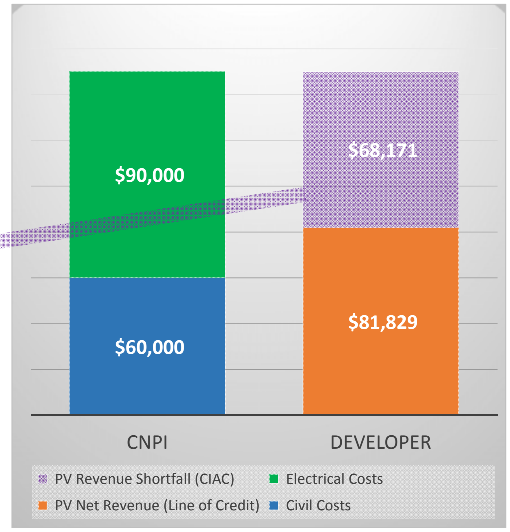
Example NPV Calculation (Simplified)

- Each FUTURE cash flow is converted to equivalent Present-Value cash flow, and then added up:
  - Result is Net-Present-Value equivalent of all cash flows
  - Calculations include allowances for:
    - Inflation and expected Rate Increases
    - Cost of interest on investments
    - Depreciation
    - CCA and Income Tax



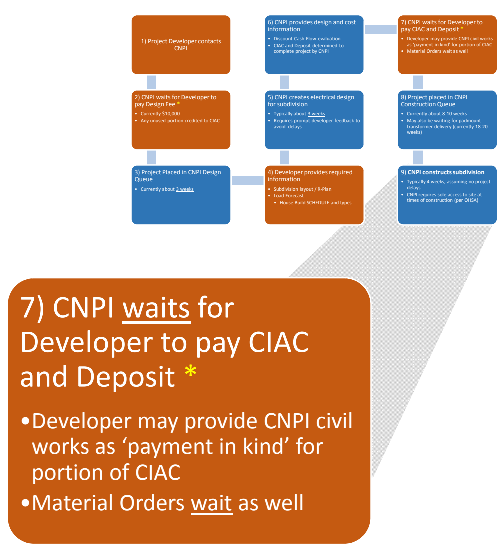
Example NPV Calculation (Simplified)

- Results:
  - Initial Construction Cost:
    - **$150,000**
    - The $60,000 Civil portion is often provided by Developer ➔ CNPI pays for it!
  - Net-Present-Value (NPV) of Future Net Revenues:
    - **$81,829**
    - Includes O&M costs as well as electricity sales by CNPI
  - Shortfall in NPV:
    - **$68,171**
    - THIS is the **CIAC** needed by CNPI in order to 'break even' on the project over 25 years
  - CNPI also needs a guarantee for the forecasted future revenues
    - What if the homes never get built? Or built smaller than promised? Or later?
    - Letter Of Credit provides guarantee for first 5 years (per the DSC)



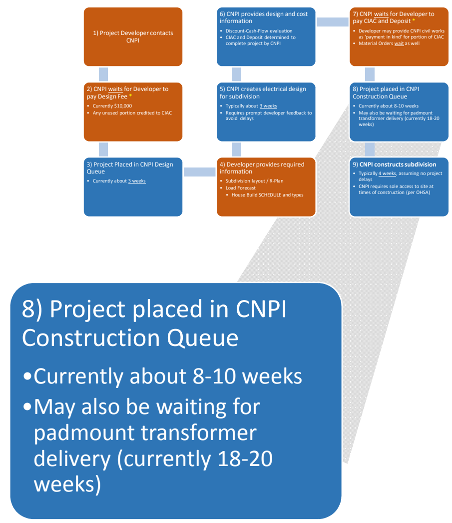
Step 7: CNPI waits for Developer to pay CIAC and Deposit

- CNPI plans out its construction schedule many weeks in advance.
  - CNPI will **NOT** reserve a spot in this schedule (or order materials) UNLESS the project is committed via payment!
  - **Typically, this construction 'queue' is 8 to 10 weeks.**
  - Delay for delivery of distribution transformers is usually 18-20 weeks
  - CNPI may also require commitment from Developer for Easements
- **Every day of delay** in committing any project will likely result in a **day of delay for energization**!
  - Also run the risk of getting 'behind' one or more other large projects



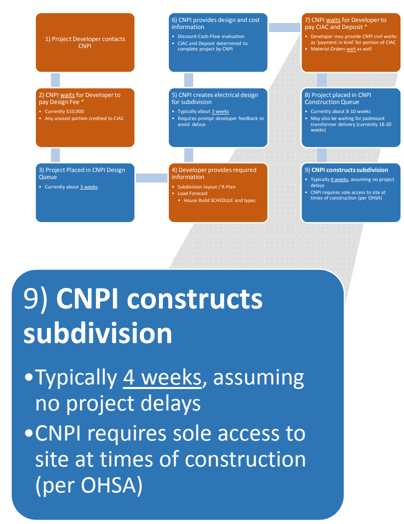
Step 8: Project placed in Construction Queue

- Once all issues are settled and payments made, project goes into CNPI 'Construction Queue'
- Typically <u>8-10 weeks</u>
  - Can be longer if volume of committed projects grows
  - If distribution transformers were NOT pre-ordered earlier in project process, then this delay will generally be <u>18-20 weeks</u> !



Step 9: CNPI constructs subdivision works

- Usually takes 4 weeks, after end of Construction Queue period
- If site is NOT ready for CNPI on day of construction start:
  - **CNPI will NOT make others wait because YOU were not ready!**
  - CNPI will reschedule to next window of opportunity
    - You will pay CNPI for any incremental costs!
- During CNPI work, OHSA must be followed:
  - Separation of time and/or space between 'constructors'



CNPI - SUBDIVISION Construction Timeline (Revised on 2015-11-26)

1) Project Developer contacts CNPI

2) CNPI waits for Developer to pay Design Fee *
- Currently $10,000
- Any unused portion credited to CIAC

3) Project Placed in CNPI Design Queue
- Currently about 3 weeks

4) Developer provides required information
- Subdivision layout / R-Plan
- Load Forecast
  - House Build SCHEDULE and types

5) CNPI creates electrical design for subdivision
- Typically about 3 weeks
- Requires prompt developer feedback to avoid delays

6) CNPI provides design and cost information
- Discount-Cash-Flow evaluation
- CIAC and Deposit determined to complete project by CNPI

7) CNPI waits for Developer to pay CIAC and Deposit *
- Developer may provide CNPI civil works as 'payment in kind' for portion of CIAC
- Material Orders wait as well

8) Project placed in CNPI Construction Queue
- Currently about 8-10 weeks
- May also be waiting for padmount transformer delivery (currently 18-20 weeks)

9) **CNPI constructs subdivision**
- Typically 4 weeks, assuming no project delays
- CNPI requires sole access to site at times of construction (per OHSA)

* Developer can prepay for padmount transformers to reduce transformer delivery delays

TOTAL Project Time = 30 weeks + any Developer delays.
Can be reduced to 22-24 weeks if transformers are prepaid.

CNPI – PRIMARY SERVICE Construction Timeline (Revised on 2015-11-26)

1) Project Developer contacts CNPI

2) CNPI waits for Developer to pay Design Fee
- Currently $5,000
- Any unused portion credited to CIAC

3) Project Placed in CNPI Design Queue
- Currently about 3 weeks

4) Customer provides required information
- Site Plan
- New/Upgraded Service Needs
- Load Forecast
- Desired In-Service Date

5) CNPI creates electrical Design for Primary Service
- Typically about 2 weeks
  - *More time if CNPI needs system upgrades*
- Requires prompt developer feedback

6) CNPI provides Design and Cost Information
- Discount-Cash-Flow evaluation
- CIAC and Deposit determined to complete project by CNPI
- CNPI Max Size transformer is 1000kVA

7) CNPI waits for Developer to pay CIAC and Deposit
- Material Orders wait as well

8) Project placed in CNPI Construction Queue
- Currently about 8-10 weeks

9) **CNPI constructs subdivision**
- Typically 4 weeks, assuming no project delays
- CNPI requires sole access to site at times of construction (per OHSA)

TOTAL Project Time = 26 weeks + any Developer delays.

CANADIAN NIAGARA POWER INC.

A FORTIS ONTARIO Company

CONTRACTOR INFORMATION SESSION

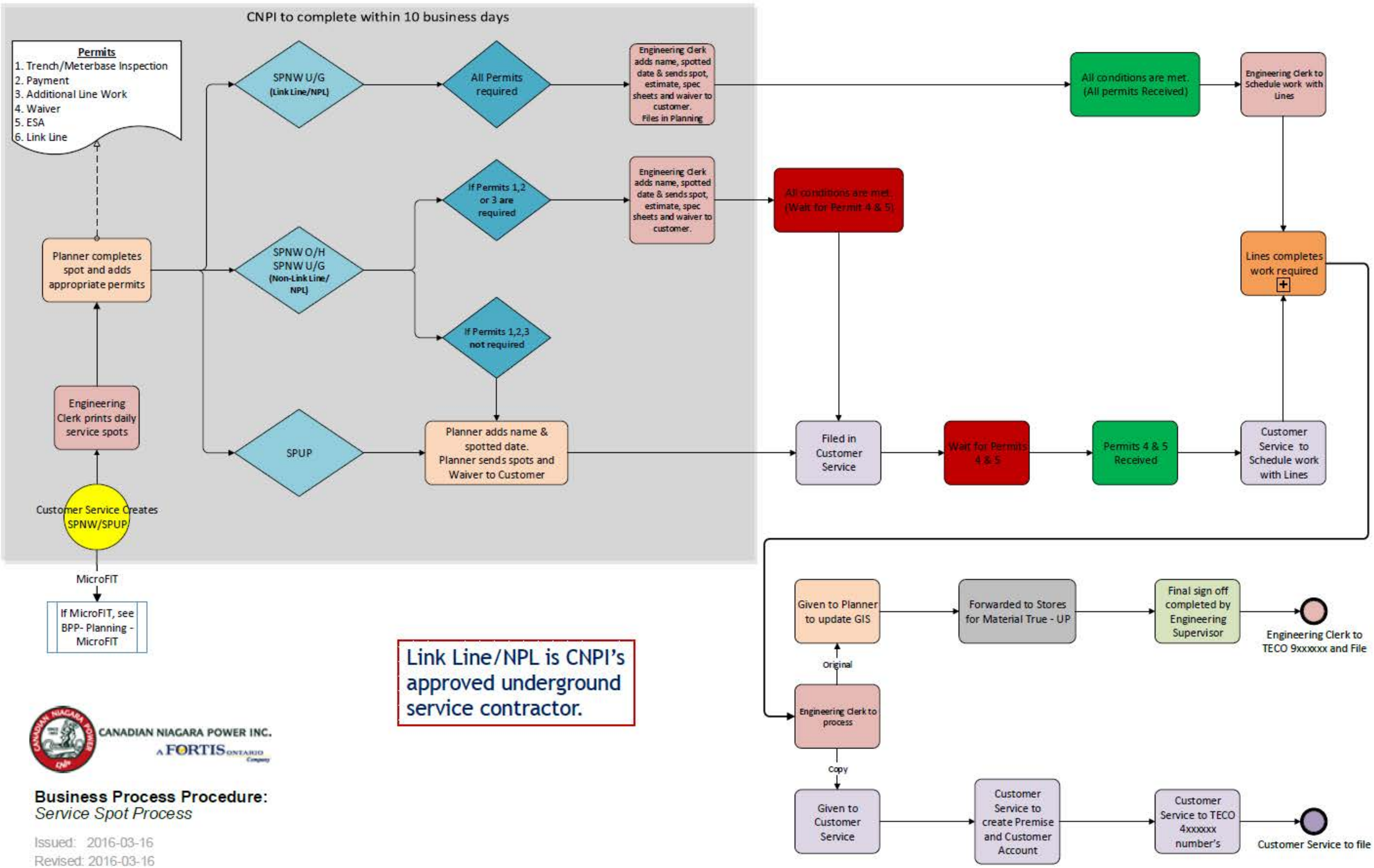
Wednesday, March 16th, 2016

Welcome and Introduction

Information presented by:

- Jeff Hoover – Planning Supervisor
- Pat Futino – Operations Supervisor
- Courtney Bonito – Customer Service Supervisor

Process for CNPI Service Spots



Link Line/NPL is CNPI's approved underground service contractor.

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Business Process Procedure:
Service Spot Process

Issued: 2016-03-16
Revised: 2016-03-16

Review Service Spot Package
(Sent out to Electricians/Builders)

- Sample Service Spot

- Underground Service Spot
  - Electrician (Spot/Spec Sheets/Waiver)
  - Builder (Spot/Invoice/Contractor Sheet/Waiver)
  - If Link Line (Spot/Contractor Acknowledgment)

- Overhead Service Spot
  - Electrician and or Builder (Spot/Waiver)

Inspections Underground Services

- Inspection Check List
- **With out** Link Line
  - Appointment must be made for Meter Base and Trench inspections
- **With** Link Line
  - Appointments must be made for Meter Base inspection.
  - Please notify CNPI as soon as meter base has been installed.

Overhead / Underground residential Service Truck Scheduling

- Calendar Bookings
  - Fort Erie - Tuesday, Wednesday, and Friday (ESA Inspection Day Wednesday).
  - Port Colborne - Monday and Thursday (ESA Inspection Day Thursday).
  - Maximum 4 scheduled appointments per day.
  - We will not schedule an appointment until all requirements are met.
  - Bookings are subject to change, due to circumstances beyond our control. (ESA, Weather)

Waivers Electrical

- Electrical Waiver

CANADIAN NIAGARA POWER INC.

A FORTIS ONTARIO Company

FAX: 905.871.8772

EMAIL: customer.service@cnpower.com

Technical Connection Waiver

This form must be completed and returned to Canadian Niagara Power Inc. "CNPI" prior to scheduling any work with CNPI. CNPI assumes no responsibility for incomplete work if all conditions of job (Including waiver, ESA & Payment) are not met.

ESA Approval to Connect

- To ensure ESA is booked CNPI requires the ESA notification number prior to scheduling.
- **Non ACP Electrical Contractors** – Please ensure that your booking for ESA is scheduled for the same day as scheduled work.
- **ACP (Authorized Contractor Program)** – ESA Inspection Notification must be received in our office one day prior to the scheduled work.
- Day of ESA approval does not apply to new services. ESA approval must be received prior to connecting the new service.

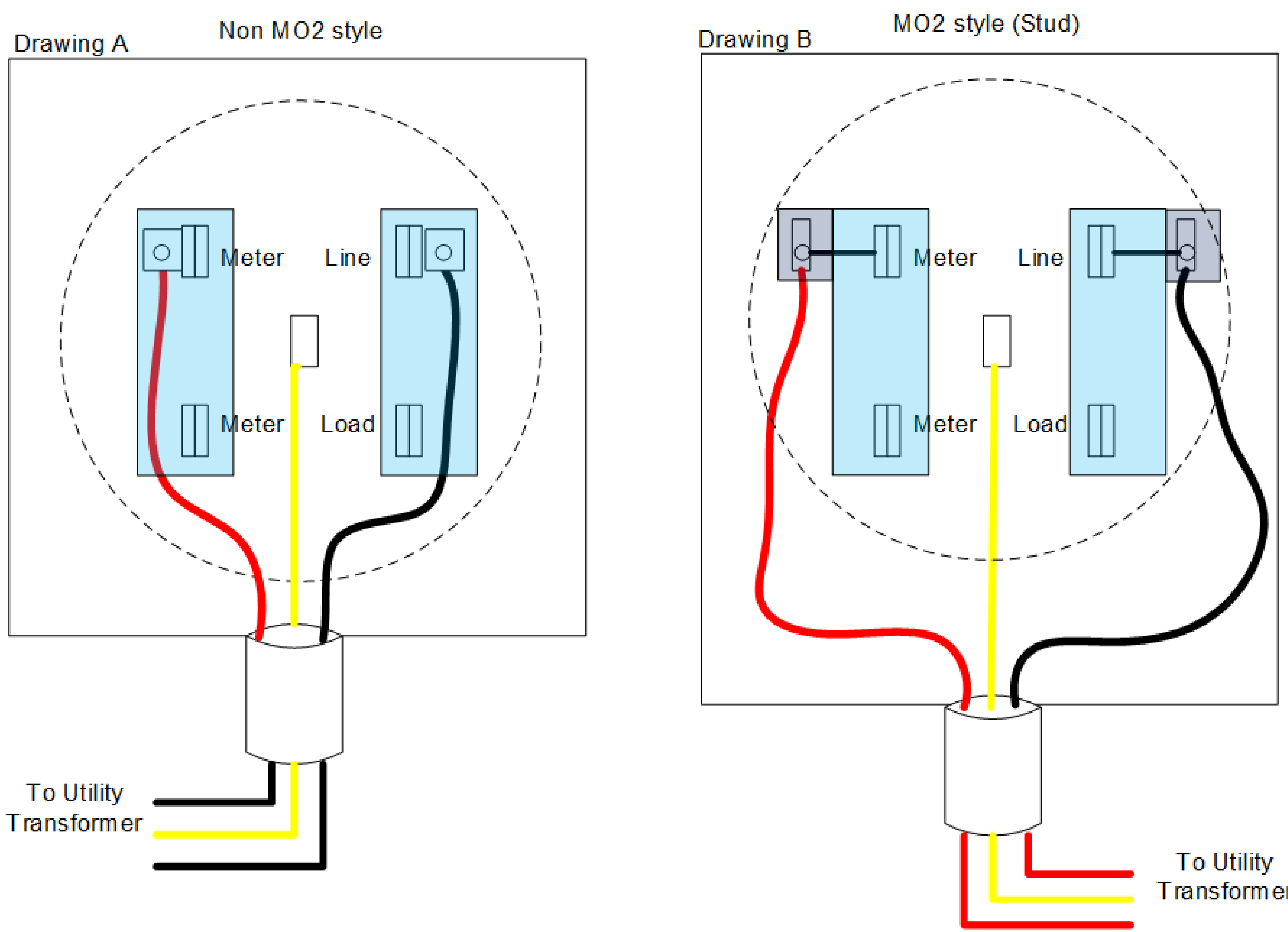
CNPI Service Special Considerations

- If any additional line work is required ($), 6-8 weeks are required for line scheduling.
- If rock is encountered additional time is required.
- Permits:
  - Trench/Meter base inspection
  - Payment
  - Additional Line work
  - Waiver
  - ESA
  - Link Line

  Do you feel that a permit check list is beneficial to a Service Spot Package?
- OEB regulations state once all CNPI conditions are met CNPI has 5 business days to connect. This is reported to OEB on a monthly basis.
- Link Line Coordination of subdivision services from CNPI secondary pedestal. CNPI and Link Line will coordinate one visit to install service and energize.
- Loading sheets are required for services forecasted to have a demand over or near 50kW.

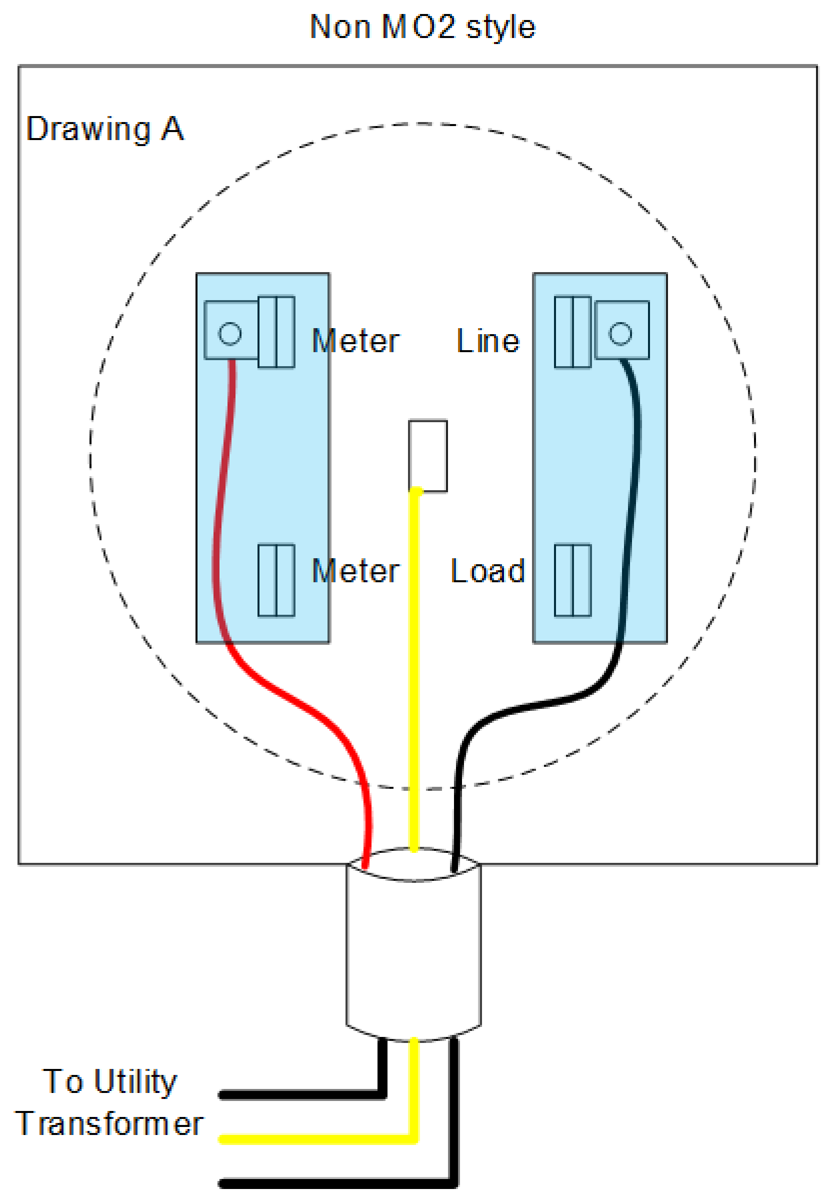
  2015_Load Summary for New Service form

MO2 Meter Bases use for Underground services



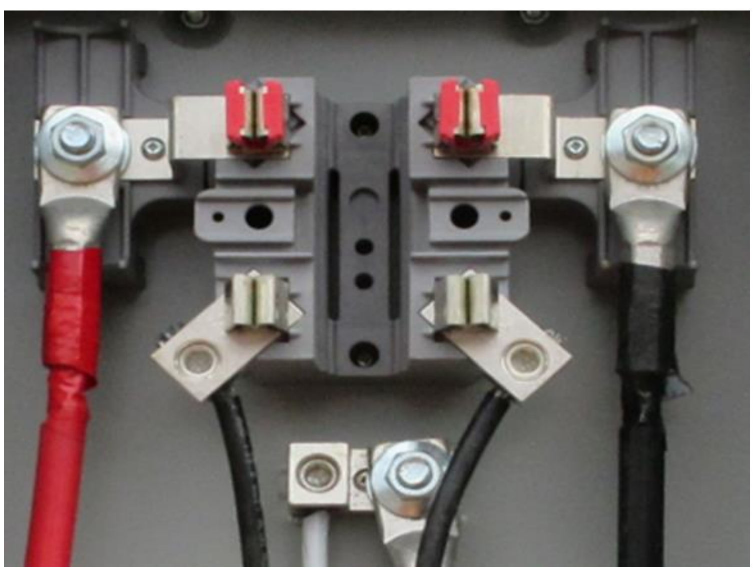
MO2 Meter Bases use for Underground services

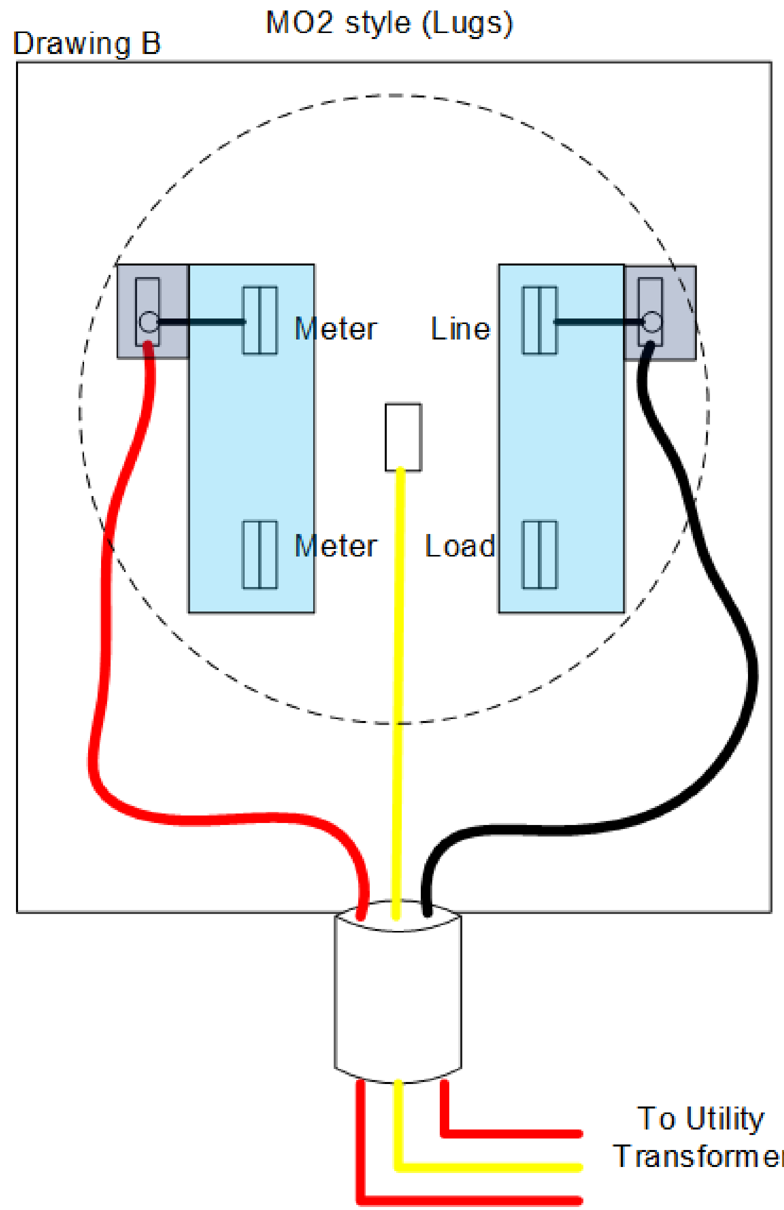
- As per Drawing A (Non MO2 stud style or equivalent) any downward force on the underground cable causes direct tension on the lug which tends to crack the polymer/ceramic base. These in turn can have the meter jaw connected freely to the meter. Once the meter is pulled the lose jaw can make contact with the meter base causing a flash.



MO2 Meter Bases use for Underground services

- As per Drawing B (MO2 stud style or equivalent) any downward force on the underground cable does not causes direct tension on the lug which tends to crack the polymer/ceramic base. The downward force is on a separate polymer/ceramic base reliving direct strain from the meter lugs.





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Questions?

CANADIAN NIAGARA POWER INC.

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thank you!

CANADIAN NIAGARA POWER INC.
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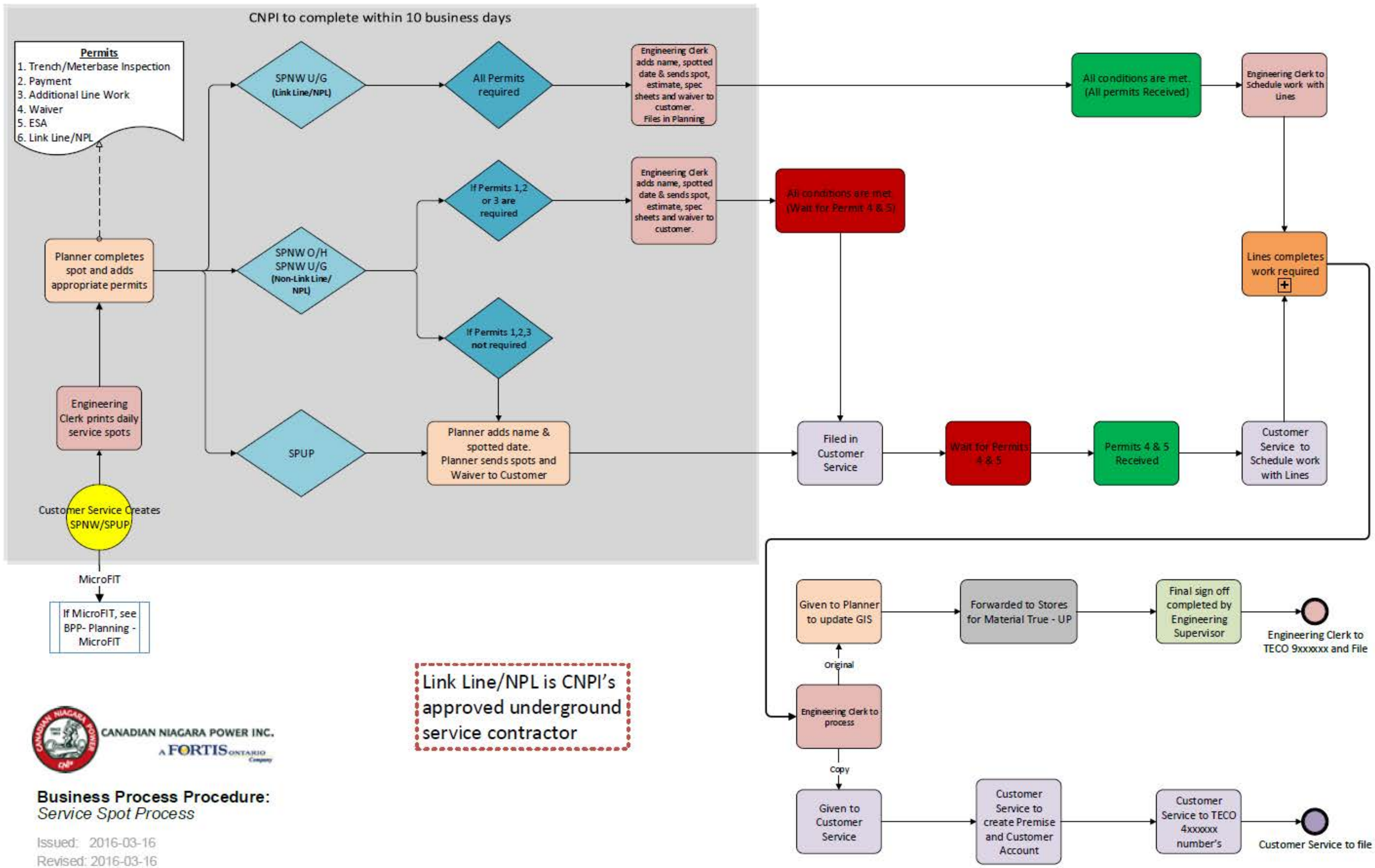

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  - If Link Line/NPL (Spot/Contractor Acknowledgment)

- Overhead Service Spot
  - Electrician and or Builder (Spot/Waiver)

2016.02.04 **Printed by: HECKMANP Original Page 1**

Service Spot-New **Order: 4652716**

9014282

Order type	SPNW	
Description	Service Spot New-[redacted]	
Start date	2016.02.03	*End date*
Priority		
Entered by	LAMBERTA	
Status	REL NMAT PRC PLNG 2000	

COPY

Service Spot New-[redacted]
LOCATION PREFERRED: SPOT ALL POSSIBLES
ADDRESS/PLOT-PLAN: [redacted]
AMPS/VOLTS: 200
SINGLE/3-PHASE: SINGLE
OH/UG: U/G
ELECTRICIAN [redacted]
PHONE: 90[redacted] FAX : 905-[redacted]
EMAIL:
OTHER/COMMENTS
ESA RECEIVED YES___ DAY OF____ NOTIFICATION#__________
WAIVER RECEIVED YES___
DISC/REC___ DISC ONLY____ CONNECT ONLY_____
VERIFIED BY:_____

SCANNED

2016-02-08

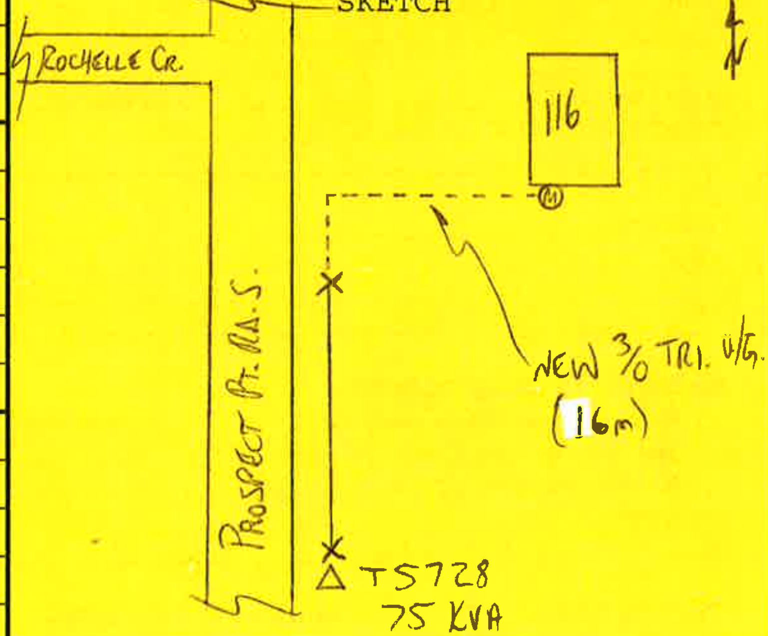
Partner 1071911 SP
Address RIDGEWAY ESTATES
RIDGEWOOD CRES
L2J 3H1

☒ **Joint Trenching Required**

Notification to Gas Comp Name: ____________________
CNP Rep. Name: ____________________ Date: ____________

NAME	RIDGEWAY ESTATES
ADDRESS	116 PROSPECT PT. RD. S.
ELECTRICIAN	[redacted]
REQUEST	NEW U/G SERVICE
AMPS MAIN SWITCH 200 A	VOLTAGE 120/240V	PHASE 1∅
2 (3) 4 WIRE	SERVICE WIRE SIZE 3/0 TRI. U/G
METER CABINET SIZE IF REQUIRED	M02 SERIES OR EQUIV.
REMARKS	- METER BASE 5'6" ABOVE GRADE - METER BASE, DUCTS, TRENCH AS PER CNP SPECS + INSPECTION.
☒ U/G CREW	☐ O/H CREW
REPORT e MAILED TO ☒	GIVEN TO ☐

SKETCH



CNP REPRESENTATIVE	K. WATSON
DATE SERVICE LOCATION	2016-02-05

179 2016.02.09. Ridgeway

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

1130 Bertie Street, P.O. Box 1218
Fort Erie, Ontario, Canada L2A 5Y2
Phone: (905) 871-0330 Fax: (905) 871-8818

Sold-to address:

Estimate

Estimate Number/Date
20007268 / 02/05/2016
Purchase Order Number/Date
FE9014282
Delivery date
Day02/05/2016
Customer No.
1909
Validity Period
02/05/2016 until 05/05/2016

We deliver according to the following terms and conditions:

Currency CAD

The 'Final amount' must be paid as a downpayment before we can proceed with this work. This document, or a copy thereof, must accompany your payment. Upon completion of the work, you will be billed any extra costs or refunded any overpayment.

Material	Qty	Description	Price	Price unit	Value
12061		FO - CAPITAL CONTRIBUTION			
	Estimate				2,150.08
	Discount on Estimate				430.00-

NEW 200 AMP U/G SERVICE
METER BASE 5'6" ABOVE GRADE.
TRENCH, DUCTS, & METER BASE AS PER CNPI SPECS AND INSPECTION.
ESA INSPECTION REQ'D.
$500 JOINT TRENCH FEE INCLUDED.

Items total				1,720.08
HST	13.000 %		1,720.08	223.61
Final amount				1,943.69

COPY

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

SAP Number

Location

* To book a trench and/or meter base inspection call the office at 905-871-0330 ext: 3236.
CNPI requires a minimum 48 hours notice for these inspections.

*Entire trench must be open for inspection if the service is customer installed.

*CNPI meter base requirement is "MO2 Series" or equivalent.

*Half yard of sand must be located within a meter of the **frost loop**, CNPI will backfill this area before energizing the service.

**Meter base inspection must be scheduled prior to Link Line installing the underground service.

*If using CNPI Contractor Link Line, entire trench line must be free and clear of all obstructions.

***If customer installed, both trench & meter base must be ready for inspection when booking an appointment.

Acknowledged by:

_______________________ _______________________

print name *dated*

____

Signature

****PLEASE SIGN AND RETURN THIS FORM to patty.heckman@cnpower.com****

CANADIAN NIAGARA POWER INC.

A FORTIS ONTARIO Company

FAX: 905.871.8772

EMAIL: customer.service@cnpower.com

Technical Connection Waiver

This form must be completed and returned to Canadian Niagara Power Inc. "CNPI" prior to scheduling any work with CNPI. CNPI assumes no responsibility for incomplete work if all conditions of job (Including waiver, ESA & Payment) are not met.

Service Address: ______________________________

This is to confirm that I, ___________________________ give permission to CNPI to connect the electrical service at the above address without my presence. I confirm that I have the authority to grant this request.

Name (Please Print):______________________________

Phone Number: __________________________________

Email Address: __________________________________

ESA Permit Number: ______________________________

Date:____

Authorized Signature: ____________________________

If a connection is not requested by 2:00 p.m. on the same day as disconnection applicable after hour charges may apply, otherwise connection will occur on the next available business day.

ACP (Authorized Contractor Program) Contractors: ESA Inspection Notification must be received in our office one day prior to the scheduled work. **Non ACP Electrical Contractors**: Please ensure that your booking for ESA is scheduled for same day of scheduled work.

****It is the responsibility of the person signing this wavier to call CNPI to schedule the Disconnection and/or Connection****

1130 BERTIE STREET • P. O. BOX 1218 • FORT ERIE, ON L2A 5Y2

TEL: 905-871-0330/905-835-0051 • FAX: 905-871-8772 • www.cnpower.com

COPY

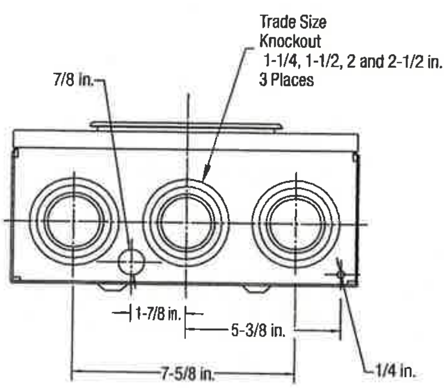
MO2 Series

200 A 600 V; Underground Only

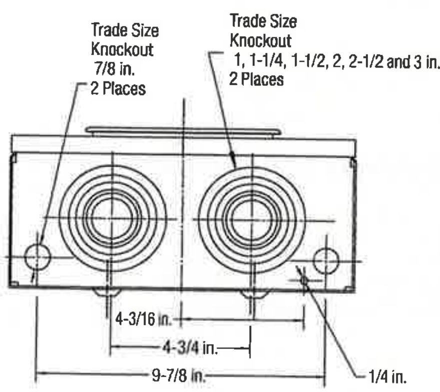
Product Specifications

- Conductor Range: Line: Single 1/2 in. studs to accommodate compression lugs 350 kcmil max. (supplied by utility), Load: 6 AWG-250 kcmil
- For underground service only
- Aluminum tunnel type connectors for load side, 1/2 in. studs on line side
- Supplied with screw type ring
- Weatherproof Type 3R enclosure
- Primarily used in: Sask., Man., Ont., Que.

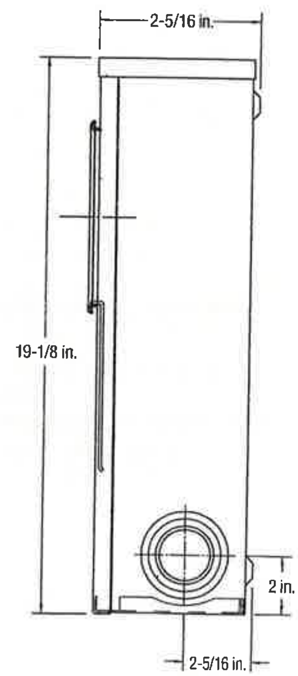
(M02-V)



M02-VO BOTTOM

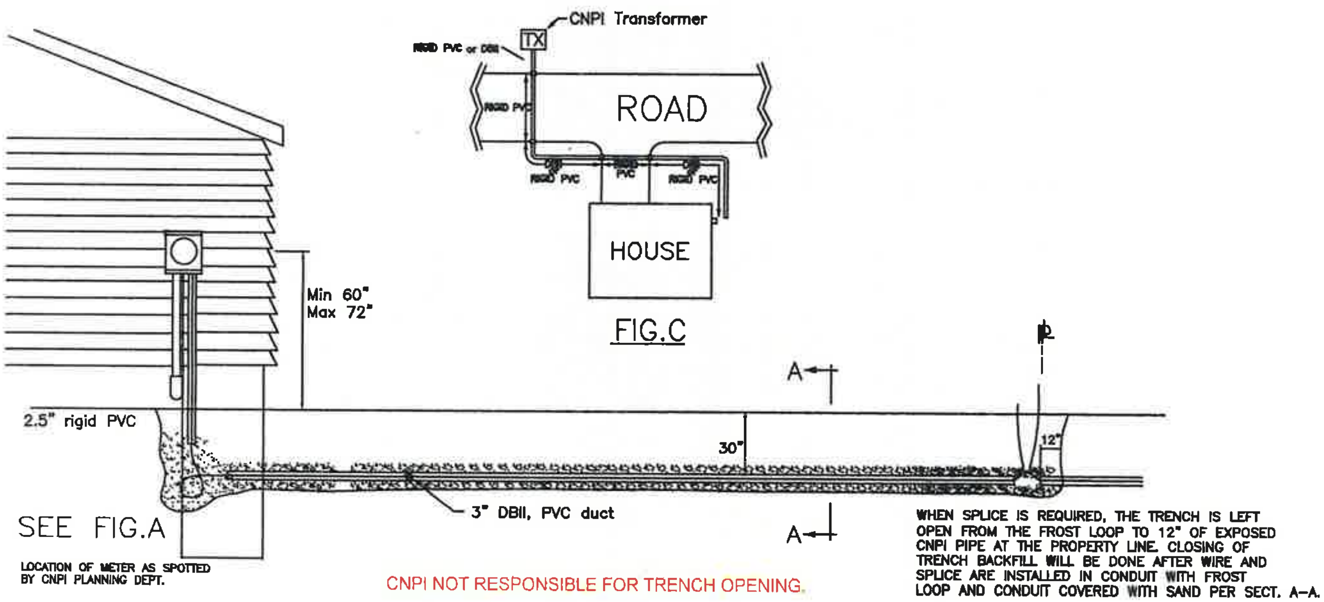


M02-V BOTTOM



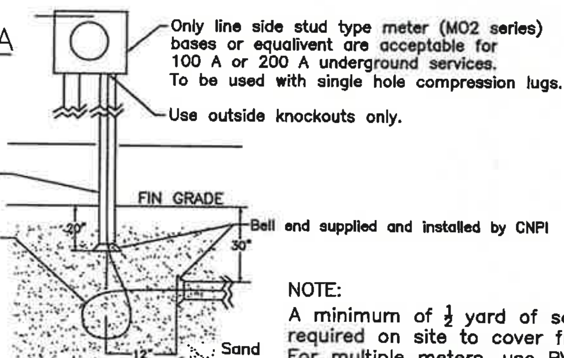
Approved for copper or aluminum

Cat. No.	Description	Dimensions (in.) H	W	D	Weight Each lb.	kg
4 JAW						
M02-V	Underground 1/2 in. studs					
M02-VO	Underground 1/2 in. studs for Ontario	19-1/8	12	5-9/16	18	8.1
M02MB-V	Underground 4/0 for Manitoba					
FACTORY-INSTALLED ACCESSORIES						
Include: -W	Water heater lugs					
-M	2/0 AWG subfeed on load side					

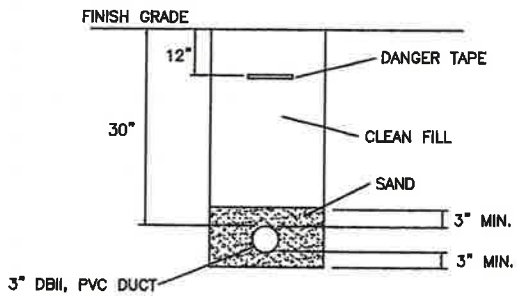


Please call 905–871–0330, ext. 3236, to set up your trench inspection. CNPI requires a minimum of 48 hours notice.

FIG. A



NOTE:
A minimum of ½ yard of sand is required on site to cover frost loop.
For multiple meters, use BV series 2/3/4 bases or equivalent



SECT. A–A

NOTES (General)

1. CNPI will own and maintain U/G service only if the design & construction is approved by CNPI.
2. Use 3" PVC (rigid conduit) under all road and driveway crossings. (See FIG.C)
3. CNPI will supply, and install cable at the customer's expense.
4. Meter to be located as per CNPI service spot sheet.
5. CNPI to do connections at line side of meter base, at pole, and in the trench.
6. CNPI to supply U/G danger tape (which customer will install at the time of backfilling to a depth of 12" below grade).

NOTES (Customer)

1. Customer is responsible for digging trench, installation of duct, fish rope (1/8" poly), and backfilling trench with rock free soil except for sand envelope per section A–A.
2. Duct, fittings, and fish rope are to be supplied by the customer.
3. No service will be connected without proper lot number and municipal address attached to the dwelling, ESA inspection approval and payment.
4. The trench and protection shall be inspected by CNPI prior to backfilling.
5. Inspection of the underground trench will be performed between the hours of 9:00a.m. – 2:00p.m. Monday to Friday.
6. Leave trench open from pole to meter base.

Please note the first inspection of the underground trench will be free of charge. If a customer calls for a CNPI crew to perform an underground service installation, but has not met all the above criteria, the crew will not install the service and the customer will be invoiced for a minimum call out. The minimum fee charged will be $170.00 plus applicable mark ups and taxes.

Please call 905-871-0330, ext. 3236, to set up your trench inspection. CNPI requires a minimum of 48 hours notice.

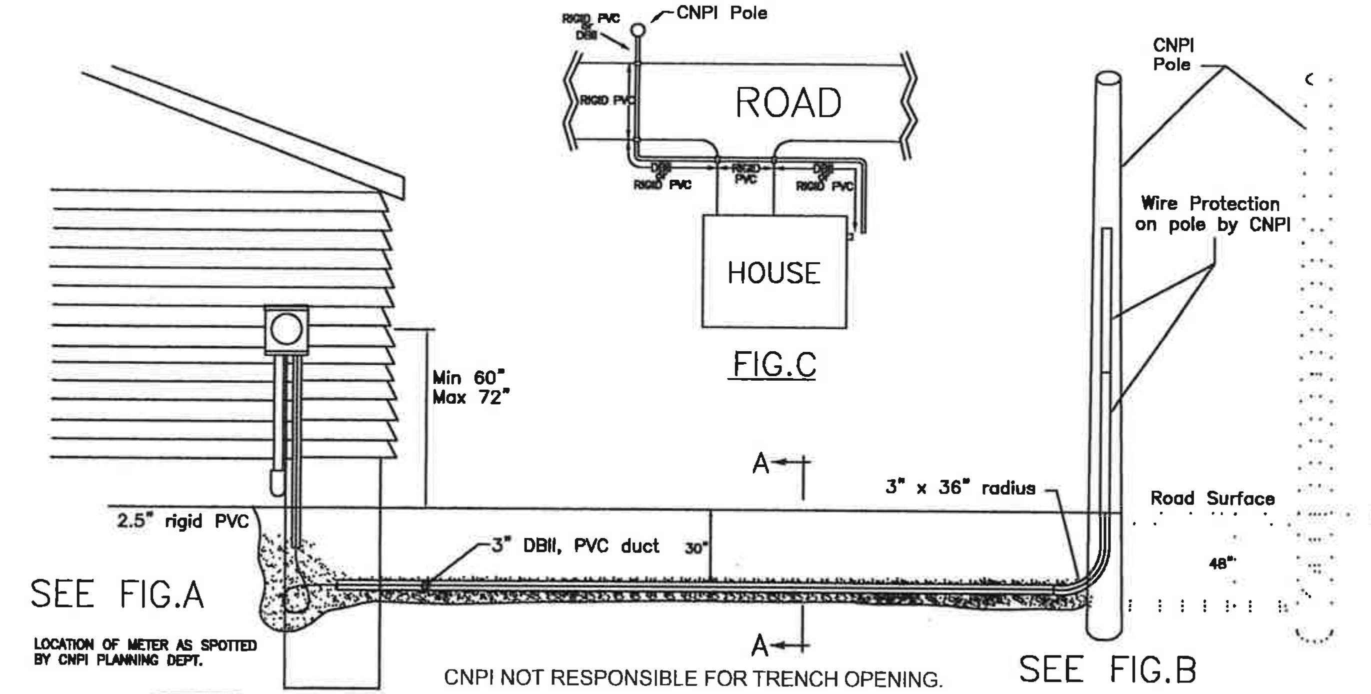
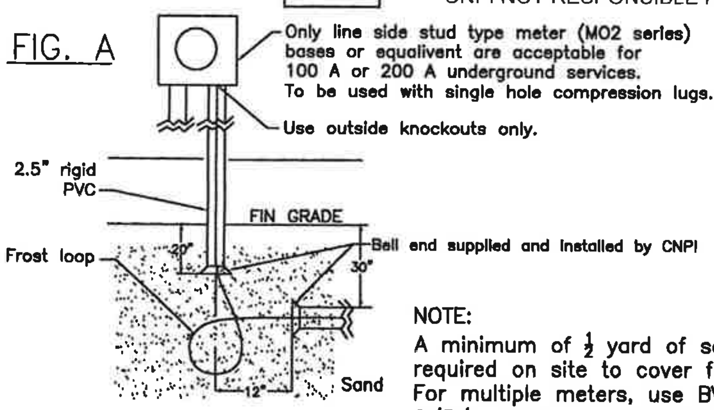
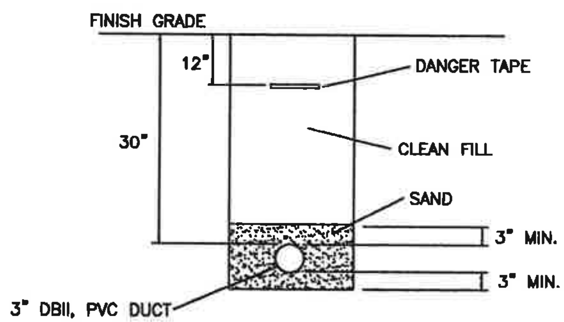


FIG. A



NOTE:
A minimum of ½ yard of sand is required on site to cover frost loop.
For multiple meters, use BV series 2/3/4 bases or equivalent



SECT. A–A

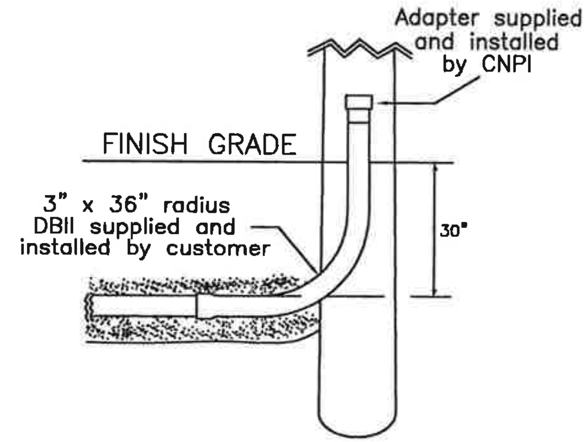


FIG.B

NOTES (General)

1. CNPI will own and maintain U/G service only if the design & construction is approved by CNPI.
2. Use 3" PVC (rigid conduit) under all road and driveway crossings. (See FIG.C)
3. CNPI will supply, and install cable at the customer's expense.
4. Meter to be located as per CNPI service spot sheet.
5. CNPI to do connections at line side of meter base, at pole, and in the trench.
6. CNPI to supply U/G danger tape (which customer will install at the time of backfilling to a depth of 12" below grade).

NOTES (Customer)

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2. Duct, fittings, and fish rope are to be supplied by the customer.
3. No service will be connected without proper lot number and municipal address attached to the dwelling, ESA inspection approval and payment.
4. The trench and protection shall be inspected by CNPI prior to backfilling.
5. Inspection of the underground trench will be performed between the hours of 9:00a.m. – 2:00p.m. Monday to Friday.
6. Leave trench open from pole to meter base.

Please note the first inspection of the underground trench will be free of charge. If a customer calls for a CNPI crew to perform an underground service installation, but has not met all the above criteria, the crew will not install the service and the customer will be invoiced for a minimum call out. The minimum fee charged will be $170.00 plus applicable mark ups and taxes.

Inspections Underground Services

- [Inspection Check List]
- **With out** Link Line/NPL
  - Appointment must be made for Meter Base and Trench inspections
- **With** Link Line/NPL
  - Appointments must be made for Meter Base inspection.
  - Please notify CNPI as soon as meter base has been installed.

CNPI TRENCH & METER BASE INSPECTION

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

DATE: ______________________ **SAP NUMBER:** ______________________

LOCATION: ______________________

CONTRACTOR: ______________________

WIRE INSTALLED BY LINK LINE **YES / NO** **DATE INSTALLED** ____________

COMPLETE	INCOMPLETE	
☐	☐	TRENCH OPEN
☐	☐	TRENCH SAND
☐	☐	FROST LOOP PIT (1m OPENING)
☐	☐	LONG RADIUS ELBOWS (36" SWEEP)
☐	☐	2.5" PIPE LINE SIDE OF METER BASE
☐	☐	DIRECTIONAL BORE (BOTH ENDS EXPOSED)
☐	☐	CAUTION TAPE ON SITE

COMPLETE	INCOMPLETE	
☐	☐	FISH ROPE
☐	☐	M02 SERIES METER BASE
☐	☐	DEPTH TRENCH 30" MIN.
☐	☐	METER IN CORRECT LOCATION

NUMBER OF 90 DEG ELBOWS ________

PICTURES ☐

☐ **PASS** ☐ **FAIL**

INSPECTORS NOTES:

CUSTOMER TO RESCHEDULE INSPECTION IF TRENCH OR METER BASE FAILS
*****A FEE OF $170.00 WILL APPLY IF EXTRA INSPECTIONS ARE REQUIRED*****

CUSTOMER: ______________________ **DATE:** ______________________

CNPI INSPECTOR: ______________________ **DATE:** ______________________

White • Customer Copy | BLUE • CNPI Copy

Overhead / Underground residential Service Truck Scheduling

- Calendar Bookings
  - Fort Erie - Tuesday, Wednesday, and Friday (ESA Inspection Day Wednesday).
  - Port Colborne - Monday and Thursday (ESA Inspection Day Thursday).
  - Maximum 4 scheduled appointments per day.
  - We will not schedule an appointment until all requirements are met.
  - Bookings are subject to change, due to circumstances beyond our control. (ESA, Weather)

Waivers Electrical

- Electrical Waiver

CANADIAN NIAGARA POWER INC.

A FORTIS ONTARIO Company

FAX: 905.871.8772

EMAIL: customer.service@cnpower.com

Technical Connection Waiver

This form must be completed and returned to Canadian Niagara Power Inc. "CNPI" prior to scheduling any work with CNPI. CNPI assumes no responsibility for incomplete work if all conditions of job (Including waiver, ESA & Payment) are not met.

CANADIAN NIAGARA POWER INC.

A FORTIS ONTARIO Company

FAX: 905.871.8772

EMAIL: customer.service@cnpower.com

Technical Connection Waiver

This form must be completed and returned to Canadian Niagara Power Inc. "CNPI" prior to scheduling any work with CNPI. CNPI assumes no responsibility for incomplete work if all conditions of job (Including waiver, ESA & Payment) are not met.

Service Address: ______________________________

This is to confirm that I, __________________________ give permission to CNPI to connect the electrical service at the above address without my presence. I confirm that I have the authority to grant this request.

Name (Please Print):______________________________

Phone Number: ______________________________

Email Address: ______________________________

ESA Permit Number: ______________________________

Date:______________________________

Authorized Signature: ____________________________

If a connection is not requested by 2:00 p.m. on the same day as disconnection applicable after hour charges may apply, otherwise connection will occur on the next available business day.

ACP (Authorized Contractor Program) Contractors: ESA Inspection Notification must be received in our office one day prior to the scheduled work. **Non ACP Electrical Contractors**: Please ensure that your booking for ESA is scheduled for same day of scheduled work.

****It is the responsibility of the person signing this wavier to call CNPI to schedule the Disconnection and/or Connection****

COPY

ESA Approval to Connect

- To ensure ESA is booked CNPI requires the ESA notification number prior to scheduling.
- **ACP (Authorized Contractor Program)** – ESA Inspection Notification must be received in our office one day prior to the scheduled work.
- **Non ACP Electrical Contractors** – Please ensure that your booking for ESA is scheduled for the same day as scheduled work.
- Day of ESA approval does not apply to new services. ESA approval must be received prior to connecting the new service.

CNPI Service Special Considerations

- If any additional line work is required ($), 6-8 weeks are required for line scheduling.
- If rock is encountered additional time is required.
- Permits:
  - Trench/Meter base inspection
  - Payment
  - Additional Line work
  - Waiver
  - ESA
  - Link Line/NPL

  Do you feel that a permit check list is beneficial to a Service Spot Package?
- OEB regulations state once all CNPI conditions are met CNPI has 5 business days to connect. This is reported to OEB on a monthly basis.
- Link Line Coordination of subdivision services from CNPI secondary pedestal. CNPI and Link Line will coordinate one visit to install service and energize.
- Loading sheets are required for services forecasted to have a demand over or near 50kW.

  2015_Load Summary for New Service form

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

LOAD SUMMARY for NEW or UPGRADED SERVICES:

Submit to: ***CNP Engineering Dept.*** ***Fax***: *(905)871-4458* ***Telephone***: *(905)871-0330*
Address: *P.O. Box 1218, 1130 Bertie Street, Fort Eire, Ontario*

Note: *Each separate service from CNP requires the submission of a separate form.*

1. General Information:

(a) Street Address: ______________________________ Building Name: _________________________

(b) Building Use: Apts: ☐ Condominium: ☐ Office: ☐ Other: __________________________

(c) Total GROSS enclosed floor area: ________________ ft^2 -or- _________________ m^2

(d) Portion of "c" which is to be used for parking: ________________ ft^2 -or- _________________ m^2

(e) Portion of "c" which is to be air-conditioned: ________________ ft^2 -or- _________________ m^2

(f) For Apt. Bldgs: Number of Apts: _____________ No. of Apts: with AC units: _____________

(g) Recreation centre total connected loads: _____________ Area for common use: ________________

2. Load Details:

	Estimated Load (kW)	Hour, First Use	Hour, Last Use
(a) Total **lighting load** (public lighting only, if Apt. Bldg):			
(b) Estimated **receptacle load**:			
(c) Total connected **space heating**:			
(d) Total connected **hot water heating**:			
(e) Total connected **duct heaters, parking garage**:			
(f) Total connected **duct heaters, rest of building**:			
(g) Total connected **heating cable**:			
(h) Total HP of **Air Conditioning (AC) equipment**:			
(i) Total HP of **Ventilation motors**:			
(j) **Kitchen equipment** (Do NOT fill in for Apt. Bldgs):			
(k) Total HP of **boilers and heating pumps:**			
(l) Total HP of **motors for elevators:**			
(m) Total HP of **motors, process or manufacturing**:			
(n) Total HP of **all other miscellaneous motors:**			
(o) **Total Connected load** (Do not fill in for Apt. Bldgs):			
(p) Number of **parking spaces with electric outlets**:			
(q) Number and size of **electric dryers**:			
(r) Number and size of **electric ranges**:			
(s) **Other** loads not listed above: __________________			
(t) Total Apt or other multi-family Res. Demand, **Code**:			
(u) **Total Apt. Bldg. Demand:** (item "t" plus all other)			

3. Desired Service Voltage:

- ☐ Primary (3Ø, kV_{L-L})
- ☐ Primary (1Ø, kV_{L-G})
- ☐ 347 / 600 V (3Ø, 4-wire)
- ☐ 120 / 208 V (3Ø, 4-wire)
- ☐ 120 / 240 V (1Ø, 3-wire)

4. Size of Main Switch or Breaker (Amps):

- ☐ 200
- ☐ 400
- ☐ 600
- ☐ 800
- ☐ 1000
- ☐ other ______________

5. Date when permanent service is required:

____

6. Date when temporary service is required:

____

7. Peak load controller used: No: ☐ Yes:☐

If yes, load to be controlled:

____

____

8. Prepared by:

Business: ________________________________ Telephone: (____) ____________

Address: ____ Fax: (____) ____________

Form Revision Date: 2016/03/15

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

9. Project Contacts:

Owner / representative:_________________________________ Phone:___________________________

Electrical / Mechanical Consultant:_______________________ Phone:___________________________

General Contractor:____________________________________ Phone:___________________________

Architect:____ Phone:___________________________

Electrical Contractor:___________________________________ Phone:___________________________

10. Construction Schedule:

Start of Construction:____

Temporary Service Required by:______________________________________

Permanente Service Required by:____________________________________

11. Owner/Billing Customer:

Business/Name: ______________________________ Telephone: (____) ____________________

Address: ____________________________________ Fax: (____) __________________________

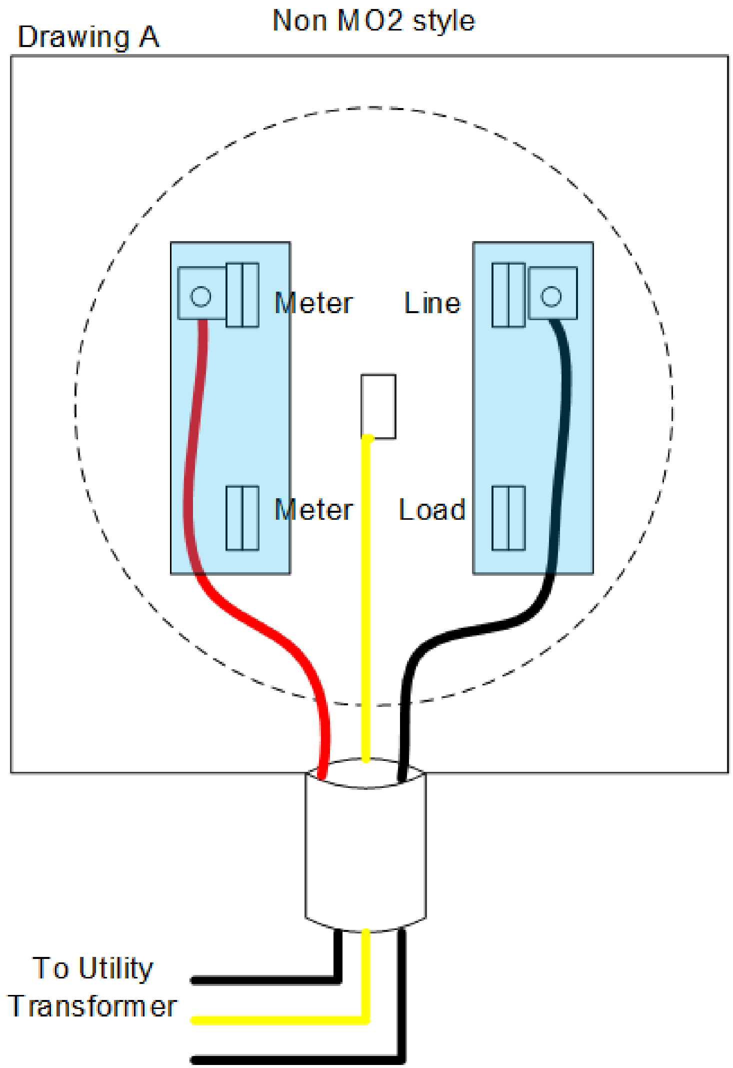
Date: ________________________ Signature: ____

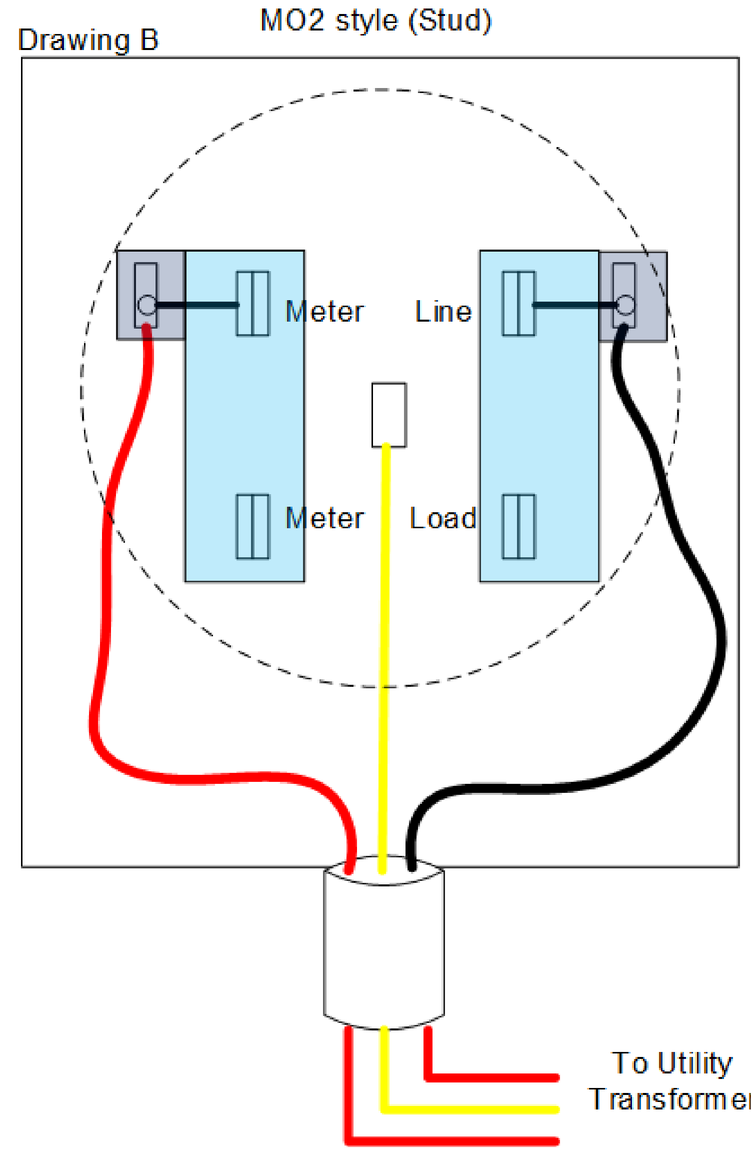
Large Commercial and Industrial Customers (1 MVA and above)

12. Guaranteed Electrical Demand (KVA)

- Year 1
  Jan____Feb____Mar____Apr____May____Jun____Jul____Aug____Sep____Oct____Nov___Dec____
- Year 2
  Jan____Feb____Mar____Apr____May____Jun____Jul____Aug____Sep____Oct____Nov___Dec____
- Year 3
  Jan____Feb____Mar____Apr____May____Jun____Jul____Aug____Sep____Oct____Nov___Dec____
- Year 4
  Jan____Feb____Mar____Apr____May____Jun____Jul____Aug____Sep____Oct____Nov___Dec____
- Year 5
  Jan____Feb____Mar____Apr____May____Jun____Jul____Aug____Sep____Oct____Nov___Dec____

MO2 Meter Bases use for Underground services

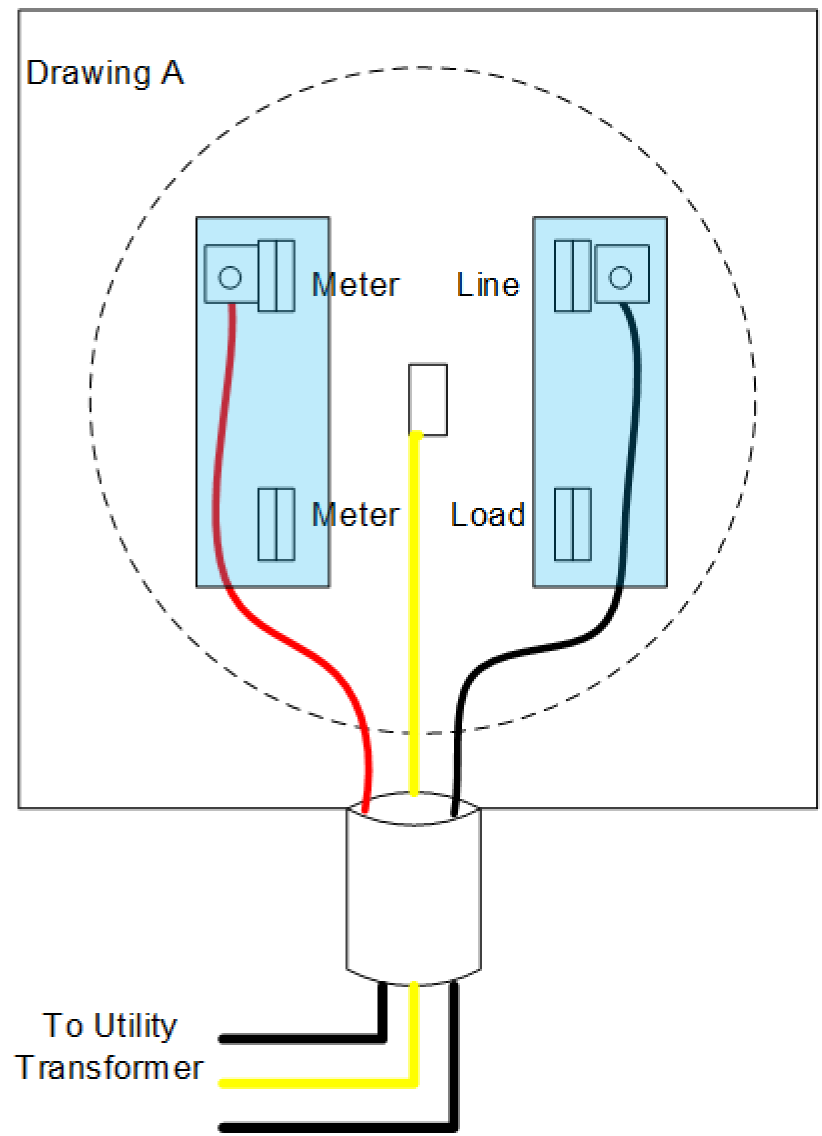




MO2 Meter Bases use for Underground services

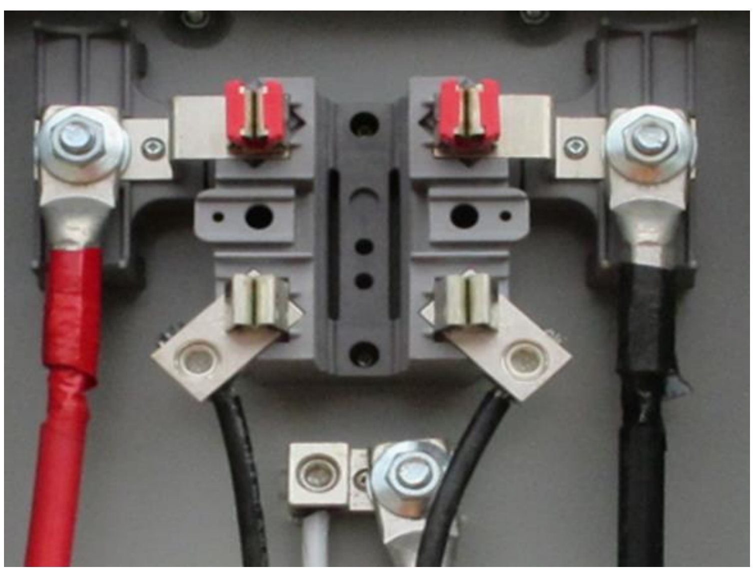
- As per Drawing A (Non MO2 stud style or equivalent) any downward force on the underground cable causes direct tension on the lug which tends to crack the polymer/ceramic base. These in turn can have the meter jaw connected freely to the meter. Once the meter is pulled the lose jaw can make contact with the meter base causing a flash.

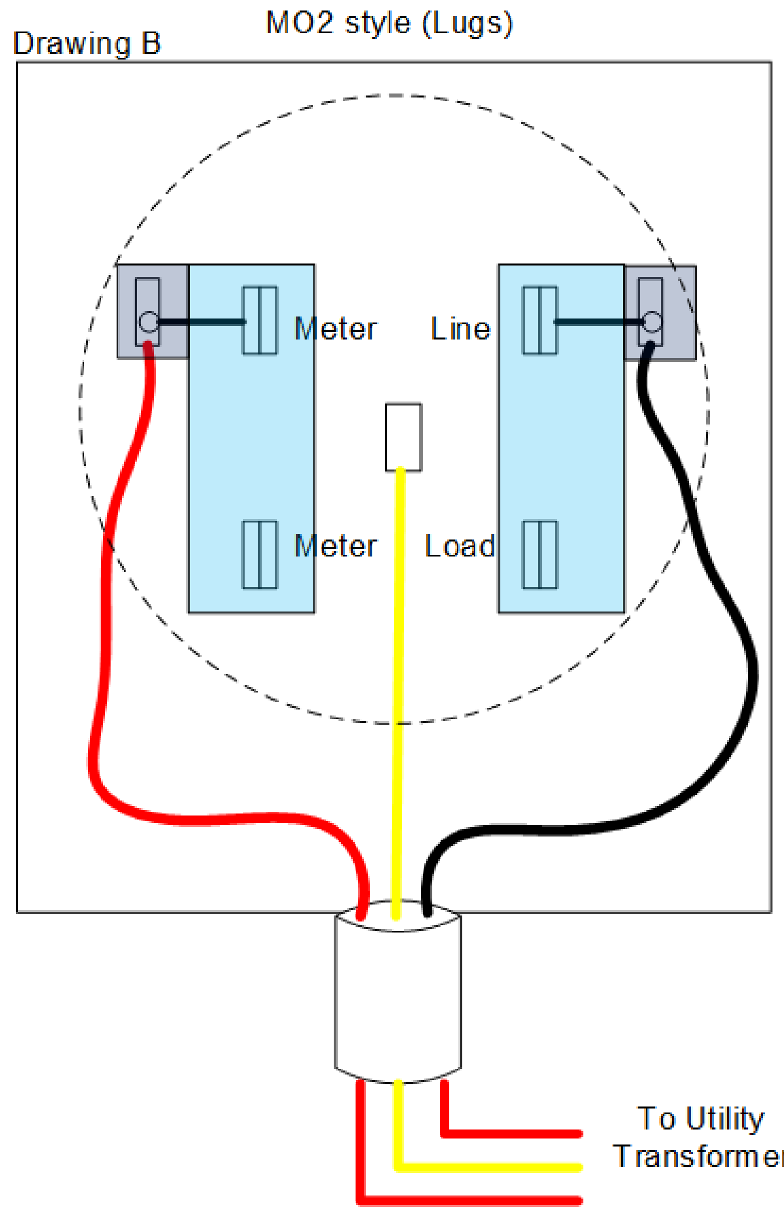
Non MO2 style



MO2 Meter Bases use for Underground services

- As per Drawing B (MO2 stud style or equivalent) any downward force on the underground cable does not causes direct tension on the lug which tends to crack the polymer/ceramic base. The downward force is on a separate polymer/ceramic base reliving direct strain from the meter lugs.





CANADIAN NIAGARA POWER INC.

A FORTIS ONTARIO Company

Questions?

CANADIAN NIAGARA POWER INC.

A FORTIS ONTARIO Company

thank you!

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Appendix G.
2016 Customer Satisfaction Survey

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Canadian Niagara Power Inc.

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

17th Annual Electric Utility Customer Satisfaction Survey

UtilityPULSE

The purpose of this report is to profile the connection between Canadian Niagara Power Inc. and its customers.

The primary objective of the Electric Utility Customer Satisfaction Survey supported by information received from Focus Groups is to: provide feedback, comment and data to support discussions about improving customer care at every level in the LDC and in making Capital & Operational expenditures.

The UtilityPULSE Report Card® and survey analysis contained in this report do not merely capture state of mind or perceptions about your customers' needs and wants - the information contained in this survey provides actionable and measurable feedback from your customers.

All comments and questions should be addressed to:

Sid Ridgley, UtilityPULSE division, Simul Corporation

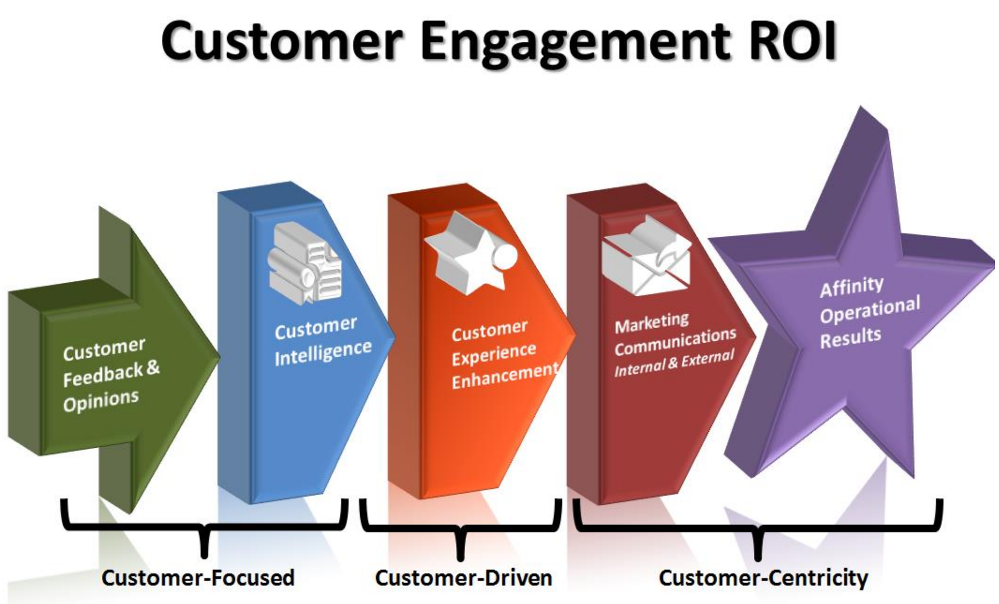
Toll free: 1-888-291-7892 or Local: 905-895-7900

Email: sidridgley@utilitypulse.com or sridgley@simulcorp.com

Survey Report

Customer engagement is a key driver for the success of energy efficiency, demand response, adoption of smart energy technologies and other programs the LDC manages. The key to effective engagement lies in understanding customers' attitudes, wants, needs, motivations, and in recognizing customers are smart people. Customer engagement is crucial for the longer term success of the LDC.

UtilityPULSE completed 410 telephone interviews with Residential and Commercial Customers in fall of 2015. This was followed up with 4 Focus Group sessions. There were 32 participants in the 2 Residential Focus Group sessions and 25 participants in the 2 Commercial Focus Group sessions.



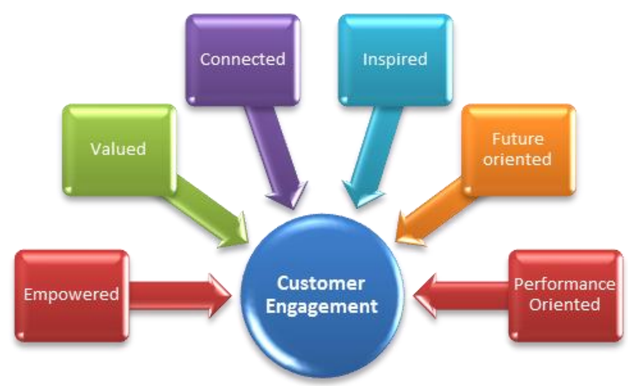
By engaging customers in a comprehensive telephone survey the goal was to provide useable information CNP could use about items such as: customer satisfaction, customer service, company image, operations, billing, outages and outage management. The goal(s) of the Focus Group (FG) sessions was to engage customers in dialogue to gain a better understanding of the findings from the telephone survey and to capture their thoughts, ideas and recommendations to CNP when moving forward with their rate application to the OEB.

Comparability

This report contains data comparisons to:

- An Ontario-wide LDC benchmark
- A National LDC benchmark
- Ontario LDCs participating in the 17th Annual Customer Satisfaction survey
- UtilityPULSE database

Customer Centric Engagement Index (CCEI)



It is important to note there are 2 sides of engagement. One side is getting customer participation in various activities while the other is about getting higher levels of emotional connection (affinity). Conducting surveys (like this one), holding town hall meetings, focus groups, etc. are examples of engaging your customers that is, getting your customers to actively participate in something. This survey also provides you with an emotional look at engagement. The CCEI index is a gauge of the amount of goodwill that has been generated. High numbers in CCEI suggest there is a high level of goodwill amongst your customers. Goodwill helps when things go awry for the utility and goodwill encourages active participation.

Utility Customer Centric Engagement Index (CCEI)			
	CNP	**National**	**Ontario**
CCEI	84%	80%	80%

Base: total respondents

Engagement is how customers think, feel and act towards the organization. Ensuring customers respond in a positive way requires being rationally satisfied with the services provided AND emotionally connected to the LDC and its brand. Connecting both rationally and emotionally strengthens and intensifies the degree to which the customer becomes engaged with the organization.

Why bother with making investments in Customer Engagement activities? (Partial list)

1. Better understanding of expectations
2. Clarify interests
3. Strategy alignment
4. Enhanced reputation/risk management
5. Improved efficiency of operations
6. Proof stakeholder input is valuable
7. Efficient use of resources
8. More effective communications
9. Improved issues management
10. Better openness in decision making
11. Increased accountability
12. Better information/intelligence

Customer engagement is not about making customers "happy" with the costs or the service being provided by their LDC. Nor is customer engagement about making the industry regulator "happy". The purpose of engaging customers is to gather usable information to help Canadian Niagara Power be more effective and efficient with higher levels of customer affinity.

Customer Focus - Customer Satisfaction - Satisfaction Survey Results

The Ontario Energy Board's consumer centric regulatory framework includes a customer satisfaction measure. Scoring well in this measure would indicate that many aspects of the LDC's operations are running well i.e., power reliability, restoring outages quickly, professional customer care, etc. Customer satisfaction is known as an effectiveness measure.

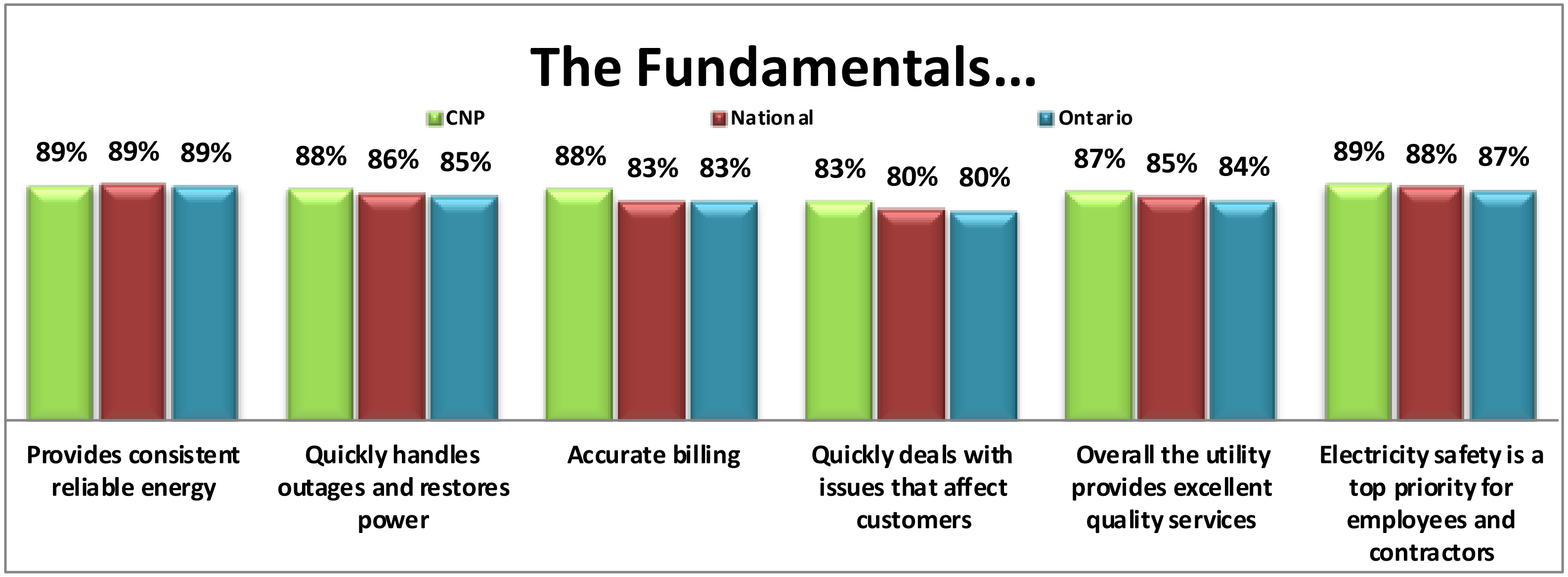
CNP's SATISFACTION SCORES – Electricity customers' satisfaction

Top 2 Boxes: 'very + fairly satisfied'	CNP	National	Ontario
PRE: Initial Satisfaction Scores	94%	89%	88%
POST: End of Interview	91%	88%	86%

Base: total respondents

- ***Satisfaction*** *happens when utility core services meet or exceed customer's needs, wants, or expectations.*
- ***Loyalty*** *(Affinity) occurs when a customer makes an emotional connection with their electric utility on a diverse range of expectations beyond core services.*

Customer satisfaction is a priority for LDCs. Rigorous measurement of this measure is an essential first step to ensuring services are delivered consistently at the expected time, money and quality levels customers desire. We remind readers, a satisfied customer is not necessarily a customer with a high affinity level i.e., emotional engagement. The satisfaction measure focuses attention on the product or service of the LDC. Customers have a more multi-faceted view about their LDC, something that is captured in the UtilityPULSE report card.



Base: total respondents

Customer Experience Performance rating (CEPr)

Some of the factors which contribute to the overall customer experience:

- Delivering accessible and consistent customer service (multi-channel)
- Understanding customer expectations

- Maintaining timely resolution timelines
- Providing effective communication(s) according to customer needs
- Demonstrating responsiveness
- Speeding up problem resolution
- Conducting problem analysis to prevent recurring issues
- Easy to do business with
- Seeking customer feedback and following through on recommendations

Customer Experience Performance rating (CEPr)			
	CNP	National	Ontario
CEPr: all respondents	86%	83%	82%

Base: total respondents

Focus Group participants were asked: *"Overall, how satisfied or dissatisfied are you with the communications you receive from CNP related specifically to your electricity service?"*

33% Very Satisfied
45% Fairly Satisfied
18% Neither
4% Fairly Dissatisfied
0% Very Dissatisfied

The CEPr rating suggests a very large majority of customers have a belief that they will have a good to excellent experience dealing with Canadian Niagara Power professionals.

Operational Effectiveness

With the exception of the Public Safety measure, performance measures would typically take the form of a monitoring and measuring (quantitative) rating. The realities are the hard numbers of actual (provable) performance may not correlate to actual customer perception.

Management Operations

Top 2 boxes, ‘strongly + somewhat agree’	CNP	National	Ontario
Provides consistent, reliable electricity	89%	89%	89%
Quickly handles outages and restores power	88%	86%	85%
Makes electricity safety a top priority for employees and contractors	89%	88%	87%
Operates a cost effective electricity distribution system	76%	70%	68%
Overall the utility provides excellent quality services	87%	85%	84%

Base: total respondents with an opinion

Focus Group participants were asked: *“Based on what you’ve heard today about Capital & Operational Investments, as you look into the future 4-5 years from now, which of the following 3 statements comes closest to your view about the overall future performance of your utility…”*

60% A- Overall performance at the utility will improve over today’s level
40% B- Overall performance will stay the same as it is, general no worse and no better
0% C- Overall performance will get worse over today’s level.

Focus Groups – Help to understand

Each of the FG sessions followed a prescribed format where a CNP executive and the UtilityPULSE moderator welcomed attendees followed by the CNP executive providing about a 15-20 minute overview of the organization and the Distribution System Plan (DSP).

Focus Group participants were provided an opportunity to ask questions. CNP personnel left the room once questions (if any) were answered. The moderator facilitated each session by sequencing the questions consistently in each session. In addition, every participant was given the opportunity to voluntarily complete a brief paper-based questionnaire and/or to provide written comments. Of the 57 people who attended the FG sessions, 51 provided responses.

Statistically speaking, data and comments from 57 people is far too small a sample size to suggest the information applies to the whole customer base. However, data and comments from focus group participants can help in gaining a better picture of issues. Focus Groups are not about the quantitative side of research but the qualitative side. Information received in FGs is less about the rational but more about the emotional.

It was clear from the telephone survey and from FG participants, customers do not want to pay more money for electricity. We did note there were participants who were quite emotional about the *"cost of* *electricity, and they want something done about it."* Unfortunately they were referring to billing items other than the CNP portion of the bill.

When FG participants were asked about their willingness to support an increase to pay for various Capital and Operational items, support levels ran the full gamut from Not Supportive to Very Supportive.

Capital Expenditures

Which of the following items are you willing to pay more for per month…Capital items					
CNP	**VS**	**SS**	**N**	**SU**	**NS**
Replacing aging equipment to improve safety and reliability	27%	33%	19%	10%	12%
Upgrading equipment to accommodate future growth in the community	17%	42%	17%	12%	12%
Adding automation and technology to reduce outage time	25%	38%	17%	10%	10%

Base: Focus Group respondents, scale: VS- Very Supportive, SS- Somewhat Supportive, N- Neither, SU- Somewhat Unsupportive, NS- Not Supportive

Focus Group participants were asked for comment regarding the following statement: "Electric utilities typically follow one of two strategies or main practices for replacing equipment. Which one of the these two statements comes closest to your beliefs? One, "run-to-failure" when there are limited customers affected ensures full-value is received from the equipment. Or Two, "pro-active replacement, even though it may cost more, should ensure reliable power."

Customers from the Commercial Focus Groups were on the side of “pro-active”, *“We don’t operate our own business in run-to-failure mode, why would we expect CNP to do so?”*

In one Commercial and one Residential Focus Group, a comment about the need for the utility to be putting money away to replace equipment, just like a business, or just like a residential customer when they are going to replace something in their home. From a residential customer: *“A bit of smoke and mirrors here. A well run business plans for replacement.”*

“Pro-active makes sense. If you run everything in your house to run-to-failure, it would cost a lot more.”

“I work for the fire-department, and maintenance is really the key.”

Diving deeper into the FG session information shows a marked difference between Residential and Commercial customers. Recognizing smaller sample sizes produce wider swings in data, it is interesting to note, 28% of the Residential participants were Somewhat Unsupportive or Not Supportive as compared to 9% of Commercial participants.

Of the 3 items listed above, whether we look at FG information or UtilityPULSE database information, *“Replacing aging equipment to improve safety and reliability”* garners the highest levels of support. However it still has to be noted, there are substantive numbers in the ‘neither supportive’ ‘and ‘unsupportive categories’.

Focus Group comments:

“I notice a huge improvement on the number of outages in our area.”

"Upgrading equipment to accommodate future growth" has high variability in our database. The reason revolves around what economic activity is actually happening in the area. For example, in the EOP territory there are 3 large condos and 1 antique boat museum scheduled to be built. In this tiny part of CNP this is substantive economic activity. As such, Focus Group participants showed 59% support as compared to about 45% in the UP database.

CNP Residential Focus Group participants were stronger than their EOP counterparts that developers ought to pay more for access.

Focus Group comments:

"Developer should pay the whole amount."

"Maybe [CNP] haven't positioned the costs well about system access. What are the benefits?"

"Adding automation and technology to reduce outage time" generally attracts support based on the respondents assumptions about technology. That is, if the respondent is cynical about the value of technology (often learned through a previous bad experience) then there is less support to pay more for it.

Focus Group comments:

"Many people have a sour taste about technology. Smart meters and their costs."

"Skepticism is part of it, that is, technology not doing what it is supposed to do."

"[I think] Privacy is a concern."

Based on observations and comments from FG participants, investments in automation and technology have to be specific and be accompanied with the benefits of the items. When FG participants were given examples of items which would fall into the "automation and technology" category there was a positive change to support levels.

Operational Expenditures

Which of the following items are you willing to pay more for per month…Capital items					
CNP	**VS**	**SS**	**N**	**SU**	**NS**
A proactive outage management communication system	18%	44%	20%	6%	12%
Increased self-serve options on the website	10%	22%	25%	16%	27%
Extended office hours	4%	10%	27%	14%	45%
Increased tree-trimming to improve reliability	18%	35%	20%	18%	10%
Educating customers about energy conservations	10%	24%	35%	10%	22%
Educating customers and the public about electricity safety	10%	31%	27%	14%	18%

Base: Focus Group respondents, scale: VS- Very Supportive, SS- Somewhat Supportive, N- Neither, SU- Somewhat Unsupportive, NS- Not Supportive

Coincidently with the exception of *"educating customers about energy conservation"*, data from the FG participants as it relates to being supportive is in line with our UP findings from over 3,000+ telephone interviews of Ontarians. In both Residential FGs there were a number of comments, mostly from much older participants, that there isn't a need to spend money on *"educating customers about energy conservation"* because information is available on-line and there has been so much information given there isn't a need to do more. However, 50% of Commercial FG customers were supportive of promoting education.

Consistent with our findings from other Ontario LDCs, there is a majority support for *"a proactive outage management communication system"* – but not unanimous. Having a majority not supportive for *"extended office hours"* is also consistent with our findings.

Tree-trimming is a controversial subject and it was so when raised at the FG sessions. The need for tree-trimming is real as it speaks to the heart of reliability. Our data shows, in the communities affected by the December 2013 ice-storm, support for tree-trimming increased.

A review of the data for *"increased self-serve options on the website"* shows a bias towards the unsupportive. Three points worthy of note. The first is, the bias is typically age related. That is, older customers less supportive than younger customers. Second, in a world where customers want their problem solved when they want their problem solved, the need for 24/7 capability is real. If the LDC didn't invest in their website, in time, they could be seen as out-of-date. Like any other operational item, the key is to fully articulate what the investment is and the value it produces.

Focus Group comments:

About self-service options on the website*:*

"I want to talk to a real live person."

"Canadian Niagara Power does a good job."

Educating customers about energy conservation:

"I can't reduce consumption much more so my support for these [operational] items is much lower."

"Preach conservativism all you want, you're going to raise rates anyways."

"We're not seeing any benefit from conserving, we're doing what we can and we're not seeing a return."

"We have surplus power and we're giving it away."

"[You] Tell us to conserve and then put a push on buying an electric car, with an incentive."

"The information is available on the web."

"We've been bombarded for the last 3 years."

Educating customers and the public about electricity safety:

"Some adults are about as bright as a 4 year old [and therefore should educate]."

"Children are trained in school, adults don't need to be taught."

The results show a range of 1 in 5 to 1 in 3 people rating the Capital or Operational items as neither supportive or unsupportive. We attribute the high numbers in this area to two things. First it is an indicator, the respondent needs to have more information before making a commitment. In short, there is a desire to make an informed choice. The second is, by being non-committal the LDC has to work harder at justifying an increase. In a somewhat perverse way, the belief is, if they say they are supportive then there really will be an increase.

The data clearly shows there is a range of views. The numbers fall into each area and, they are not small numbers that can or should be ignored. What we have noticed is, if a respondent is Somewhat Unsupportive (SU) or Not Supportive (NS) for 1 of the 3 Capital items, there is a high probability they will be SU or NS for all 3. The conclusion is simple, once a respondent (i.e., customer) is in the non-supportive camp, so-to-speak, they remain in that camp for other items which don't directly benefit them. In short, if a respondent is SU or NS for capital items then there is a very high probability they will be SU or NS for operational items. Conclusion, once there is a negative entrenched view that view is the lens by which the respondent makes decisions.

How much are customers willing to pay?

Much has been written and reported in regards to the cost of electricity. A goal of customer engagement, in addition to understanding wants & needs, is to reduce the worry customers have about the reliability and future costs of electricity. What readers may not know is, CNP has to focus on day-to-day operations while it builds, re-builds, re-furbishes and prepares the organization for a changed future. In addition, LDCs need to think in terms of decades, not just today, this week, this month, or this quarter. They need to do so in a regulated environment that is a 5 year planning environment. FG participants were asked “how much” more per month they would be willing to pay for Capital items and Operational items.

Data from our UtilityPULSE files shows lower income customers identify smaller amounts of increase for various Capital or Operational items than higher income customers. Our files also show, regardless of income, the amount a customer is willing to pay is not proportional to the number of items they support. For example, the amount a customer is willing to pay for 3 items is not 3 times the amount they would have paid for 1 item.

It is also important to note, data from all UtilityPULSE sources shows survey respondents do not have a sense of what things cost. Telling a customer an item/project costs $750,000 means little, but telling them it would increase their bill by $2.00 per month puts it in a context the customer can certainly understand and relate to. What matters most to customers is not the amount of the investment rather the personal impact of the investment.

Our database also shows about 1 in 4 customer respondents indicated they do not support any increase for any capital expense item or any operational expense item. This is a significant level of resistance. The amounts customers are willing to pay have significant variability based on income levels, personal interest in an item and/or personal benefit from an item.

Focus Group participants were asked: *“As it relates to increasing costs, what does CNP have to be mindful of?”* Here are some of the comments:

"They need to prove the benefits."

"If it is going to cost us, what do we get?"

"Understand why rates [overall bill] are lower in other places. Quebec rates are so much lower than ours."

"Every family is different. My costs are monthly, I would hope they would think about my household."

"My pay has been frozen for 3 years."

"Go after the other 82% on the bill."

"Not a large salary increase."

"My ability to pay is low, increases should not be above inflation."

"An increase is coming, have you done the due diligence for the increase?"

While support for or against an item can be emotional, it is interesting to notice the difference in responses when FG participants were asked about how the LDC ought to approach the development of their DSP.

While statistically speaking the FG data collected may not be generalizable to the entire customer population, the results do however, demonstrate a person's ability to make choices when the issue is not specific and not personal e.g., "tree-trimming".

Could you tell us how important it is for CNP to pursue the following objectives?					
CNP	**VI**	**SI**	**N**	**SU**	**NI**
Construct, maintain and operate all assets in a safe manner	41%	37%	16%	4%	2%
Monitor and address asset condition issues in a timely manner to ensure continued reliability of supply of electricity	39%	43%	12%	6%	0%
Asset investment plans align with customer expectations of power reliability, quick restoration of power and customer service	45%	41%	12%	2%	0%
Asset investment planning is done in a way to mitigate rate impacts	37%	47%	10%	4%	2%
Ensure that environmental considerations are taken into account when designing and maintaining the overall electricity system	35%	45%	14%	6%	0%

Base: Focus Group respondents, scale: VI- Very Important, SI- Somewhat Important, N- Neither, SU- Somewhat Unimportant, NI- Not Important

Based on Focus Group data (pages 11 & 14), the data tells us that when CNP, or any other utility for that matter, is trying to "sell" an increase it will be met with some cynicism and resistance. This resistance is not unique to the LDC industry.

The above chart tells us, people will support doing things in the right way(s) for the right reason(s). Selling the cost increase of the DSP will cause resistance and for some, outrage and anger. Focus Group participants said a number of times there needs to be a cost-benefit analysis, there needs to be a benefit. Explaining "how" the DSP is done coupled with an explanation on "what" Capital and Operational expenditures are needed, will help people understand "why" there is an increase.

The Killer B’s (Bills and Blackouts)

There will always be issues. To the customer the expectations from the physical world i.e., call-centre and the virtual world i.e., website, are the same: Solving the problem is the first priority. In terms of Billing Accuracy, Canadian Niagara Power rating was 88%, the Ontario benchmark was 83%.

Percentage of Respondents indicating that they had a Billing problem in the last 12 months			
	CNP	**National**	**Ontario**
2015	14%	9%	15%
2014	-	16%	25%
2013	-	8%	10%
2012	-	12%	13%
2011	-	10%	16%

Base: total respondents/ (-) not a participant of the survey year

Customers understandably expect accurate bills and timely resolution of any billing issues. Billing is a frequent touch point with customers and presents an opportunity to create a positive experience and forge stronger relationships. Some the typical billing problems still encountered are:

- 78% : the amount owed was too high
- 9% : the bill arrived late
- 7% : too many extra charges
- 5% : the payment made was recorded incorrectly.
- 2% : the bill was difficult to understand

Outage Management

Outage management is a real customer concern. Expectations about the timelines of information and speed of restoration are increasing.

Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months			
	CNP	**National**	**Ontario**
2015	51%	52%	51%
2014	-	47%	49%
2013	-	41%	35%
2012	-	44%	46%
2011	-	43%	43%

Base: total respondents / (-) not a participant of the survey year

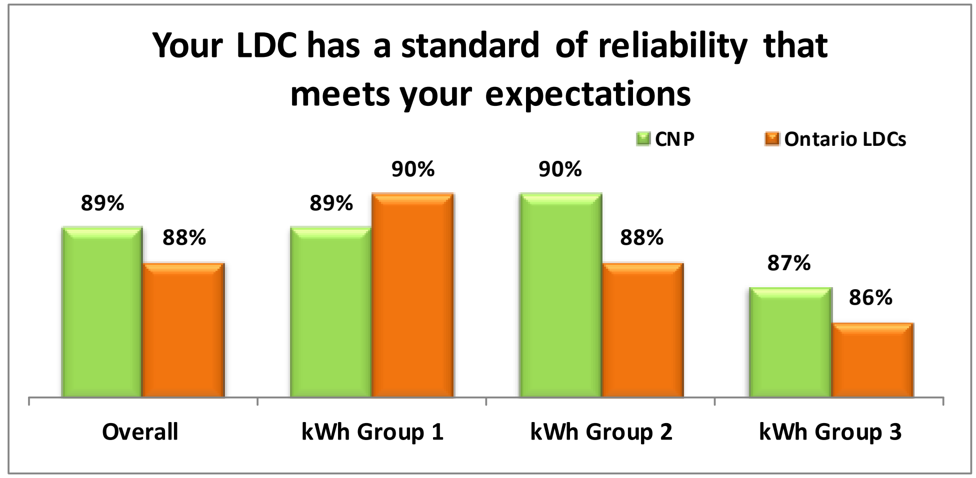
The perception of LDC competency and value are certainly linked to the frequency and duration of power outages. 88% of respondents with an opinion agree (top 2 boxes) Canadian Niagara Power "quickly handles outages and restores power."

Customers have increased their expectations as it relates to getting information about outages. What makes the dissemination of information challenging for the LDC is the need to provide the information via multiple media channels and in a timely manner whilst trying to get the power restored.

	Yes	**No**	**Depends**
Ontario LDCs	57%	35%	8%
CNP	54%	38%	8%

Base: An aggregate of respondents from the 2015 participating LDCs / total respondents from the local utility

Recognizing the importance of this topic to customers, a question about LDC reliability standards has been added to the core survey.



Base: An aggregate of respondents from the 2015 participating LDCs/total respondents from the local utility

Customers who responded to the survey offer a paradox. On the one hand, when asked about "your LDC has a standard of reliability that meets your expectations", scores are very high – no doubt somewhat comforting to the LDC. On the other hand, when asked "Should your LDC improve its reliability standards" the majority certainly said "yes".

Customers who responded to the survey offer a paradox. On the one hand, when asked about "your LDC has a standard of reliability that meets your expectations", scores are very high – no doubt somewhat comforting to the LDC. On the other hand, when asked "Should your LDC improve its reliability standards" the majority certainly said "yes". What we didn't do is tell the customer how much more money they would have to pay per month for higher standards.

An outage management system helps LDC employees to discover, locate and resolve power outages in a more informed, orderly, efficient and timely manner.

How many outages are acceptable over 12 months?		
	Ontario LDCs	**CNP**
None	23%	17%
One	15%	9%
Two	26%	28%
Three	13%	16%
Four	5%	7%
Five or more	7%	12%
Don't Know	9%	11%

Reasonable amount of time for an unplanned outage?		
	Ontario LDCs	**CNP**
Less than 15 minutes	14%	0%
16-30 minutes	15%	20%
31-60 minutes	13%	11%
1 to 2 hours	29%	36%
3 to 5 hours	13%	14%
6 to 12 hours	5%	5%
More than 12	3%	4%
Don't Know	8%	9%

Base: An aggregate of respondents from the 2015 participating LDCs / total respondents from the local utility

Focus Group participants were asked about the findings regarding 'how many outages are acceptable over 12 months'.

"Around here the season plays a role in number of outages."

"We have severe weather, blizzards and other major storms."

"Maybe if everything was underground we could get to zero."

"Long outages are killers, especially in the deep cold of winter or the high heat of summer."

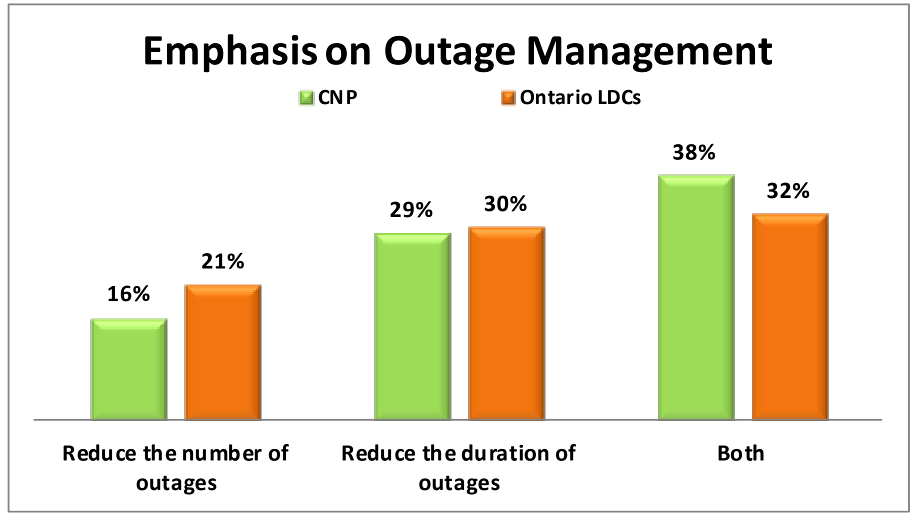
"Like to see some of the work for planned outages moved to a weekend." [Commercial customer]

"I'd like to see them look at a second (electricity) feed into our territory." [Commercial customer]

How many outages are acceptable over 12 months? Canadian Niagara Power respondents who said "none" was 17%; "one" was 9%. Clearly expectations are very high.

Respondents were asked about emphasis on outage management: reduce the number; reduce the duration; or both with an understanding a rate increase would be required.

Focus Group feedback tended towards 'reducing the duration' and 'both'.



Base: An aggregate of respondents from the 2015 participating LDCs / total respondents from the local utility

"[I think] They want both, until they get the bill."

"They're resigned that rates are going up, and if so, then do so for something that would be beneficial. [comment in support of both]

"It is the length of the outage that is a concern. In our municipality, we have to monitor our reservoir during an outage because we could run out of water."

"We run a retirement home and length of outage causes many people issues. When we know in advance we can plan, but even then we have to worry about the length of time. We have a generator but it only looks after the common room [for our residents]."

"Better equipment means better service."

LDC effectiveness responding to outages		
	Ontario LDCs	CNP
Responding to the power outage	85%	95%
Restoring power quickly	86%	88%
Using media channels for updates	54%	46%
Providing information about the outage	61%	61%

Base: An aggregate of respondents from the 2015 participating LDCs / total respondents from the local utility

Preferred methods for LDC to contact the customer		
	Ontario LDCs	CNP
Recorded telephone message	53%	57%
Email notice	29%	10%
Posted on utility's website	24%	6%
Social media - such as Twitter, facebook	17%	5%
Text message	28%	13%
Local radio	31%	6%
Local TV	23%	3%
Don't Know	3%	0%

Base: An aggregate of respondents from the 2015 participating LDCs / total respondents from the local utility

Being effective during an outage situation from the point of view of a customer requires:

- timely information on outages is provided
- utilities understand even a short outage in duration is impactful
- in large scale events, utilities should proactively provide tips on how to prepare for extended outages

- being kept informed about what is going on during an outage makes customers feel valued and that they matter.

Customer Focus – Customer Satisfaction – First Contact Resolution

Satisfaction with the contact experience

While employees can't control everything, they can control the quality of the experience. How a problem is handled can validate or invalidate a customer's perception about the utility's competency in providing excellent quality services. Customers, who contacted your LDC, rated their one-on-one transaction as follows:

Satisfaction with Customer Service			
Top 2 Boxes: 'very + fairly satisfied'	**CNP**	**National**	**Ontario**
The time it took to contact someone	80%	74%	70%
The time it took someone to deal with your problem	78%	72%	66%
The helpfulness of the staff who dealt with you	85%	72%	70%
The knowledge of the staff who dealt with you	78%	72%	70%
The level of courtesy of the staff who dealt with you	84%	79%	80%
The quality of information provided by the staff who dealt with you	79%	71%	69%

Base: total respondents who contacted the utility

Given today's technology, many customers use more than one service channel. This gives the LDC a great opportunity to connect to both digital and physical service, providing customers a true omni-channel experience.

Overall satisfaction with most recent experience			
	CNP	**National**	**Ontario**
Top 2 Boxes: 'very + fairly satisfied'	80%	76%	69%

Base: total respondents who contacted the utility

Problem solved rating

Respondents who said they contacted the utility were also asked "Do you consider the problem solved or not solved?" 73% of your LDC's respondents said the problem was solved. The Ontario benchmark rating is 69%.

Customer Focus – Service Quality

Current measures in the LDC scorecard are: New Residential Services Connected on Time; Scheduled Appointments Met on Time; and, Telephone Calls Answered on Time. These are good examples of efficiency measures as all are time based. Showing up on time may not create satisfaction; not showing up on time will cause dissatisfaction. Other dimensions of Service Quality that customers value include:

Customer Service Quality			
Top 2 boxes, 'strongly + somewhat agree'	**CNP**	**National**	**Ontario**
Deals professionally with customers' problems	86%	82%	82%
Pro-active in communicating changes and issues affecting Customers	81%	74%	77%
Quickly deals with issues that affect customers	83%	80%	80%
Customer-focused and treats customers as if they're valued	82%	74%	76%
Is a company that is 'easy to do business with'	87%	81%	81%
Cost of electricity is reasonable when compared to other utilities	62%	62%	58%
Provides good value for money	73%	67%	66%
Delivers on its service commitments to customers	88%	84%	84%

Base: total respondents with an opinion

CNP has superb ratings, 73% Provides good value for money, when compared to the Ontario benchmark and the UtilityPULSE database. None-the-less finding a way to increase the LDC's value proposition remains a challenge for every LDC.

FG participants were asked: *"Before this survey, how familiar were you with the percentage of your electricity bill that went to CNP?"*

12%	Very familiar	25%	Not very familiar
20%	Somewhat familiar	43%	Not familiar at all

FOCUS GROUP

Data collected in the FG shows Commercial customers are far and away more likely to say they are Very familiar or Somewhat Familiar, versus Residential customer.

Customer Affinity

Customers continue to be more sophisticated, educated and demanding and with less money available. They expect value and quality services – not either/or but and/also. Recognizing that customers have a meaningful perspective can help the LDC drive out waste, reduce complaints, embrace new processes and new technologies leading to greater efficiency and effectiveness.

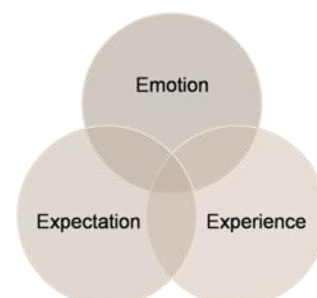
> "Whether a customer is loyal and/or satisfied will be determined by an alignment of the emotion, experience and expectation of both the customer and the LDC."

There are many reasons why LDCs should put a premium on satisfying customers. Such as: there is an obligation to satisfy people; it makes sense economically; the industry has to prove it is valuable to its customers and, increased customer satisfaction can influence employee morale and retention. A big reason is, higher levels of customer affinity (Loyalty). Loyalty, for private industry, is a behavioural metric. Loyalty, for natural monopolies (like LDCs) is an attitudinal metric.

Customer Loyalty Groups

	Secure	Favorable	Indifferent	At Risk
CNP	31%	14%	55%	0%
National	18%	11%	61%	10%
Ontario	17%	11%	61%	11%

Base: total respondents



UtilityPULSE Report Card®

The purpose of the UtilityPULSE Report Card is to provide your utility with a snapshot of performance – it represents the sum total of respondents' ratings on 6 categories of attributes that research has shown are important to customers in influencing satisfaction and affinity levels with their utility.

CNP's UtilityPULSE Report Card®

Performance

	CATEGORY	CNP	National	Ontario
1	**Customer Care**	**A**	**B+**	**B**
	Price and Value	B+	B	B
	Customer Service	A	B+	B+
2	**Company Image**	**A**	**A**	**B+**
	Company Leadership	A	B+	B+
	Corporate Stewardship	A	A	A
3	**Management Operations**	**A**	**A**	**A**
	Operational Effectiveness	A	A	A
	Power Quality and Reliability	A	A	A
	OVERALL	**A**	**A**	**A**

Base: total respondents

Credibility and Trust

Higher levels of trust are the hallmarks of Secure customers and utilities benefit from a trusted relationship with their empowered customers. When people interact, either face-to-face, by telephone or on-line, if there is a lack of trust, the interaction is not going to be efficient. Trust improves the speed at which the interaction can be accomplished. The attributes which help an LDC to be seen as trusted and highly credible are: knowledge, integrity, involvement and trust. Trust is not a thing, it is a feeling. On demonstrating Credibility and Trust, Canadian Niagara Power has done well.

Credibility and Trust Index

	CNP	National	Ontario
Knowledge	86%	84%	84%
The LDC is seen as being knowledgeable about the services it provides, about what is happening in the industry, and how customers can reduce costs or manage consumption.			
Integrity	86%	82%	72%
The LDC is seen as an organization that will act in the best interests of its customers and can be counted on to provide services and resolve problems in a professional manner.			
Involvement	80%	75%	76%
The LDC is actively involved in the industry, in the community and in things that affect the customer.			
Trust	86%	81%	81%
The LDC is an organization that can be trusted and is worthy of respect.			
Overall	**85%**	**81%**	**81%**

Base: total respondents

Company Image

How customers think about their LDC has a direct influence on how customers act, react or engage with Canadian Niagara Power. For example, customers with a positive impression put less strain on the operations. In 2006, 10 years ago, our industry research showed Company Image had an 18% weighting as it relates to shaping perception about their LDC. Today, Company Image weighting for Canadian Niagara Power is 32%, Ontario is 33%, a significant change.

Attributes strongly linked to a hydro utility's image			
	CNP	**National**	**Ontario**
Is a respected company in the community	88%	82%	82%
A leader in promoting energy conservation	82%	78%	77%
Keeps its promises to customers and the community	86%	79%	80%
Is a socially responsible company	85%	80%	80%
Is a trusted and trustworthy company	88%	81%	81%
Adapts well to changes in customer expectations	75%	71%	71%
Is 'easy to do business with'	87%	81%	81%
Provides good value for your money	73%	67%	66%
Overall the utility provides excellent quality services	87%	85%	84%
Operates a cost effective electricity distribution system	76%	70%	68%

Base: total respondents with an opinion

Marketing communications should capitalize on the strong image scores to reduce the worry customers have about reliability, future costs and other concerns. Technically performing the expected job well is one thing, but the LDC also has to be "seen" as performing well.

Focus Group participants were asked: “*What is it going to take for customers to see more value in the price of electricity [the CNP portion]?”*

“More incentive programs for commercial operations and market the incentives.”

“Put a face to the utility.”

“An education campaign on the 18%.”

“We take it [electricity service] for granted.”

“We’ve seen some real operational improvements.”

“Fortis has done some things right.”

“The transformer change was wonderfully handled, they (CNP) were pro-active.” [Commercial]

“Provide some comparisons with other jurisdictions.”

“I think you could ask the same question about water and gas.”

What do customers think about electricity costs?

For years electric utility customers have had a very real concern about high bills and the cost of electricity. We’ve constantly and consistently have told our clients “when a value proposition doesn’t exist or is unclear, then people will focus on price.” LDCs in Ontario certainly score low on “value for money.” When a customer struggles to pay their electricity bill they also struggle to see the LDC providing good value for money.

The good news is, LDCs have been doing more to engage customers about the utilities' plans to spend money to improve operations and/or make capital investments. While this is seen as an important process, especially by the Ontario Energy Board, it doesn't deal with the basic issue at hand – the customer's own struggle to pay the bill. Our first year of research, 1999, showed us there was a very high correlation between ability to pay and satisfaction – in 2015 the correlation is still high.

Is paying for electricity a worry or major problem …

	CNP	National	Ontario
Not really a worry	67%	67%	59%
Sometimes I worry	22%	22%	25%
Often it is a major problem	9%	8%	10%
Depends	1%	2%	2%

Base: total respondents

Additional Insights from the UtilityPULSE Database

As it relates to SMART Grid knowledge, customers polled in the Ontario survey show 37% *"have heard the term SMART Grid but know very little about it"* and 32% claimed they *"have not heard the term"*. This suggests customers will not automatically understand and accept SMART Grid technology.

The Ontario survey shows that interest in purchasing an electric vehicle remains at 34% - unchanged since 2012. 75% of those that are “interested in purchasing” claim they wouldn’t be acting on their interest in purchasing for 24 months or more. The adoption rate of EVs is still in its infancy.

UtilityPULSE asked 1,269 Residential customers, located throughout Ontario and who pay the electricity bill questions pertaining to the solicitation of customer feedback and opinions on different electricity industry matters. These questions were asked with the intent of gauging the customer’s perception of requesting feedback and the importance thereof. Percentage of respondents who said it was important to solicit feedback [Top 2 Boxes: ‘very + somewhat important’]:

- 89% on “overall satisfaction with the utility”
- 83% on “how much money is being spent on repairing equipment”
- 86% on “how much money is being spent on keeping the system reliable”
- 84% on “extending the system to help economic development in the community”.

The data on the importance of “feedback” tells us customers want their voice heard. We believe this is completely in sync with, what experts call, customer centricity. However asking for feedback, but not acting on that feedback or not using the feedback in a constructive way could have some adverse consequences for the LDC i.e., lower levels of trust, credibility and customer affinity.

We’ve often been asked: “What does it take to be seen as having great customer service?” Our answer continues to be “have genuine empathy for customers.” If you and your fellow employees don't have it, then your organization will not achieve the highest levels of customer engagement and affinity as may be possible. This requires Canadian Niagara Power to ensure it is truly embracing the strategic intent of being "customer centric" AND it requires the establishment of a corporate culture which supports both customer and employee engagement.

Focus Group participants were asked: *"What are some of the things CNP does well?"*

"Their customer service is excellent. I've never had to wait on a call. Live people."

"Office staff are extremely polite and cooperative."

"I think they do a really good job."

"We have less outages."

"They come across as professional with a good corporate image."

"They collect the money well."

"They support the community."

"Good community involvement proves they are a good corporate citizen."

"Local telephone number is great."

"Arborist was brought in when I had a tree-trimming issue. I was impressed that they did so."

"Good at advising people on planned outages."

"The linesmen are on the road right away when there is an outage. "

Customers do have a major concern over the cost of electricity – the whole bill. While it is true, customers with a high emotional attachment towards their electric utility tend to have less resistance the reality is the majority of customers do not have a high emotional connection. Justifying an increase, frankly any increase, will be negatively received. As such, we recommend highlighting the benefits or rationale for the increase. As stated earlier are you "selling" a price increase or what the increased investments are going to do for customers?

We recommend having meaningful two-way dialogue with employees (and others) to leverage the results from your 2015 customer satisfaction survey derived from speaking with 410 Canadian Niagara Power customers [October 8-22, 2015]. After-all, people cannot care about the things that they don't know about.

UtilityPULSE
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March, 2016

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Satisfaction (pre & post)

In Ontario, the Ontario Energy Board (OEB) has made it clear Customer Satisfaction measurement will be part of an Electricity Distributor's reporting. Of the many reasons why every LDC should place a premium on satisfying customers, here are some of the important ones:

1- Every enterprise has an obligation to satisfy its customers
2- Economically, high levels of satisfaction lead to less customer complaints and less scrutiny (hence less cost)
3- As an effectiveness measure it prompts discussion about policies, procedures, planning, use of technology, and more
4- When things go wrong (and they do), customers with high levels of satisfaction handle the problem far better than customer with very low levels of satisfaction
5- For employees there is a morale boost when working in an organization with a high level of customer satisfaction
6- Customers (as well as others) have growing levels of expectations which means the things that satisfy customers today may not tomorrow.

A focus on satisfaction prompts an organization to continue to evolve in ways that make sense to those who pay the bills. A focus on satisfaction is a focus on effectiveness in the delivery of service to the customer. Satisfied customers who trust their LDC may be more likely to seek advice i.e. energy efficiency methods, and may be more receptive to important messages i.e. safety, new capital projects, etc.

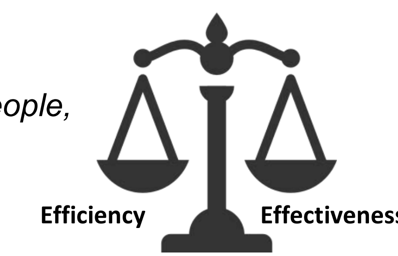
A word of caution to readers, please do not assume that great performance in an efficiency rating (such as answering the phone in 30 seconds) will lead to customer satisfaction. It will not. Answering the phone in 20 seconds but not solving the customer's problem is not going to ameliorate the customer's perception about the transaction.

Efficiency ratings won't lead to satisfaction but they can lead to dissatisfaction. Taking 90 seconds to answer the phone will create an agitated customer who, for the most part starts off being dissatisfied with the service – before you've even had a chance to deal with or solve their problem.

Customer expectations of their electricity LDC have evolved past the "provide electricity reliably, safely and billed both accurately with fair pricing". They do expect their LDC to be ethical, forward-thinking, competent and trustworthy.

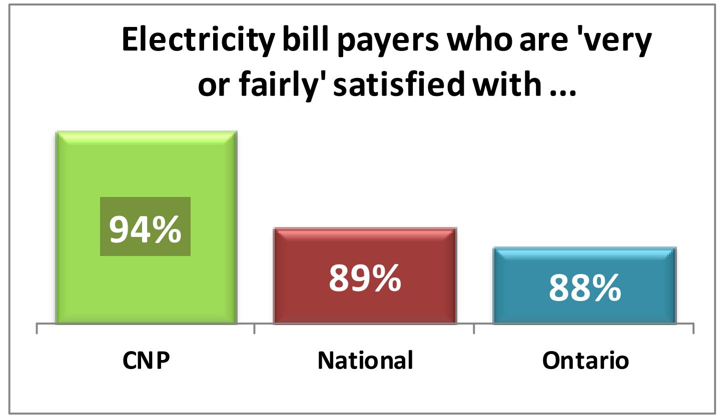
In a nutshell:

- Satisfaction is not a program, it is an outcome.
- ***Efficiency*** *is about achieving objectives with the minimum amount of people, time, money and other resources.*
- ***Effectiveness*** *ratings are measures that keep the organization and its people more future focused than efficiency ratings*
- Finding the right balance between efficiency and effectiveness measures is difficult.



- **Satisfaction** happens when utility core services meet or exceed customer's needs, wants, or expectations.

- **Loyalty** occurs when a customer makes an emotional connection with their electric utility on a diverse range of expectations beyond core services.



Base: total respondents

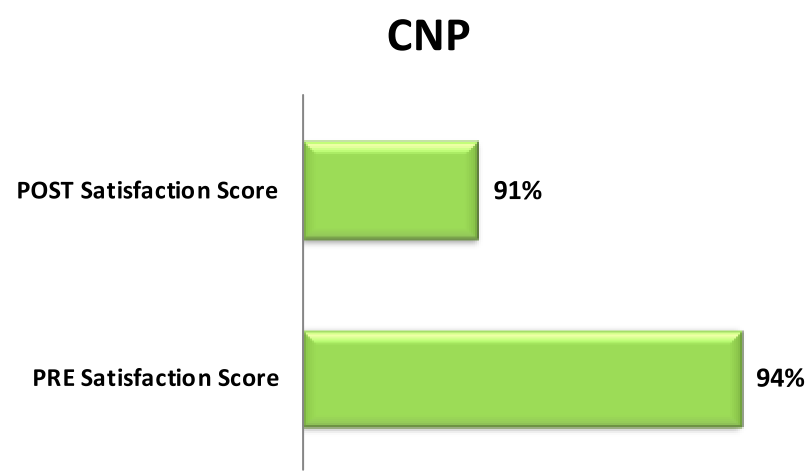
Satisfaction alone does not make a customer loyal; a willingness to commit and advocate for a company along with satisfaction identifies the three basic customer attitudes which underpin loyalty profiles. While satisfaction is an important component of loyalty, the loyalty definition needs to incorporate more attitudinal and emotive components.

Electricity bill payers who are 'very or fairly' satisfied with…					
	2015	**2014**	**2013**	**2012**	**2011**
CNP	94%	-	-	-	-
National	89%	89%	90%	88%	89%
Ontario	88%	83%	90%	86%	84%

Base: total respondents/ (-) not a participant of the survey year

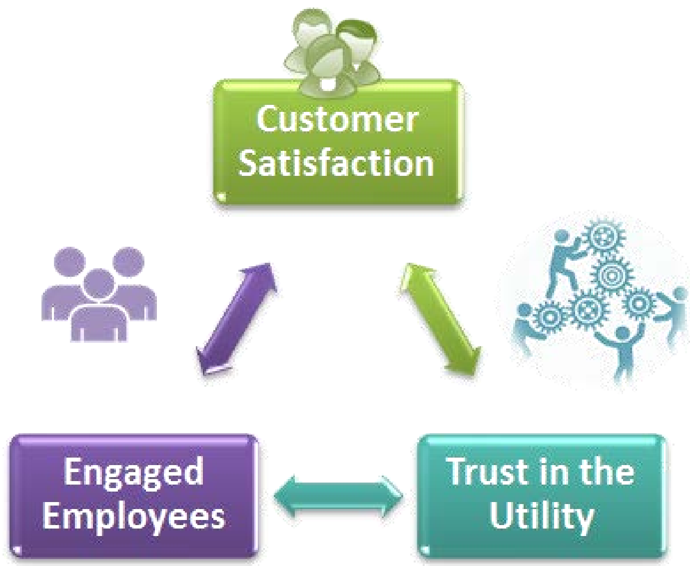
Every LDC we've worked with over the past 17 years conducting this survey can provide examples of employees who have certainly gone above and beyond the call of duty. Just listen to employees, at all levels, as they talk – with pride – about what their LDC is doing.

In the Simul/UtilityPULSE Customer Satisfaction survey, the overall satisfaction question is asked both at the beginning (PRE) and the end (POST). Asking the general satisfaction question at the start of the survey avoids bias and we obtain a spontaneous rating. This allows measurement of customers' overall impressions of the utility prior to prompting them to think of specific aspects of the relationship. After we have asked about specific aspects of the customer experience, we gain a more *considered* (or conditioned) response.



Base: total respondents

Satisfied and engaged employees who work in an organizational culture that promotes service excellence is key for completing the job both efficiently and effectively. After-all employees do more than deliver customer service – they personalize the relationship between customer and the utility



SATISFACTION SCORES – Electricity customers' satisfaction			
Top 2 Boxes: 'very + fairly satisfied'	**CNP**	**National**	**Ontario**
PRE: Initial Satisfaction Scores	94%	89%	88%
POST: End of Interview	91%	88%	86%

Base: total respondents

Customers, as human beings, are both rational and emotional. The rational side of the customer holds the LDC accountable for doing its job. The emotional side of the customer is about fulfilling expectations. Not meeting rational needs – creates dissatisfaction. Meeting emotional needs, can move a customer from neutral to higher levels of satisfaction.

Attributes strongly linked to a hydro utility's image			
	CNP	National	Ontario
RATIONAL NEEDS			
Provides consistent, reliable electricity	89%	89%	89%
Quickly handles outages	88%	86%	85%
Accurate billing	88%	83%	83%
Provides good value for money	73%	67%	66%
Is 'easy to do business' with	87%	81%	81%
Operates a cost effective electricity distribution system	76%	70%	68%
EMOTIONAL NEEDS			
Deals professionally with customers' problems	86%	82%	82%
Provides information to help customers reduce electricity costs	80%	76%	76%
Pro-active in communicating changes	81%	74%	77%
Quickly deals with issues that affect customers	83%	80%	80%
Adapts well to changes in customer expectations	75%	71%	71%
Overall the utility provides excellent quality services	87%	85%	84%

Base: total respondents with an opinion

Customer Service

There is no way the quality of customer service can exceed the quality of the people delivering it. LDCs can have all the elements of customer service in place, but if customers are disappointed with the way their transaction was handled or its results, they will not be satisfied. There are lots of things the LDC and its people cannot control, but employees can control the quality of the experience.

Having well-trained employees is foundational. The keys to good customer service is listening to understand with real empathy and then responding in a professional, knowledgeable, and timely manner. After-all it is the customer who decides whether the interaction was worthwhile and/or valued.

Respondents, who contacted their utility via the telephone or in-person about a problem, were asked about six aspects of their most recent experience with a representative from Canadian Niagara Power.

- Information – quality of information provided
- Staff attitude – level of courtesy
- Professionalism – the knowledge of staff
- Delivery – helpfulness of staff
- Timeliness – the length of time it took to get what they needed
- Accessibility – how easy it was to contact someone

“What do our **customers** want?”

1. *Their problem solved quickly*
2. *To have personal interaction with a customer care representative*
3. *To speak with a knowledgeable and courteous customer care representative*

Base: total respondents who contacted the utility

Satisfaction with Customer Service			
Top 2 Boxes: 'very + fairly satisfied'	**CNP**	**National**	**Ontario**
The time it took to contact someone	80%	74%	70%
The time it took someone to deal with your problem	78%	72%	66%
The helpfulness of the staff who dealt with you	85%	72%	70%
The knowledge of the staff who dealt with you	78%	72%	70%
The level of courtesy of the staff who dealt with you	84%	79%	80%
The quality of information provided by the staff who dealt with you	79%	71%	69%

Base: total respondents who contacted the utility

Respondents, who contacted their utility via an electronic means, e.g., email, website, social media, were asked about four aspects of their most recent experience with a representative.

Satisfaction with Customer Service via electronic means	
Top 2 Boxes: 'very + fairly satisfied'	**Overall**
The timeliness of response	60%
The quality of information provided	66%
The helpfulness of the information	66%
The level of professionalism	65%

Base: total respondents from the full 2015 database

Overall satisfaction with most recent experience			
	CNP	**National**	**Ontario**
Top 2 Boxes: 'very + fairly satisfied'	80%	76%	69%

Base: total respondents who contacted the utility

The difference between overall service quality and service encounter quality (most recent experience), viewing the service encounter as a discrete event occurring over a defined period/moment of time (such as a call about their "September billing"). Customers hold expectations of the quality of each service encounter, just as they hold expectations about the overall service quality of an LDC. When the expectations are about individual service encounters, they are likely to be more specific and concrete (such as the number of minutes one waited for a CSR) than the expectations about overall service quality (like prompt service).

Interestingly when customers do have a problem, contact their LDC, and get the problem solved their satisfaction ratings are very similar to the overall level of satisfaction that exists. It is important that LDCs have an obsession with “first call resolution” as it is very beneficial and is more than a “nice idea”.

SATISFACTION SCORES – Electricity customers’ satisfaction

	Overall	Problems Solved	Problems Not Solved
Top 2 Boxes: ‘very + fairly satisfied’	89%	88%	60%
Bottom 2 Boxes: ‘fairly + very dissatisfied’	7%	8%	37%

Base: total respondents from the full 2015 database

Satisfaction with Customer Service

Top 2 Boxes: ‘very + fairly satisfied’	Overall	Paying for electricity: No worries	Paying for electricity: Often worry
The time it took to contact someone	74%	75%	64%
The time it took someone to deal with your problem	71%	72%	58%
The helpfulness of the staff who dealt with you	75%	78%	59%
The knowledge of the staff who dealt with you	75%	76%	65%
The level of courtesy of the staff who dealt with you	83%	83%	73%
The quality of information provided by the staff who dealt with you	73%	75%	62%

Base: total respondents from the full 2015 database

While there is more information about customer loyalty in this report, the following chart shows the difference in customer service ratings given by customers who are "secure" versus customers who are "at risk". In addition, "at risk" customers seem to have more problems than other customers and are much more likely to contact their LDC to do something about it.

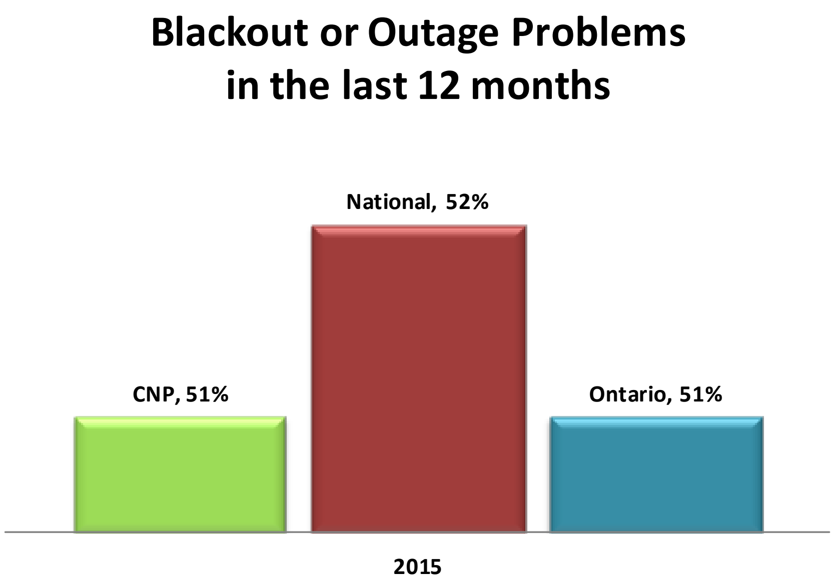
Base: total respondents from the full 2015 database

Important attributes which shape perceptions about service quality			
	CNP	**National**	**Ontario**
Deals professionally with customers' problems	86%	82%	82%
Is pro-active in communicating changes and issues which may affect customers	81%	74%	77%
Quickly deals with issues that affect customers	83%	80%	80%
Customer-focused and treats customers as if they're valued	82%	74%	76%
Is a company that is 'easy to do business with'	87%	81%	81%
Cost of electricity is reasonable when compared to other utilities	62%	62%	58%
Provides good value for money	73%	67%	66%
Delivers on its service commitments to customers	88%	84%	84%
Trusted and trustworthy company	88%	81%	81%
Respected company in the community	88%	82%	82%
Provides information and tools to help manage electricity consumption	82%	77%	77%
Adapts well to changes in customer expectations	75%	71%	71%

Base: total respondents with an opinion

Bill payers’ recent problems and problem resolution

Outages and billing problems, we call them the “Killer B’s”, the two issues most likely to cause grief to utility customers. Ensuring power reliability has and will continue to be the key operational priority for electric utilities.



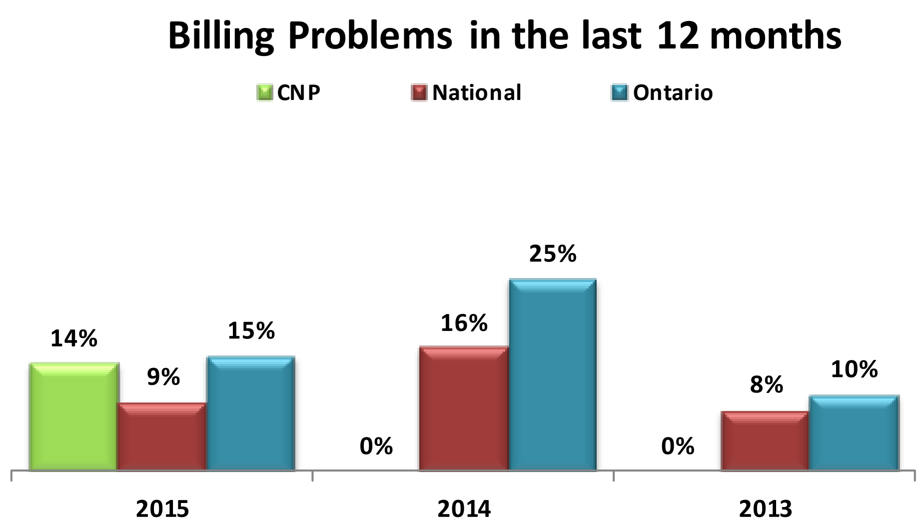
The perception of competency and value are certainly linked to the frequency and duration of power outages. 88% of respondents with an opinion agree (top 2 boxes) Canadian Niagara Power “quickly handles outages and restores power” and 89% agreed (top 2 boxes) that this LDC has a standard of reliability meeting expectations.

Base: total respondents

Like it or not, there will be times when the power goes off – and for reasons beyond the control of the LDC.

Percentage of Respondents indicating they had a Blackout or Outage problem in the last 12 months			
	CNP	**National**	**Ontario**
2015	51%	52%	51%
2014	-	47%	49%
2013	-	41%	35%
2012	-	44%	46%
2011	-	43%	43%

Base: total respondents / (-) not a participant of the survey year



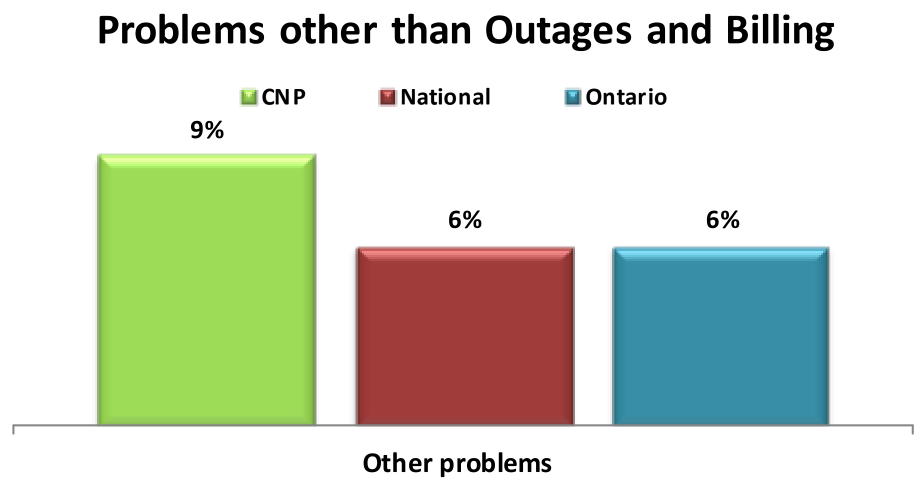
Percentage of Respondents indicating they had a Billing problem in the last 12 months			
	CNP	**National**	**Ontario**
2015	14%	9%	15%
2014	-	16%	25%
2013	-	8%	10%
2012	-	12%	13%
2011	-	10%	16%

Base: total respondents / (-) not a participant of the survey year

Types of Billing Problems	
	CNP
The amount owed was too high	78%
The bill arrived late	9%
Too many extra charges	7%
Payment incorrectly recorded	5%
The bill was difficult to understand	2%

Base: total respondents with billing problems

As it relates to problems, the Killer B's – Bills and Blackouts still occupy top ranking – while moving/setting up a new account, maintenance repairs, high bills, information on pricing, ways to save energy, incentives on energy conservation are issues which also **contribute to customer contact levels through a call-centre or electronic media.**



Base: total respondents

Survey respondents were asked about how they contacted their utility when there was a problem. For utilities, customers continue to favour the telephone.

What method did you use to contact your electric utility when you had a problem?

Base: total respondents

Problems aggravate customers. It could be said some problems can actually anger customers. As a minimum, a problem is an inconvenience to the customer – and they want it solved/resolved. When the problem is solved with the first interaction (often called first call resolution) overall customer satisfaction improves. When customer satisfaction improves the utility benefits.

Percentage of Respondents who contacted their utility and had their problem solved in the last 12 months

	CNP	National	Ontario
Yes	73%	78%	69%
No	21%	20%	27%

Base: total respondents

Attributes describing operational effectiveness

	Overall Score	Problem Solved	Problem Not Solved
Provides consistent, reliable electricity	90%	88%	77%
Delivers on its service commitments to customers	86%	85%	68%
Accurate billing	86%	84%	64%
Quickly handles outages and restores power	87%	85%	73%
Makes electricity safety a top priority	88%	90%	79%
Has a standard of reliability that meets expectations	88%	87%	72%
Is efficient at managing the electricity system	82%	81%	63%
Is a company that is 'easy to do business with'	84%	82%	59%
Overall the utility provides excellent quality services	85%	84%	66%

Base: total respondents from the full 2015 database with an opinion

While an LDC is a natural monopoly i.e., customers can't go elsewhere and an LDC can't "fire" a customer, we recommend LDCs continue to build and strengthen their relationship with customers. UtilityPULSE categorizes respondents into 3 customer groups. Interestingly when the customer relationship is strong i.e., customers are Secure, they recall less outages and billing problems than customers who are At Risk.

Bill payers recalling a power failure or outage

	Secure	Favorable	Indifferent	At Risk
Yes	31%	40%	46%	58%
No	68%	60%	53%	42%

Base: total respondents from the full 2015 database

Bill payers recalling a billing problem

	Secure	Favorable	Indifferent	At Risk
Yes	3%	5%	10%	38%
No	97%	94%	89%	61%

Base: total respondents from the full 2015 database

Bill payers who said their problem was solved

	Secure	Favorable	Indifferent	At Risk
Yes	94%	84%	73%	37%
No	5%	15%	23%	61%

Base: total respondents from the full 2015 database

Customer Experience Performance rating (CEPr)

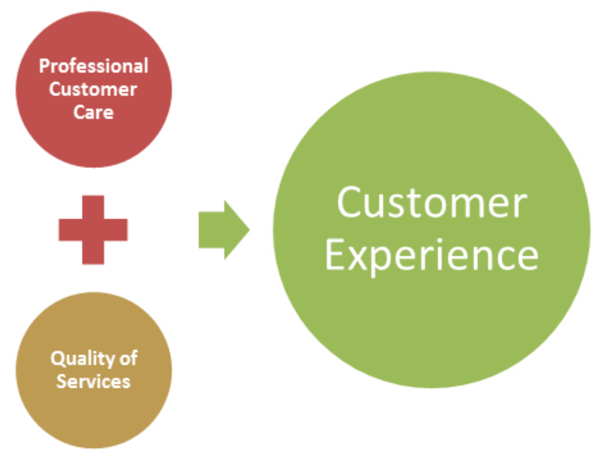
The CEPr score is an effectiveness rating and is affected by many dimensions of service. Every touch point with customers on the phone, website or in-person influences what customers think and feel about the organization. While an excellent transaction today creates a positive experience today, the perception created is that future transactions will be excellent too. Of course a negative transaction creates the perception future transactions will be negative.

When the customer experience is strong, the opportunity to build loyalty is great. When the experience is a negative one, customers often conclude the organization doesn't care. When a customer believes the organization doesn't care, outrage and anger are a very real possibility.

Understanding your customer's expectations for service is the first step in providing an amazing customer experience. It is essential customer care call centers develop a comprehensive understanding of what

At the heart of the CEPr are 4 central questions:

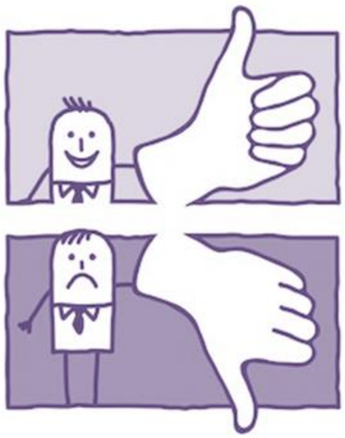
1. *Are interactions with the organization professional and productive?*
2. *Is the organization 'easy to deal with'?*
3. *Does the organization effectively meet your needs?*
4. *Does the organization provide high quality services?*



customers expect from them, whether or not their needs are being met and how they can improve their service to meet their expectations.

Some of the factors which contribute to the overall customer experience:

- Delivering accessible and consistent customer service (multi-channel)
- Understanding customer expectations
- Maintaining timely resolution timelines
- Providing effective communication(s) according to customer needs
- Demonstrating responsiveness
- Speeding up problem resolution
- Conducting problem analysis to prevent recurring issues
- Easy to do business with
- Seeking customer feedback and following through on recommendations



Customer Experience Performance rating (CEPr)			
	CNP	National	Ontario
CEPr: all respondents	86%	83%	82%

Base: total respondents

The CEPr for Canadian Niagara Power is 86%. This rating would suggest a very large majority of customers have a belief they will have a good to excellent experience dealing with Canadian Niagara Power professionals.

Customer Centric Engagement Index (CCEI)

Customer engagement is often thought of as a series of activities involving the customer such as conducting a survey, holding town hall type meetings, focus groups, etc. One could call these types of activities as the behaviour side of engagement. However there is an emotional side to engagement.

This survey also provides you with an emotional look at engagement. The UtilityPULSE CCEI is a gauge of the amount of goodwill that has been generated. High numbers in CCEI suggest there is a high level of goodwill amongst your customers – this is important for two reasons. First when something goes awry for the utility, goodwill helps the utility to be resilient. Second, goodwill encourages active participation in requests to participate in engagement activities or program offerings from the utility.

The CCEI is a metric designed to get a more in-depth look at the attachment a customer has with your LDC and its brand. High levels of customer engagement (emotional) correlate strongly to high levels of Secure and Favourable customer numbers.

Engagement is how customers think, feel and act towards the organization. As such, ensuring that customers respond in a positive way requires that they are rationally satisfied with the services provided AND emotionally connected to your LDC and its brand. The more frequently and consistently an organization's products and services can connect with a customer, especially on an emotional level, the stronger and deeper the customer becomes engaged with the organization.

UtilityPULSE has identified the six key dimensions of what defines customer engagement. They are: empowered, valued, connected, inspired, future oriented and performance oriented.

Utility Customer Centric Engagement Index (CCEI)

	CNP	National	Ontario
CCEI	84%	80%	80%

Base: total respondents

Customer centric engagement is a measure of "goodwill" towards the utility. Customers who are less engaged, as measured by the CCEI are more likely to let costs and/or price impact their perceptions of their LDC. Customers who are highly engaged are more inclined to look past costs and money issues and use a rational approach to make values-based decisions. Highly engaged customers have a stronger emotional connection to your utility. It's this emotional connection that will drive commitment, loyalty and advocacy.

UtilityPULSE Report Card®

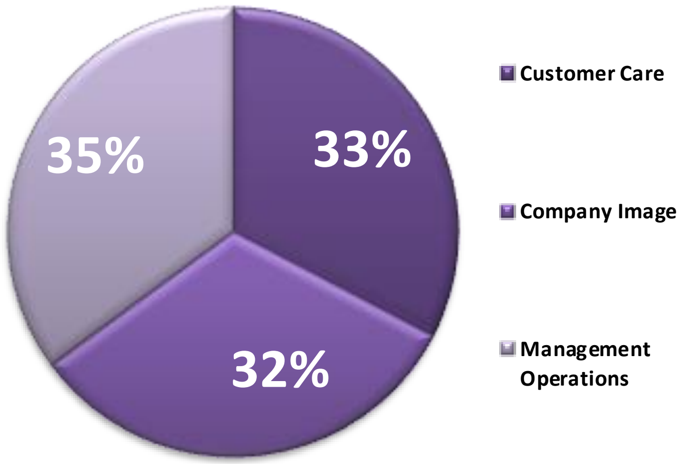
Simul's UtilityPULSE Report Card® is based on tens of thousands of customer interviews gathered over seventeen years. The purpose of the UtilityPULSE Report Card® is to provide electric utilities with a snapshot of performance – on the things that customers deem to be important. Research has identified over 20 attributes, sorted into six topic categories (we call these drivers), that customers have used to describe their utility when they have been satisfied or very satisfied with their utility. These attributes form the nucleus, or base, from which "scores" are assigned. Customer satisfaction and loyalty also play a major role in the calculations.

There are two main dimensions of the UtilityPULSE Report Card® the first is customer psyche and the other is customer perceptions about how the utility executes its business.

The Psyche of Customers

Every utility has virtually the same responsibility – provide safe and reliable electricity – yet not all customers are the same. The following chart shows the weight or significance of each category to the customer when forming their overall impression of the utility. Three major themes, each with two major categories make up the UtilityPULSE Report Card®. In effect the Report Card provides feedback about your customers' perception on the importance of each category and driver – as it relates to the benchmark.

UtilityPULSE Report Card® for Canadian Niagara Power



The UtilityPULSE Report Card is a zero sum game. As customer interest/concern in one area goes up, the others go down.

Base: total respondents

The UtilityPULSE Report Card® also provides customer perceptions about how your utility executes or performs its responsibilities. This is different, very different, from what a customer might say about a major concern or worry that they have about electricity. As our survey has shown since its inception the primary suggestion for improvement is “reduce prices”, which is also a major concern which your customers have about municipal taxes, gas for the vehicle, and other utilities.

Readers of this report should note that the categories and drivers are interdependent. Which means that, for example, failure to provide high levels of power quality and reliability will have a negative impact on customer perceptions as it relates to customer service. Customer care, when it doesn’t meet customer expectations has a negative impact on Company Image, etc.

Defining the categories and major drivers:

Category: Customer Care

Drivers: Price and Value; Customer Service

Just because everyone likes good customer care, that in and by itself, is not a reason to provide it – though it may be important to do so. In highly competitive industries good customer service may be a differentiating factor. The case for electric utilities is simple, high levels of customer care result in less work (hence cost) of responding to customer inquiries and higher levels of acceptance of the utility's actions.

Price and Value:

Customers have to purchase electricity because life and lifestyle depend on it. This driver measures customer perceptions as to whether the total costs of electricity represent good value and whether the utility is seen as working in the best interests of its customers as it relates to keeping costs affordable.

Customer Service:

Customers do have needs and every now and again have to interface with their utility. How the utility handles various customers' requests and concerns is what this driver is all about. Promptly answering inquiries, providing sound information, keeping customers informed and doing so in a professional manner are the major components of this driver.

Category: Company Image

Drivers: Company Leadership; Corporate Stewardship

Utilities have an image even if they do not undertake any activities to try to build it. A company's image is both a simple and complex concept. It is simple because companies do create images that are easily described and recognized by their target customers. It is complex because it takes many discrete elements to create an image which includes, but is not limited to: advertising, marketing communications, publicity, service offering and pricing.

An electric utility trying to manage its image has one more challenge to deal with, and that is the electric industry itself. There are so many players that residential customers (in particular) don't know who does what or who is responsible for what. So when there are political or regulatory announcements, the local utility is often swept up into the collective reaction of the population.

Company Leadership

This driver is comprised of customer perceptions as it relates to industry leadership, keeping promises and being a respected company in the community.

Corporate Stewardship

Customers rely on electricity and want to know that their utility is both a trusted and credible organization that is well managed, is accountable, is socially responsible and has its financial house in order.

Category: Management Operations

Drivers: Operational Effectiveness; Power Quality and Reliability

Electrical power is the primary product which utilities provide their customers and, they have very high expectations that the power will be there when they need it. Customers have little tolerance for outages. The reality is, every utility has to get this part right…no excuses. It is the utility's core business. This category and its drivers are clearly the most important for fulfilling the rational needs of a utility's customers.

Operational Effectiveness

This driver measures customers' perceptions as they relate to ensuring that their utility runs smoothly. Attributes such as: accurate billing and meter reading, completing service work in a professional and timely manner and maintaining equipment in good repair are deemed as important to customers.

Power Quality and Reliability

Power outages are a fact of life – and, customers know it. They expect their utility to provide consistent, reliable electricity, handle outages and restore power quickly and make using electricity safely an important priority.

CNP's UtilityPULSE Report Card®

Performance

	CATEGORY	CNP	National	Ontario
1	**Customer Care**	**A**	**B+**	**B**
	Price and Value	B+	B	B
	Customer Service	A	B+	B+
2	**Company Image**	**A**	**A**	**B+**
	Company Leadership	A	B+	B+
	Corporate Stewardship	A	A	A
3	**Management Operations**	**A**	**A**	**A**
	Operational Effectiveness	A	A	A
	Power Quality and Reliability	A	A	A
	OVERALL	**A**	**A**	**A**

Base: total respondents

As the UtilityPULSE Report Card® shows, the total customer experience with an electric utility is defined as more than “keeping the lights on”. Customers deal with your utility every day for a variety of reasons, most likely because they need someone to help them solve a problem, answer a question or take their order for service. All your employees, from customer service representatives to linemen, leave a lasting impression on the customers they interact with. In effect there are many moments of truth. Moments of truth are every customer touch point a utility has with their customers. Therefore, managing these moments of truth creates higher levels of Secure customers while reducing the number of At Risk customers that exist.

It's the small things done consistently that matter: Things like greeting every customer, whether on the phone or in person, in a friendly and helpful manner. Things like listening to the customer's needs, providing solutions to their problems and showing appreciation to the customer for their business.

Utilities now recognize customer communications as a valuable aspect of their business. The better a utility communicates with customers in a manner that speaks to them, the more satisfied they are with their overall service. “Sending out information” is not the same as having a “conversation” with a customer. We believe it is increasingly important to channel your communications to the various customer segments which exist.

Obviously employees – in every area – play a critical role in customer service success. Consequently how they feel about their job responsibilities and role in the company will be communicated indirectly through the level of service which they actually provide customers with whom they interact. The reality is engaged employees are the key to excellent customer care.

Our survey work with employees shows there are many elements of an organizational culture to support the people model needed to achieve high levels of engagement.

Our research has identified 6 main drivers that promote and support people giving their best:

People Model

- **Empowered**
- **Valued**
- **Connected**
- **Inspired**
- **Growing**
- **Performance oriented**

There are 12 key processes from “attracting employees” to “saying goodbye to employees” are part of your people model to get the best performance from every employee.

We believe taking the time to understand the difference between employee satisfaction and organizational culture is worthwhile from a resourcing perspective and from a people development perspective. Every organization has a culture – we believe it is a leadership imperative to install and maintain a culture that ensures you attain the achievements and successes of your utility’s many investments in people, technology and equipment. It is true, organization culture affects everyone and everyone affects organization culture.

The Loyalty Factor

Hierarchy of Loyalty

© UtilityPULSE

If a customer is satisfied, it doesn't necessarily mean he or she is loyal. Satisfaction is about fulfilling promises/expectations; loyalty goes way beyond that by creating exceptional experiences and long-lasting relationships. There is a reason why marketing campaigns strive to build brand loyalty, not brand satisfaction. Measuring customer loyalty in an industry where many customers don't have a choice of providers doesn't make sense. Or does it?

The answer depends on how you define "customer loyalty."

Private industry often equates customer loyalty with basic customer retention. If a customer continues to do business with a company, the customer is, by definition, considered to be loyal. If this definition were applied to many companies in the utility industry, all customers would automatically be considered loyal. As such, measuring customer loyalty would appear to be unnecessary.

Natural monopolies (like LDCs) are not really different in what they should measure except that trying to determine which customers are "loyal" or "at risk" is not about their future behaviour but more about their "attitudinal" loyalty (are they advocates?).

Whether a customer is loyal and/or satisfied will be determined by an alignment of the emotion, experience and expectation of both the customer and the LDC.

Perhaps a better or more relevant way for utilities to approach the definition of customer loyalty is to further expand how they think about loyalty. Consider the following definition: Customer loyalty is an emotional disposition on the part of the customer affecting the way(s) in which the customer (consistently) interacts, responds or reacts towards the company – its products & services and its brand.

So what does it mean to respond favourably to a company? At a basic level, this can mean choosing to remain a customer. As previously mentioned however, this is essentially a non-issue for many utility companies. It then becomes necessary to think beyond just customer retention. One needs to consider other ways in which customers can respond favourably toward a company.

Some Tips to build loyalty:

- ✓ **Solve problems quickly**
- ✓ **Treat customers right**
- ✓ **Listen to complaints**
- ✓ **Be personal; create a great experience**
- ✓ **Friendly customer service**
- ✓ **Accessible information or help**
- ✓ **Good reputation**
- ✓ **Demonstrate you care**

Other favourable responses or behaviours can be classified into one of three categories reflecting the concept of customer loyalty:

- Participation
- Compliance or Influence
- Advocacy

Specific examples of potential participatory behaviour in the electric utility industry include:

- Signing up for programs that help the customer reduce or manage their energy consumption
- Using the utility as a consultant when selecting energy products and services from a third party
- Participating in pilot programs or research studies.

Specific examples of potential compliance or influence behaviours that utility customers might exhibit include:

- Seeking the utility's advice or expertise on an energy-related issue
- Voluntarily cutting back on electricity usage if the utility advised the customer to do so
- Accepting the utility's energy advice or referrals to energy contractors or equipment
- Being influenced by the utility's opinion regarding energy- management advice, equipment, or technologies
- Providing personal information that enables the utility to better serve the customer
- Paying bills online.

Creating customer advocates can be especially important for a company in a regulated industry. In the absence of customer advocates, or worse, in a situation where customers speak unfavourably about a company or actively work to support issues that are counter to those the company supports, companies can suffer a variety of negative consequences like increased business costs, lawsuits, fines and construction delays. For an electric utility, specific examples of potential advocacy behaviour include:

- Supporting the utility's positions or actions on energy-related public issues, including the environment
- Supporting the utility's position on the location and construction of facilities
- Providing testimonials about positive experiences with the utility.

In sum, loyal behaviour in the utility industry may not be as evident as it is in a more competitive environment. Measuring customer loyalty in a generally non-competitive industry requires one to think about loyalty in non-traditional ways. Customer loyalty is an intangible asset that has positive consequences or outcomes associated with it no matter what the industry. Properly measuring loyalty among utility customers requires thoughtful probing to thoroughly identify the range of participation, compliance, and advocacy behaviours that will ultimately benefit the company in meaningful ways, and foster happier and more loyal customers.

The UtilityPULSE Customer Loyalty Performance Score segments customers into four groups: **Secure** – the most loyal - **Still Favorable**, **Indifferent**, and **At risk**.

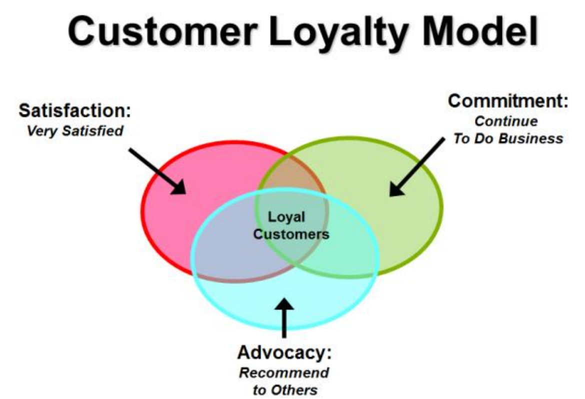
Secure customers are "very satisfied" overall with their local electricity utility. They have a very high emotional connection with their utility and definitely would recommend their local utility.

Still favorable customers are "very satisfied" overall, "definitely" or "probably" would recommend their local utility and not switch if they could.

Indifferent customers are less satisfied overall than secure and still-favorable customers and less inclined to recommend their local utility or say they would not switch.

At risk customers, who are "very dissatisfied" with their electricity utility, "definitely" would switch and "definitely" would not recommend it.

Loyalty is driven primarily by a company's interaction with its customers and how well it delivers on their wants and needs.

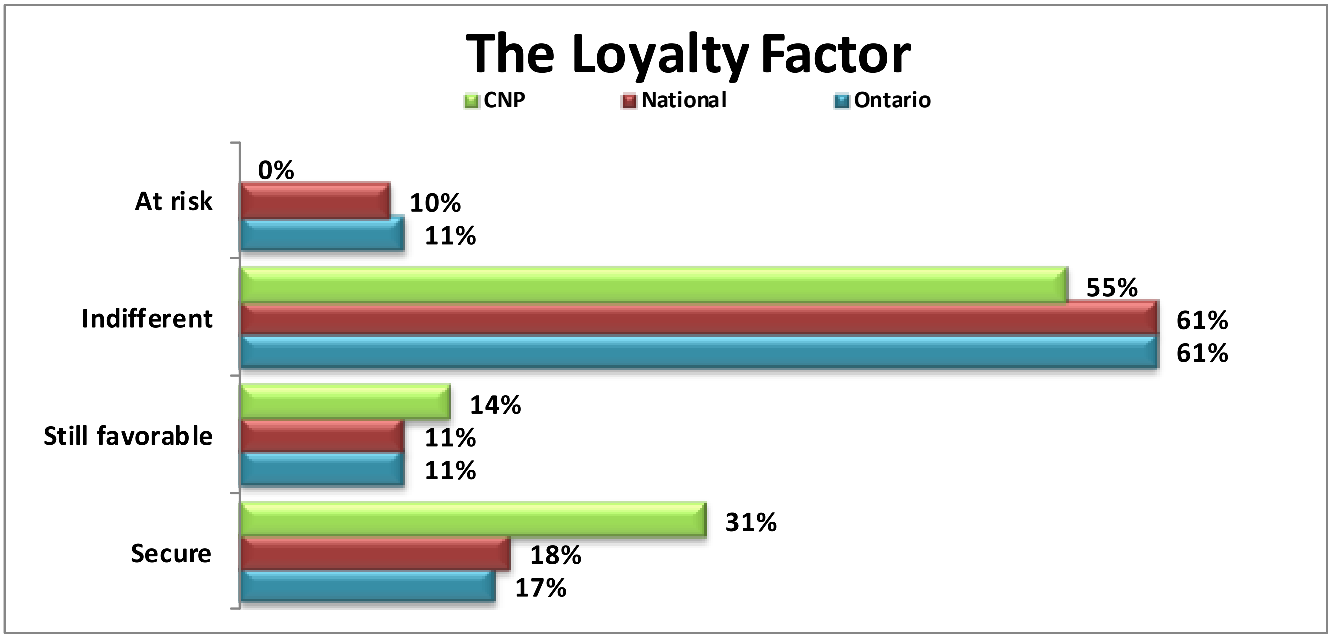


Loyalty is based on likelihood to:

- ***Satisfaction: overall satisfaction***
- ***Commitment: continue as a customer***
- ***Advocacy: willingness to recommend***

Customer Loyalty Groups				
	Secure	Favorable	Indifferent	At Risk
2015	31%	14%	55%	0%

Base: total respondents

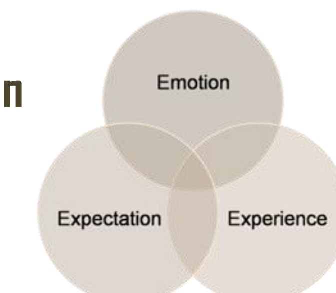


Base: total respondents

Customer Loyalty Groups				
	Secure	**Favorable**	**Indifferent**	**At Risk**
Ontario				
2015	17%	11%	61%	11%
2014	17%	10%	57%	17%
2013	24%	15%	51%	11%
2012	20%	13%	53%	14%
2011	17%	13%	54%	16%
National				
2015	18%	11%	61%	10%
2014	20%	11%	56%	13%
2013	26%	17%	47%	10%
2012	30%	13%	46%	11%
2011	28%	14%	46%	12%

Base: total respondents

"Whether a customer is loyal and/or satisfied will be determined by an alignment of the emotion, experience and expectation of both the customer and the LDC."



Secure customers’ experiences and perceptions are distinct from those of Indifferent customers. There is yet an even greater gap between those identified as Secure versus At Risk.

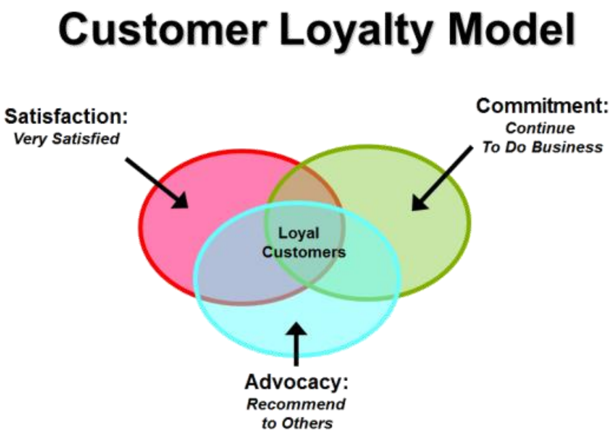
- Problems are experienced and remain unresolved far more often by the Indifferent or At Risk segments in comparison to others. This is not an unusual finding.
- Other areas of interaction also revealed considerable differences among the segments. Consistently, Secure customers’ perceptions are most positive.

Important attributes which shape perceptions about customer affinity

	Overall	Secure	At Risk
Customer focused and treats customers as if they're valued	79%	94%	49%
Is pro-active in communicating changes and issues which may affect customers	79%	92%	5%
Deals professionally with customers' problems	85%	96%	60%
Provides information to help customers reduce their electricity costs	78%	91%	53%
Quickly deals with issues that affect customers	82%	96%	56%
Delivers on its service commitments to customers	86%	98%	65%
Provides information and tools to help manage electricity consumption	79%	92%	53%
Is 'easy to do business with'	84%	97%	55%
Adapts well to changes in customer expectations	75%	90%	45%
The cost of electricity is reasonable when compared to other utilities	60%	79%	34%
Provides good value for your money	69%	88%	36%
Provides consistent reliable electricity	90%	99%	76%
Operates a cost effective electricity distribution system	72%	91%	40%
Overall the utility provides excellent quality services	85%	98%	61%

Base:data from the full 2015 database from those respondents with an opinion

Customer commitment



Customer loyalty is a term used to embrace a range of customer attitudes and behaviours. One of the metrics used to gauge loyalty is the measure of **retention,** or intention to buy again; this loyalty attitude is termed **commitment.** For LDCs commitment is not about behaviour it is about attitude i.e., do they want to remain your customer.

Customer commitment is a very important driver of customer loyalty in the electricity service industry. In a similar way to trust, commitment is considered an important ingredient in successful relationships. In simpler terms, commitment refers to the motivation to continue to do business with and maintain a relationship with a business partner i.e. the local utility.

For electric utilities, this measurement is about identifying the number of customers who feel they “want to” vs “have to” do business with you. Potential benefits of commitment may include word of mouth communications - an important aspect of attitudinal loyalty. Committed customers have been known to demonstrate a number of beneficial behaviours, for example committed customers tend to:

- Come to you. One of the key benefits of establishing a good level of customer loyalty is, customers will come to you when they need a product or service

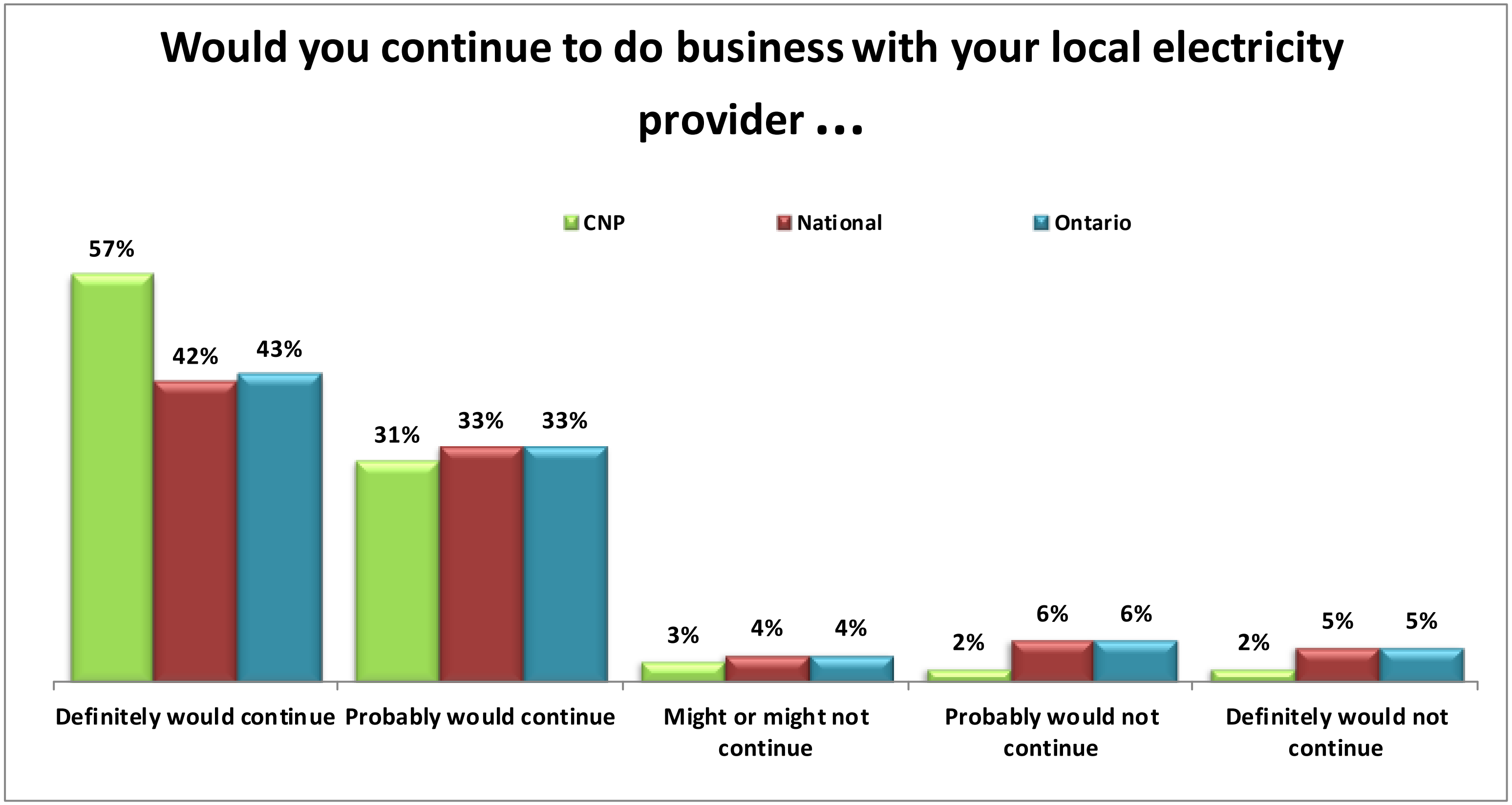
- Validate information received from 3rd parties with information and expertise that you have
- Try new products/initiatives
- Perhaps they will even trust you when recommendations are made
- Be more price tolerant
- More receptivity of utility viewpoints on various issues
- More tolerance of errors or issues which inevitably take a swipe at the utility
- Stronger levels of perception regarding how the utility is managed.

Though customers can not physically leave you, they can emotionally leave you and when they do, it becomes an extreme challenge to garner their participation or support for utility initiatives.

Electricity customers' loyalty – … Is a company that you would like to continue to do business with

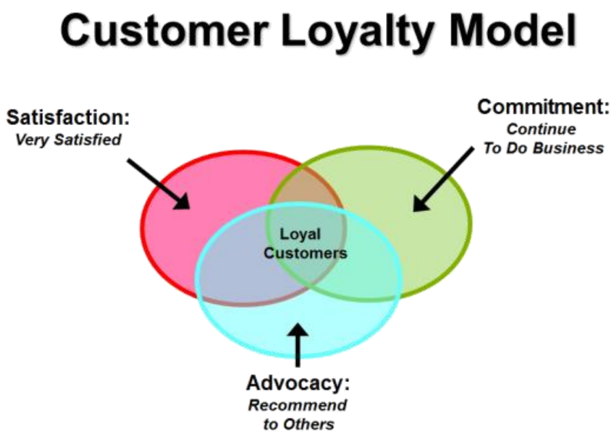
	CNP	National	Ontario
Top 2 Boxes: 'Definitely + Probably' would continue	88%	75%	77%
Definitely would continue	57%	42%	43%
Probably would continue	31%	33%	33%
Might or might not continue	3%	4%	4%
Probably would not continue	2%	6%	6%
Definitely would not continue	2%	5%	5%

Base: total respondents



Base: total respondents

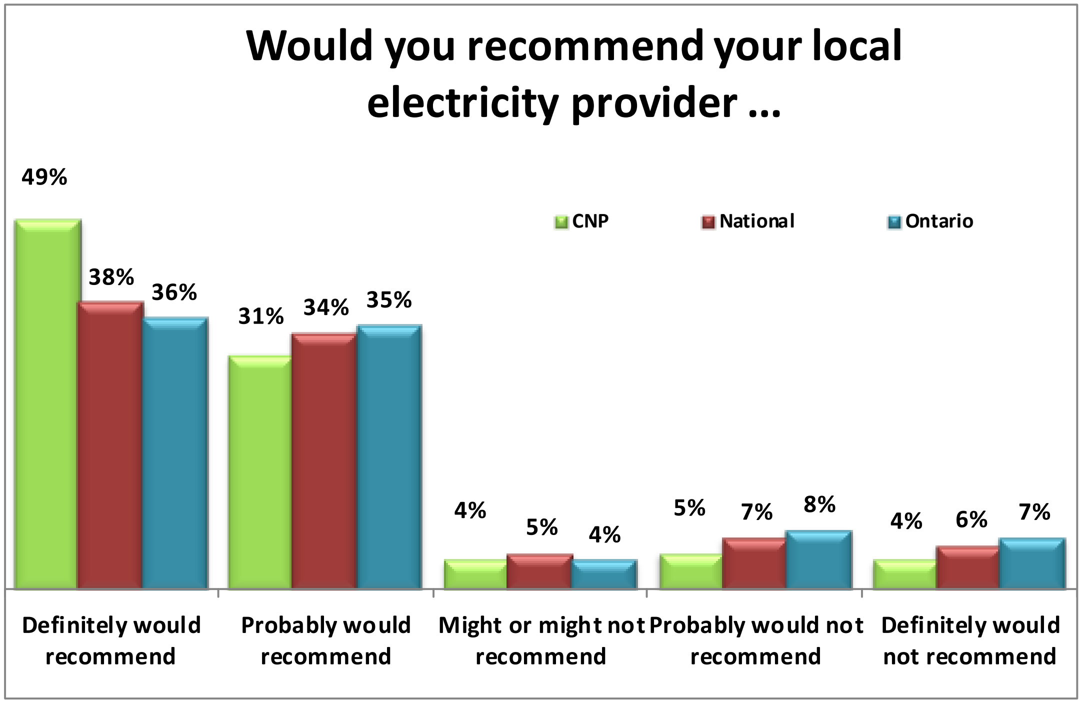
Word of mouth



Advocacy is one of the metrics measured in determining customer loyalty. Essentially, companies believe a loyal customer is one that is spreading the value of the business to others, leading new people to the business and helping the company grow. Customer referrals, endorsements and spreading the word are extremely important forms of customer behaviour. For LDCs this is about generating positive referants about the LDC as a relevant and valuable enterprise.

When customers are loyal to a company, product or service, they not only are more likely to purchase from the company again, but they are more likely to recommend it to others – to openly share their positive feelings and experiences with others. In today's world, thanks to the Internet, they can tell and influence millions of people. That equates to new customers and revenue. The same holds true, if not more, when customers are disloyal. Disgruntled customers could share their negative experiences with an ever-widening audience, jeopardizing a company's reputation and resulting in fewer engaged customers and/or customers who are Favourable or Secure. Secure customers, typically are advocates and they are deeply connected and brand-involved.

Would you tell me if you agree or disagree with the following statement? Canadian Niagara Power is a company that you would recommend to a friend or colleague …



Base: total respondents

Word of mouth communication is a very powerful form of communication and influence. When customers are speaking to other customers (or their peers) it is more credible, goes through less perceptual filters and can enhance the view of services or products better than marketing communication.

There are two forms of word of mouth which utilities need to understand. The first is Experience-based word of mouth which is the most common and most powerful form. It results from a customer's direct experience with the utility or the re-statement of a direct experience from a trusted source.

The second is Relay-based word of mouth. This is when customers pass along important messages to others based on what they have learned through the more traditional forms of communications. For example, if the utility was communicating an offer for "free LED lights" chances are high that the offer will be "relayed" to others through word of mouth.

For an electric utility, specific examples of potential positive advocacy behaviour include:

- *Recommending that other customers specifically locate in the geographic area that is serviced by that utility*
- *Supporting the utility's positions or actions on energy-related public issues, including the environment*
- *Supporting the utility's position on the location and construction of facilities*
- *Providing testimonials about positive experiences with the utility*

Electricity customers' loyalty – … is a company that you would recommend to a friend or colleague			
	CNP	**National**	**Ontario**
Top 2 boxes: 'Definitely + Probably' would recommend	79%	72%	71%
Definitely would recommend	49%	38%	35%
Probably would recommend	31%	34%	35%
Might or might not recommend	4%	5%	4%
Probably would not recommend	5%	7%	8%
Definitely would not recommend	4%	6%	7%

Base: total respondents

Our survey research as well as theory backs up the fact that if your customers are willing to endorse you and put their reputation on the line to recommend you, they also trust you and are satisfied with the service you are providing. As stated earlier, loyalty is not about behaviour in the LDC world, but one of attitude.

Corporate image

Twenty years ago many LDCs didn't put too much effort into managing their corporate brand/image. One could argue customers cared less about image and more about operational items such as reliability, restoring power quickly and billing accuracy. In fact, our research from 2006 shows Company Image represented about an 18% weight in affecting the customer's perception about their utility.

But times and customer expectations have changed a lot since then. Customers expect their utility to do the core job exceptionally well AND be much more to customers and the community. They expect you'll be socially responsible, have information they can use to reduce energy costs, be available to answer questions about the industry, etc. In 2015, Company Image represents about a 33% weight in affecting the customer's perception.

In a world where most customers feel time pressed and bombarded with information, a utility should put some real energy behind communicating its brand. The brand of a company is really its reputation. Just like a personal reputation, a brand reputation is formed based on the behaviors and actions of the company (or person), and how those behaviors and actions are perceived. After-all a positive brand image supports a positive perception of the organization. There will always be a brand/image, an LDC should actively manage its reputation, image and brand in order to have the brand/image it desires.

Every LDC has a brand and a brand image, while an image can be affected by events in the industry beyond the control of the LDC, the reality is there is a cost benefit to improving the customer experience, generating higher levels of customer engagement and growing the numbers of Favourable and Secure customers. Customers expect your utility will conduct its business professionally ***AND*** be a proactive enterprise. How would they know, if you don't communicate with them?

Marketing – Communications			
	CNP	**National**	**Ontario**
Topics that require more pro-active communication			
Cost of electricity is reasonable when compared to other utilities	62%	62%	58%
Adapts well to changes in customer expectations	75%	71%	71%
Provides good value for money	73%	67%	66%
Spends money prudently to keep the system reliable and up-to-date	79%	73%	73%
Operates a cost effective electricity distribution system	76%	70%	68%
Topics that your utility scores very well on			
Is a respected company in the community	88%	82%	82%
A company to "continue to do business with'	85%	82%	82%
Overall the utility provides excellent quality services	87%	85%	84%
Standard of reliability delivering electricity that meets expectations	89%	87%	87%
Provides consistent, reliable energy	89%	89%	89%

Base: total respondents with an opinion

Corporate Credibility & Trust

So, you have taken the time to listen to your customers and stakeholders. What next? Everyone will be looking at you to follow through on this feedback. You need to start establishing your credibility. You have to demonstrate that you can be trusted to get the job done and deliver on your promises. And, you need to do this in a way which builds your credibility and improves trust.

Creating credibility is a process, which advances only through honest, continuous communication between the utility, its regulators, and the public at large. Pro-active and credible communications from an LDC should do three things for its customers: 1- demonstrate competency 2- build confidence and 3- show a future orientation.

Attributes strongly linked to Credibility & Trust			
	CNP	**National**	**Ontario**
Overall the utility provides excellent quality services	87%	85%	84%
Keeps its promises to customers and the community	86%	79%	80%
Customer-focused and treats customers as if they're valued	82%	74%	76%
Is a trusted and trustworthy company	88%	81%	81%

Base: total respondents with an opinion

Trust and credibility are indicators of the degree of confidence stakeholders have in your organization's ability to deliver on its commitments. Trust and credibility are outcomes based on what your utility actually does, not what it might be doing.

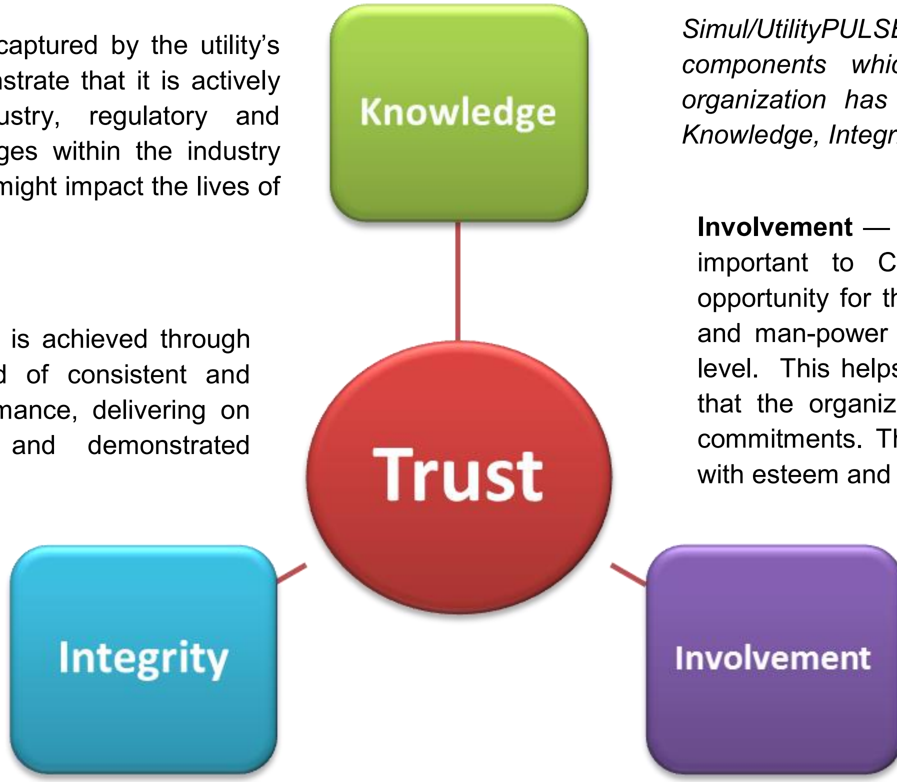
Simul/UtilityPULSE research shows the under-pinning components which lead customers to believe an organization has credibility and can be trusted are: Knowledge, Integrity, Involvement and Trust.

Knowledge is captured by the utility's ability to demonstrate that it is actively aware of industry, regulatory and economic changes within the industry and how these might impact the lives of customers.

Trust — Trust is achieved through a track record of consistent and reliable performance, delivering on commitments and demonstrated accountability.

Involvement — Corporate Involvement is increasingly important to Canadian communities as it is an opportunity for their local utility to use their resources and man-power to benefit people at the community level. This helps to build credibility as customers see that the organization is acting and delivering on its commitments. This helps customers regard the utility with esteem and respect.

Integrity is established by demonstrating adherence to a code of conduct. It requires consistently acting in accordance with the values and goals that have been communicated to customers.



Credibility and Trust Index

Canadian Niagara Power 85%

Ontario 81%

National 81%

How can service to customers be improved?

Every business, even natural monopolies, need to keep a focus on its customers, its standards of operations and in being responsive to problems. Insights into what isn't working or what can be done to improve often come from customers. Continuous improvement is the new normal.

Customers are more informed, more aware, more conscious of what's going on around them and in this age of internet and social media, they are better equipped to influence service quality and outcomes. They have learned to compare products and services, to document and monitor customer service and satisfaction, and to request or demand higher quality. And, when things go wrong, customers also know they are "one click" away from the world knowing about it.

As a further way to identify pressure points and areas of concern, respondents were asked to give their top one or two priorities for improvement to their local utility's service.

For 2015 there is heightened awareness for the need to maintain equipment, keep things up to date, improve reliability, and communicate effectively, but true to historical form the number one suggestion remains "better prices/lower rates".

And we are interested in knowing what you think are the one or two most important things Canadian Niagara Power could do to improve service to their customers?

One or two most important things 'your local utility' could do to improve service	
CNP	**% of all suggestions**
Better prices/lower rates	55%
Improve reliability of power	19%
Better communication with customers	7%
Improve/simplify/clarify billing	6%
Extend service hours/availability of hydro representative	6%
Be more efficient	4%
Better maintenance	4%
Eliminate SMART meters	2%
Information & incentives on energy conservation	1%
Better online presence	1%
Staff related concerns	1%

Base: total respondents with suggestions

What do customers think about electricity costs?

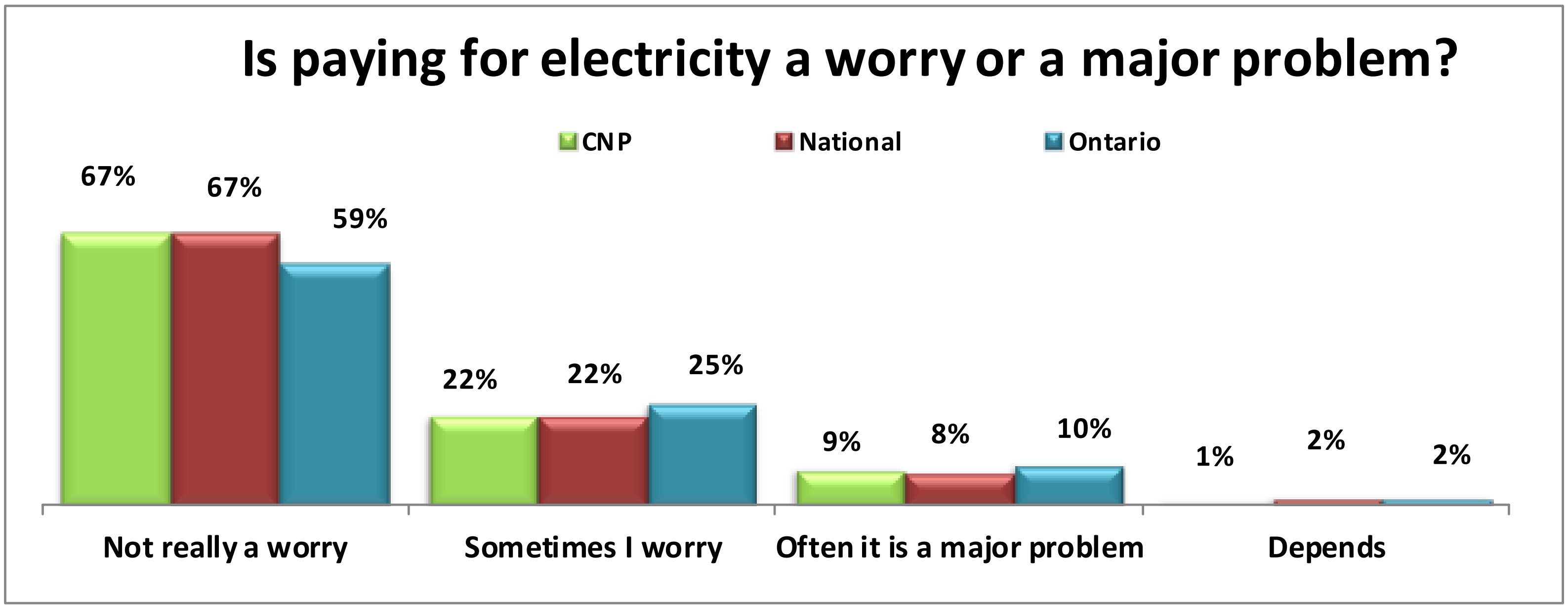
For years electric utility customers have had a very real concern about high bills and the cost of electricity. We've constantly and consistently have told our clients "when a value proposition doesn't exist or is unclear, then people will focus on price". LDCs in Ontario certainly score low on "value for money". The reality is, when a customer struggles to pay their electricity bill they struggle to see the LDC providing good value for money.

The good news is LDCs have been doing more to engage customers about the utilities' plans to spend money to improve operations and/or make capital investments. While this is seen as an important process, especially by the Ontario Energy Board, it doesn't deal with the basic issue at hand – the customer's own struggle to pay the bill. Our first year of research, 1999, showed us there was a very high correlation between ability to pay and satisfaction – in 2015 the correlation is still very high.

Next I am going to read a number of statements people might use about paying for their electricity. Which one comes closest to your own feelings, even if none is exactly right? Paying for electricity is not really a worry, Sometimes I worry about finding the money to pay for electricity, or Paying for electricity is often a major problem?

Is paying for electricity a worry or a major problem?				
	Not a worry	**Sometimes**	**Often**	**Depends**
CNP	67%	22%	9%	1%
National	67%	22%	8%	2%
Ontario	59%	25%	10%	2%

Base: total respondents



Base: total respondents

Is paying for electricity a worry or a major problem?				
	Not a worry	**Sometimes**	**Often**	**Depends**
		CNP		
<$40,000	60%	32%	8%	0%
$40<$70,000	67%	18%	11%	1%
$70,000+	78%	12%	10%	0%

Base: total respondents

For 2015, UtilityPULSE segmented respondents into 3 "average kWh groups". Group 1 represents 25% of the customer base derived from segmenting the customer data file into the first quartile of kWh usage. Group 2 represents the middle 50% of the customer base; and Group 3 represents the top quartile of kWh customers. Group 1 uses the least amount of electricity on average, while Group 3 uses the most.

Is paying for electricity a worry or a major problem?			
	kWh Group 1	**kWh Group 2**	**kWh Group 3**
Not really a worry	71%	66%	66%
Sometimes I worry	19%	21%	24%
Often it is a major problem	7%	10%	10%
Depends	1%	1%	0%

Base: total respondents

Is paying for electricity a worry or a major problem?				
	Not a worry	**Sometimes**	**Often**	**Depends**
Ontario				
2015	59%	25%	10%	2%
2014	59%	26%	11%	2%
2013	66%	21%	11%	1%
2012	59%	27%	11%	2%
2011	52%	31%	13%	3%
National				
2015	67%	22%	8%	2%
2014	69%	20%	7%	3%
2013	70%	18%	8%	2%
2012	67%	22%	8%	2%
2011	63%	25%	8%	2%

Base: 2015 Ontario and National benchmark surveys

What do small commercial customers think?

Small commercial customers represent a significant amount of any LDC's customer base yet the amount of customer intelligence a LDC has on this customer segment is extremely low. Beyond having a contact telephone number, name of company and address there often isn't much more information.

In an time when "targeted" communication is important, knowing the type of category of small commercial account would assist LDCs in delivering meaning messages in an effective way. This could be particularly important in the area of energy conservation i.e., pulling together messages and programs for specific types of businesses. After all, a small restaurant is different from a small accounting office.

Small commercial customers have, in many ways, very similar concerns with Residential customers but there are some differences. For example, small business customers are 1.5X more likely to contact their LDC when there is an outage or billing issue.

Small Commercial Customer (General Service < 50kW Demand)

A small commercial customer is defined by the OEB as a non-residential customer in a less than 50 kW demand rate class. These customers are similar to the residential customer in that their bill does not have a demand component to it and their charges are based upon KWH of consumption. Most of these customers would occupy small storefront locations or offices

Deposit requirements, monthly energy bills (and, therefore, energy usage), power quality, and reliability all directly impact a small business's financial situation. Unlike residential customers who tend to describe the cost of power interruptions in terms of a "inconvenience", commercial (and industrial) customers associate power interruptions with the cost of lost business, i.e., a loss in production is a loss in profits.

Likewise, based on the requirement of electricity to sustain business operations, there exists a difference in actual levels of demand response. For instance, small business and commercial users are unlikely to choose to decrease their electricity consumption if it is incompatible with efficient management of their business processes or threatens contracted deliveries to their primary product markets. In some cases, electricity consumption is a relatively small proportion of total input and operating costs, which substantially reduces the financial incentive for shutting down production during off peak pricing.

The tables associated with this report will contain Ontario LDC specific information as it relates to residential and commercial customers. Recognizing smaller data samples are susceptible to greater data swings, for most LDCs there would be 60 or 90 responses from small commercial customers. We have compiled the following based on a group composite of all of our 2015 discussions with small commercial and residential customers.

Satisfaction: Pre & Post		
Satisfaction (Top 2 Boxes: 'very + somewhat satisfied')	**Residential**	**Commercial**
Initially	89%	90%
End of Interview	89%	90%

Base: total respondents from the full 2015 database

As it relates to the six attributes associated with customer service:

Very or fairly satisfied with…	Residential	Commercial
The time it took to contact someone	73%	78%
The time it took someone to deal with your problem	70%	75%
The helpfulness of the staff who dealt with your problem	74%	80%
The knowledge of the staff who dealt with your problem	73%	82%
The level of courtesy of the staff who dealt with your problem	81%	88%
The quality of information provided by the staff member	72%	76%

Base: total respondents from the full 2015 database

Residential respondents had lower satisfaction levels with customer service versus Commercial respondents.

Overall satisfaction with most recent experience		
	Residential	**Commercial**
Top 2 Boxes: 'very + somewhat satisfied'	72%	77%
Bottom 2 Boxes: 'somewhat + very dissatisfied'	26%	22%

Base: total respondents from the full 2015 database

Comparisons between Residential and Commercial		
Loyalty Groups	**Residential**	**Commercial**
Secure	23%	25%
Still Favourable	10%	10%
Indifferent	59%	57%
At risk	8%	8%

Base: total respondents from the full 2015 database

Loyalty Model Factors	Residential	Commercial
Very/somewhat satisfied	89%	90%
Definitely/probably would continue	81%	81%
Definitely/probably would recommend	75%	78%

Base: total respondents from the full 2015 database

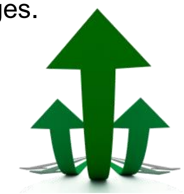
Outages & Bill problems	Residential	Commercial
Respondents with outage problems	44%	37%
Respondents with billing problems	10%	12%

Base: total respondents from the full 2015 database

Attempts to contact local utility…	Residential	Commercial
Respondents with outage problems	19%	30%
Respondents with billing problems	39%	63%

Base: total respondents from the full 2015 database

Residential respondents reported a considerably higher incidence of outages.



Commercial respondents were more likely to call in about billing and outage problems.

Important attributes which describe operational effectiveness		
	Residential	Commercial
Provides consistent, reliable electricity	90%	90%
Delivers on its service commitments to customers	86%	87%
Accurate billing	86%	85%
Quickly handles outages and restores power	87%	87%
Makes electrical safety a top priority	88%	90%
Uses responsible environmental practices when completing work	88%	89%
Is efficient at managing the electricity distribution system	82%	82%
Is a company that is 'easy to do business with'	84%	84%
Operates a cost effective electricity distribution system	72%	72%

Base: total respondents with an opinion from the full 2015 database

Important attributes which shape perceptions about corporate image		
	Residential	**Commercial**
Is a respected company in the community	85%	86%
A leader in promoting energy conservation	80%	81%
Keeps its promises to customers and the community	82%	83%
Is a socially responsible company	83%	84%
Is a trusted and trustworthy company	84%	85%
Adapts well to changes in customer expectations	74%	76%
Overall the utility provides excellent quality services	85%	86%

Base: total respondents with an opinion from the full 2015 database

Important attributes which shape perceptions about service quality and value		
	Residential	**Commercial**
Is pro-active in communicating changes and issues which may affect customers	79%	80%
Provides good value for money	68%	69%
Customer-focused and treats customers as if they're valued	79%	80%
Deals professionally with customers' problems	84%	87%
Spends money prudently	77%	77%
Quickly deals with issues that affect customers	82%	82%
Provides information and tools to help manage electricity consumption	79%	77%
Provides information to help customers reduce their electricity costs	78%	77%
The cost of electricity is reasonable when compared to other utilities	60%	59%

Base: total respondents with an opinion from the full 2015 database

Is paying for electricity a worry or a major problem?		
	Residential	**Commercial**
Not really a worry	63%	61%
Sometimes I worry	24%	27%
Often it is a major problem	8%	9%
Depends	3%	1%

Base: total respondents from the full 2015 database

When there is an outage, which of the following methods would you want your utility to use to give you information about the outage?

Preferred methods to give you information about the outage from your utility…		
	Residential	**Commercial**
Recorded telephone message	60%	58%
E-mail	32%	40%
Post on utility's website	25%	28%
Social media - Twitter	19%	20%
Text message	32%	35%
Local radio	41%	43%
Local TV	30%	30%

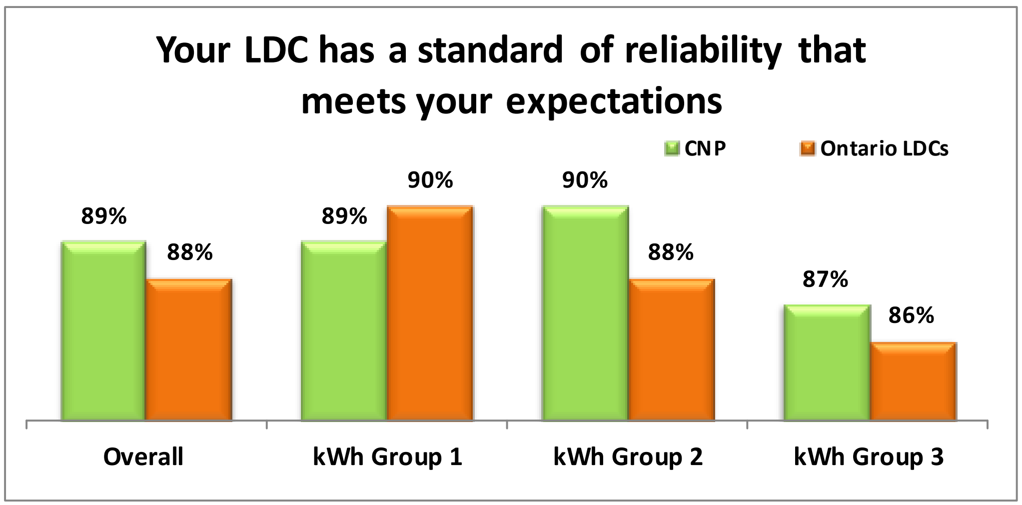
Base: total respondents from the full 2015 database

SUPPLEMENTAL QUESTIONS

Outage Management

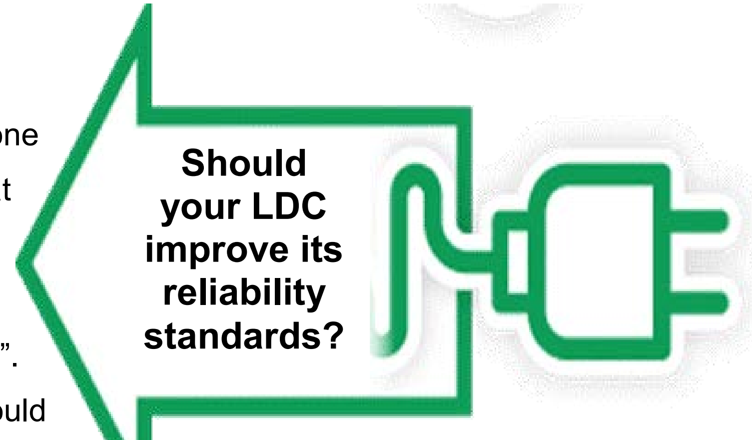
The ice-storm of December 2013 put more emphasis on how LDCs should be communicating with customers when there is an outage – both planned and unplanned outages. Since then much has been written about outage management thereby heightening customers' awareness about the issue. None-the-less every LDC has made changes and/or enhancements to their outage management practices.

Recognizing the importance of this topic to customers, a question about LDC reliability standards has been added to the core survey.



Base: An aggregate of respondents from the 2015 participating LDCs / total respondents from the local utility

Customers who responded to the survey offer a paradox. On the one hand, when asked about "your LDC has a standard of reliability that meets your expectations", scores are very high – no doubt somewhat comforting to the LDC. On the other hand, when asked "Should your LDC improve its reliability standards" the majority certainly said "yes". What we didn't do is tell the customer how much more money they would have to pay per month for higher standards.



Base: An aggregate of respondents from the 2015 participating LDCs / total respondents from the local utility

	Yes	No	Depends
Ontario LDCs	57%	35%	8%
CNP	54%	38%	8%

An outage management system helps LDC employees to discover, locate and resolve power outages in a more informed, orderly, efficient and timely manner.

How many outages are acceptable over 12 months?

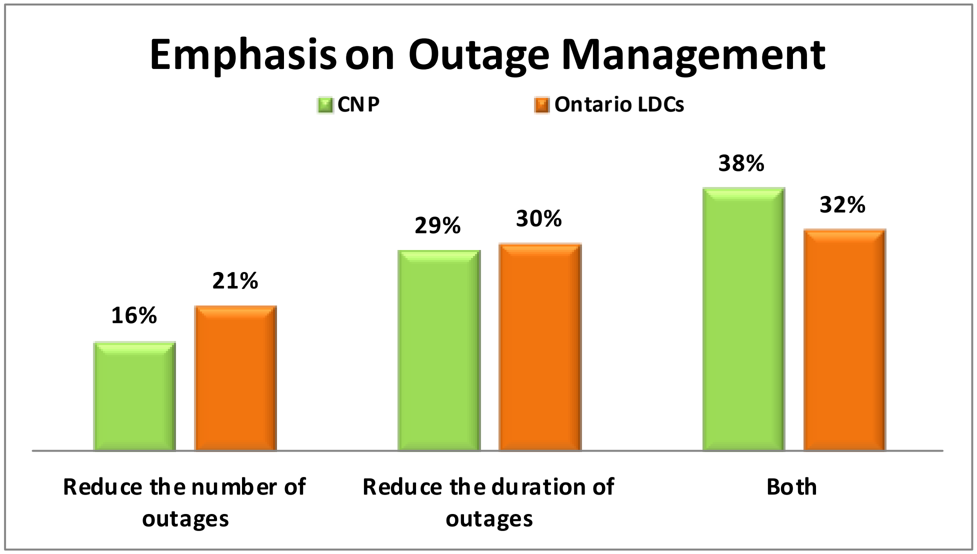
	Ontario LDCs	CNP
None	23%	17%
One	15%	9%
Two	26%	28%
Three	13%	16%
Four	5%	7%
Five or more	7%	12%
Don't Know	9%	11%

Reasonable amount of time for an unplanned outage?

	Ontario LDCs	CNP
Less than 15 minutes	14%	0%
16-30 minutes	15%	20%
31-60 minutes	13%	11%
1 to 2 hours	29%	36%
3 to 5 hours	13%	14%
6 to 12 hours	5%	5%
More than 12	3%	4%
Don't Know	8%	9%

Base: An aggregate of respondents from the 2015 participating LDCs / total respondents from the local utility

If the utility were to improve reliability should they put more emphasis on reducing the number of or unplanned outages or reducing the duration of the unplanned outage? Or both which requires an increase.



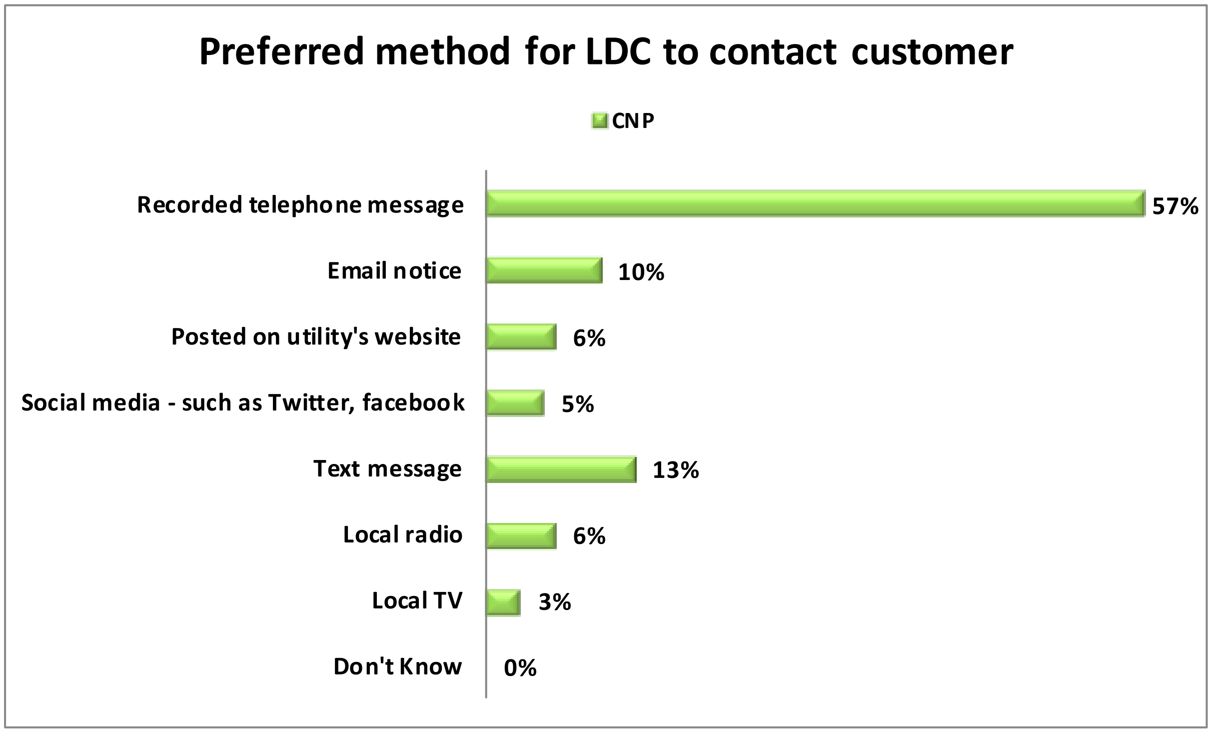
Base: An aggregate of respondents from the 2015 participating LDCs / total respondents from the local utility

Which communication channel do customers prefer to use? The telephone is the most used and preferred method to contact the LDC to communicate with customer care representatives.

	Telephone	Email	Utility Website	Social Media	Mail	In Person
Ontario LDCs	84%	5%	2%	1%	0%	0%
CNP	89%	4%	2%	2%	0%	3%

Base: An aggregate of respondents from the 2015 participating LDCs / total respondents from the local utility

While the telephone is still the communication channel most would prefer to use to communicate with or to be communicated to, customers do have an expectation for the LDC to use varied methods to contact them. Communication channels other than the telephone received higher preference scores when asked about the utility contacting the customer versus the customer's use of such channels to contact the utility. This indicates the onus is on the utility to find a way to contact a customer when necessary and that it should use various means to ensure the message is communicated. Proactive communication channels which include recorded calls, emails and SMS (text messaging) are increasingly being used by utilities to reach customers affected by outages.



Base: total respondents

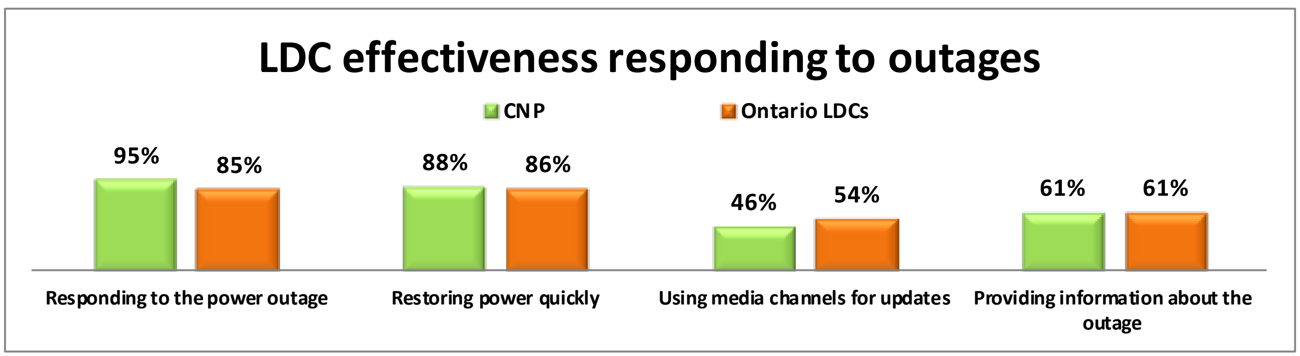
Responding to outages and making sure power is restored quickly is a priority item with customers as well as communications during outage events. Being effective during an outage situation from the point of view of a customer requires:

- timely information on outages is provided
- utilities understand that even a short outage in duration is impactful
- in large scale events, utilities should proactively provide tips on how to prepare for extended outages
- being kept informed about what is going on during an outage makes customers feel valued.

LDC effectiveness responding to outages

	Ontario LDCs	CNP
Responding to the power outage	85%	95%
Restoring power quickly	86%	88%
Using media channels for updates	54%	46%
Providing information about the outage	61%	61%

Base: An aggregate of respondents from the 2015 participating LDCs / total respondents from the local utility



Base: An aggregate of respondents from the 2015 participating LDCs / total respondents from the local utility

The types of information customers require during an outage include:

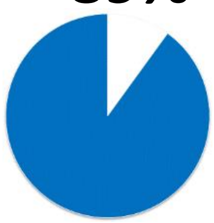
- *When will their power be restored?*
- *What areas are affected?*
- *How many customers are impacted?*
- *Have work crews been dispatched to the affected area and is the utility working to restore power?*
- *What was the cause of the power outage?*
- *What can customers do to cope during the outage?*

Soliciting Feedback

The Ontario Energy Board, in its publication: *“EB-2010-0379 Report of the Board Performance Measurement for Electricity Distributors: A Scorecard approach”,* referenced staff recommendations that distributors would be required to survey customer satisfaction among other items in an effort to continually seek ways in which to improve performance and productivity while better understanding and engaging with their customers.

UtilityPULSE asked 1,269 Residential customers, located throughout Ontario and who pay the electricity bill questions pertaining to the solicitation of customer feedback and opinions on different electricity industry matters. These questions were asked with intent of gauging the customer’s perception of requesting feedback and the importance thereof.

89%

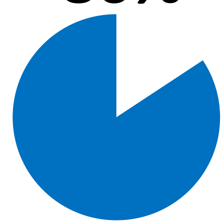


89% of Ontario respondents feel it is ‘very + somewhat’ important for their LDC to solicit customer feedback on customers’ overall satisfaction with the utility.

83%

83% of Ontario respondents feel it is ‘very + somewhat’ important for their LDC to solicit customer feedback on how much money is being spent on repairing equipment.

86%



86% of Ontario respondents feel it is ‘very + somewhat’ important for their LDC to solicit customer feedback on how much money is being spent on keeping the system reliable.

84%

84% of Ontario respondents feel it is ‘very + somewhat’ important for their LDC to solicit customer feedback on the utility’s plans to spend money on extending the system to help economic development in the community.

Importance of soliciting customer opinions and feedback on ….				
	Top 2 boxes: 'very + somewhat' important	Bottom 2 boxes: 'somewhat + very' unimportant	Neither	Don't know
… customers' overall satisfaction with the utility …	89%	8%	1%	3%
… how much money is being spent on repairing equipment …	83%	9%	1%	6%
… how much money is being spent on keeping the system reliable …	86%	6%	2%	6%
… the utility's plans to spend money on extending the system to help economic development in the community …	84%	10%	2%	4%

Base: 1,269 Residential respondents from the 2015 Ontario Benchmark survey

The data reveals customers do believe the LDC should be seeking their opinions on certain operational matters as well as their overall satisfaction. It could be the customer's view that by having their input counted especially where spending is concerned, they might play a part in controlling costs and stop any unnecessary spending.

SMART Grid

A number of functions will be available to electricity system stakeholders due to the advance of SMART Grid technologies. Providing tools to address peak demand, to improve system reliability, to manage distribution and energy storage are tools available to LDCs and system operators, SMART Grid technologies offer consumers possibilities as well. For the electricity customer, SMART grid technologies can provide the opportunity to manage electricity use, to control bills, and to sell power back the grid. How much of this is the average consumer aware of or “in the know”? While many industry insiders talk about the SMART Grid, i.e., its benefits and its challenges, the reality is, the average person is not very knowledgeable about it.

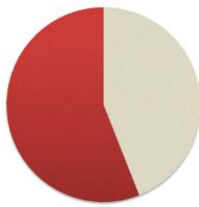
Level of knowledge about the SMART Grid

	Ontario 2015	Ontario 2014
I have a fairly good understanding of what it is and how it might benefit homes and businesses	9%	9%
I have a basic understanding of what it is and how it might work	21%	25%
I’ve heard of the term, but don’t know much about it	37%	36%
I have not heard of the term	32%	29%
Don’t know	1%	1%

Base: total respondents from the 2015/2014 Ontario Benchmark survey

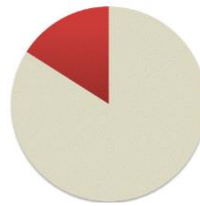
Once again, this year's survey probed around the concept of SMART Grid. While another year has passed, it is evident that the SMART Grid is still not a much talked about concept, only 30% [34%;2014] have a basic or good understanding of what it is, 69% have either not heard of the term or if they did, do not know much about it.

56%



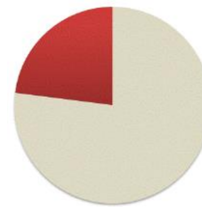
56% of Ontario respondents feel it is 'very + somewhat' important to pursue the implementation of SMART Grid technologies

16%



16% of Ontario respondents feel it is 'very + somewhat' unimportant to pursue the implementation of SMART Grid technologies

23%



23%, one in four Ontarians simply admitted they "do not know" if SMART grid technologies should be pursued.

Base: total respondents from the 2015 Ontario Benchmark survey

Support towards working with neighbouring utilities on SMART Grid initiatives

	Ontario 2015	Ontario 2014
Very supportive	40%	41%
Somewhat supportive	39%	37%
Neither supportive or unsupportive	2%	4%
Somewhat unsupportive	5%	4%
Unsupportive	6%	4%
Don't know	8%	10%

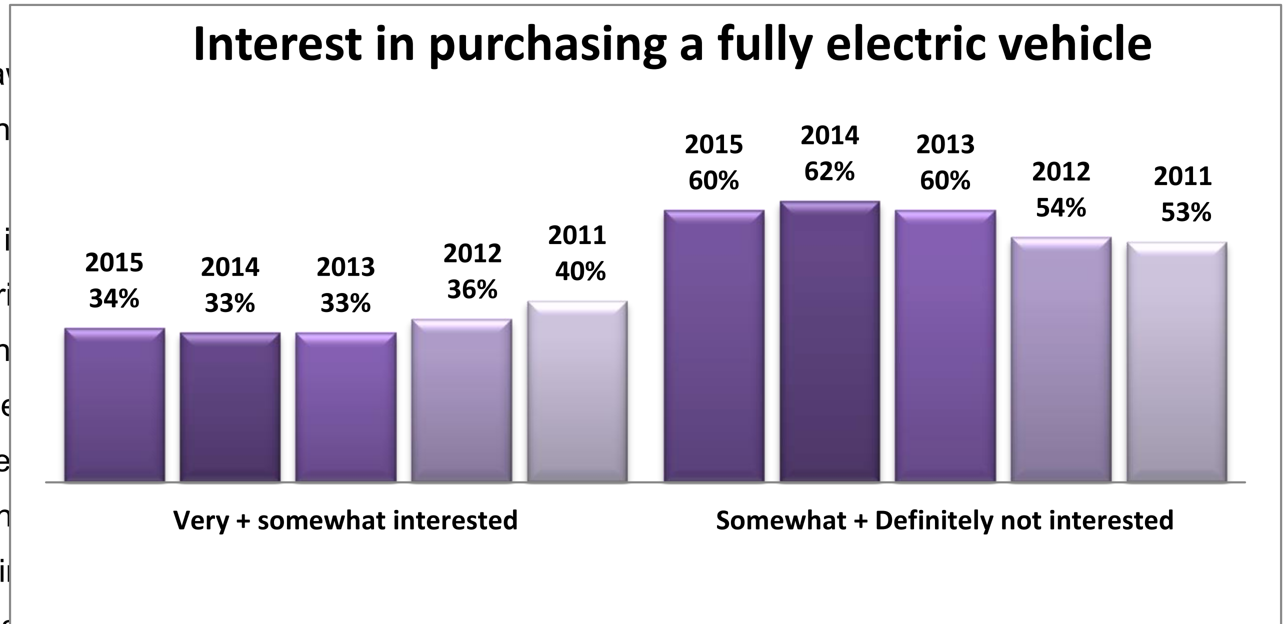
Base: total respondents from the 2015/2014 Ontario Benchmark survey

With inconsistencies between Ontario LDCs' about the definition of SMART Grid coupled with different levels of technical maturity --- collaboration amongst LDCs is very difficult.

Purchasing an Electric Vehicle

For 5 years UtilityPULSE has been collecting information and tracking electricity customers interest in purchasing an electric vehicle. In fact, we've asked the same questions in the same way for 5 years.

While the actual ra
numbers are interestin
e.g., 34% are very
somewhat interested i
purchasing an electri
vehicle, the 5 year tren
is also interesting. Othe
than the first year whe
various manufacturers h
the airwaves about thei
EVs the interest level has remained in the 34% area. We can conclude that "interest" in purchasing doesn't actually translate to a customer acting on that interest and buying an electric vehicle. Perhaps it is because the EV industry has not done a good job in allaying fears about distances that can be travelled between charges, or time to charge from empty, or the higher depreciation costs associated with most EVs.



From a demographics perspective respondents in the 35-54 age group had the highest level of interest at 45% (39% in 2014). Data from the survey also tells us there is very little variance in interest to purchase based on the respondents ability to pay for their electricity bills. Customers who said they have "No worries" or said they "Often worry" about paying their electricity bills were statistically equal in their level of interest.

Interest in purchasing a fully electric vehicle

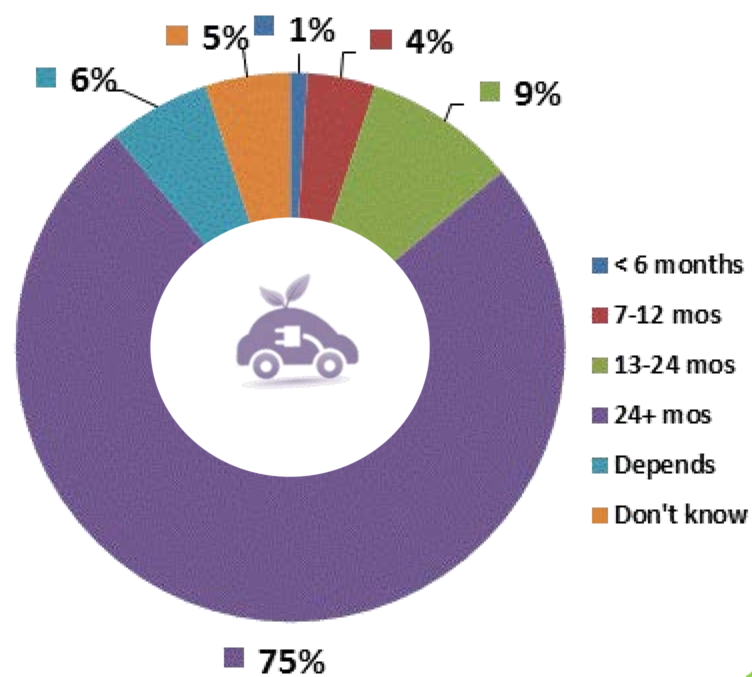
	Income <$40K	Income $40K<$70K	Income $70K +	Age 18-34	Age 35-54	Age 55+
Top 2 Boxes: 2015 'very + somewhat interested'	30%	28%	41%	29%	45%	29%
Top 2 Boxes: 2014 'very + somewhat interested'	30%	28%	42%	27%	39%	28%

Base: total respondents from the 2015 Ontario Benchmark survey

Length of time before purchasing a fully electric vehicle

	Ontario 2015	Ontario 2014
Immediately to next 6 months	6%	2%
7 to 12 months	4%	2%
13 to 24 months	9%	9%
Over 24 months	75%	79%
Depends	6%	5%
Don't know	5%	3%

Base: total respondents from the 2015/2014 Ontario Benchmark survey



Method

The findings in this report are based on telephone interviews conducted for Simul Corp. / UtilityPULSE by Greenwich Associates between October 8-22, 2015, with 410 respondents who pay or look after the electricity bills from a list of residential and small and medium-sized business customers supplied by CNP.

The sample of phone numbers chosen was drawn randomly to insure that each business or residential phone number on the list had an equal chance of being included in the poll.

The sample was stratified so that 85% of the interviews were conducted with residential customers and 15% with commercial customers.

In sampling theory, in 19 cases out of 20 (95% of polls in other words), the results based on a random sample of 410 residential and commercial customers will differ by no more than ±4.84 percentage points where opinion is evenly split.

This means you can be 95% certain that the survey results do not vary by more than 4.84 percentage points in either direction from results that would have been obtained by interviewing all CNP residential and small and medium-sized commercial customers if the ratio of residential to commercial customers is 85%:15%.

The margin of error for the sub samples is larger. To see the error margin for subgroups use the calculator at http://www.surveysystem.com/sscalc.htm.

Interviewers reached 1,483 households and businesses from the customer list supplied by CNP. The 410 who completed the interview represent a 28% response rate.

The findings for the Simul/UtilityPULSE National Benchmark of Electric Utility Customers are based on telephone interviews conducted with adults throughout the country who are responsible for paying electric utility bills. The ratio of 85% residential customers and 15% small and medium-sized business customers in the National study reflects the ratios used in the local community surveys. The margin of error in the National poll is ±2.7 percentage points at the 95% confidence level.

For the National study, the sample of phone numbers chosen was drawn by recognized probability sampling methods to insure that each region of the country was represented in proportion to its population and by a method that gave all residential telephone numbers, both listed and unlisted, an equal chance of being included in the poll.

The data were weighted in each region of the country to match the regional shares of the population.

The margin of error refers only to sampling error; other non-random forms of error may be present. Even in true random samples, precision can be compromised by other factors, such as the wording of questions or the order in which questions were asked.

Random samples of any size have some degree of precision. A larger sample is not always better than a smaller sample. The important rule in sampling is not how many respondents are selected but how they are selected. A reliable sample selects poll respondents randomly or in a manner that insures that everyone in the population being surveyed has an equal chance of being selected.

How can a sample of only several hundred truly reflect the opinions of thousands or millions of electricity customers within a few percentage points?

Measures of sample reliability are derived from the science of statistics. At the root of statistical reliability is probability, the odds of obtaining a particular outcome by chance alone. For example, the chances of having a coin come up heads in a single toss are 50%. A head is one of only two possible outcomes.

The chance of getting two heads in two coin tosses is less because two heads are only one of four possible outcomes: a head/head, head/tail, tail/head and tail/tail.

But as the number of coin tosses increases, it becomes increasingly more likely to get outcomes that are either close to or exactly half heads and half tails because there are more ways to get such outcomes. Sample survey reliability works the same way but on a much larger scale.

As in coin tosses, the most likely sample outcome is the true percentage of whatever we are measuring across the total customer base or population surveyed. Next most likely are outcomes very close to this true percentage. A statement of potential margin of error or sample precision reflects this.

Some pages in the computer tables also show the standard deviation (S.D.) and the standard error of the estimate (S.E.) for the findings. The standard deviation embraces the range where 68% (or approximately two-thirds) of the respondents would fall if the distribution of answers were a normal bell-shaped curve. The spread of responses is a way of showing how much the result deviates from the "standard mean" or average. In the CNP data on corporate image, Simul converted the answers to a point scale with 4 meaning agree strongly, 3 meaning agree somewhat and so on (see in the computer tables).

For example, the mean score is 3.56 for providing consistent, reliable electricity. The average is 3.18 for providing information to help customers reduce their energy costs.

For reliable electricity the standard deviation is 0.69. For affordable energy the S.D. is 0.92. These findings mean there is a wider range of opinion – meaning less consensus – about whether CNP provides information to help customers to reduce their energy costs than about whether CNP energy supplies are reliable.

Beneath the S.D. in the tables is the standard error of the estimate. The S.E. is a measure of confidence or reliability, roughly equivalent to the error margin cited for sample sizes. The S.E. measures how far off the sample's results are from the standard deviation. The smaller the S.E., the greater the reliability of the data.

In other words, a low S.E. indicates that the answers given by respondents in a certain group (such as residential bill payers or women) do not differ much from the probable spread of the answers "predicted" in sampling and probability theory.

Certain questions pertaining to conservation and conservation efforts used an aggregate data approach whereby similar data sets were accumulated to form a larger sample size establishing a higher confidence interval, forecasting value and modeling data.

In certain instances, all of the sub-datasets from the entire UtilityPULSE database for 2015 were concatenated in order to use the average of all the control samples for comparison. The cumulated population base for these questions was in excess of 9,000.

At a 95% confidence level the margin of error is ±1.03 and at a 99% confidence level the margin of error would be ±1.36. So the aggregate strategy has given a very good population sample size which better, or more accurately, reflects the true feelings and beliefs of the population as a whole.

Good things happen when work places work. You'll receive both strategic and pragmatic guidance about how to improve Customer satisfaction & Employee engagement with leaders that lead and a front-line that is inspired. We provide: training, consulting, surveys, diagnostic tools and keynotes. The electric utility industry is a market segment that we specialize in. Both large and small utilities have received actionable insights. For seventeen years we have been talking to 1000's of utility customers in Ontario and across Canada and we have expertise that is beneficial to every utility.

Culture, Leadership & Performance – Organizational Development	**Focus Groups, Surveys, Polls, Diagnostics**	**Customer Service Excellence**
Leadership development	Diagnostics ie. Change Readiness, Leadership Effectiveness, Managerial Competencies	Service Excellence Leadership
Strategic Planning	Surveys & Polls	Telephone Skills
Teambuilding	Customer Satisfaction and Loyalty Benchmarking Surveys	Customer Care
Organizational Culture Transformation	Organization Culture Surveys	Dealing with Difficult Customers

Benefit from our expertise in Customer Satisfaction, Leadership development, Strategy development or review, and Front-line & Top-line driven-change. We're experts in helping you assess and then transform your organization's culture to one where achieving goals while creating higher levels of customer satisfaction is important. Anyone can present data, or design programs – we believe having an understanding of the industry before doing so is cruicial. Call us when creating an organization where more employees satisfy more customers more often, is important.

Your personal contact is:

Sid Ridgley, CSP

Phone: (905) 895-7900 Fax: (905) 895-7970 E-mail: sidridgley@utilitypulse.com or sridgley@simulcorp.com

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Appendix H.

Executive Presentation of Customer DSP Focus Groups

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CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Customer Engagement Focus Group

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

- Agenda
  - Introductions
  - Overview of Canadian Niagara Power – 15 minutes
  - Discussion and Feedback – 60 minutes
  - Wrap-up -15 minutes

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

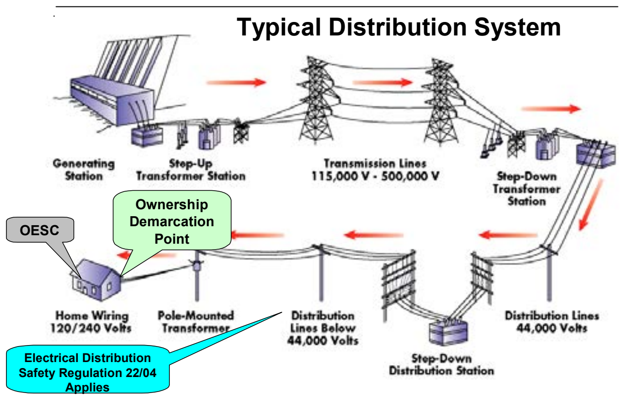
- Who is Canadian Niagara Power (CNP)?
  - CNP is the Local Distribution Company Serving Fort Erie and Port Colborne
  - Serve approximately 24,000 electricity customers
  - Peak Demand- 85 MW
  - Total KM lines - 844.11

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

- What are our Core Values?
  - Respect for People
  - Safety and the Environment
  - Financial Success
  - Customer Service
  - Productivity
  - Community Involvement

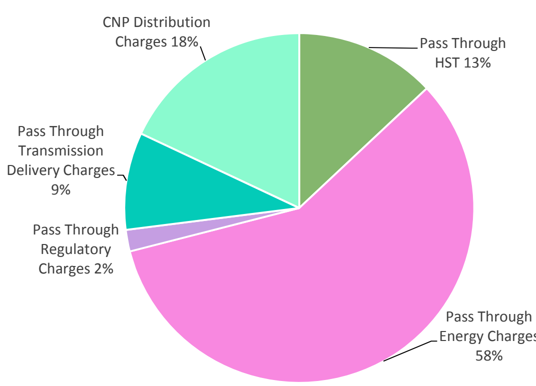
CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Power System Overview



CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

- What makes up your electricity bill?



CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

- What is a Distribution System Plan (DSP)?
  - ❑A comprehensive document detailing how the distribution system is maintained and upgraded.
    - ✓Distribution Asset Management Plan
    - ✓Distribution System Planning Studies
    - ✓Public inputs
    - ✓Operational inputs
    - ✓Government polices, rules, regulation (OEB, ESA…)
    - ✓It is a five year plan and updated annually
    - ✓Summited to OEB as part of Rate application

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

- What is a Distribution Asset Management Plan (DAMP)?
  - ❑A comprehensive document detailing all assets within the distribution system.
    - ✓Details of our equipment
    - ✓The locations of all of our equipment
    - ✓The condition of the equipment
    - ✓The plan for inspecting and maintaining the equipment
    - ✓Identifies equipment that should be replaced based upon their condition.

- What is a Distribution System Planning Study?
  - ❑Technical assessment of the system operation and components
    - ✓Equipment capacity
    - ✓Power quality
    - ✓System reliability
    - ✓Public, employee, and equipment safety
    - ✓System efficiency (losses)
- Develop the action plan

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

- What are some major capital projects in the current plan?
  - ➢Rebuild Gilmore Distribution Substation
  - ➢Voltage conversion in North of Town of Fort Erie
  - ➢Port Colborne Downtown Conductor Upgrade
  - ➢Hydro Services for New Subdivisions
    - Westwood
    - South Coast Village Phase 2
    - Ridgeway Shares Phase 2
    - Parklane Place
    - Others …

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

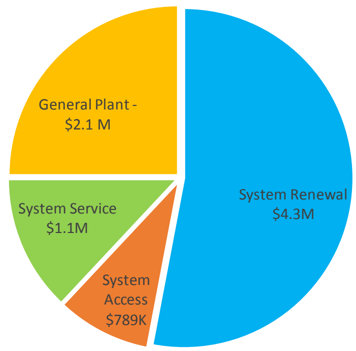
- How Rates are Determined?
  - CNPI develops and updates the DSP
  - The DSP provides all evidences and the action plan
  - The costs of operating, maintaining and upgrading the system are developed from the action plan
  - CNPI calculates new rates based on Ontario Energy Board (OEB) rules
  - CNPI provides the evidence and new rates to OEB in a Rate Application
  - The public (interveners) challenge the expenses through an intervention process
  - OEB determines the new rates considering all evidences

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

- What Factors Impact Rates?
  - User pay system
    - Operating cost
    - Depreciation (Capital investment)
    - Taxes
    - Return on Capital

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

- What are our capital investments in 2016?



CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

- Feedback & Discussion

Eastern Ontario Power
A FORTIS ONTARIO Company

Customer Engagement Focus Group

Eastern Ontario Power
A FORTIS ONTARIO Company

- Agenda
  - Introductions
  - Overview of Eastern Ontario Power – 10 minutes
  - Discussion and Feedback – 60 minutes
  - Wrap-up -15 minutes

Eastern Ontario Power
A FORTIS ONTARIO Company

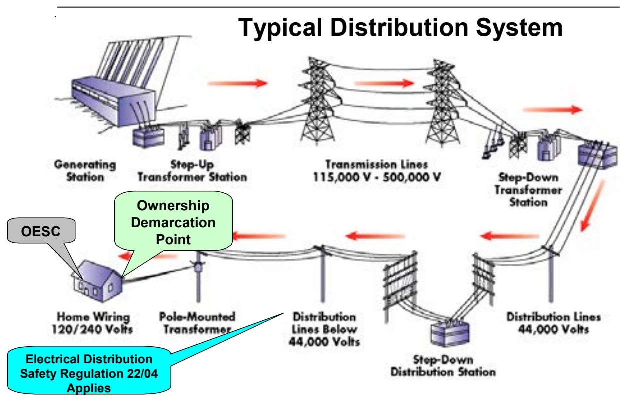
- Who is Eastern Ontario Power?
  - ➢Serve approximately 3,500 electricity customers in Gananoque, Ontario
  - ➢ Peak Demand – 14.4 MW
  - ➢Total KM lines - 182

Eastern Ontario Power
A FORTIS ONTARIO Company

- What are our Core Values?
  - ❖Respect for People
  - ❖Safety and the Environment
  - ❖Financial Success
  - ❖Customer Service
  - ❖Productivity
  - ❖Community Involvement

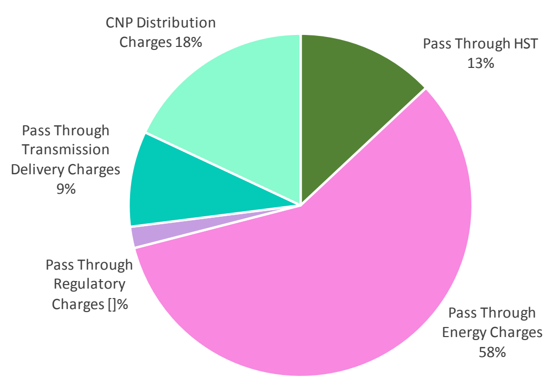
Eastern Ontario Power
A FORTIS ONTARIO Company

Power System Overview



CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

- What makes up your electricity bill?



Eastern Ontario Power
A FORTIS ONTARIO Company

- What is a Distribution System Plan (DSP)?
  - ❑A comprehensive document detailing how the distribution system is maintained and upgraded.
    - ✓Distribution Asset Management Plan
    - ✓Distribution System Planning Studies
    - ✓Public inputs
    - ✓Operational inputs
    - ✓Government polices, rules, regulation (OEB, ESA…)
    - ✓It is a five year plan and updated annually
    - ✓Summited to OEB as part of Rate application

Eastern Ontario Power
A FORTIS ONTARIO Company

- What is a Distribution Asset Management Plan (DAMP)?
  - ❑A comprehensive document detailing all assets within the distribution system.
    - ✓Details of our equipment
    - ✓The locations of all of our equipment
    - ✓The condition of the asset
    - ✓The plan for inspecting and maintaining the equipment
    - ✓Identifies assets that should be replaced based upon their condition.

Eastern Ontario Power
A FORTIS ONTARIO Company

- What is a Distribution System Planning Study?
  - ❑Technical assessment of the system operation and components
    - ✓Equipment capacity
    - ✓Power quality
    - ✓System reliability
    - ✓Public, employee, and equipment safety
    - ✓System efficiency (losses)
- Develop the action plan

Eastern Ontario Power
A FORTIS ONTARIO Company

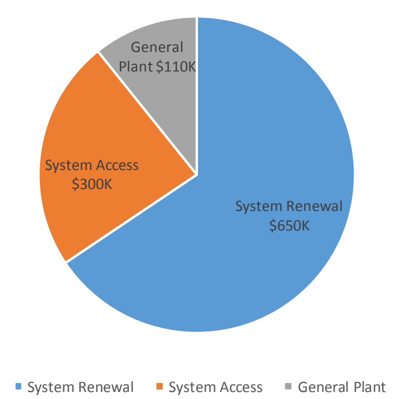
- What are some major capital projects in the current plan?

Eastern Ontario Power
A FORTIS ONTARIO Company

- What Factors Impact Rates?
  - ❑User pay system
    - Operating cost
    - Depreciation (Capital investment)
    - Taxes
    - Return on Capital

Eastern Ontario Power
A FORTIS ONTARIO Company

- How are we planning to spend in 2016?



Eastern Ontario Power

A FORTIS ONTARIO Company

- Feedback & Discussion

Appendix I.

CNPI Capital Expenditure Approval Forms 2012-2017

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CANADIAN NIAGARA POWER INC. A FORTIS ONTARIO Company	Capital Expenditure Approval Form - Distribution Lines
Project Name:	Overhead Services
Settlement Account:	102027, 101164
OEB Category	(●) SYSTEM ACCESS ( ) SYSTEM RENEWAL ( ) SYSTEM SERVICE ( ) GENERAL PLANT
OEB Primary ("Trigger") Driver:	Customer Service Request
Project Information:	
Number of Circuits:	N/A
Number of Phases:	N/A
Number of Poles Installed:	N/A
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	January 2012
Completion Date:	December 2017
Is this a multi-year project?	YES

Project Description:

Overhead service connections are required to permit the expansion of distribution facilities to both residential and commercial customers. Overhead service connections are tracked under various, service specific orders.

Applicable Justification Criteria:	☑ 1. Efficiency, Customer Value, Reliability ☐ 2. SAFETY ☐ 3. Cyber-security, Privacy ☐ 4. Coordination, Interoperability ☐ 5. Economic Development ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

1. Customer Value - Obligation per our conditions of service. Overhead connections are required to permit the expansion of distribution facilities.

Total:	**2012 - $ 156,473** **2013 - $ 241,748** **2014 - $ 298,464** **2015 - $ 300,145** **2016 - $ 389,183** **2017 - $ 212,731**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

CANADIAN NIAGARA POWER INC. A FORTIS ONTARIO Company	Capital Expenditure Approval Form - Distribution Lines
Project Name:	Underground Services
Settlement Account:	102028, 101165
OEB Category	(●) SYSTEM ACCESS ( ) SYSTEM RENEWAL ( ) SYSTEM SERVICE ( ) GENERAL PLANT
OEB Primary ("Trigger") Driver:	Customer Service Request
Project Information:	
Number of Circuits:	N/A
Number of Phases:	N/A
Number of Poles Installed:	N/A
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	January 2012
Completion Date:	December 2017
Is this a multi-year project?	YES

Project Description:

Underground service connections are required to permit the expansion of distribution facilities to both residential and commercial customers. Underground service connections are tracked under various, service specific orders.

Applicable Justification Criteria:	☑ 1. Efficiency, Customer Value, Reliability ☐ 2. SAFETY ☐ 3. Cyber-security, Privacy ☐ 4. Coordination, Interoperability ☐ 5. Economic Development ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

1. Customer Value - Obligation per our conditions of service. Underground connections are required to permit the expansion of distribution facilities.

Total:	**2012 - $ 194,342** **2013 - $ 137,752** **2014 - $ 154,130** **2015 - $ 211,346** **2016 - $ 153,037** **2017 - $ 159,301**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Distribution Lines	
Project Name:	Distribution Upgrades and Expansions
Settlement Account:	102021, 101170
OEB Category	(●) SYSTEM ACCESS ( ) SYSTEM RENEWAL ( ) SYSTEM SERVICE ( ) GENERAL PLANT
OEB Primary ("Trigger") Driver:	Third Party Infastructure Development, Customer Service Requests
Project Information:	
Number of Circuits:	N/A
Number of Phases:	N/A
Number of Poles Installed:	N/A
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	January 2012
Completion Date:	December 2017
Is this a multi-year project?	YES

Project Description:

Distribution system upgrades and expansions to support externally driven projects from third party entities. This includes reinforcements to permit the construction of new distribution facilities to service load customers.

Applicable Justification Criteria:

- [ ] 1. Efficiency, Customer Value, Reliability
- [ ] 2. SAFETY
- [ ] 3. Cyber-security, Privacy
- [x] 4. Coordination, Interoperability
- [x] 5. Economic Development
- [ ] 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

4. Coordination, Interoperability - System upgrades and expansions required to maintain access to our distribution system facilitating customer connection and third party attachment.

5. Economic Development - Coordination of system upgrades with municipal/regional development minimizes disruption to customers in affected areas.

Total:

2012 - $ 881,754
2013 - $ 501,091
2014 - $1,056,320
2015 - $ 958,459
2016 - $1,211,377
2017 - $ 950,202

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

CANADIAN NIAGARA POWER INC. A FORTIS ONTARIO Company	**Capital Expenditure Approval Form - Distribution Lines**
Project Name:	Distribution Transformers and Regulators
Settlement Account:	102025, 100925
OEB Category	(●) SYSTEM ACCESS ( ) SYSTEM RENEWAL ( ) SYSTEM SERVICE ( ) GENERAL PLANT
OEB Primary ("Trigger") Driver:	Customer Service Request
Project Information:	
Number of Circuits:	N/A
Number of Phases:	N/A
Number of Poles Installed:	N/A
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	January 2015
Completion Date:	December 2015
Is this a multi-year project?	NO

Project Description:

Purchase of transformer inventory to fulfill customer service requests for connection to CNPI's distribution system.

Applicable Justification Criteria:	☑ 1. Efficiency, Customer Value, Reliability ☐ 2. SAFETY ☐ 3. Cyber-security, Privacy ☐ 4. Coordination, Interoperability ☐ 5. Economic Development ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

1. Efficiency, Customer Value, Reliability - Service connections are required to permit the expansion of distribution facilities to both residential and commercial customers.

Total:	**$ 138,084**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Distribution Lines

Project Name:	New Smart Centre Garrison Road
Settlement Account:	102021, 102025, 102028
OEB Category	(●) SYSTEM ACCESS ( ) SYSTEM RENEWAL ( ) SYSTEM SERVICE ( ) GENERAL PLANT
OEB Primary ("Trigger") Driver:	Customer Service Request
Project Information:	
Number of Circuits:	N/A
Number of Phases:	N/A
Number of Poles Installed:	N/A
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	January 2013
Completion Date:	December 2013
Is this a multi-year project?	NO

Project Description:

New commercial development on Garrison Road in Fort Erie service territory. Customers were part of Walmart's Smart Centre development project.

Applicable Justification Criteria:

- [x] 1. Efficiency, Customer Value, Reliability
- [ ] 2. SAFETY
- [ ] 3. Cyber-security, Privacy
- [ ] 4. Coordination, Interoperability
- [x] 5. Economic Development
- [ ] 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

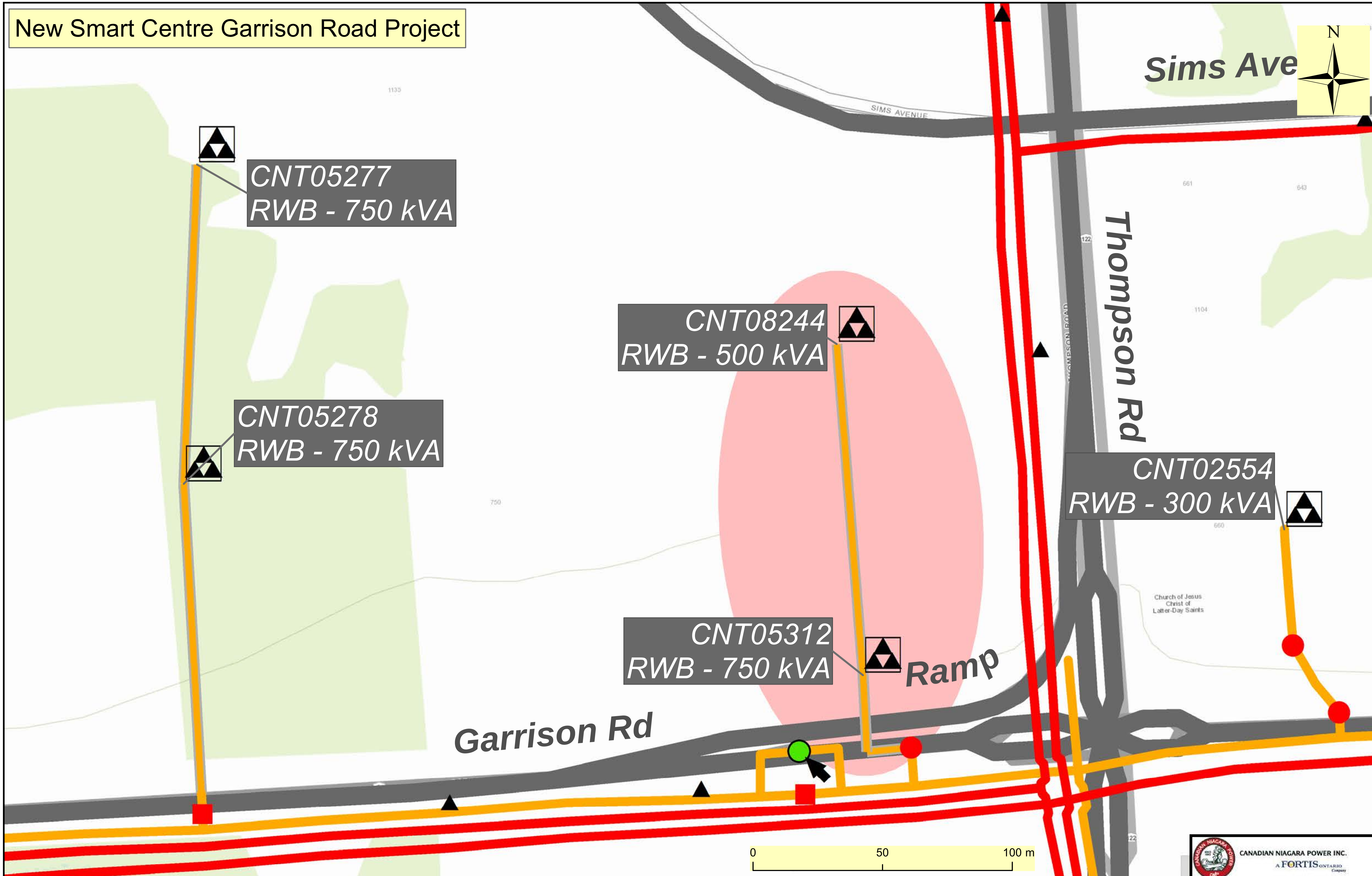
1. Efficiency, Customer Value, Reliability -Obligation per our conditions of service. Commercial service connections are required to permit the expansion of distribution facilities.

5. Economic Development - Customer connections were part of a larger "Smart Centre" construction on Garrison Road in Fort Erie near the Walmart development.

Total:	**$ 114,004**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	



New Smart Centre Garrison Road Project
N
Sims Ave
SIMS AVENUE
CNT05277
RWB - 750 kVA
CNT05278
RWB - 750 kVA
CNT08244
RWB - 500 kVA
CNT05312
RWB - 750 kVA
CNT02554
RWB - 300 kVA
Thompson Rd
Ramp
Garrison Rd
Church of Jesus Christ of Latter-Day Saints
0
50
100 m
CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Distribution Lines

Project Name:	Killaly Street Relocate from Knoll to King
Settlement Account:	102021
OEB Category	(●) SYSTEM ACCESS ( ) SYSTEM RENEWAL ( ) SYSTEM SERVICE ( ) GENERAL PLANT
OEB Primary ("Trigger") Driver:	Third Party Infastructure Development
Project Information:	
Number of Circuits:	2
Number of Phases:	3 Phase
Number of Poles Installed:	42
Primary Conductor (Circuit km) Installed:	2 km
Primary U/G cable (Circuit m) Installed:	0
Secondary U/G (Circuit m) Installed:	0
Starting Date:	2013
Completion Date:	2013
Is this a multi-year project?	NO

Project Description:

CNPI rebuilt line on Killaly Street in Port Colborne service territory between Knoll Street and King Street due to request by the Niagara Region. CNPI upgraded its exisiting plant to a 3 phase, double circuit, while fulfilling the Niagara Region's request. An extra feeder was also added, which ties to the new Fielden Substation.

Applicable Justification Criteria:

- [x] 1. Efficiency, Customer Value, Reliability
- [ ] 2. SAFETY
- [ ] 3. Cyber-security, Privacy
- [x] 4. Coordination, Interoperability
- [ ] 5. Economic Development
- [ ] 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

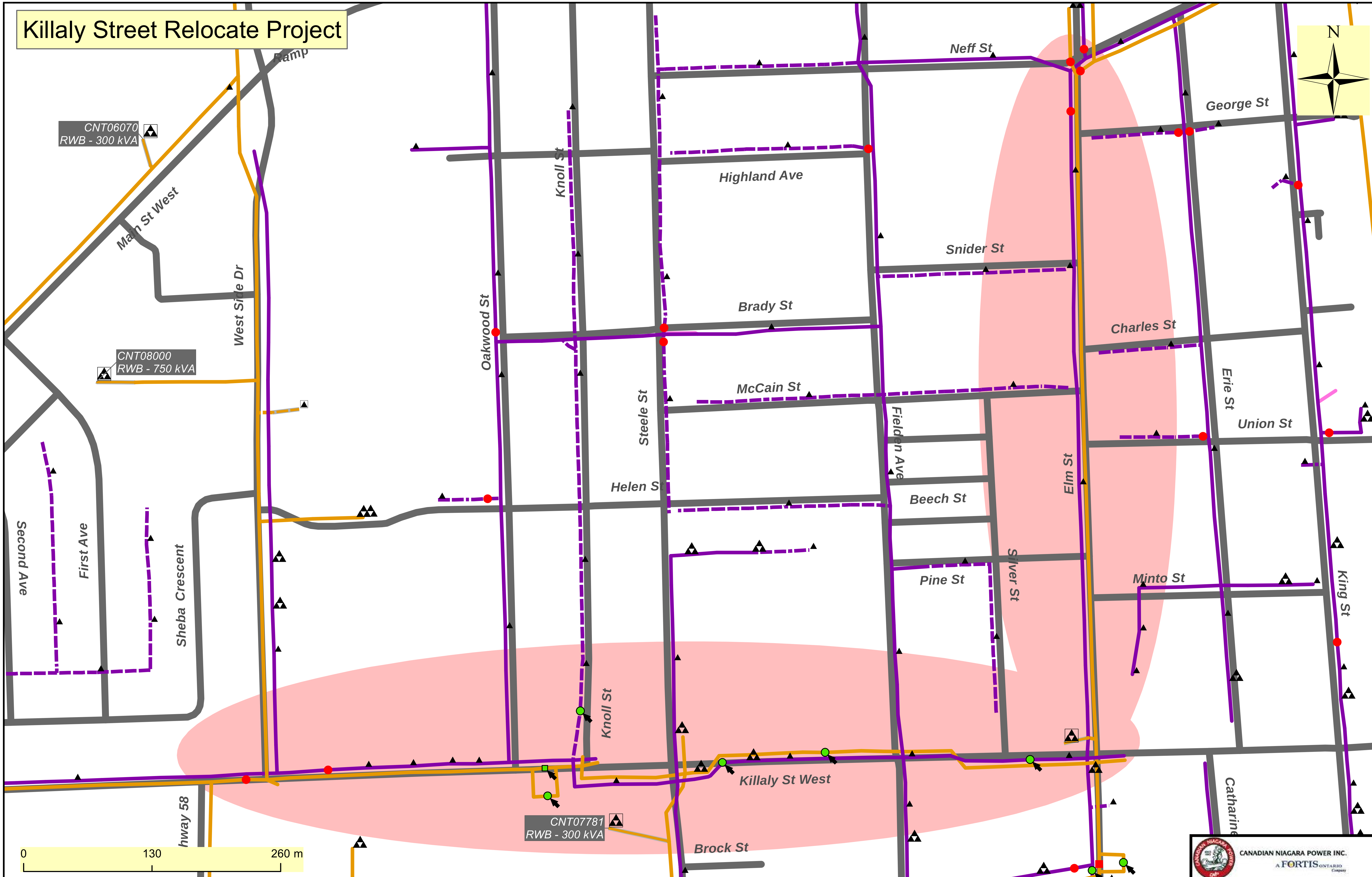
1. Efficiency, Customer Value, Reliability - Improve system efficiency while replacing aged assets.

4. Coordination, Interoperability - CNPI complying with a 3rd party request to meet their infastructure development requirements.

Total:	**$ 512,119**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	



Killaly Street Relocate Project
N
Ramp
CNT06070
RWB - 300 kVA
Main St West
West Side Dr
CNT08000
RWB - 750 kVA
Oakwood St
Knoll St
Steele St
Highland Ave
Neff St
Snider St
Brady St
McCain St
Helen St
Fielden Ave
Beech St
Pine St
Silver St
Elm St
George St
Charles St
Erie St
Union St
Minto St
King St
Second Ave
First Ave
Sheba Crescent
Knoll St
Killaly St West
CNT07781
RWB - 300 kVA
Brock St
Catharine
0
130
260 m
CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

CANADIAN NIAGARA POWER INC. A FORTIS ONTARIO Company	**Capital Expenditure Approval Form - Distribution Lines**
Project Name:	Sugarloaf and Lynwood Upgrade - 3rd Party Access
Settlement Account:	102021
OEB Category	◉ SYSTEM ACCESS ○ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Third Party Infastructure Development
Project Information:	
Number of Circuits:	1
Number of Phases:	3 Phase
Number of Poles Installed:	9
Primary Conductor (Circuit km) Installed:	0
Primary U/G cable (Circuit m) Installed:	0
Secondary U/G (Circuit m) Installed:	0
Starting Date:	2014
Completion Date:	2014
Is this a multi-year project?	NO

Project Description:

CNPI rebuilt line on Sugarloaf and Lynwood Street in Port Colborne service territory due to request by Cogeco. CNPI upgraded its existing plant to a 3 phase, single circuit, while fulfilling Cogeco's request.

Applicable Justification Criteria:	☑ 1. Efficiency, Customer Value, Reliability ☐ 2. SAFETY ☐ 3. Cyber-security, Privacy ☑ 4. Coordination, Interoperability ☐ 5. Economic Development ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

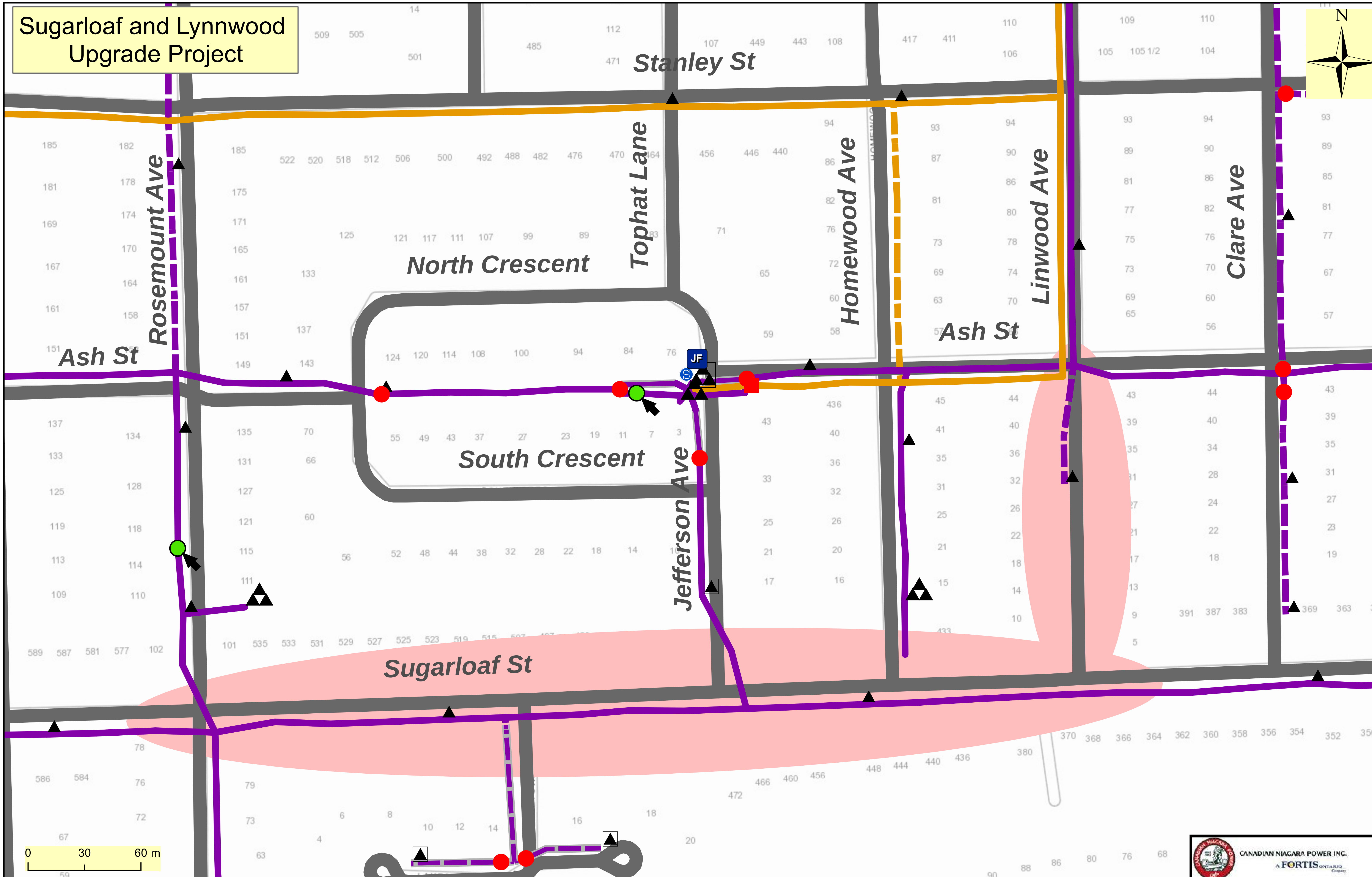
1. Efficiency, Customer Value, Reliability - Improve system efficiency while replacing aged assets.

4. Coordination, Interoperability - CNPI complying with a 3rd party request to meet their infastructure development requirements.

Total:	**$ 105,986**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	



Sugarloaf and Lynnwood Upgrade Project
N
Stanley St
Tophat Lane
Rosemount Ave
North Crescent
Homewood Ave
Linwood Ave
Clare Ave
Ash St
Ash St
South Crescent
Jefferson Ave
Sugarloaf St
JF
S
0
30
60 m
CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

CANADIAN NIAGARA POWER INC. A FORTIS ONTARIO Company	**Capital Expenditure Approval Form - Distribution Lines**
Project Name:	Central Avenue Bridge Replacement, Line Rebuild
Settlement Account:	102021, 102030
OEB Category	◉ SYSTEM ACCESS ○ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Third Party Infastructure Development
Project Information:	
Number of Circuits:	2
Number of Phases:	3 Phase
Number of Poles Installed:	6
Primary Conductor (Circuit km) Installed:	0.3 km
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	June 2014
Completion Date:	July 2015
Is this a multi-year project?	YES

Project Description:

CNPI to rebuild line on East side of Central Avenue between Courtwright Street and Bowden Street due to the Niagara Region replacing the Central Avenue Bridge over CN Rail Tracks. The double circuit at the top 34.5 ad lowe 4.8 circuit, both to be removed during bridge construction and reestablished after bridge erection. Central Avenue Bridge is located within the Fort Erie service territory.

Applicable Justification Criteria:	☑ 1. Efficiency, Customer Value, Reliability ☐ 2. SAFETY ☐ 3. Cyber-security, Privacy ☑ 4. Coordination, Interoperability ☐ 5. Economic Development ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

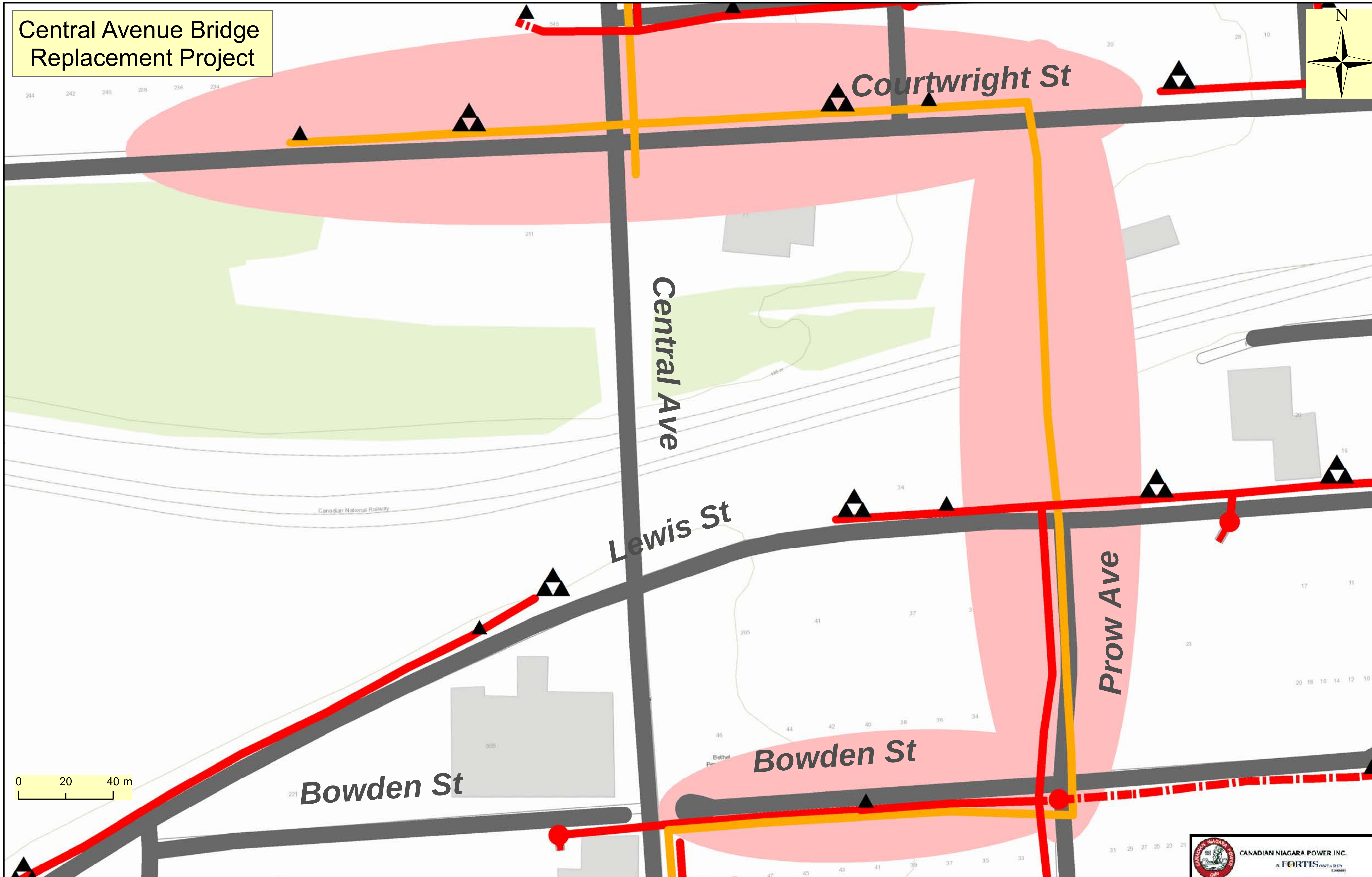
1. Efficiency, Customer Value, Reliability - Improve system efficiency while replacing aged assets.

4. Coordination, Interoperability - CNPI complying with a 3rd party request to meet their infastructure development requirements.

Total:	**2014 - $140,774** **2015 - $164,959**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	



Central Avenue Bridge Replacement Project
N
Courtwright St
Central Ave
Lewis St
Prow Ave
Bowden St
Bowden St
Canadian National Railway
0
20
40 m
CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

CANADIAN NIAGARA POWER INC. A FORTIS ONTARIO Company	**Capital Expenditure Approval Form - Distribution Lines**
Project Name:	Ridgeway By The Lake Subdivision
Settlement Account:	102021
OEB Category	(●) SYSTEM ACCESS ( ) SYSTEM RENEWAL ( ) SYSTEM SERVICE ( ) GENERAL PLANT
OEB Primary ("Trigger") Driver:	Third party Infastructure Development, Customer Service Requests
Project Information:	
Number of Circuits:	1
Number of Phases:	1
Number of Poles Installed:	0
Primary Conductor (Circuit km) Installed:	0
Primary U/G cable (Circuit m) Installed:	1000 M
Secondary U/G (Circuit m) Installed:	600 M
Starting Date:	2015
Completion Date:	2015
Is this a multi-year project?	NO

Project Description:

Servicing of underground subdivision per third party request. Ridgeway By The Lake development is located within the Fort Erie Service Territory.

Applicable Justification Criteria:

- [x] 1. Efficiency, Customer Value, Reliability
- [ ] 2. SAFETY
- [ ] 3. Cyber-security, Privacy
- [ ] 4. Coordination, Interoperability
- [x] 5. Economic Development
- [ ] 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

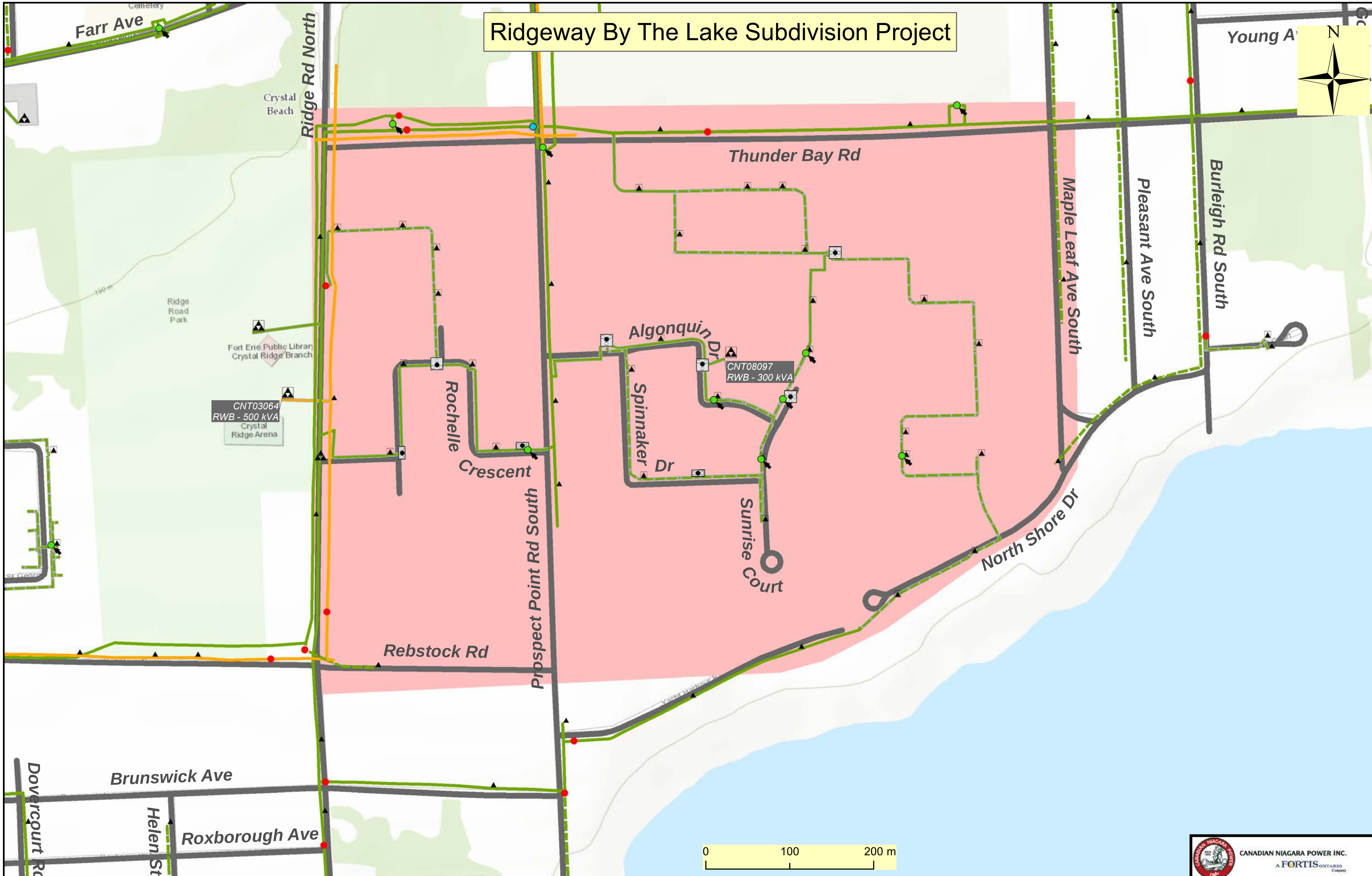
1. Efficiency, Customer Value, Reliability - System upgrades and expansions required to maintain access to our distribution system facilitating new customer connections.

5. Economic Development - New residential connections and load increase contributed to the expansion of CNPI's distribution system.

Total:	**$ 111,398**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	


Ridgeway By The Lake Subdivision Project
N
Farr Ave
Cemetery
Ridge Rd North
Crystal Beach
Ridge Road Park
Fort Erie Public Library Crystal Ridge Branch
CNT03064
RWB - 500 kVA
Crystal Ridge Arena
Thunder Bay Rd
Young Av
Algonquin Dr
CNT08097
RWB - 300 kVA
Rochelle Crescent
Spinnaker Dr
Sunrise Court
Prospect Point Rd South
Maple Leaf Ave South
Pleasant Ave South
Burleigh Rd South
North Shore Dr
Rebstock Rd
Brunswick Ave
Roxborough Ave
Dovercourt Rd
Helen St
0
100
200 m
CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

CANADIAN NIAGARA POWER INC. A FORTIS ONTARIO Company	**Capital Expenditure Approval Form - Distribution Lines**
Project Name:	Spears Road Subdivision and Line Extension
Settlement Account:	102021
OEB Category	(●) SYSTEM ACCESS ( ) SYSTEM RENEWAL ( ) SYSTEM SERVICE ( ) GENERAL PLANT
OEB Primary ("Trigger") Driver:	Third party Infastructure Development, Customer Service Requests
Project Information:	
Number of Circuits:	2
Number of Phases:	3 Phase (road) / 1 Phase (subdivision)
Number of Poles Installed:	7
Primary Conductor (Circuit km) Installed:	0.5 km
Primary U/G cable (Circuit m) Installed:	1400 M
Secondary U/G (Circuit m) Installed:	500 M
Starting Date:	2015
Completion Date:	2015
Is this a multi-year project?	NO

Project Description:

Servicing of underground subdivision per third party request. 34.5 kV line extension required to feed stepdown transformer for Fort Erie subdivision. Line extension also allows for future 10 Line loop with Bertie and Spears.

Applicable Justification Criteria:

- [x] 1. Efficiency, Customer Value, Reliability
- [ ] 2. SAFETY
- [ ] 3. Cyber-security, Privacy
- [ ] 4. Coordination, Interoperability
- [x] 5. Economic Development
- [ ] 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

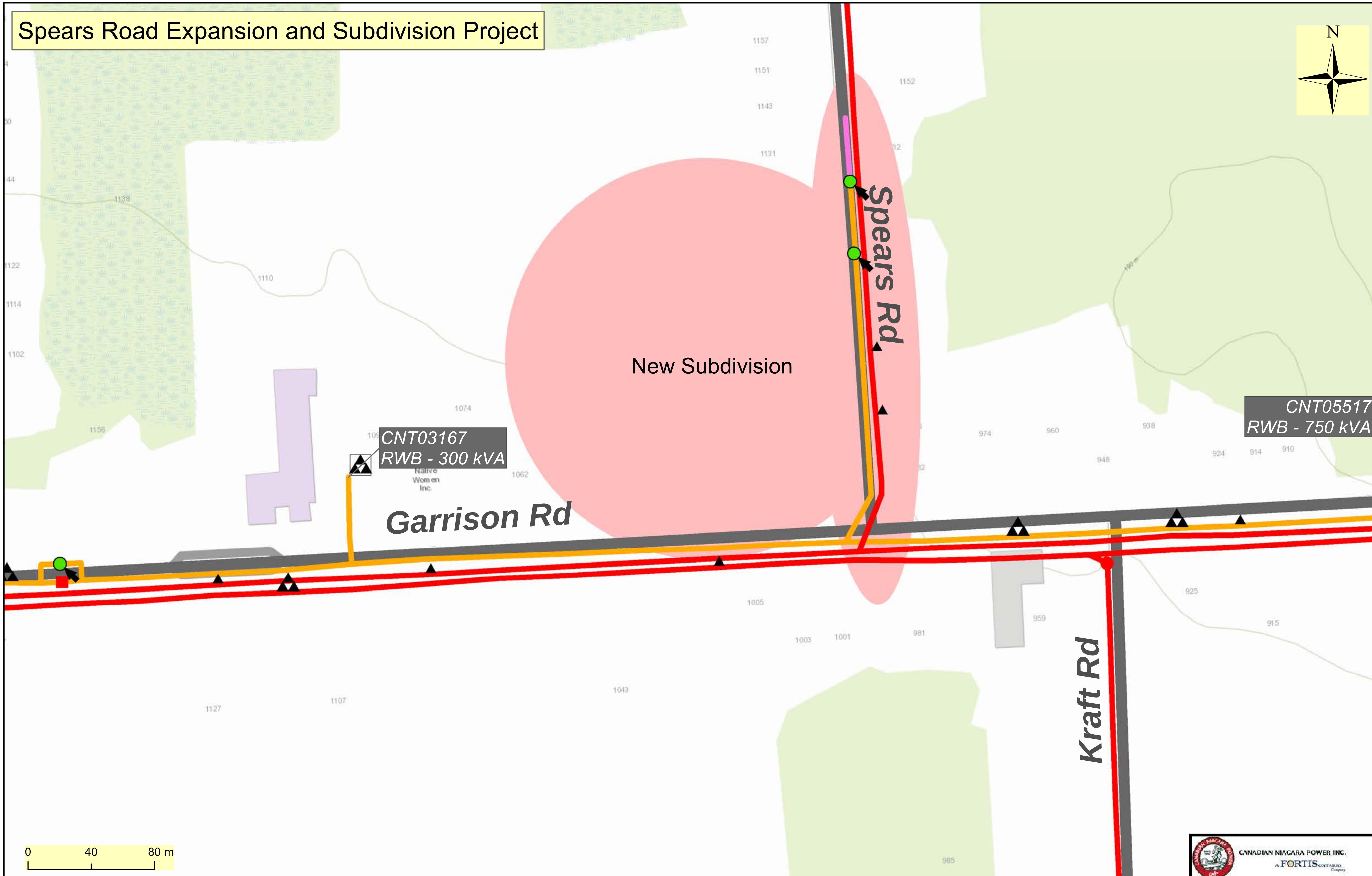
1. Efficiency, Customer Value, Reliability - System upgrades and expansions required to maintain access to our distribution system facilitating new customer connections.

5. Economic Development - New residential connections and load increase contributed to the expansion of CNPI's distribution system.

Total:	**$**	**181,291**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	



Spears Road Expansion and Subdivision Project
N
New Subdivision
Spears Rd
Garrison Rd
Kraft Rd
CNT03167
RWB - 300 kVA
CNT05517
RWB - 750 kVA
Native Women Inc.
0
40
80 m
CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

CANADIAN NIAGARA POWER INC. A FORTIS ONTARIO Company	Capital Expenditure Approval Form - Distribution Lines
Project Name:	Station 19 Project
Settlement Account:	100124
OEB Category	○ SYSTEM ACCESS ◉ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Risk of Failure
Project Information:	
Number of Circuits:	1
Number of Phases:	3 Phase
Number of Poles Installed:	0
Primary Conductor (Circuit km) Installed:	0
Primary U/G cable (Circuit m) Installed:	0
Secondary U/G (Circuit m) Installed:	0
Starting Date:	2012
Completion Date:	2012
Is this a multi-year project?	NO

Project Description:

This item provided for the reconfiguration of Station 19 on Burleigh Road, Fort Erie, Ontario. The reconfiguration saw the extension of 17L67 so that it would be located on an accessible right away along Bowen Road and Stevensville Road. Sections of the 17L67 that were inaccessbile were also decomissioned and removed due to their location and age.

Applicable Justification Criteria:	☑ 1. Efficiency, Customer Value, Reliability ☑ 2. SAFETY ☐ 3. Cyber-security, Privacy ☐ 4. Coordination, Interoperability ☐ 5. Economic Development ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

1. Efficiency, Customer Value, Reliability - The historically located 17L67 ran through an inaccessible area en route to Station 19. Should a disruption occur in this area prior to the reconfiguration, repair and/or maintenance would pose great difficulty.

2. Safety - The aged 17L67 Line contained equipment, both poles and line from the mid 1900's. This equipment may have been structurally compromised due to it's age. Decomission and removal of this equipment reduced the likelihood of a safety risk.

Total:	**$ 121,109**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

CANADIAN NIAGARA POWER INC. A FORTIS ONTARIO Company	**Capital Expenditure Approval Form - Distribution Lines**
Project Name:	Station 19 Project
Settlement Account:	100124
OEB Category	○ SYSTEM ACCESS ◉ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Risk of Failure
Project Information:	
Number of Circuits:	N/A
Number of Phases:	N/A
Number of Poles Installed:	N/A
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	2017
Completion Date:	2017
Is this a multi-year project?	NO

Project Description:

Station 19 currently utilizes fused protection for transformation. The station also incorporates a single 8.32 kV low side switchgear. The station also operates as an island, it cannot intertie to any adjacent substations within the CNPI distribution system. In order to improve reliaiblity and redundancy of this substation, electronic differential relaying will be implemented for transformer protection. Additionaly protection upgrades will mitigate risks associated with single points of failure within the switchgear. Relay upgrades will replace end of life components within the low side switchgear.

Applicable Justification Criteria:

- ☑ 1. Efficiency, Customer Value, Reliability
- ☑ 2. SAFETY
- ☐ 3. Cyber-security, Privacy
- ☐ 4. Coordination, Interoperability
- ☐ 5. Economic Development
- ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

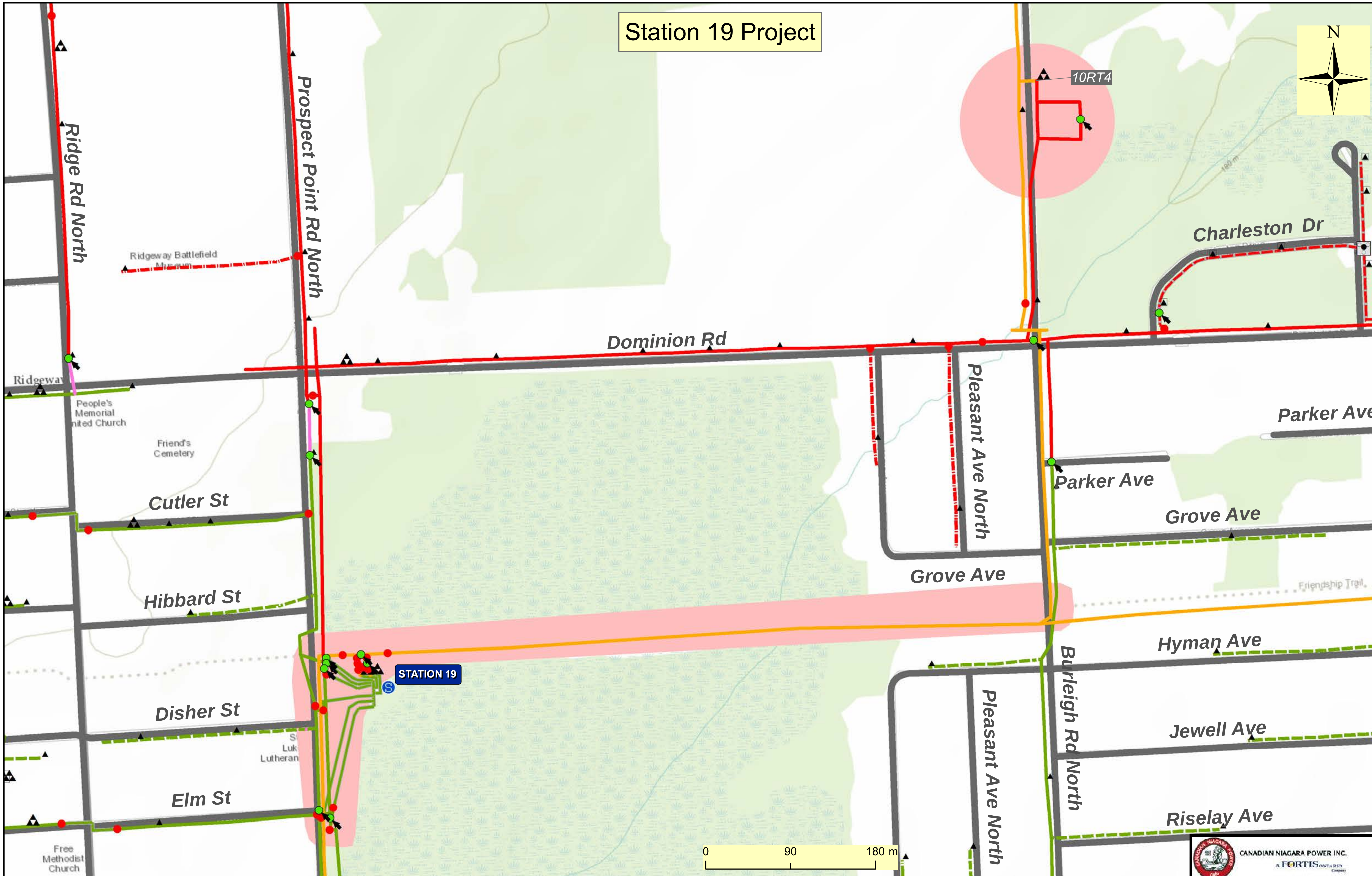
1. Efficiency, Customer Value, Reliability - Protection upgrades will mitigate the risks assocaited with critical asset failure, positively impacting reliability for the connected customers.

4. Coordination, Interoperability - Upgraded relays will improve coordination with upstream and downstream protection elements. This also provides a higher level of protection for critical assets within the station.

Total:	**$ 347,849**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	



Station 19 Project
N
10RT4
Ridge Rd North
Prospect Point Rd North
Ridgeway Battlefield Museum
Charleston Dr
Dominion Rd
Ridgeway
People's Memorial
nited Church
Friend's Cemetery
Parker Ave
Parker Ave
Pleasant Ave North
Cutler St
Grove Ave
Grove Ave
Hibbard St
Friendship Trail
Hyman Ave
STATION 19
Disher St
Jewell Ave
Lutheran
Burleigh Rd North
Pleasant Ave North
Elm St
Riselay Ave
Free Methodist Church
0
90
180 m
CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

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CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Distribution Lines

Project Name:	M11 Line Rebuild
Settlement Account:	100730
OEB Category	○ SYSTEM ACCESS ◉ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Risk of Failure
Project Information:	
Number of Circuits:	1
Number of Phases:	3 Phase
Number of Poles Installed:	46
Primary Conductor (Circuit km) Installed:	2166 M
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	April 2012
Completion Date:	June 2013
Is this a multi-year project?	YES

Project Description:

A section of CNPI's line had previously failed in an area that was not easily accessible for crews to repair. This lead to the rebuilding and extension of 43M12 along Snider Road from Forks Road to Third Concession. This new line was also subject to a service upgrade to 3 phase. The previous line was rerouted to create an accessible area surrounding it, the aged equipment was decomissioned and removed.

Applicable Justification Criteria:

- ☑ 1. Efficiency, Customer Value, Reliability
- ☐ 2. SAFETY
- ☐ 3. Cyber-security, Privacy
- ☐ 4. Coordination, Interoperability
- ☐ 5. Economic Development
- ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

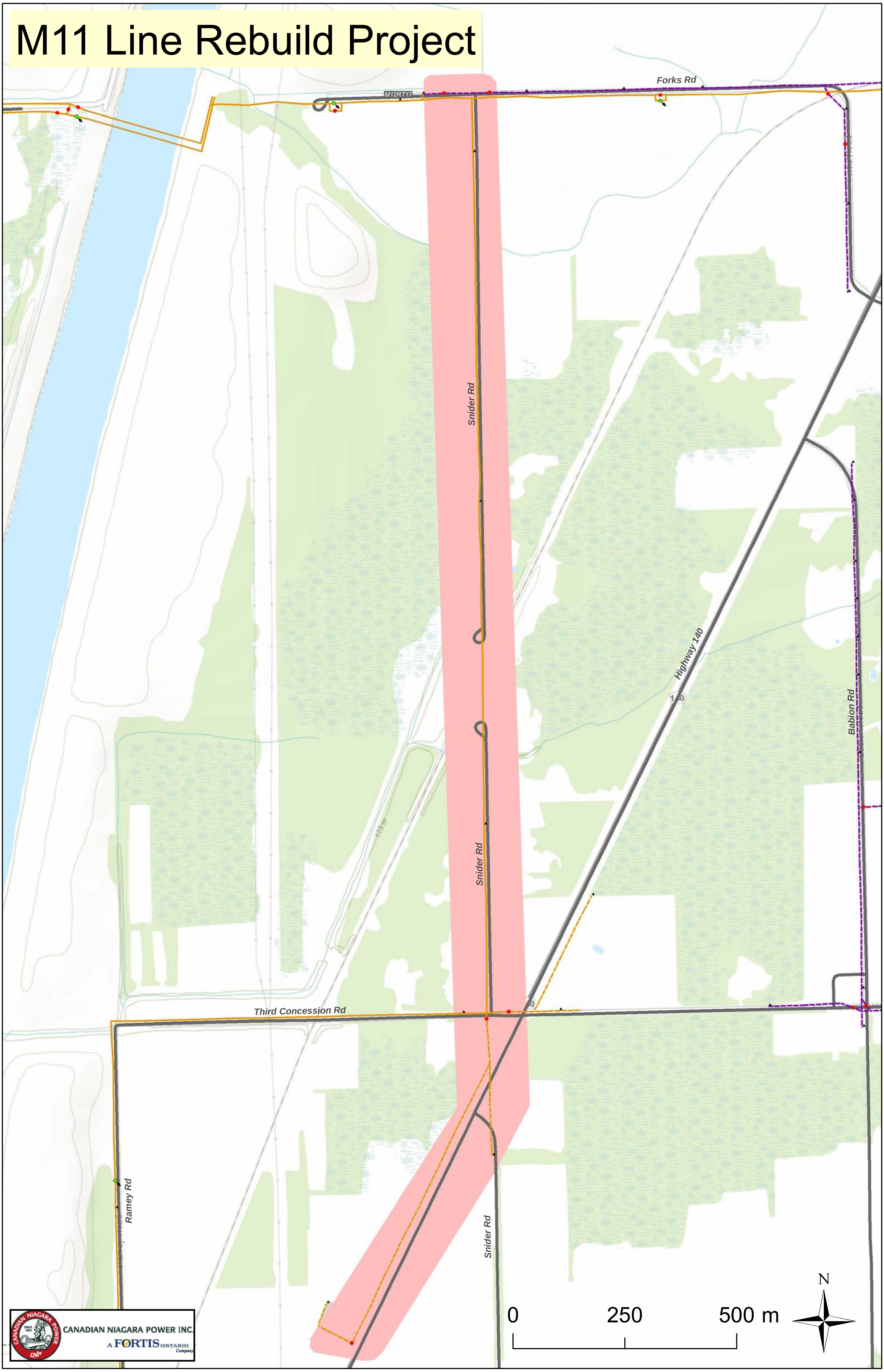
1. Efficiency, Customer Value, Reliability - The historical 42M12 ran through an area that had limited accessibility which greatly impacted it's reliability and increased the reapir time when a problem did arise. It was this accessibility issue combined with aged assets that was cause for the upgrade and renewal of this section of line stretching from Forks Road to Third Concession along Snider Road. Aged equipment assets were decomissioned and removed in an effort to mitigate future reliability issues.

Total:	**2012 - $ 161,691** **2013 - $ 218,904**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

M11 Line Rebuild Project



CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Distribution Lines

Project Name:	18L10 Line Rebuild Albany and Helena
Settlement Account:	100124
OEB Category	○ SYSTEM ACCESS ● SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Risk of Failure
Project Information:	
Number of Circuits:	2
Number of Phases:	3 Phase
Number of Poles Installed:	25
Primary Conductor (Circuit km) Installed:	2.6 km
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	2013
Completion Date:	2014
Is this a multi-year project?	YES

Project Description:

In 2013 CNPI built stage one of creating a 10 Line loop on Albany and Helena Street. To eliminate a radial feed along Garrison Road. In 2014, stage 2 was constructed, which is a double circuit along Helena Street from Garrison Road to Albany. (10 Line crossing ROW) Once completed, it will also eliminate 10 Line in CNPI ROW from bingo hall on Garrison Road to crossing at Helena Street.

Applicable Justification Criteria:

- ☑ 1. Efficiency, Customer Value, Reliability
- ☐ 2. SAFETY
- ☐ 3. Cyber-security, Privacy
- ☐ 4. Coordination, Interoperability
- ☐ 5. Economic Development
- ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

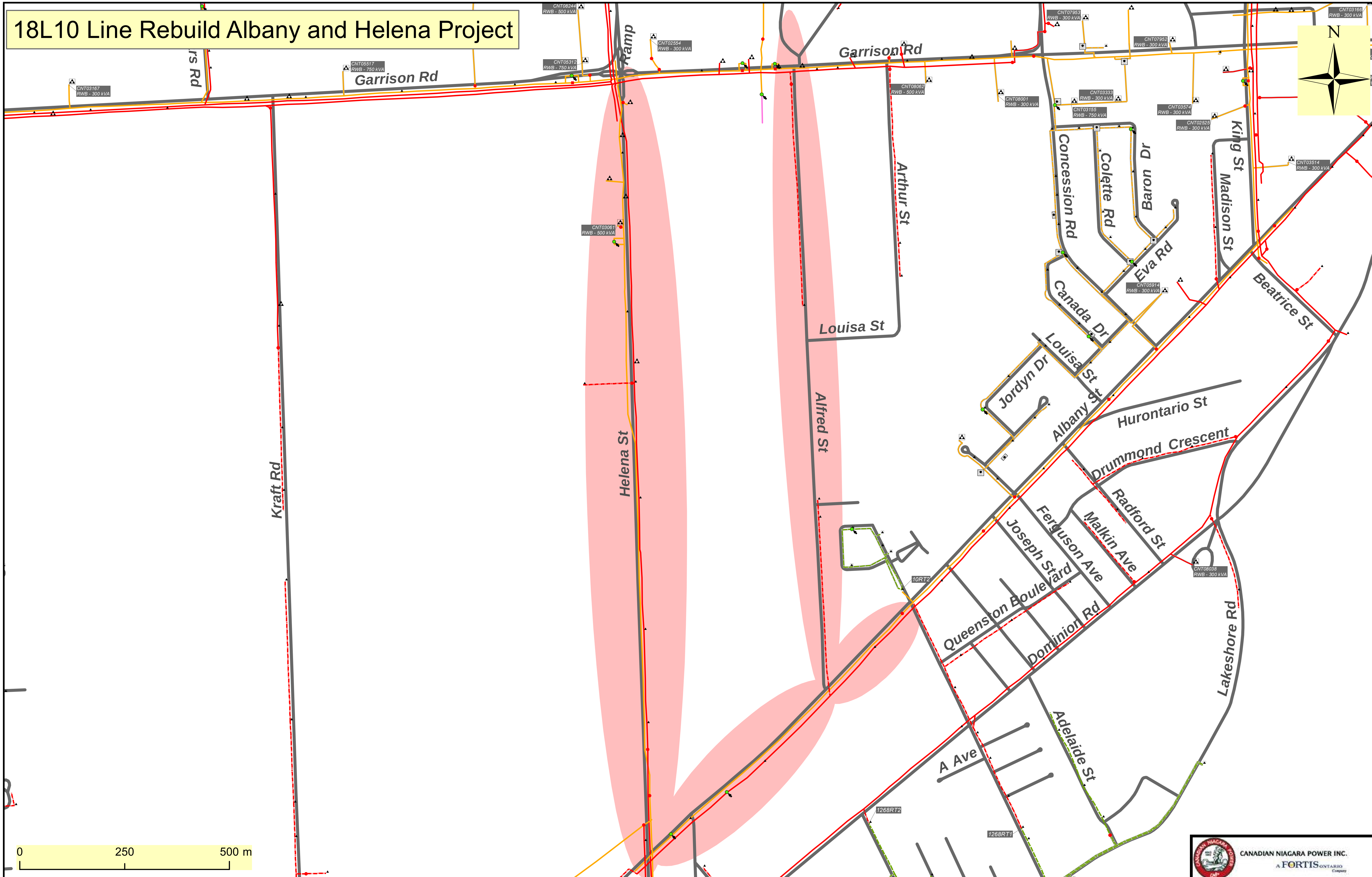
1. Efficiency, Customer Value, Reliability - There are two drivers of this project which are the elimination of a radial feed on 10 Line Garrison Road which serves a lot of major commercial customers, also the removal of another circuit from a CNPI right of way. This will create customer reliability and reduce costs of maintaining a CNPI right of way.

Total:	**2013 - $ 213,553** **2014 - $ 194,171**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

18L10 Line Rebuild Albany and Helena Project



CANADIAN NIAGARA POWER INC. A FORTIS ONTARIO Company	Capital Expenditure Approval Form - Distribution Lines
Project Name:	Dodd's Court Rebuild
Settlement Account:	100124
OEB Category	○ SYSTEM ACCESS ◉ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Risk of Failure
Project Information:	
Number of Circuits:	1
Number of Phases:	1 Phase
Number of Poles Installed:	1
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	574 M
Secondary U/G (Circuit m) Installed:	1500 M
Starting Date:	August 2012
Completion Date:	December 2012
Is this a multi-year project?	NO

Project Description:

The underground service within Dodd's Court, Fort Erie, Ontario was extensively aged and breaking down structurally. This posed as a possible risk to the system's reliability. In order to remedy this possible system issue, the underground service was replaced in it's entirety. All historical assets were decomissioned and retired at this point.

Applicable Justification Criteria:

- ☑ 1. Efficiency, Customer Value, Reliability
- ☑ 2. SAFETY
- ☐ 3. Cyber-security, Privacy
- ☐ 4. Coordination, Interoperability
- ☐ 5. Economic Development
- ☑ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

1. Efficiency, Customer Value, Reliability - The aged underground service could have negatively impacted system reliability due to it's increasing failure risk.

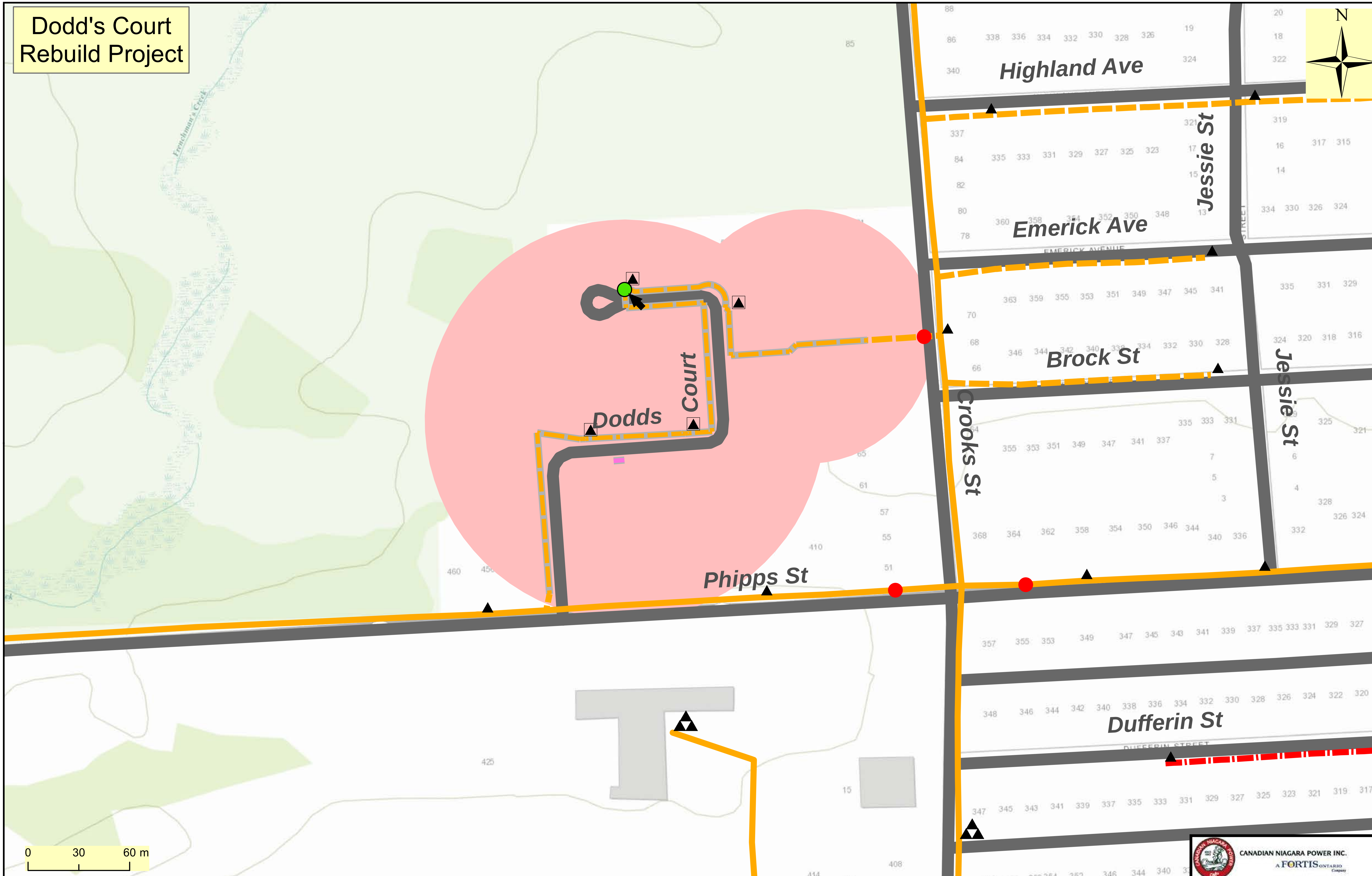
2. Safety - The existing underground service was quite aged and was breaking down structurally. This created a potential safety issue.

3. Environmental Benefits - Due to the system's age, the historical transformers being used were posing as a risk to the environment, thorugh their oil leakage. Environment Canada Statute SOR/2008-273 sets specific deadlines for the use of PCBs in transformers, and Fortis Inc. has mandated that all equipment with unknown concentrations of PCBs be tested or eliminated prior to December 31, 2014.

Total:	**$**	**293,384**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	



Dodd's Court Rebuild Project
N
Highland Ave
Emerick Ave
Jessie St
Brock St
Dodds Court
Crooks St
Phipps St
Dufferin St
0 30 60 m
CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Distribution Lines

Project Name:	Royal Road Phase 2
Settlement Account:	100730
OEB Category	○ SYSTEM ACCESS ◉ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Risk of Failure
Project Information:	
Number of Circuits:	1
Number of Phases:	1 Phase
Number of Poles Installed:	N/A
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	500 M
Secondary U/G (Circuit m) Installed:	500 M
Starting Date:	January 2012
Completion Date:	June 2012
Is this a multi-year project?	NO

Project Description:

This item provided for the installation of a new underground system. The new system replaced aged and failing assets that were decommissioned and retired. The area of work consisted of Royal Road, Elmvale Court, and Elmvale Crescent in Port Colborne, Ontario.

Applicable Justification Criteria:

- ☑ 1. Efficiency, Customer Value, Reliability
- ☑ 2. SAFETY
- ☐ 3. Cyber-security, Privacy
- ☐ 4. Coordination, Interoperability
- ☐ 5. Economic Development
- ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

1. Efficiency, Customer Value, Reliability - The aged system posed as a reliability risk as there was some history of cable failures. Post upgrade, the efficiency, customer value and reliability were all greatly improved upon.

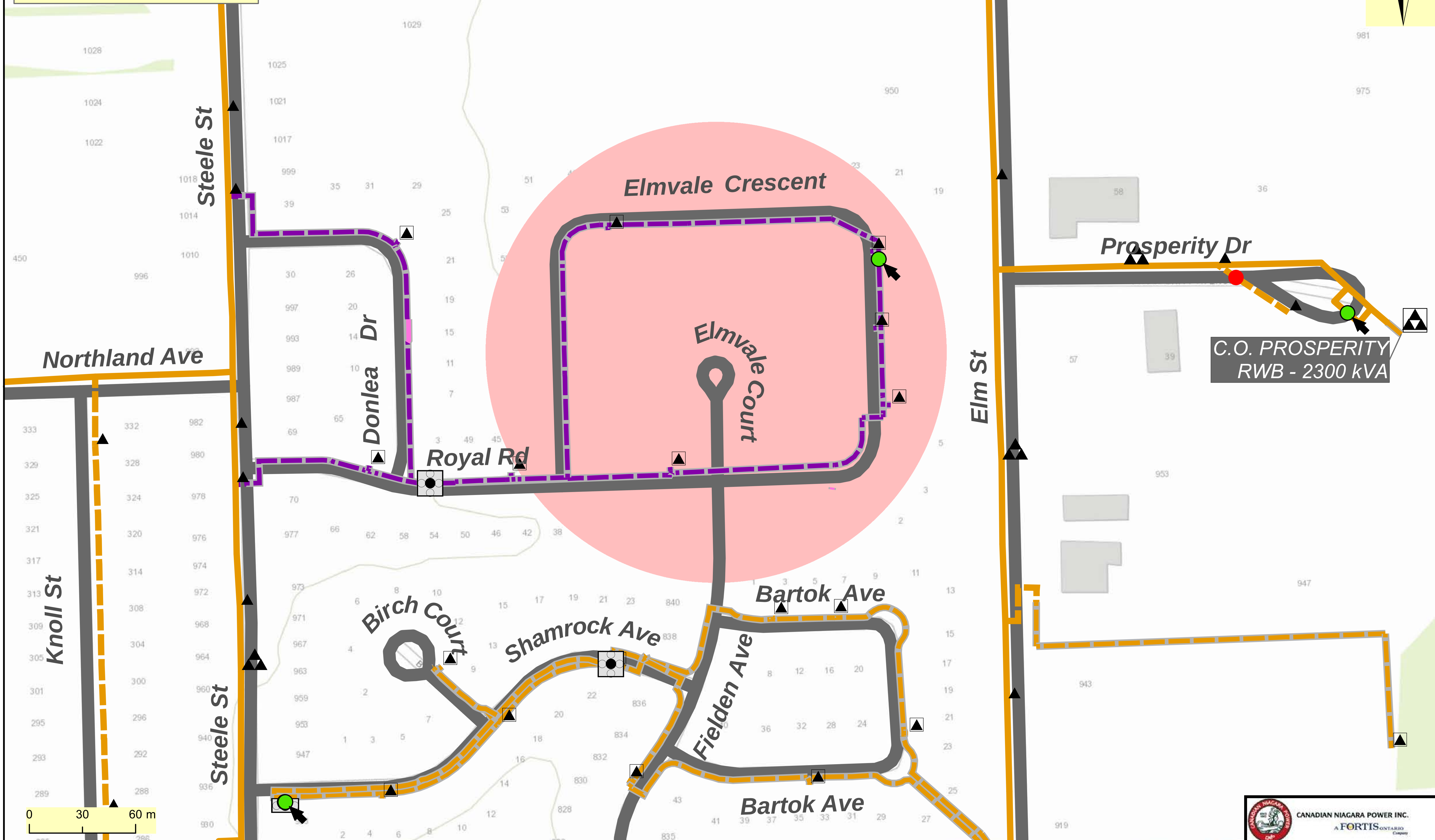
2. Safety - The historical pole-trans posed as a safety risk. Their removal and replacement eliminated this safety hazard.

Total:	**$**	**131,826**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

Royal Road Phase II



CANADIAN NIAGARA POWER INC. A FORTIS ONTARIO Company	**Capital Expenditure Approval Form - Distribution Lines**
Project Name:	Rose and Gaspare Rebuild
Settlement Account:	102022, 101115
OEB Category	○ SYSTEM ACCESS ● SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Risk of Failure
Project Information:	
Number of Circuits:	0 - Removed primary pole transformers
Number of Phases:	Secondary installation
Number of Poles Installed:	2
Primary Conductor (Circuit km) Installed:	0
Primary U/G cable (Circuit m) Installed:	0
Secondary U/G (Circuit m) Installed:	700 M
Starting Date:	December 2013
Completion Date:	January 2015
Is this a multi-year project?	YES

Project Description:

The Rose and Gaspare rebuild project was initiated to remove pole transformers from CNP's distribution system. Subdivision was rebuilt to secondary feeds in from Lakeshore Road on West side of Rose and East side of Gaspere.

Applicable Justification Criteria:	☑ 1. Efficiency, Customer Value, Reliability ☑ 2. SAFETY ☐ 3. Cyber-security, Privacy ☐ 4. Coordination, Interoperability ☐ 5. Economic Development ☑ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

1. Efficiency, Customer Value, Reliability - Work completed during this project was aimed at sustaining current levels of reliability by replacement of end of life assets.

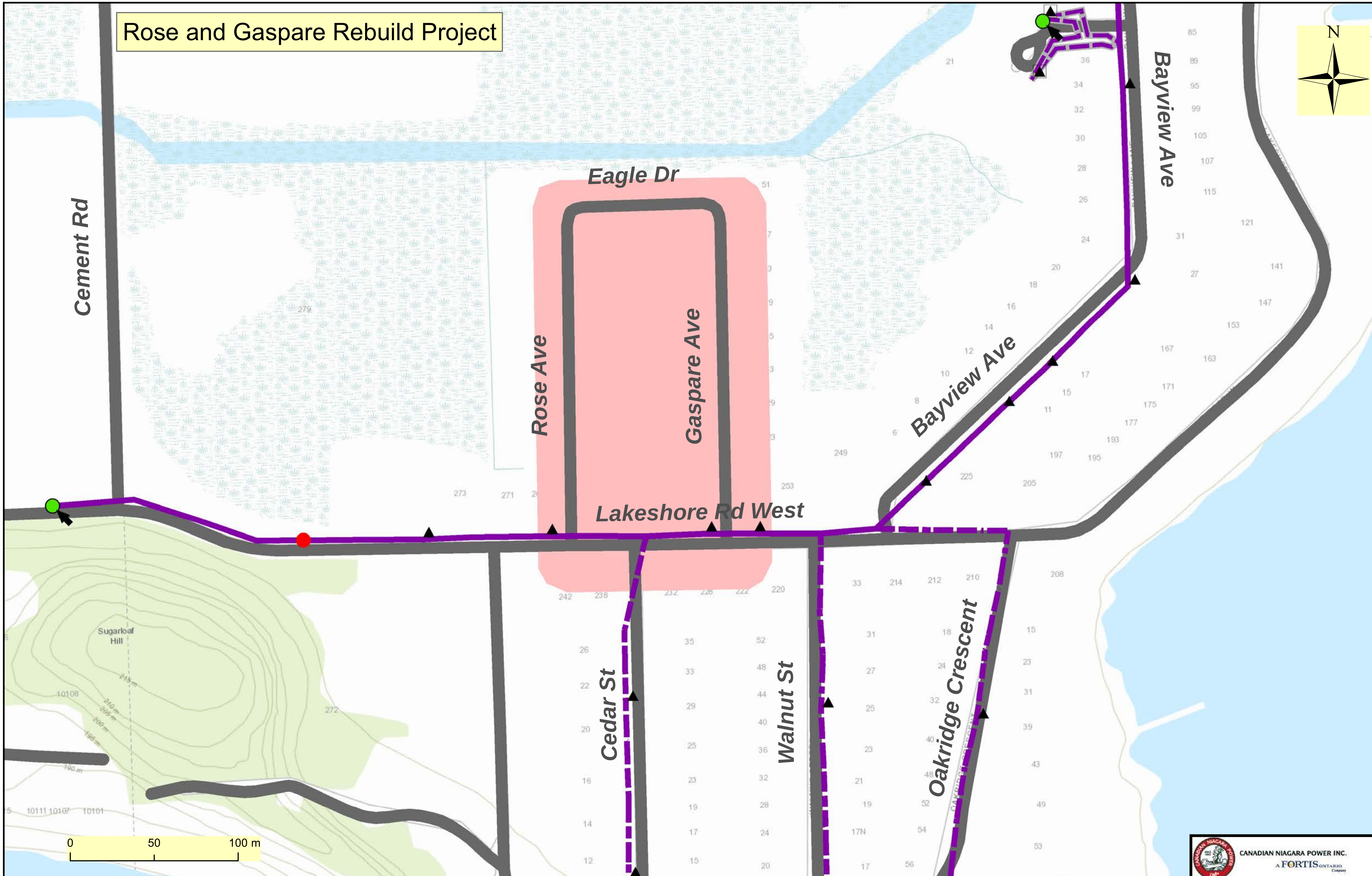
2. Safety - End of life assets did not meet current standards as pole transformers were rusting and deteriorating.

3. Environmental Benefits - While energized, could not test transformers for PCB content, once removed, all tested negative.

Total:	**2013 - $100,368** **2014 -$183,919**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	


Rose and Gaspare Rebuild Project
N
Cement Rd
Eagle Dr
Rose Ave
Gaspare Ave
Bayview Ave
Bayview Ave
Lakeshore Rd West
Cedar St
Walnut St
Oakridge Crescent
Sugarloaf Hill
0
50
100 m
CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

CANADIAN NIAGARA POWER INC. A FORTIS ONTARIO Company	**Capital Expenditure Approval Form - Distribution Lines**
Project Name:	Barrick Conversion and Rebuild
Settlement Account:	102031, 102022, 102027, 102030
OEB Category	○ SYSTEM ACCESS ● SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Failure Risk, End of life assets
Project Information:	
Number of Circuits:	2
Number of Phases:	3 Phase
Number of Poles Installed:	30
Primary Conductor (Circuit km) Installed:	1 km
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	February 2014
Completion Date:	April 2015
Is this a multi-year project?	YES

Project Description:

Transfering load from Barrick Station onto 43M11. The section between Highway 58, Barrick Road and Elm St. will be transferred to 43M11. This will lead to the eventual decomissioning of Barrick Substation.

Applicable Justification Criteria:	☑ 1. Efficiency, Customer Value, Reliability ☐ 2. SAFETY ☐ 3. Cyber-security, Privacy ☐ 4. Coordination, Interoperability ☐ 5. Economic Development ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

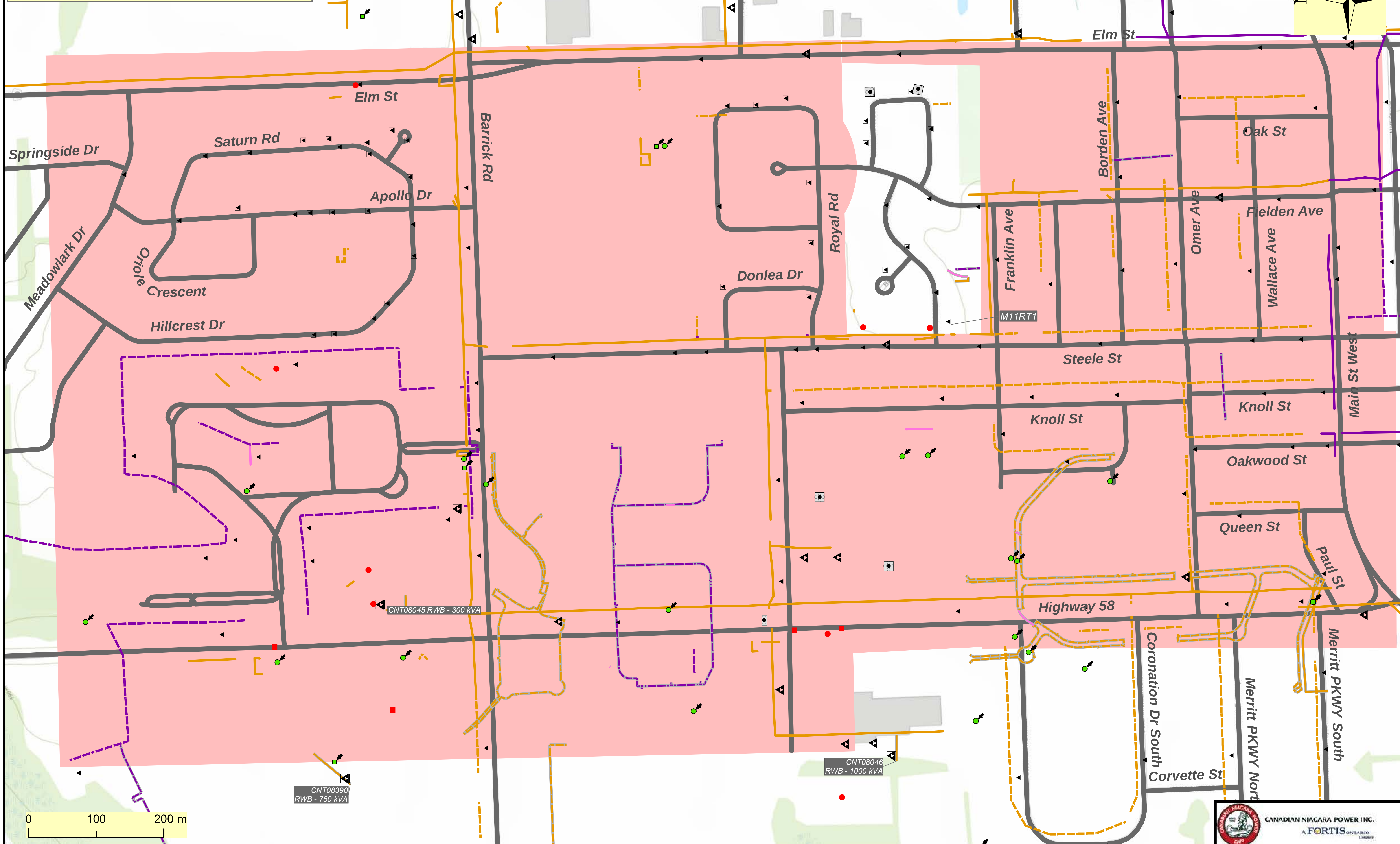
1. Efficiency, Customer Value, Reliability - This will greatly improve the system efficiency and distribution loss reduction. System capacity upgrade.

Total:	**2014 - $644,011** **2015 -$754,132**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

Barrick Conversion Project



CANADIAN NIAGARA POWER INC. A FORTIS ONTARIO Company	**Capital Expenditure Approval Form - Distribution Lines**
Project Name:	Fielden Station Projects
Settlement Account:	100723
OEB Category	○ SYSTEM ACCESS ◉ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Functional Obsolescence
Project Information:	
Number of Circuits:	N/A
Number of Phases:	N/A
Number of Poles Installed:	N/A
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	2013
Completion Date:	2015
Is this a multi-year project?	YES

Project Description:

This item provides for the expansion of Fielden DS in Port Colborne to provide for the addition of:
- 6.5MVA 27.6 : 4.16kV Padmounted Transformer
- 27.6kV Primary padmount switchgear
- 4.16kV Feeder padmount switchgear c/w three 4.16kV feeders
- ancillary primary cables and protection&control equipment
- all civil works as required

Note: There are related projects to this one, making up a portion of the CNPI Integrated System Plan for Port Colborne.

Applicable Justification Criteria:	☑ 1. Efficiency, Customer Value, Reliability ☐ 2. SAFETY ☐ 3. Cyber-security, Privacy ☐ 4. Coordination, Interoperability ☐ 5. Economic Development ☑ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

This project allows for the retirement of Barrack DS by expanding the capacity of Fielden DS to accommodate Barrack's legacy load area. This provides for relief of several issues extant at Barrack DS:

1. Efficiency, Customer Value, Reliability- The vintage switchgear at Barrack is of an obsolete design, no longer supported by any manufacturer. In recent years, this equipment has been miss-operating, creating and expanding the impact of several customer outages. In addition, the transformer is aged and nearing the end of its useful technical life. The use of a padmounted design for the expansion at Fielden DS is also expected to result in lower construction costs than a traditional live-front design, AND require reduced maintenance, easing strain on future manpower requirements.

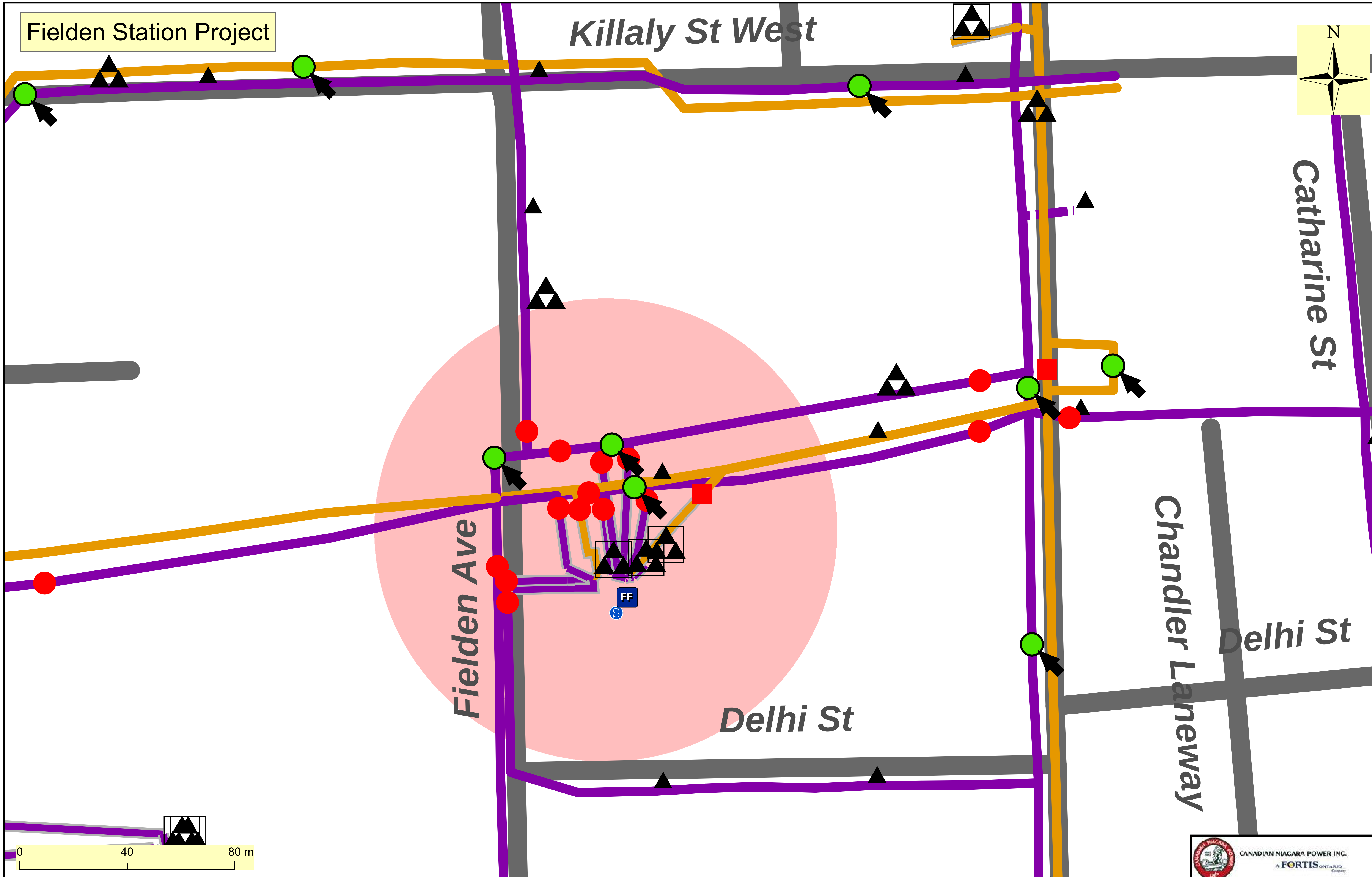
6. Environmental Benefits - Barrack DS has no oil collection system, and its design does provide for a reasonably-priced retrofit. In addition,the power transformer bushings at Barrack have no means to test for PCB contamination or for replacement. Environment Canada Statute SOR/2008-273 sets specific deadlines for the use of PCBs in transformers, and Fortis Inc. has mandated that all equipment with unknown concentrations of PCBs be tested or eliminated prior to December 31, 2014.

Alternative analysis explored several options to meet the long term needs of Port Colborne, including A) Rebuilding Barrack DS "Where-Is",B)Building a new station near Barrack DS C) Voltage Conversions of all Barrack's service area and D) Expand Fielden DS. Option (D) was selected as the lowest up-front cost AND provides for the best future system flexibility.

Total:	**2013 - $ 235,175** **2014 - $ 573,401** **2015 - $ 645,004**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	


Fielden Station Project
Killaly St West
Catharine St
Fielden Ave
Chandler Laneway
Delhi St
Delhi St
FF
S
N
0
40
80 m
CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

CANADIAN NIAGARA POWER INC. A FORTIS ONTARIO Company	Capital Expenditure Approval Form - Distribution Lines
Project Name:	Construct Gilmore DS
Settlement Account:	102042
OEB Category	○ SYSTEM ACCESS ◉ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Failure Risk, Replacement of assets at end of useful life
Project Information:	
Number of Circuits:	N/A
Number of Phases:	N/A
Number of Poles Installed:	N/A
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	2015
Completion Date:	2016
Is this a multi-year project?	YES

Project Description:

This project provides for the full construction of a distribution substation (DS) on Gilmore Road on the same property as Station 18. This project includes design, procurement, construction and commissioning.The station will have:
- two 7.5/10 MVA 34.5 : 8.3 kV power transformers
- five Viper bus reclosers
- four Viper feeder reclosers (with provision for two more)
- ancillary primary cables and protection&control equipment
- all civil works as required

Applicable Justification Criteria:	☑ 1. Efficiency, Customer Value, Reliability ☐ 2. SAFETY ☐ 3. Cyber-security, Privacy ☐ 4. Coordination, Interoperability ☐ 5. Economic Development ☑ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

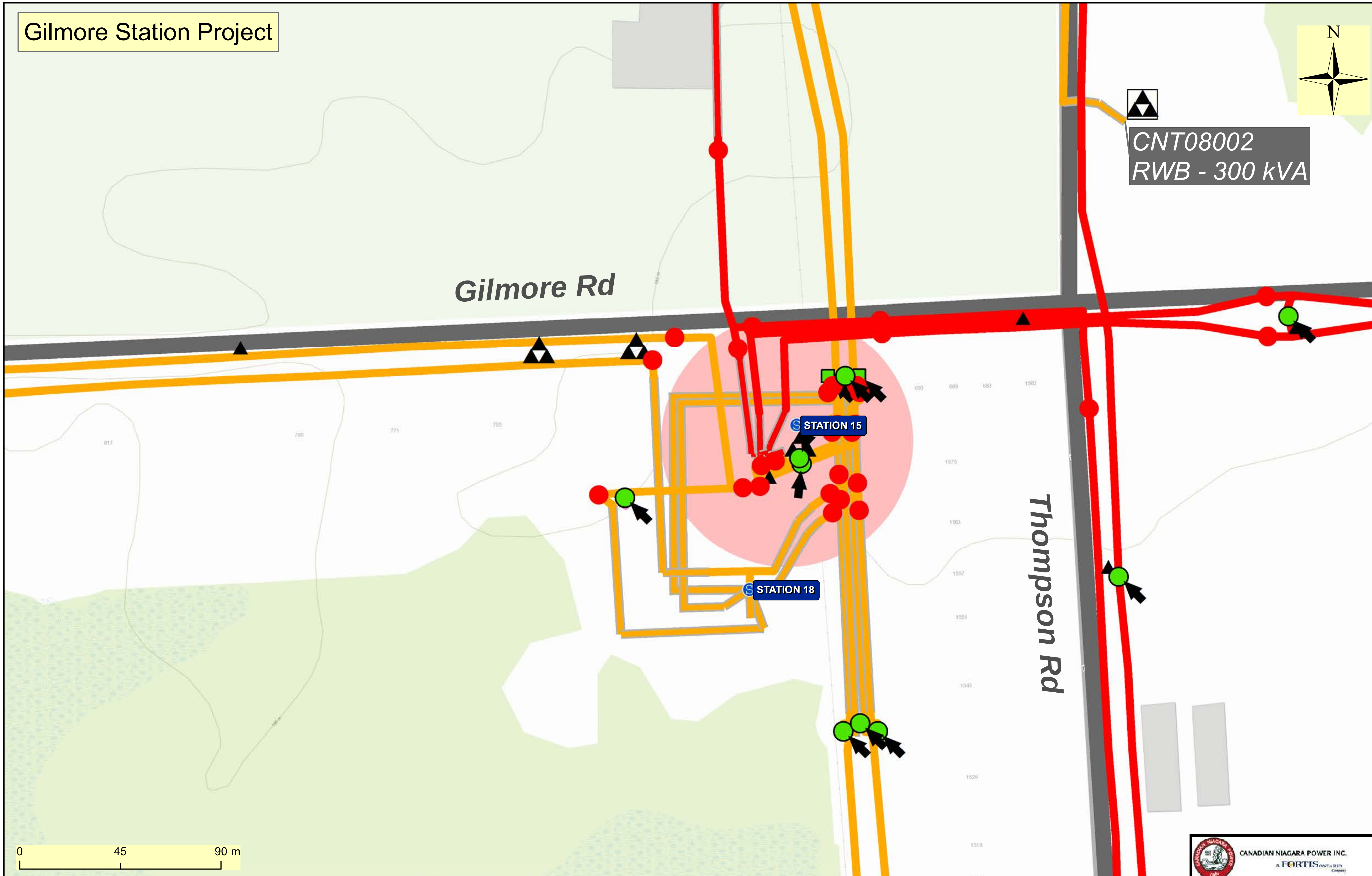
1. Efficiency, Customer Value, Reliability- The construction of this DS is necessary to provide a source to begin the conversion of Fort Erie's legacy 4.8 kV delta system. This will allow for the elimination of the obsolescent three wire delta system as recommended in the 2016 CNPI Long Term Area Planning Study. The conversion of the 4.8 kV delta system to 8.3 kV wye will result in a significant reduction in distribution losses.

6. Environmental Benefits- This project allows for the immediate retirement of Station 15 and the eventual retirement of Station 12. The legacy substations have no oil collection systems and their design does not allow for reasonably priced retrofit. As a result of the construction of Gilmore DS, transformer 12-TB1 at Station 12 will be removed from service. This is the last transformer in the CNPI system that cannot be tested for PCB content. Environment Canada Statute SOR/2008-273 sets specific deadlines for the use of PCBs in transformers, and Fortis Inc. has mandated that all equipment with unknown concentrations of PCBs be tested or eliminated prior to December 31, 2014.

Total:	**2015 - $ 135,530** **2016 - $1,604,002**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	



Gilmore Station Project
N
CNT08002
RWB - 300 kVA
Gilmore Rd
STATION 15
STATION 18
Thompson Rd
0
45
90 m
CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

CANADIAN NIAGARA POWER INC. A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Distribution Lines

Project Name:	Gilmore Egress Project
Settlement Account:	102042
OEB Category	○ SYSTEM ACCESS ◉ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Failure Risk, Replacement of assets at end of useful life
Project Information:	
Number of Circuits:	N/A
Number of Phases:	N/A
Number of Poles Installed:	N/A
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	2016
Completion Date:	2016
Is this a multi-year project?	NO

Project Description:

This project provides for the construction of feeder exits to interconnect the new Gilmore DS to the CNPI distribution system. This is being performed as a separate project to ensure proper settlement to the appropriate OEB accounts.

Applicable Justification Criteria:

- [x] 1. Efficiency, Customer Value, Reliability
- [ ] 2. SAFETY
- [ ] 3. Cyber-security, Privacy
- [ ] 4. Coordination, Interoperability
- [ ] 5. Economic Development
- [x] 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

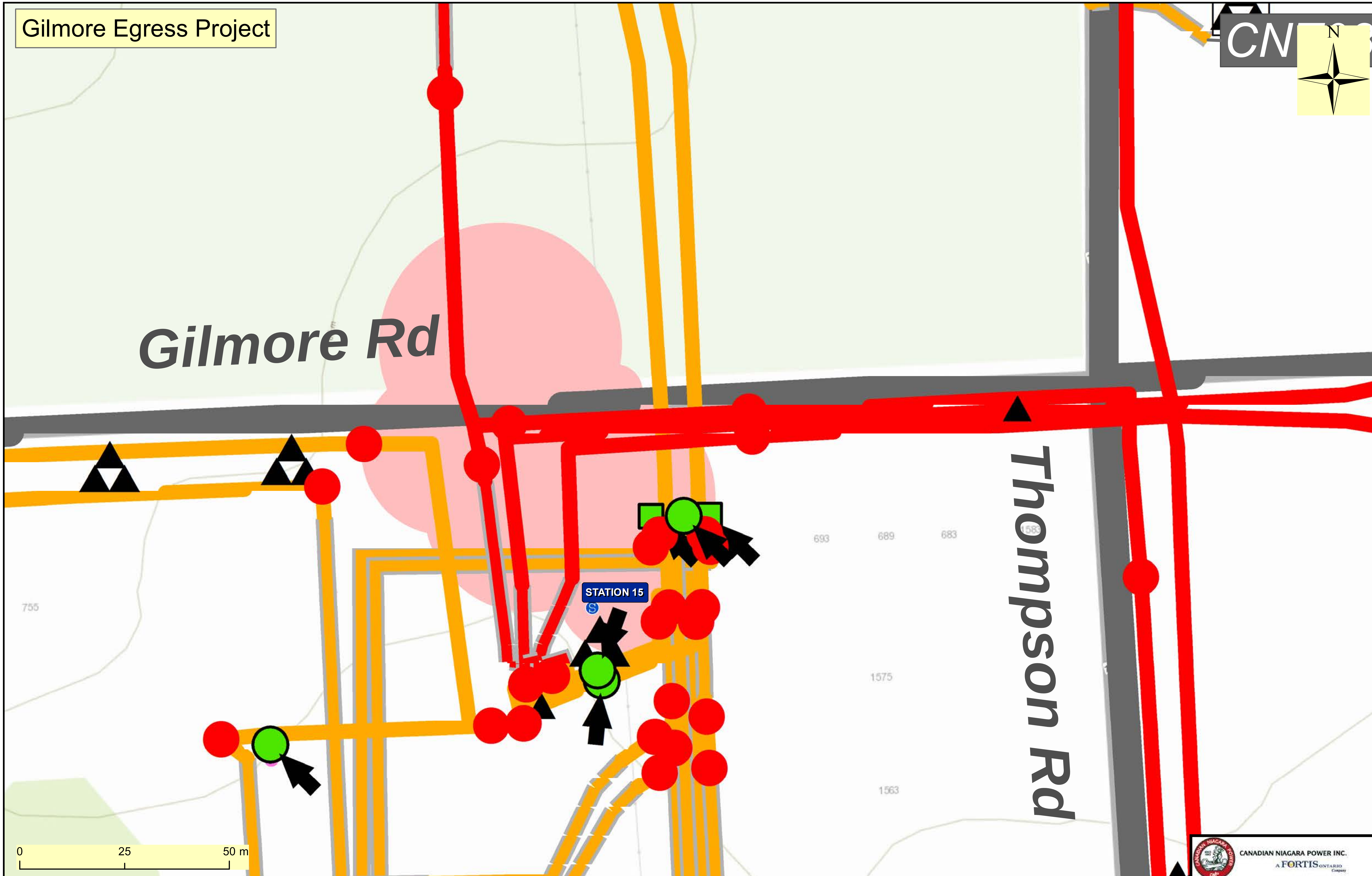
1. Efficiency, Customer Value, Reliability- The construction of this DS is necessary to provide a source to begin the conversion of Fort Erie's legacy 4.8 kV delta system. This will allow for the elimination of the obsolescent three wire delta system as recommended in the 2016 CNPI Long Term Area Planning Study. The conversion of the 4.8 kV delta system to 8.3 kV wye will result in a significant reduction in distribution losses.

6. Environmental Benefits- This project allows for the immediate retirement of Station 15 and the eventual retirement of Station 12. The legacy substations have no oil collection systems and their design does not allow for reasonably priced retrofit. As a result of the construction of Gilmore DS, transformer 12-TB1 at Station 12 will be removed from service. This is the last transformer in the CNPI system that cannot be tested for PCB content. Environment Canada Statute SOR/2008-273 sets specific deadlines for the use of PCBs in transformers, and Fortis Inc. has mandated that all equipment with unknown concentrations of PCBs be tested or eliminated prior to December 31, 2014.

Total:	**$ 519,944**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	



Gilmore Egress Project
Gilmore Rd
Thompson Rd
STATION 15
693
689
683
755
1575
1563
0
25
50 m
N
CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Distribution Lines

Project Name:	FE North Rebuilds Supporting Conversion
Settlement Account:	102020
OEB Category	○ SYSTEM ACCESS ◉ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Replacement of assets at end of useful life
Project Information:	
Number of Circuits:	N/A
Number of Phases:	N/A
Number of Poles Installed:	N/A
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	January 2016
Completion Date:	December 2017
Is this a multi-year project?	YES

Project Description:

This project allows for the conversion of all of the legacy 4.8 kV (Delta) system to 4.8/8.3 kV (Wye) in the town of Fort Erie that lies north of the Queen Elizabeth Highway (QEW). Please refer to map on following page to show area to be rebuilt. It is part of a long term program to eliminate all of the legacy three-wire Delta primary system, with replacement by a modern four wire "Wye" system.

Approximately 36 km of this legacy distribution system will be converted to and energized at 4.8/8.3kV, with a further 3 km converted to and energuized at 19.9/34.5 kV. Both of these higher line voltages are already standard at CNPI.

- 7 km of new double circuit three-phase 8.3kV will be constructed to serve as 'feeder trunks'
- 11 km of overhead line and 1.2 km of underground line (including primary customer services) will be completely rebuilt to address condition concerns.
- 13 km of overhead line will be rebuilt and/or re-framed as required to address asset condition concerns where all components have not reached the end of their useful lives.
- 7 km of overhead line will have a minimum of components replaced (e.g. post insulators) as they are converted to 4.8/8.3kV Wye.

More detailed information on this project may be found in the CNPI Distribution System Plan.

Applicable Justification Criteria:

- ☑ 1. Efficiency, Customer Value, Reliability
- ☑ 2. SAFETY
- ☐ 3. Cyber-security, Privacy
- ☐ 4. Coordination, Interoperability
- ☐ 5. Economic Development
- ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

1. Efficiency, Customer Value, Reliability - Conversion from 4.8kV Delta to 8.3kV Wye reduces line losses to less than half of their pre-converted values. These savings in line losses are passed on directly to customers via a reduced loss factor. In addition, conversion allows for reducing the number of circuits on many streets and ROWs. This should result in incremental long-term savings in O&M costs.

Much of the project area contains poles in deteriorated condition that have a negative impact on reliability, if not replaced as they reach the end of their useful lives. Once these assets are renewed, there should be an overall reduction in O&M costs.

2. Safety - This project addresses two basic safety concerns. Much of the project area contains poles in deteriorated condition that might represent a hazard to workers or the public if not replaced as they reach the end of their useful lives. In addition, the legacy three-wire 4.8kV Delta system possesses inherent safety issues, such as difficulty in detecting faults/grounded conditions. Energized conductors can be in direct contact with objects or the ground with no means to detect this condition. Delta distribution systems, although common at one point in the history of the electricity industry, have become quite rare in Ontario, and workers may be less familiar with their operation. CNPI has been engaged in a long-term program to eliminate all of its legacy delta system. This project represents significant progress in achieving that goal.

More detailed information on this project may be found in the CNPI Distribution System Plan

Total:	**2016 - $ 751,054** **2017 - $ 884,802**
Additional Information on Cost Estimate:	
Manager Responsible:	
Project Approval:	

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CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Distribution Lines

Project Name:	Port Colborne New South DS
Settlement Account:	102051
OEB Category	◉ SYSTEM ACCESS ○ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Customer Service Request
Project Information:	
Number of Circuits:	N/A
Number of Phases:	N/A
Number of Poles Installed:	N/A
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	January 2017
Completion Date:	December 2017
Is this a multi-year project?	NO

Project Description:

This item provides for the construction of a new distribution station in the South of Port Colborne to provide for:
- land acquisition
- 6.5MVA 27.6 : 4.16kV Padmounted Transformer
- 27.6kV Primary padmount switchgear
- 4.16kV Feeder padmount switchgear c/w three 4.16kV feeders (with provision for a fourth)
- ancillary primary cables and protection&control equipment
- all civil works as required
- provide for communication, protection and control

Note: There are related projects to this one, making up a portion of the CNPI Integrated System Plan for Port Colborne.

Applicable Justification Criteria:

- ☑ 1. Efficiency, Customer Value, Reliability
- ☐ 2. SAFETY
- ☐ 3. Cyber-security, Privacy
- ☐ 4. Coordination, Interoperability
- ☐ 5. Economic Development
- ☑ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

1. Efficiency, Customer Value, Reliability - This project allows for the eventual retirement of Catharine DS and Jefferson DS, which are nearing the end of their useful lives. This new DS will feature modern SEL protection relays for improved reliability and operability.

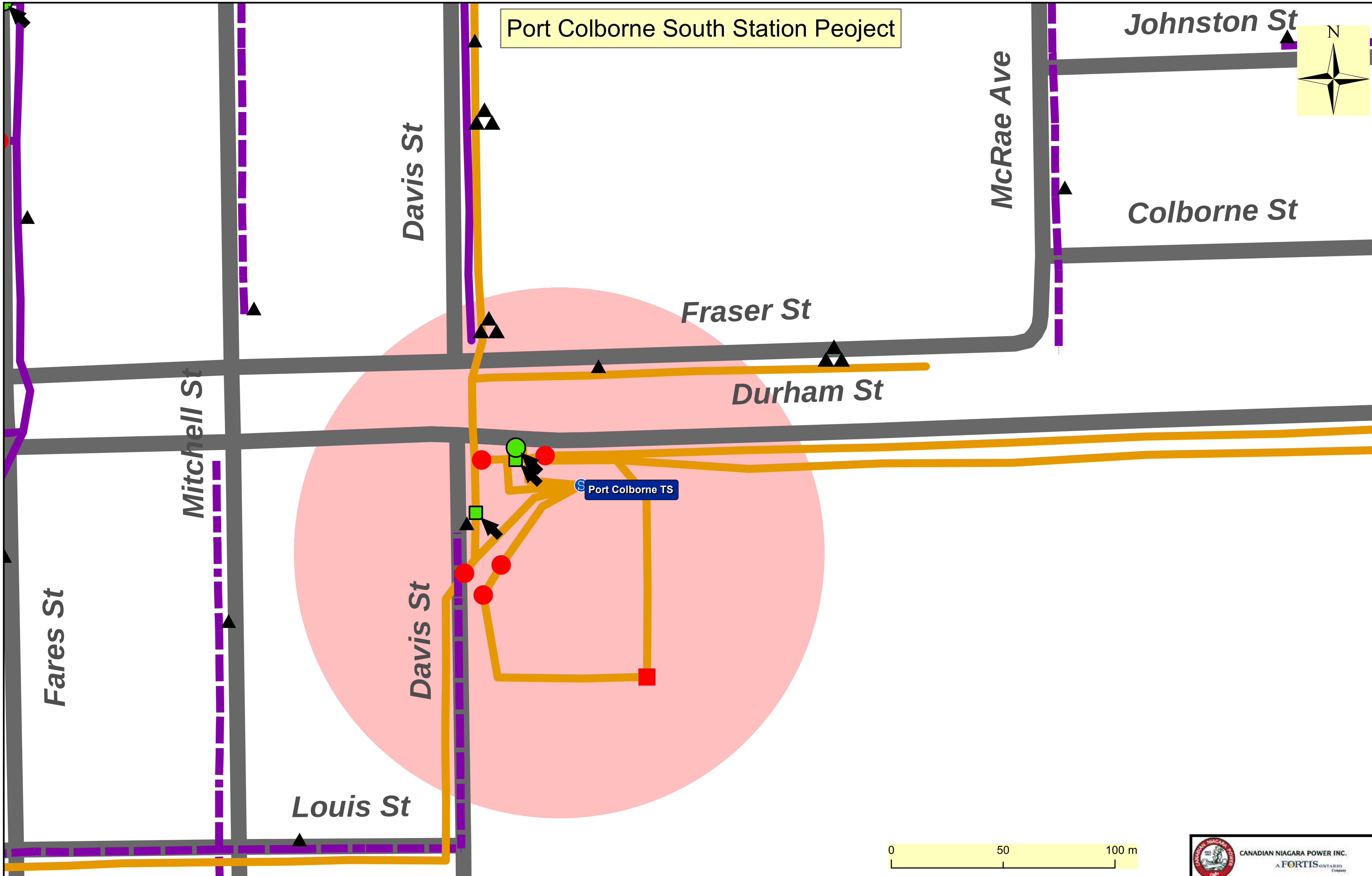
6. Environmental Benefits - Catharine DS and Jefferson DS have no oil collection systems, and their design does not provide for a reasonably-priced retrofit.

Details of this project justification can be found in the 2016 CNPI Long Term Area Planning Study.

Total:	**$ 409,245**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	



Port Colborne South Station Peoject
Johnston St
N
McRae Ave
Colborne St
Davis St
Fraser St
Durham St
Mitchell St
Port Colborne TS
Fares St
Davis St
Louis St
0
50
100 m
CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

CANADIAN NIAGARA POWER INC. A FORTIS ONTARIO Company	Capital Expenditure Approval Form - Distribution Lines
Project Name:	5/8 Line Rebuild from Pettit Road to Miller Road along CNPI R.O.W.
Settlement Account:	102022, 102030
OEB Category	○ SYSTEM ACCESS ● SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Failure Risk, End of life assets
Project Information:	
Number of Circuits:	2
Number of Phases:	3 Phase
Number of Poles Installed:	15
Primary Conductor (Circuit km) Installed:	1.2 km
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	January 2014
Completion Date:	February 2015
Is this a multi-year project?	YES

Project Description:

Tower removal project to remove all towers from Bowen Rd. to Switch Rd. in Fort Erie service territory along CNPI right of way. The second section is between Pettit Rd. and Miller Road. Removing 14 towers and 4 circuits, replacing with single pole line with double circuit.

Applicable Justification Criteria:	☑ 1. Efficiency, Customer Value, Reliability ☑ 2. SAFETY ☐ 3. Cyber-security, Privacy ☐ 4. Coordination, Interoperability ☐ 5. Economic Development ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

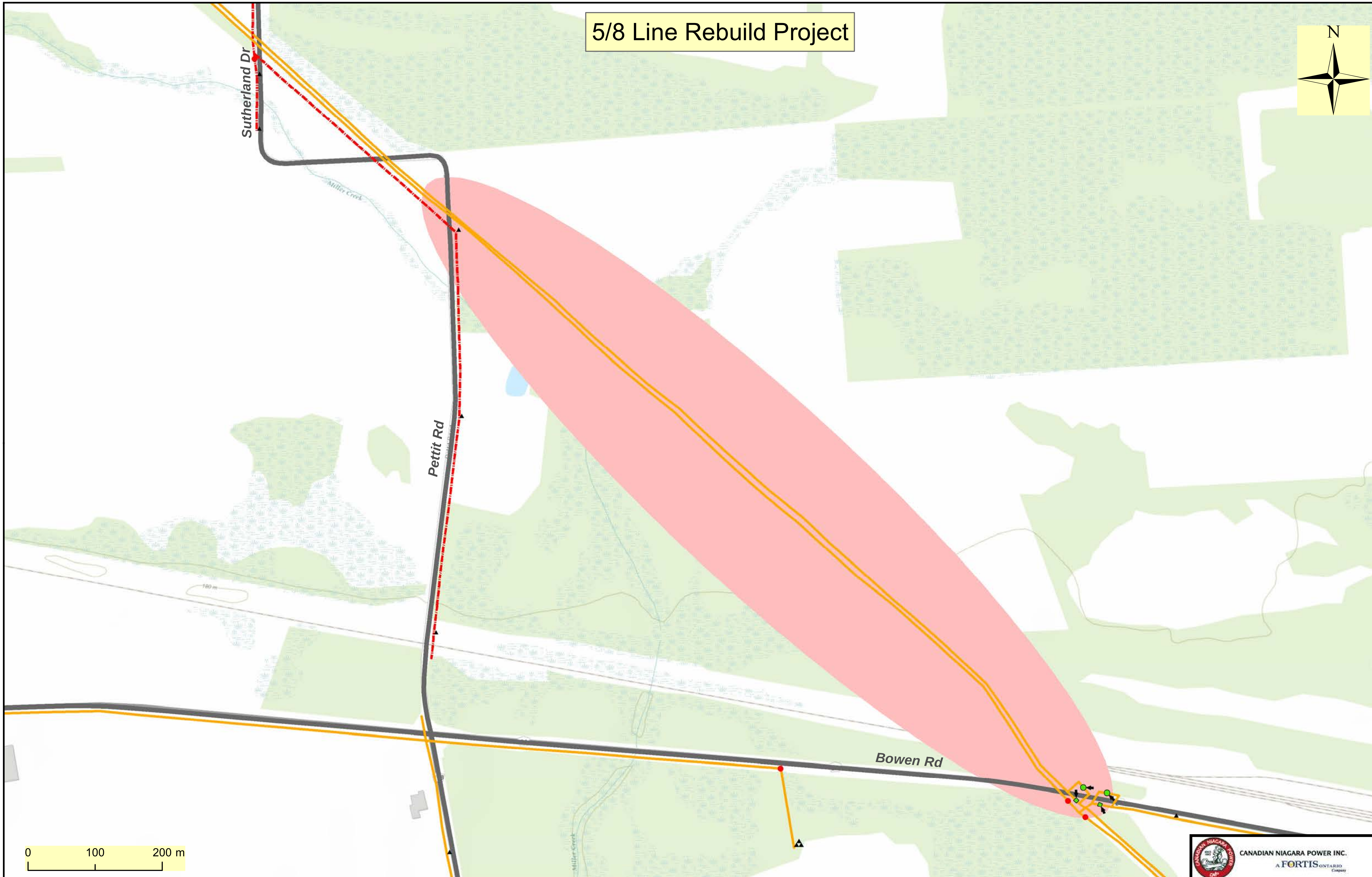
1. Efficiency, Customer Value, Reliability - 5/8 line are ties between Station 17 and Station 18. Without the tie line, the thousands of customers will have no power if Station 17 or 18 is out of service.

2. Safety - The existing tower line was built in early 1900s. The towers were rusty and may have structural weakness.

Total:	**2014 - $ 218,193** **2015 - $ 275,833**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	



5/8 Line Rebuild Project
N
Sutherland Dr
Pettit Rd
Miller Creek
Bowen Rd
0
100
200 m
CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Distribution Lines

Project Name:	Forks Road Canal Riser Rebuild
Settlement Account:	102030
OEB Category	○ SYSTEM ACCESS ◉ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Failure Risk
Project Information:	
Number of Circuits:	2
Number of Phases:	3 Phase
Number of Poles Installed:	6
Primary Conductor (Circuit km) Installed:	0.25 km
Primary U/G cable (Circuit m) Installed:	0
Secondary U/G (Circuit m) Installed:	0
Starting Date:	January 2015
Completion Date:	December 2015
Is this a multi-year project?	NO

Project Description:

Replacement of existing riser pole switches as they had reached end of useful life. During replacement, switches were relocated from inaccessible, third party owned, property out to Forks Road, which is more easily accessible. Forks Road is located within the Fort Erie service territory.

Applicable Justification Criteria:

- ☑ 1. Efficiency, Customer Value, Reliability
- ☑ 2. SAFETY
- ☐ 3. Cyber-security, Privacy
- ☐ 4. Coordination, Interoperability
- ☐ 5. Economic Development
- ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

1. Efficiency, Customer Value, Reliability - Work completed under this project is aimed at sustaining current levels of reliability by replacement of end of life assets.

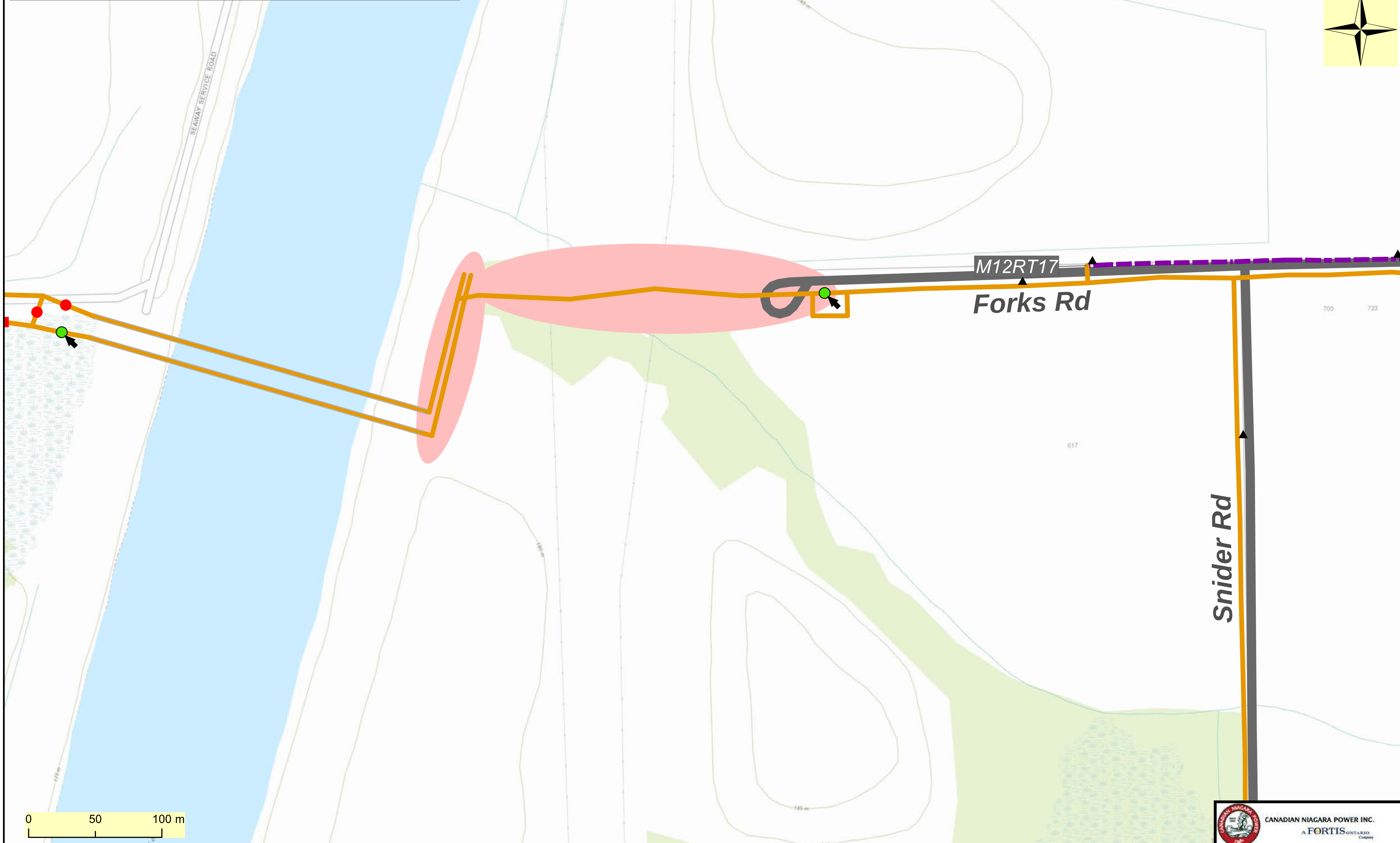
2. Safety - End of life assets do not meet current standards and impact public and worker safety.

Total:	**$ 184,826**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

Forks Road Canal Riser Rebuild Project



CANADIAN NIAGARA POWER INC. A FORTIS ONTARIO Company	**Capital Expenditure Approval Form - Distribution Lines**
Project Name:	Distribution Upgrades and Expansions
Settlement Account:	102020, 101137
OEB Category	○ SYSTEM ACCESS ◉ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Failure Risk
Project Information:	
Number of Circuits:	N/A
Number of Phases:	N/A
Number of Poles Installed:	N/A
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	January 2012
Completion Date:	December 2017
Is this a multi-year project?	YES

Project Description:

Various distribution system upgrades and expansions required to replace assets that are at end of useful life. This work is required to sustain the current level of supply stability. An example of a component of this project is a pole replacment initiated by CNPI asset management processes.

Applicable Justification Criteria:	☑ 1. Efficiency, Customer Value, Reliability ☑ 2. SAFETY ☐ 3. Cyber-security, Privacy ☐ 4. Coordination, Interoperability ☐ 5. Economic Development ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

1. Efficiency, Customer Value, Reliability - Work completed under this project is aimed at sustaining current levels of reliability by replacement of end of life assets.

2. Safety - End of life assets do not meet current standards and impact public and worker safety.

Total:	**2012 - $ 1,544,666** **2013 - $ 1,641,998** **2014 - $ 1,297,651** **2015 - $ 1,758,291** **2016 - $ 1,567,692** **2017 - $ 2,073,958**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

CANADIAN NIAGARA POWER INC. A FORTIS ONTARIO Company	**Capital Expenditure Approval Form - Distribution Lines**
Project Name:	FE Ridgeway Rebuilds Supporting Conversions
Settlement Account:	102025, 100925
OEB Category	○ SYSTEM ACCESS ◉ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Replacement of assets at end of useful life
Project Information:	
Number of Circuits:	N/A
Number of Phases:	N/A
Number of Poles Installed:	N/A
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	January 2016
Completion Date:	December 2017
Is this a multi-year project?	YES

Project Description:

The Ridgeway area contains approximately 66 circuit-km of the total 191 circuit-km of 4.8kV delta lines within the FE distribution system. A portion of this area has already been rebuilt during the historical investment period to support a wye connected configuration. In order to eliminate the delta system in this area, CNPI estimates the following effort will be required:

Effort Line Length (km):

- Line Rebuild 8.2
- Line Refurbishment 13.8
- Line Conversion 41.8

Based on the schedule for conversion in this area for the period 2016 through to 2020, CNPI estimates the following annual pole replacements:

Year:	2016	2017	2018	2019	2020
Est. Pole Count	94	14	68	56	77

CNPI plans to eliminate the Delta system in the Ridgeway area by the end of 2020.For more information, please refer to DSP, sections 5.4.6.4 and 5.4.6.5

Applicable Justification Criteria:	☑ 1. Efficiency, Customer Value, Reliability ☐ 2. SAFETY ☐ 3. Cyber-security, Privacy ☐ 4. Coordination, Interoperability ☐ 5. Economic Development ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

1. Efficiency, Customer Value, Reliability - Conversion from 4.8kV Delta to 8.3kV Wye reduces line losses to less than half of their pre-converted values. These savings in line losses are passed on directly to customers via a reduced loss factor. In addition, conversion allows for reducing the number of circuits on many streets and ROWs. This should result in incremental long-term savings in O&M costs.

Much of the project area contains poles in deteriorated condition that have a negative impact on reliability, if not replaced as they reach the end of their useful lives. Once these assets are renewed, there should be an overall reduction in O&M costs.

2. Safety - This project addresses two basic safety concerns. Much of the project area contains poles in deteriorated condition that might represent a hazard to workers or the public if not replaced as they reach the end of their useful lives. In addition, the legacy three-wire 4.8kV Delta system possesses inherent safety issues, such as difficulty in detecting faults/grounded conditions. Energized conductors can be in direct contact with objects or the ground with no means to detect this condition. Delta distribution systems, although common at one point in the history of the electricity industry, have become quite rare in Ontario, and workers may be less familiar with their operation. CNPI has been engaged in a long-term program to eliminate all of its legacy delta system. This project represents significant progress in achieving that goal.

More detailed information on this project may be found in the CNPI Distribution System Plan

Total:	**2016 - $ 620,000** **2017 - $ 294,938**
Additional Information on Cost Estimate:	
Manager Responsible:	
Project Approval:	

CANADIAN NIAGARA POWER INC. A FORTIS ONTARIO Company	**Capital Expenditure Approval Form - Distribution Lines**
Project Name:	Distribution Transformers and Regulators
Settlement Account:	102024
OEB Category	○ SYSTEM ACCESS ◉ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Failure, Failure Risk
Project Information:	
Number of Circuits:	N/A
Number of Phases:	N/A
Number of Poles Installed:	N/A
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	January 2012
Completion Date:	December 2017
Is this a multi-year project?	NO

Project Description:

Purchase of transformer inventory for connection to CNPI's distribution system.

Applicable Justification Criteria:	☑ 1. Efficiency, Customer Value, Reliability ☐ 2. SAFETY ☐ 3. Cyber-security, Privacy ☐ 4. Coordination, Interoperability ☐ 5. Economic Development ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

1. Efficiency, Customer Value, Reliability - Purchase of transformer inventory will allow for the proactive, or reactive installation of transformers within CNPI's distribution system.

Total:	**2012 - $ 205,999** **2013 - $ 261,400** **2014 - $ 261,842** **2015 - $ 278,843** **2016 - $ 306,000** **2017 - $ 315,000**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Distribution Lines

Project Name:	New MIST Meters
Settlement Account:	102049, 102048
OEB Category	○ SYSTEM ACCESS ◉ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Replacement of assets at end of useful life
Project Information:	
Number of Circuits:	N/A
Number of Phases:	N/A
Number of Poles Installed:	N/A
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	2015
Completion Date:	2015
Is this a multi-year project?	NO

Project Description:

Purchase of new MIST meters to replace previously installed meters within CNPI service territory. Legislated by the Ontario Energy Board.

Applicable Justification Criteria:

- [x] 1. Efficiency, Customer Value, Reliability
- [ ] 2. SAFETY
- [ ] 3. Cyber-security, Privacy
- [ ] 4. Coordination, Interoperability
- [ ] 5. Economic Development
- [ ] 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

1. Efficiency, Customer Value, Reliability - Purchases aimed at maintaining quality and integrity of metering efforts across CNPI under OEB legislation.

Total:	**$**	**234,065**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

	Capital Expenditure Approval Form - Distribution Lines
Project Name:	New Meters
Settlement Account:	100926, 102036
OEB Category	○ SYSTEM ACCESS ◉ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Failure Risk
Project Information:	
Number of Circuits:	N/A
Number of Phases:	N/A
Number of Poles Installed:	N/A
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	January 2012
Completion Date:	December 2017
Is this a multi-year project?	YES

Project Description:

Purchase of new meters to replace previously installed meters within CNPI service territory. Replacement may be for a variety of reasons,across multiple customer classes. Effort to maintain quality and integrity of metering, held to Measurement Canada standards.

Applicable Justification Criteria:	☑ 1. Efficiency, Customer Value, Reliability ☐ 2. SAFETY ☐ 3. Cyber-security, Privacy ☐ 4. Coordination, Interoperability ☐ 5. Economic Development ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

1. Efficiency, Customer Value, Reliability - Purchases aimed at maintaining quality and integrity of metering efforts across CNPI under OEB legislation.

Total:	**2012 - $ 131,194** **2013 - $ 164,326** **2014 - $ 132,694** **2015 - $ 127,324** **2016 - $ 180,072** **2017 - $ 189,419**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

CANADIAN NIAGARA POWER INC. A FORTIS ONTARIO Company	**Capital Expenditure Approval Form - Distribution Lines**
Project Name:	New Smart Meters
Settlement Account:	100926, 102036
OEB Category	○ SYSTEM ACCESS ● SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Failure Risk
Project Information:	
Number of Circuits:	N/A
Number of Phases:	N/A
Number of Poles Installed:	N/A
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	2012
Completion Date:	2013
Is this a multi-year project?	YES
Project Description:	
Purchase of new smart meters to replace previously installed meters within CNPI service territory. Legislated by the Ontario Energy Board.	
Applicable Justification Criteria:	☑ 1. Efficiency, Customer Value, Reliability ☐ 2. SAFETY ☐ 3. Cyber-security, Privacy ☐ 4. Coordination, Interoperability ☐ 5. Economic Development ☐ 6. Environmental Benefits
Project Justification (Note that EACH Justification Criterion must be addressed)	
1. Efficiency, Customer Value, Reliability - Purchases aimed at maintaining quality and integrity of metering efforts across CNPI under OEB legislation.	
Total:	**2012 - $ 355,960** **2013 - $ 4,879,044**
Additional Information on Cost Estimate:	
Manager Responsible:	
Project Approval:	

CANADIAN NIAGARA POWER INC. A FORTIS ONTARIO Company	**Capital Expenditure Approval Form - Distribution Lines**
Project Name:	Ontario Street Rebuild
Settlement Account:	101274
OEB Category	○ SYSTEM ACCESS ● SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Failure Risk
Project Information:	
Number of Circuits:	1 4 kV circuit
Number of Phases:	1 Phase
Number of Poles Installed:	12
Primary Conductor (Circuit km) Installed:	300 M
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	January 2013
Completion Date:	December 2013
Is this a multi-year project?	NO

Project Description:

Rebuild existing rear lot single phase line construction of South of King Street between Maple Street and Ontario Street in the Gananoque service territory. This will include the replacement of eleven(11) poles and the addition of one new pole. Rear lot primary will be reduced to secondary where possible and distribution transformers will be re-located to road-side poles for line truck access. All primary and secondary conductors will be replaced.

Applicable Justification Criteria:	☑ 1. Efficiency, Customer Value, Reliability ☑ 2. SAFETY ☐ 3. Cyber-security, Privacy ☐ 4. Coordination, Interoperability ☐ 5. Economic Development ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

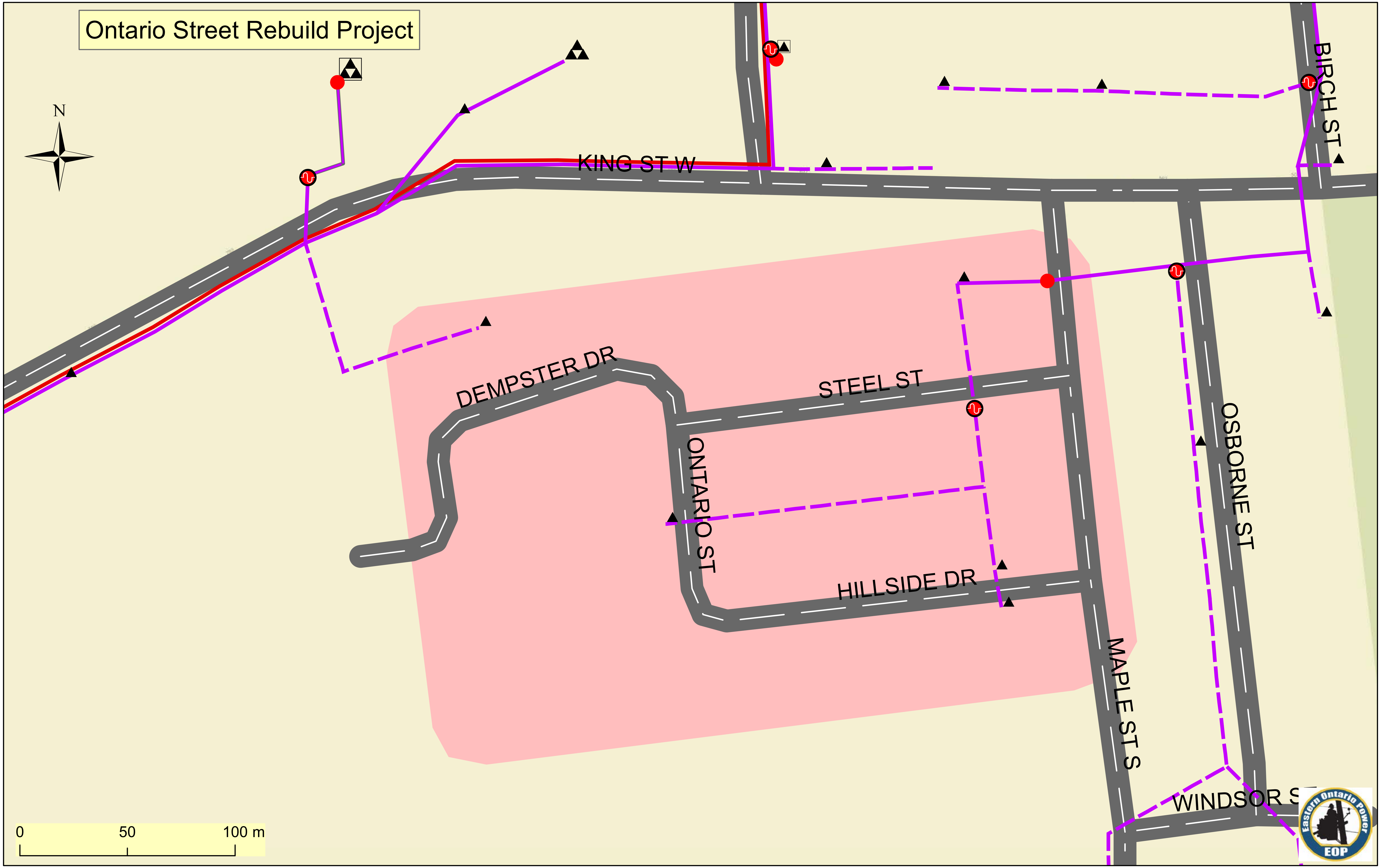
1. Efficiency, Customer Value, Reliability - The existing pole line is in the order of 40 to 60 years old and is due for replacement.

2. Safety - The existing construction standards do not meet the requirements of CSA C22.3 No. 1 in some locations. The reconstruction of the 4 kV circuit will reduce the potential for outages due to potential failures. The reconstruction of the 4 kV circuit will reduce system losses with respect to small wire size losses. Moving distribution transformers to the road side and reducing rear-lot primary to secondary bus will simply future maintenance by providing easy line truck access to polemount transformers.

Total:	**$ 122,901**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	



Ontario Street Rebuild Project
N
KING ST W
BIRCH ST
DEMPSTER DR
STEEL ST
ONTARIO ST
HILLSIDE DR
OSBORNE ST
MAPLE ST S
WINDSOR S
0
50
100 m
Eastern Ontario Power
EOP

CANADIAN NIAGARA POWER INC. A FORTIS ONTARIO Company	Capital Expenditure Approval Form - Distribution Lines
Project Name:	Oak Alley Rebuild
Settlement Account:	101274
OEB Category	○ SYSTEM ACCESS ● SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Failure Risk
Project Information:	
Number of Circuits:	Two 4 kV distributions ccts, one 26 kV subtransmission cct.
Number of Phases:	3 Phases
Number of Poles Installed:	11
Primary Conductor (Circuit km) Installed:	Three cirucits of three phases at 340 metres each
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	2013
Completion Date:	2014
Is this a multi-year project?	YES

Project Description:

Replace end of life, double circuit 4kV pole line spanning from William Street to Stone Street along Oak Alley. Construction will include the replacement of end of life poles, primary conductors, transformers, secondary bus and the addition of one 26.4 kV circuit. All three circuits to be built to meet today's construction standards.

Applicable Justification Criteria:	☑ 1. Efficiency, Customer Value, Reliability ☐ 2. SAFETY ☐ 3. Cyber-security, Privacy ☐ 4. Coordination, Interoperability ☐ 5. Economic Development ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

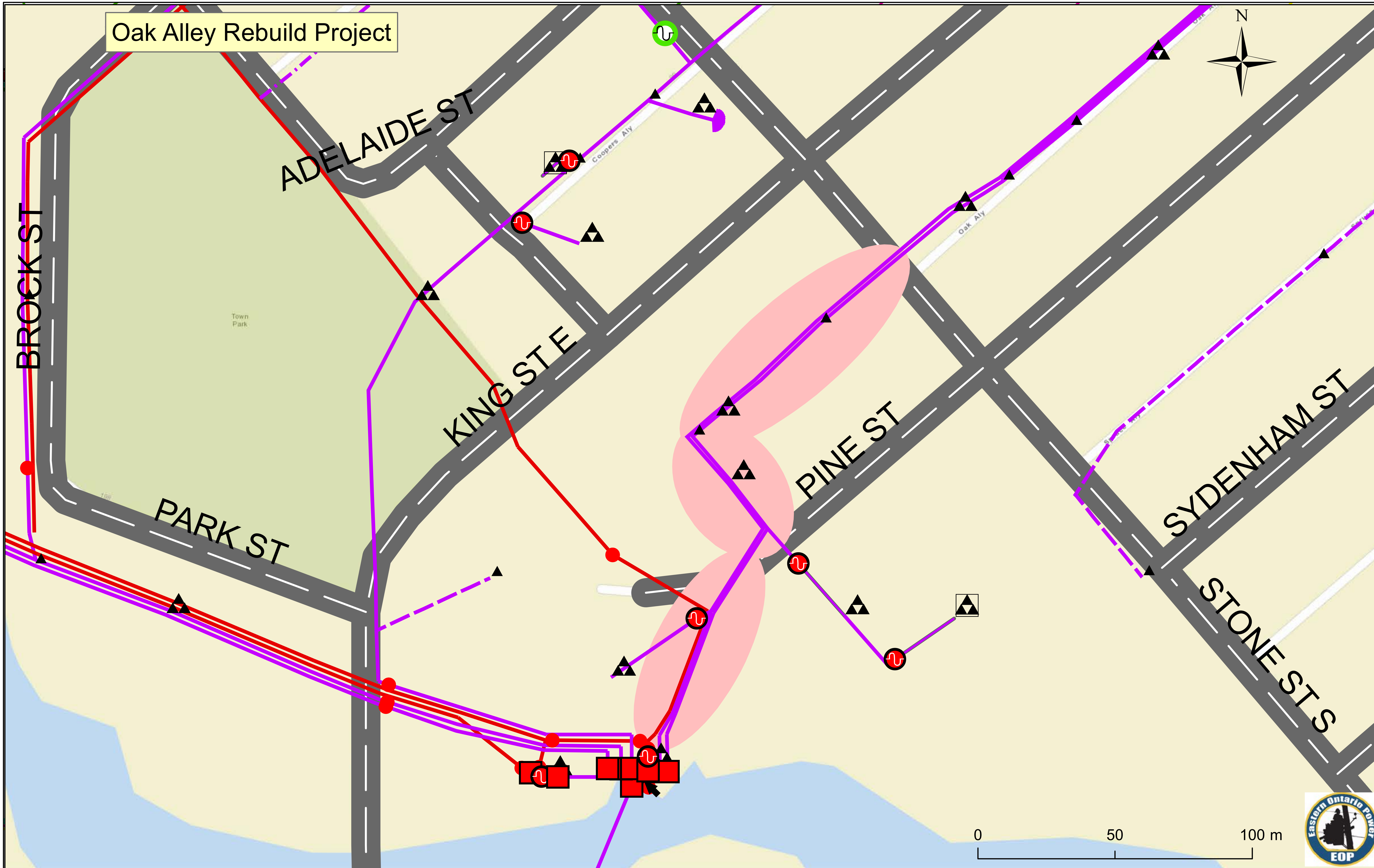
1. Efficiency, Customer Value, Reliability-The existing pole line has many end of life assets which are due for replacement. The reconstruction of the 4 kV circuits will reduce the potential for outages due to potential failures. The addition of the 26 kV circuit will facilitate the objective of providing a second 26.4kV supply to Herbert substation which is currently radially fed. The reconstruction of the 4kV circuits will improve reliability due to increased line capacity from the substations allowing for enhanced alternative supplies that will minimize outage sizes and durations for customers in the area. The reconstruction of the 4 kV circuits will reduce system losses with respect to small wire size losses as well as distribution transformer losses.

2. Safety - The existing construction standards do not meet the requirements of CSA C22.3 No. 1 in numerous locations. Clearances are often compromised posing hazards to line crews.

Total:	**2013 - $ 186,384** **2014 - $ 133,333**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	


Oak Alley Rebuild Project
N
ADELAIDE ST
BROCK ST
KING ST E
PARK ST
PINE ST
SYDENHAM ST
STONE ST S
Coopers Aly
Oak Aly
Town Park
0
50
100 m
Eastern Ontario Power
EOP

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Distribution Lines

Project Name:	Elizabeth Street Pole Replacement
Settlement Account:	101274
OEB Category	◯ SYSTEM ACCESS ◉ SYSTEM RENEWAL ◯ SYSTEM SERVICE ◯ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Failure Risk
Project Information:	
Number of Circuits:	1 4 kV circuit
Number of Phases:	Mostly 3 Phase, partly 1 Phase
Number of Poles Installed:	9
Primary Conductor (Circuit km) Installed:	360 M of 3 Phase + 240 M 1Phase
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	2014
Completion Date:	2015
Is this a multi-year project?	YES

Project Description:

Replace existing back lot circuit on Arthur and Elizabeth Streets with new construction. Project to extend from William Street to Pine Street. Replace 9-10 rotten poles. Poles with adequate size and health will remain. All primary and secondary conductors to be replaced.

Applicable Justification Criteria:

- ☑ 1. Efficiency, Customer Value, Reliability
- ☑ 2. SAFETY
- ☐ 3. Cyber-security, Privacy
- ☐ 4. Coordination, Interoperability
- ☐ 5. Economic Development
- ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

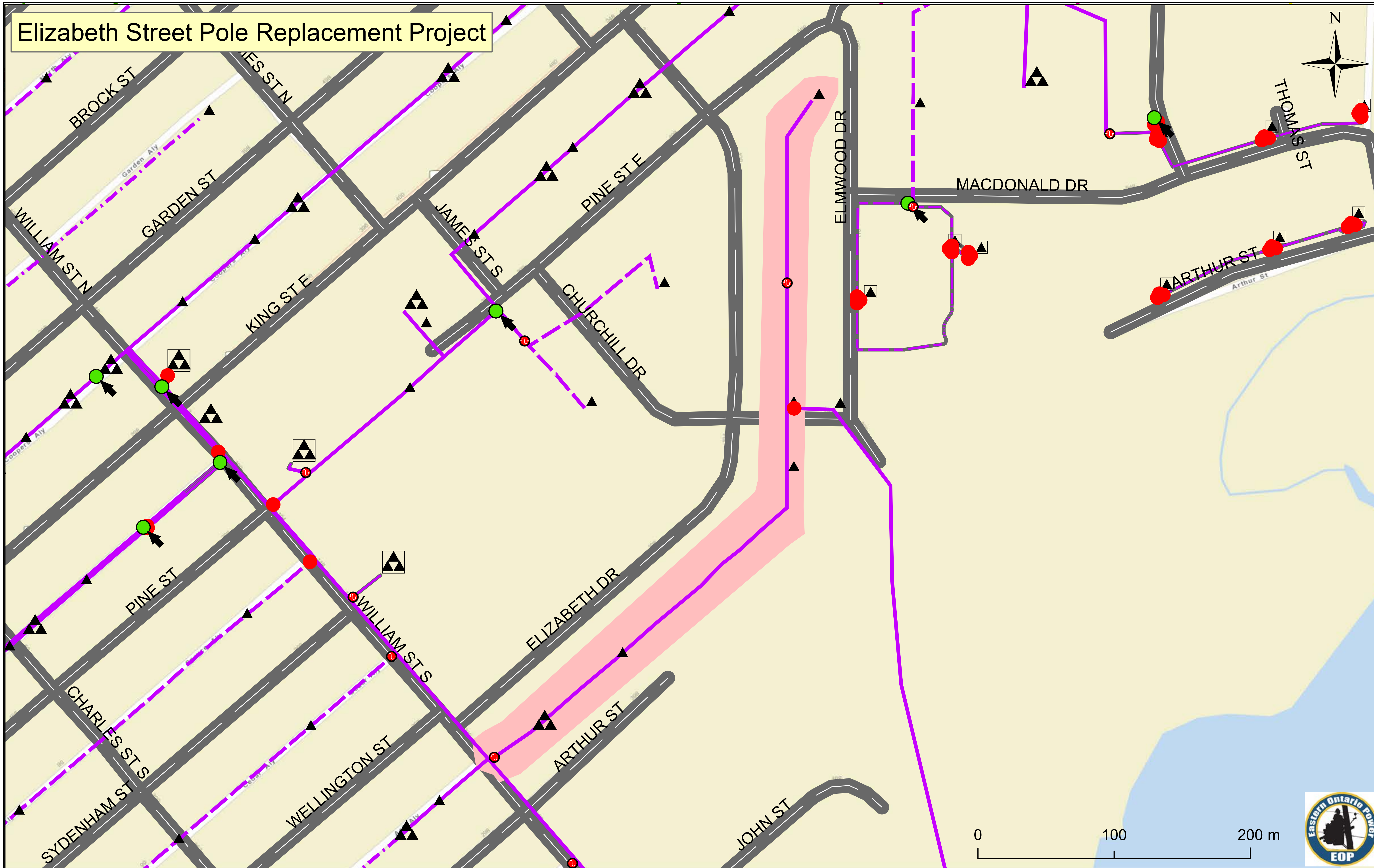
1. Efficiency, Customer Value, Reliability - The existing pole line is in the order of 50 to 60 years old and is due for replacement. Many of the poles are end of life.The reconstruction of the 4 kV circuit will reduce the potential for outages due to potential failures.The reconstruction of the 4 kV circuit will reduce system losses with respect to small wire size losses as well as distribution transformer losses.

2. Safety - New construction to meet the requirements of CSA C22.3 No. 1 which will improve safety to residents with respect to structural integrity as well as clearance improvements in some areas.

Total:	**$ 138,805**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	



Elizabeth Street Pole Replacement Project
N
BROCK ST
GARDEN ST
WILLIAM ST N
KING ST E
JAMES ST S
PINE ST E
CHURCHILL DR
ELMWOOD DR
MACDONALD DR
THOMAS ST
ARTHUR ST
PINE ST
ELIZABETH DR
WILLIAM ST S
CHARLES ST S
SYDENHAM ST
WELLINGTON ST
ARTHUR ST
JOHN ST
0
100
200 m
Eastern Ontario Power
EOP

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Distribution Lines

Project Name:	Pine Street Pole Replacement
Settlement Account:	101274
OEB Category	○ SYSTEM ACCESS ◉ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	End of service life, Risk of failure
Project Information:	
Number of Circuits:	One 4 kV circuit
Number of Phases:	3 Phase
Number of Poles Installed:	15
Primary Conductor (Circuit km) Installed:	440 M of 3 Phase circuit
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	January 2014
Completion Date:	December 2014
Is this a multi-year project?	NO

Project Description:

Replace the existing back lot construction of one 4 kV circuit on the south side of King Street between James and Elmwood Streets.

Applicable Justification Criteria:

- ☑ 1. Efficiency, Customer Value, Reliability
- ☑ 2. SAFETY
- ☐ 3. Cyber-security, Privacy
- ☐ 4. Coordination, Interoperability
- ☐ 5. Economic Development
- ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

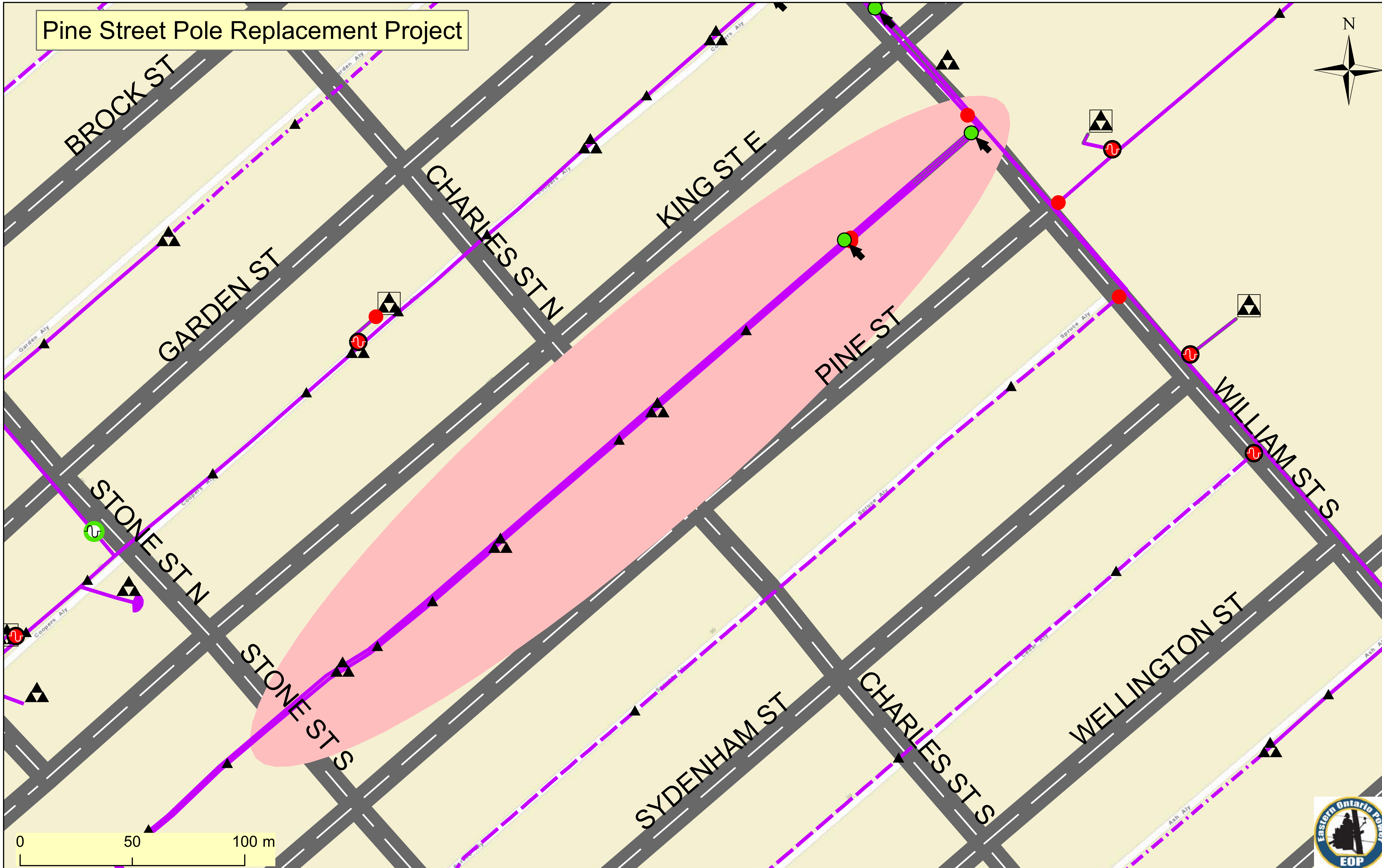
1. Efficiency, Customer Value, Reliability - The existing pole line is in the order of 40 to 60 years old and is due for replacement. The reconductoring of this circuit will improve reliability as it is an important link for providing backup to the Herbert Street substation 4 kV feeders. At present, there are certain parts of the year that would be very difficult to back up all of the Herbert Street circuits if the substation were to fail. The reconstruction of the 4 kV circuit will reduce the potential for outages due to potential failures. The reconstruction of the 4 kV circuit will reduce system losses with respect to small wire size losses as well as distribution transformer losses.

2. Safety - The existing construction standards do not meet the requirements of CSA C22.3 No. 1 in some locations. Clearances are often compromised posing hazards to line crews as well as homeowners in some cases.

Total:	**$ 235,266**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	



Pine Street Pole Replacement Project
N
BROCK ST
GARDEN ST
KING ST E
PINE ST
SYDENHAM ST
WELLINGTON ST
CHARLES ST N
CHARLES ST S
STONE ST N
STONE ST S
WILLIAM ST S
0
50
100 m
Eastern Ontario Power
EOP

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Distribution Lines

Project Name:	Construct Herbert DS to Gananoque DS Intertie
Settlement Account:	101137
OEB Category	○ SYSTEM ACCESS ● SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	End of Service Life, Risk of Failure

Project Information:

Number of Circuits:	Two 4 kV distribution ccts, one 26 kV subtransmission cct.
Number of Phases:	3 Phase
Number of Poles Installed:	24
Primary Conductor (Circuit km) Installed:	
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	2016
Completion Date:	2016
Is this a multi-year project?	NO

Project Description:

This project focuses on rebuilding end-of-life 4-kV interties between Herbert DS and Gananonque DS. This project has been broken down into two smaller projects as described below.

1. Coopers Alley
Replace existing back lot construction of multiple circuits with new front of lot circuits from the main substation to a previously completed project on Oak Alley. Construction will include the relocation of two 4 kV circuits from back lot to front lot and the relocation of one 26 kV circuit from customer owned lands. All three circuits to be reconfigured to meet today's construction standards.

2. Pine Street
Replace existing 4 kV circuit with new 4 kV and 26 kV circuits from William Street to Herbert Street along Coopers Alley as well as extending 26 kV circuit along existing pole line on Herbert Street. The secondary bus will be replaced as well. The new circuit will be built to meet today's construction standards.

Applicable Justification Criteria:

- [x] 1. Efficiency, Customer Value, Reliability
- [x] 2. SAFETY
- [ ] 3. Cyber-security, Privacy
- [ ] 4. Coordination, Interoperability
- [ ] 5. Economic Development
- [ ] 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

1. Efficiency, Customer Value, Reliability
The reconstruction of the 4 kV circuits will reduce the potential for outages due to potential failures. The installation of the 26 kV circuit is part of the overall project to loop the 26 kV circuit through Gananoque to improve reliability and operability on the 26 kV network. The reconstruction of the 4 kV circuits will reduce system losses with respect to small wire size losses as well as increase the capacity of these interties to provide additional flexibility when transferring load between Herbert and Gananoque DS.

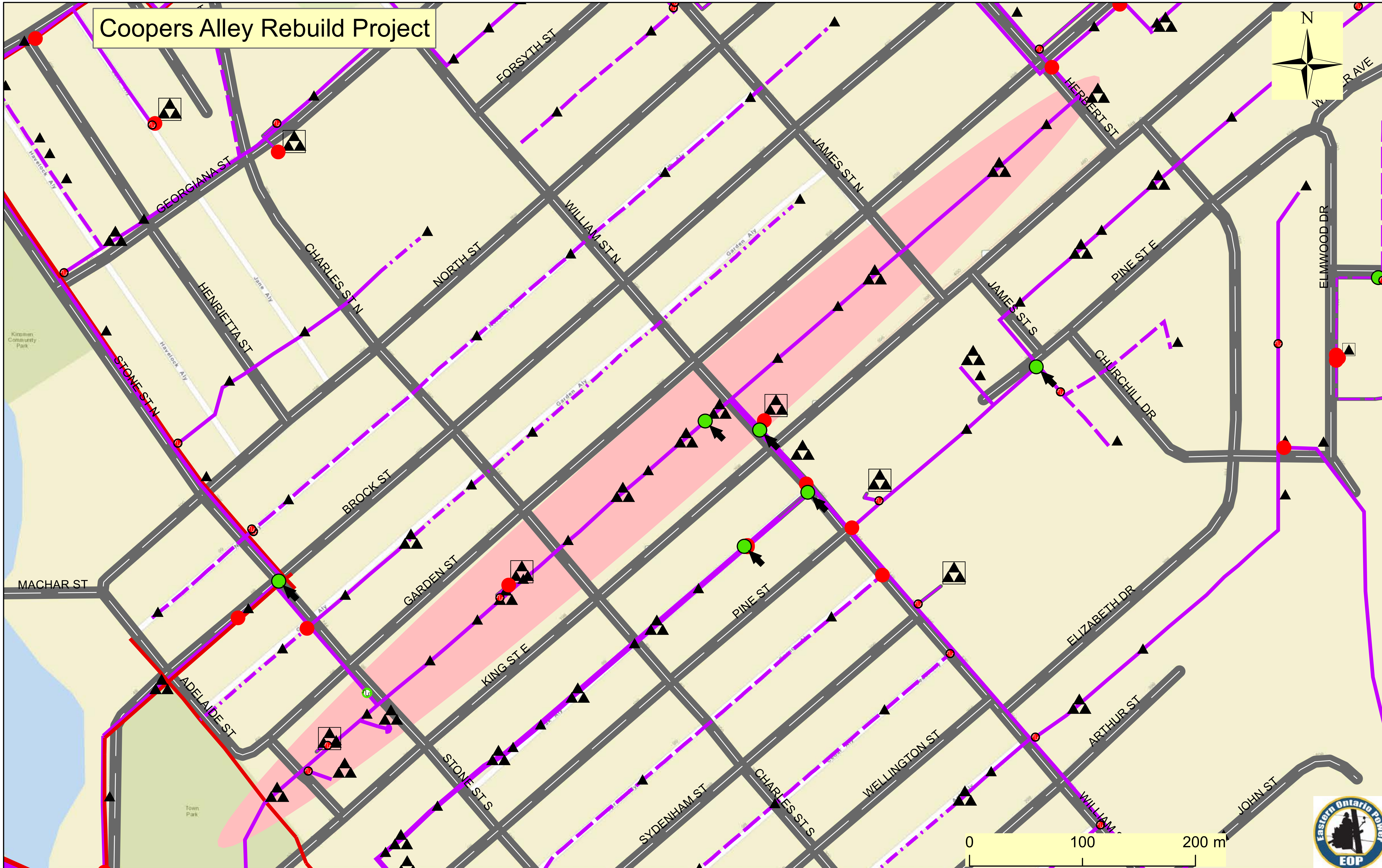
2. Safety
The existing pole lines are in the order of 50 to 60 years old and due for replacement. The existing construction standards do not meet the requirements of CSA C22.3 No. 1 in numerous locations. Clearances are often compromised posing hazards to line crews as well as homeowners in some cases.

More detailed information on this project may be found in the CNPI Distribution System Plan

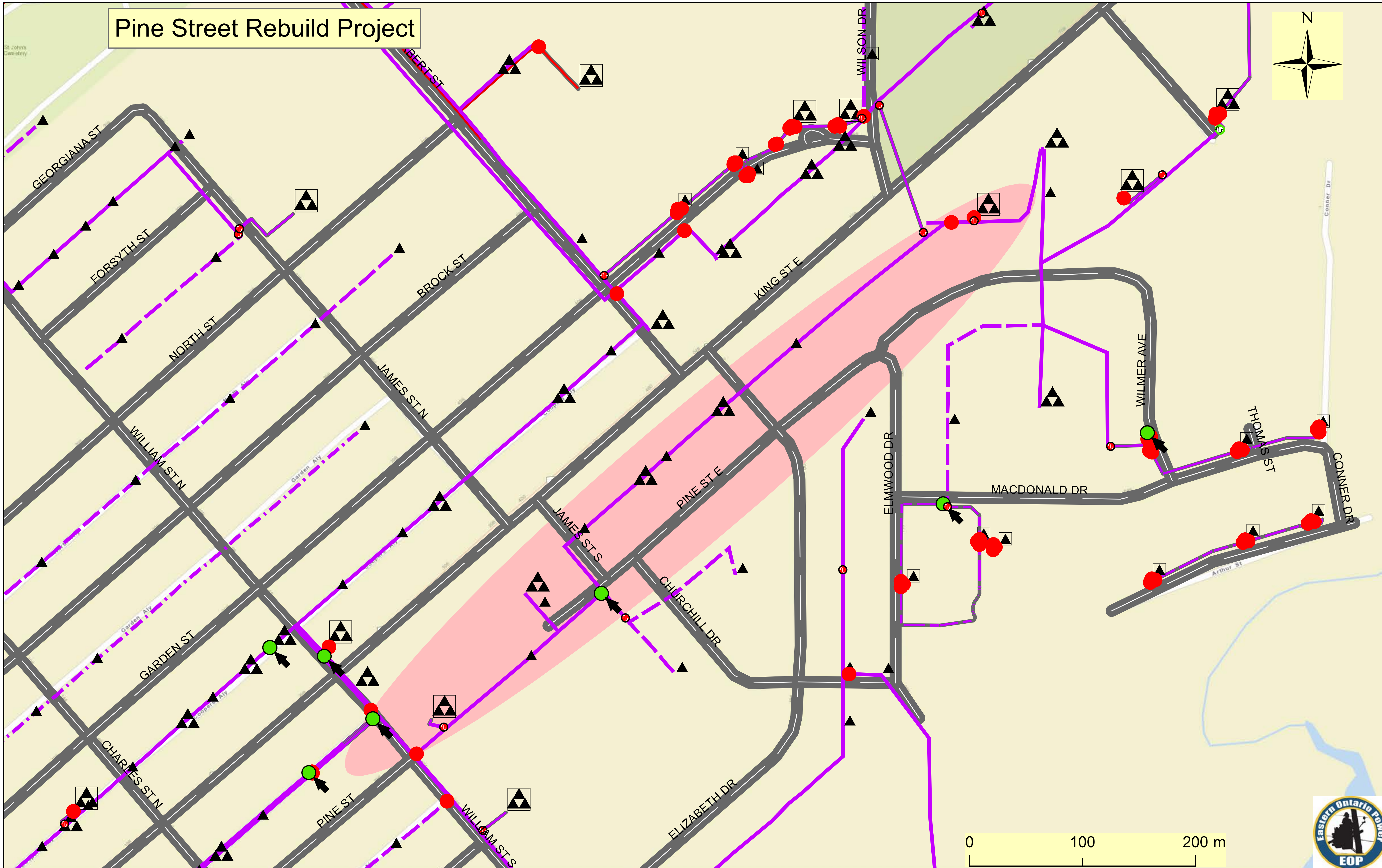
Total:	**$ 380,000**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	



Coopers Alley Rebuild Project
N
FORSYTH ST
GEORGIANA ST
HERBERT ST
JAMES ST N
WILLIAM ST N
CHARLES ST N
NORTH ST
HENRIETTA ST
STONE ST N
BROCK ST
GARDEN ST
MACHAR ST
ADELAIDE ST
KING ST E
PINE ST
PINE ST E
JAMES ST S
CHURCHILL DR
ELMWOOD DR
ELIZABETH DR
STONE ST S
SYDENHAM ST
CHARLES ST S
WELLINGTON ST
ARTHUR ST
JOHN ST
0
100
200 m
Eastern Ontario Power
EOP



Pine Street Rebuild Project
GEORGIANA ST
FORSYTH ST
NORTH ST
BROCK ST
KING ST E
PINE ST E
JAMES ST N
JAMES ST S
WILLIAM ST N
WILLIAM ST S
GARDEN ST
CHARLES ST N
PINE ST
CHURCHILL DR
ELIZABETH DR
ELMWOOD DR
WILSON DR
MACDONALD DR
WILMER AVE
THOMAS ST
CONNER DR
N
0
100
200 m
Eastern Ontario Power
EOP

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CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Distribution Lines

Project Name:	North Line Rebuild
Settlement Account:	101137
OEB Category	○ SYSTEM ACCESS ◉ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	End of Service Life, Risk of Failure
Project Information:	
Number of Circuits:	One 26.4 kV distribution cct.
Number of Phases:	One circuit of three phases.
Number of Poles Installed:	Thirty to Thirty Five (30-35) poles.
Primary Conductor (Circuit km) Installed:	One 26.4 kV distribution cct of 2 kilometres.
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	July 2017
Completion Date:	December 2017
Is this a multi-year project?	NO

Project Description:

EOP currently owns an approximately 40km, 26.4 kV, 3-wire distribution circuit (North Line) spanning from EOP's main substation to three remote hydro generation plants. Along with the generation plants, the North line also services 1 residential and 1 commmercial customer. EOP is proposing to rebuild the existing 26.4kV 3-wire line with a new 26.4 kV 4-wire circuit. The complete rebuild of the North line will occur over multiple phases with this project being phase one. EOP will also attempt to re-align the North Line where feasible as part of the rebuild to provide easier truck access at various locations.

Applicable Justification Criteria:

- ☑ 1. Efficiency, Customer Value, Reliability
- ☑ 2. SAFETY
- ☐ 3. Cyber-security, Privacy
- ☐ 4. Coordination, Interoperability
- ☐ 5. Economic Development
- ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

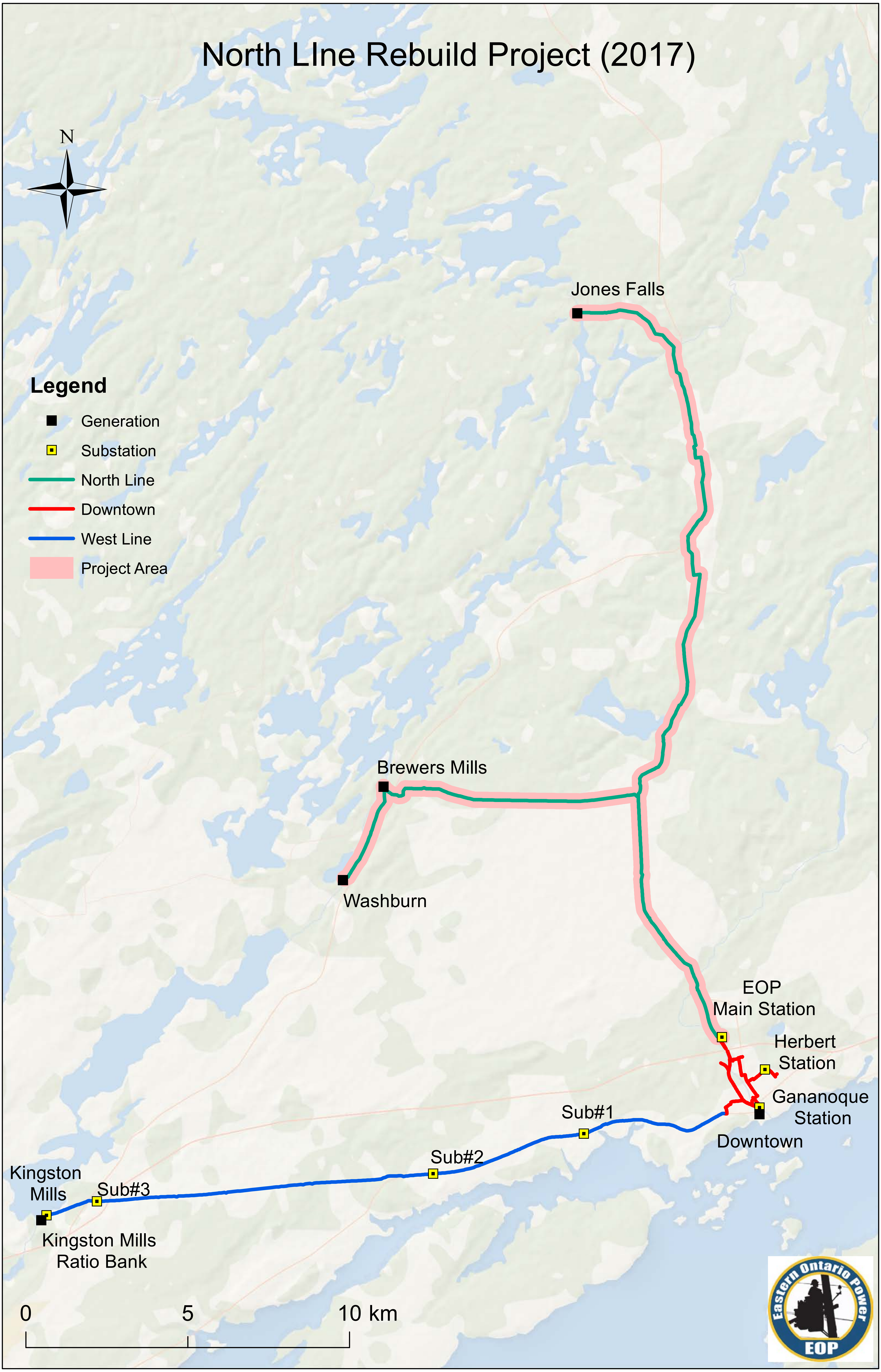
1. Efficiency, Customer Value, Reliability -The existing pole line is in the order of 50 to 60 years old and is due for replacement. The existing pole line traverses over some difficult terrain and through some dense bush limiting truck access in many areas and leaving the line vulnerable to tree/branch contacts even with preventative line clearing. The reconstruction of the 26.4 kV circuit will reduce the potential for outages due to potential failures. The reconstruction of the 26.4 kV circuit will reduce system losses with respect to small wire size losses.

2. Safety - The existing 3-wire construction poses a safety risk with no return path for single phase to ground faults.

Total:	**$ 257,110**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	



North LIne Rebuild Project (2017)
N
Legend
Generation
Substation
North Line
Downtown
West Line
Project Area
Jones Falls
Brewers Mills
Washburn
EOP
Main Station
Herbert
Station
Gananoque
Station
Downtown
Sub#1
Sub#2
Sub#3
Kingston
Mills
Kingston Mills
Ratio Bank
0
5
10 km
Eastern Ontario Power
EOP

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Distribution Lines

Project Name:	Substation TX Replacement (#1, #2, Leaky Creek)
Settlement Account:	101270
OEB Category	○ SYSTEM ACCESS ◉ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Obsolescent Performance, Failure
Project Information:	
Number of Circuits:	N/A
Number of Phases:	N/A
Number of Poles Installed:	N/A
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	2013
Completion Date:	2013
Is this a multi-year project?	NO

Project Description:

Remove three small substations from service. Thoroughly test to confirm that they do not contain PCBs. (Destructive testing of transformer bushings). Dispose of equipment and decommission the sites. These substations will be replaced by three platform mounted ratio bank installations within the road allowance.

Applicable Justification Criteria:

- [x] 1. Efficiency, Customer Value, Reliability
- [x] 2. SAFETY
- [ ] 3. Cyber-security, Privacy
- [ ] 4. Coordination, Interoperability
- [ ] 5. Economic Development
- [ ] 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

1. Efficiency, Customer Value, Reliability - Three small substations are to be taken out of service to properly test PCB concentrations in transformer bushings (destructive test). Two of the three substations have reached the end of their service lives and are showing severe degradation in transformer winding insulation (oil sample test results). Replacement stations are being built as part of 2013 budget. The third substation is nearing the end of its service life and doesn't match the characteristics of the rest of the distribution system. (Unable to transfer load between this station and other stations without incurring significant short term outage).

6. Environmental Benefits - Final stage of project is to decommission and dispose of existing, aged substation equipment as well as to clean up substation sites if required.

Total:	**$ 328,232**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

CANADIAN NIAGARA POWER INC. A FORTIS ONTARIO Company	**Capital Expenditure Approval Form - Distribution Lines**
Project Name:	Distribution Automation
Settlement Account:	102031
OEB Category	○ SYSTEM ACCESS ○ SYSTEM RENEWAL ◉ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Reliability
Project Information:	
Number of Circuits:	N/A
Number of Phases:	N/A
Number of Poles Installed:	N/A
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	January 2012
Completion Date:	December 2017
Is this a multi-year project?	YES

Project Description:

This project is part of a muli-year program aimed at the introduction of field based automated switching and protection devices. Based on analysis of reliability data, CNPI targets sections of feeders with poor performance and implements automation aimed at improving outage frequency, duration, and response time. The installations typically consist of a motor operated switch or recloser coupled with protective relay and control devices. The resulting installation is capable of remote interrogation and operation via CNPI's SCADA system.

Applicable Justification Criteria:	☑ 1. Efficiency, Customer Value, Reliability ☐ 2. SAFETY ☐ 3. Cyber-security, Privacy ☑ 4. Coordination, Interoperability ☐ 5. Economic Development ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

1. Efficiency, Customer Value, Reliability - The introduction of distributed automation leads to a reduction in response and restoration times during outages.

2. Coordination, Interoperability: The installation of field based automated devices reduce the amount of feeder exposure under outage conditions.

Total:	**2012 - $144,333** **2013 - $180,676** **2016 - $308,283** **2017 - $311,432**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Distribution Lines

Project Name:	Delta to Wye Conversion Niagara
Settlement Account:	102031
OEB Category	○ SYSTEM ACCESS ○ SYSTEM RENEWAL ◉ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Safety
Project Information:	
Number of Circuits:	N/A
Number of Phases:	N/A
Number of Poles Installed:	N/A
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	January 2012
Completion Date:	December 2015
Is this a multi-year project?	YES

Project Description:

This project is part of a multi-year program to convert delta connected CNPI load to a wye grounded system. This project is executed in conjunction with projects to rebuild CNPI's delta connected distribution substations to a wye grounded source. Conversion efforts include the installation of transformer protection elements, neutral conductor, grounding conductor and pole replacements where necessary.

Applicable Justification Criteria:

- ☑ 1. Efficiency, Customer Value, Reliability
- ☑ 2. SAFETY
- ☐ 3. Cyber-security, Privacy
- ☐ 4. Coordination, Interoperability
- ☐ 5. Economic Development
- ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

1. Efficiency, Customer Value, Reliability - CNPI is improving customer reliability and system efficiency by implementing a four wire grounded distribution system. The grounded system will improve the ability to sense system ground faults and positively impact protection coordination.The system will be operated at an increased voltage level which contriubtes to loss reduction.

2. Safety - The delta distribution system limits the capability of detecting ground faults resulting in downed conductors remaining energized under certain conditions. Elimination of the delta system removes this public and worker safety risk.

Total:	**2012 - $155,910** **2013 - $156,934** **2015 - $127,675**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

CANADIAN NIAGARA POWER INC. A FORTIS ONTARIO Company	**Capital Expenditure Approval Form - Distribution Lines**
Project Name:	Ridgeway Delta to Wye Conversion Niagara
Settlement Account:	102031
OEB Category	○ SYSTEM ACCESS ○ SYSTEM RENEWAL ◉ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Safety
Project Information:	
Number of Circuits:	N/A
Number of Phases:	N/A
Number of Poles Installed:	N/A
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	January 2016
Completion Date:	December 2017
Is this a multi-year project?	YES

Project Description:

This project is part of a multi-year program to convert delta connected CNPI load to a wye grounded system. This project is executed in conjunction with projects to rebuild CNPI's delta connected distribution substations to a wye grounded source. Conversion efforts include the installation of transformer protection elements, neutral conductor, grounding conductor and pole replacements where necessary.

Applicable Justification Criteria:	☑ 1. Efficiency, Customer Value, Reliability ☑ 2. SAFETY ☐ 3. Cyber-security, Privacy ☐ 4. Coordination, Interoperability ☐ 5. Economic Development ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

1. Efficiency, Customer Value, Reliability - CNPI is improving customer reliability and system efficiency by implementing a four wire grounded distribution system. The grounded system will improve the ability to sense system ground faults and positively impact protection coordination. The system will be operated at an increased voltage level which contriubtes to loss reduction.

2. Safety - The delta distribution system limits the capability of detecting ground faults resulting in downed conductors remaining energized under certain conditions. Elimination of the delta system removes this public and worker safety risk.

Total:	**2016 - $330,000** **2017 - $450,313**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Distribution Lines

Project Name:	Stevensville Upgrade - Stepdown Load Relief
Settlement Account:	100124
OEB Category	○ SYSTEM ACCESS ○ SYSTEM RENEWAL ◉ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Reliability
Project Information:	
Number of Circuits:	2
Number of Phases:	Three
Number of Poles Installed:	20
Primary Conductor (Circuit km) Installed:	1230 M
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	March 2012
Completion Date:	July 2012
Is this a multi-year project?	NO

Project Description:

This project is centered around the Ott Road and Fox Road intersection in Stevensville, Ontario. Upgraded rabbit load relief combined with new reclosers and other equipment resulted in downline rabbit relief. Additionally, a conversion from DELTA to WYE was made during the project. The Electrical Safety Authority requires the removal of dated DELTA systems. The existing 1 phase line was replaced with an updated 3 phase line, a structure mounted transformer was also installed.

Applicable Justification Criteria:

- [x] 1. Efficiency, Customer Value, Reliability
- [ ] 2. SAFETY
- [ ] 3. Cyber-security, Privacy
- [ ] 4. Coordination, Interoperability
- [ ] 5. Economic Development
- [ ] 6. Environmental Benefits

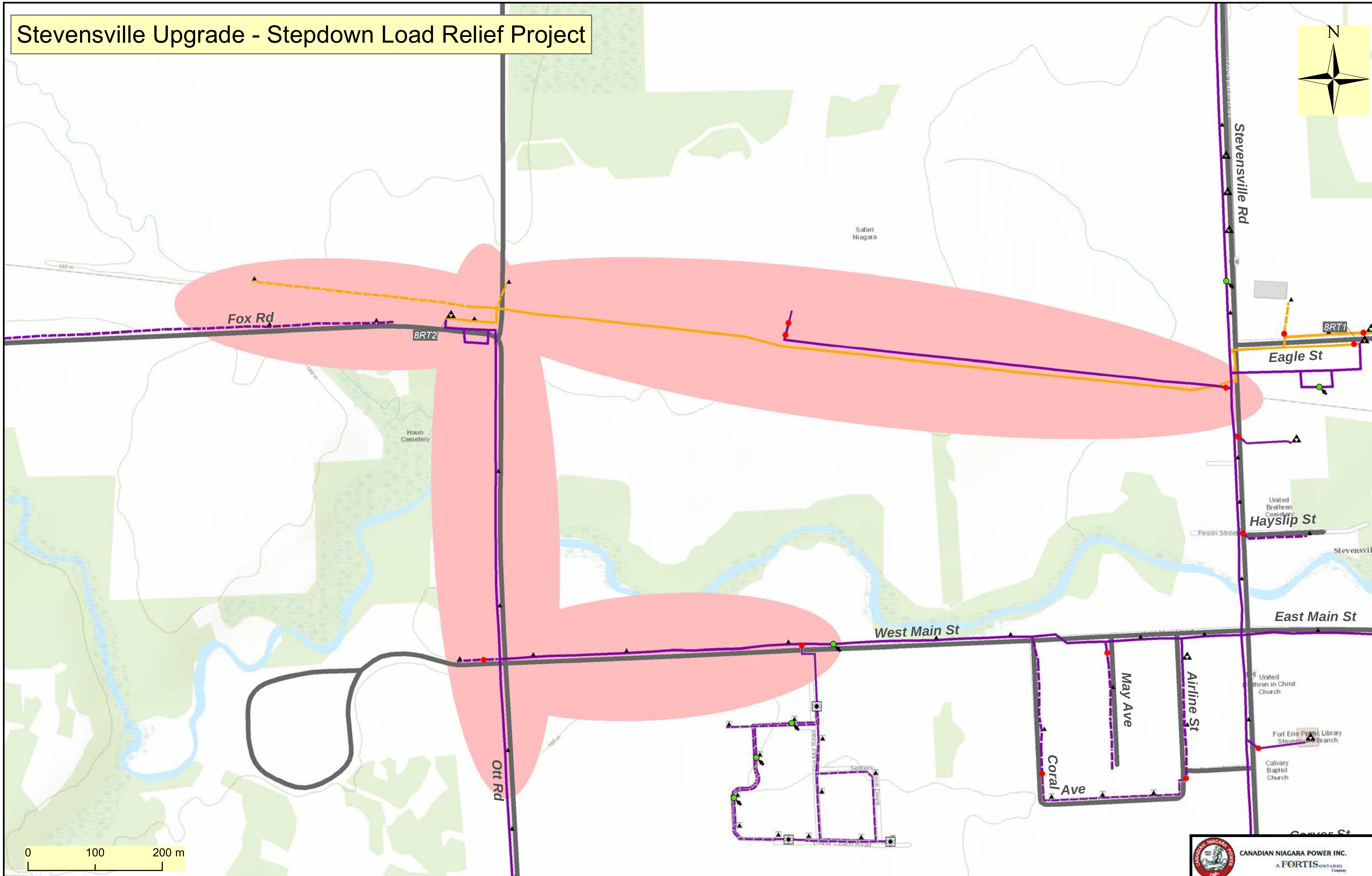
Project Justification (Note that EACH Justification Criterion must be addressed)

1. Efficiency, Customer Value, Reliability - The conversion from a DELTA to a WYE system was madatory given that the ESA requires the removal of dated DELTA systems. Aged single phase line and rabbits were replaced in an effort to mitigate future system interference. Post system renewal, the efficencies of these assets and system reliability were both improved.

Total:	**$ 152,381**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	



Stevensville Upgrade - Stepdown Load Relief Project
N
Fox Rd
8RT2
8RT1
Safari Niagara
Stevensville Rd
Eagle St
Haun Cemetery
United Brethren Cemetery
Hayslip St
Pirson Street
Stevensville
East Main St
West Main St
Ott Rd
May Ave
Airline St
Coral Ave
United Brethren in Christ Church
Fort Erie Public Library Stevensville Branch
Calvary Baptist Church
0
100
200 m
CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

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A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Distribution Lines

Project Name:	Station 18 New Feeder Configuration
Settlement Account:	100481
OEB Category	(●) SYSTEM ACCESS ( ) SYSTEM RENEWAL ( ) SYSTEM SERVICE ( ) GENERAL PLANT
OEB Primary ("Trigger") Driver:	Customer Service Request
Project Information:	
Number of Circuits:	N/A
Number of Phases:	N/A
Number of Poles Installed:	N/A
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	2013
Completion Date:	2013
Is this a multi-year project?	NO

Project Description:

This project is centered around the reconfiguration of Station 18 exit feeders. New duct work and riser poles were installed in 2013. Station 18 is located in the Fort Erie service territory.

Applicable Justification Criteria:

- [x] 1. Efficiency, Customer Value, Reliability
- [ ] 2. SAFETY
- [ ] 3. Cyber-security, Privacy
- [ ] 4. Coordination, Interoperability
- [ ] 5. Economic Development
- [ ] 6. Environmental Benefits

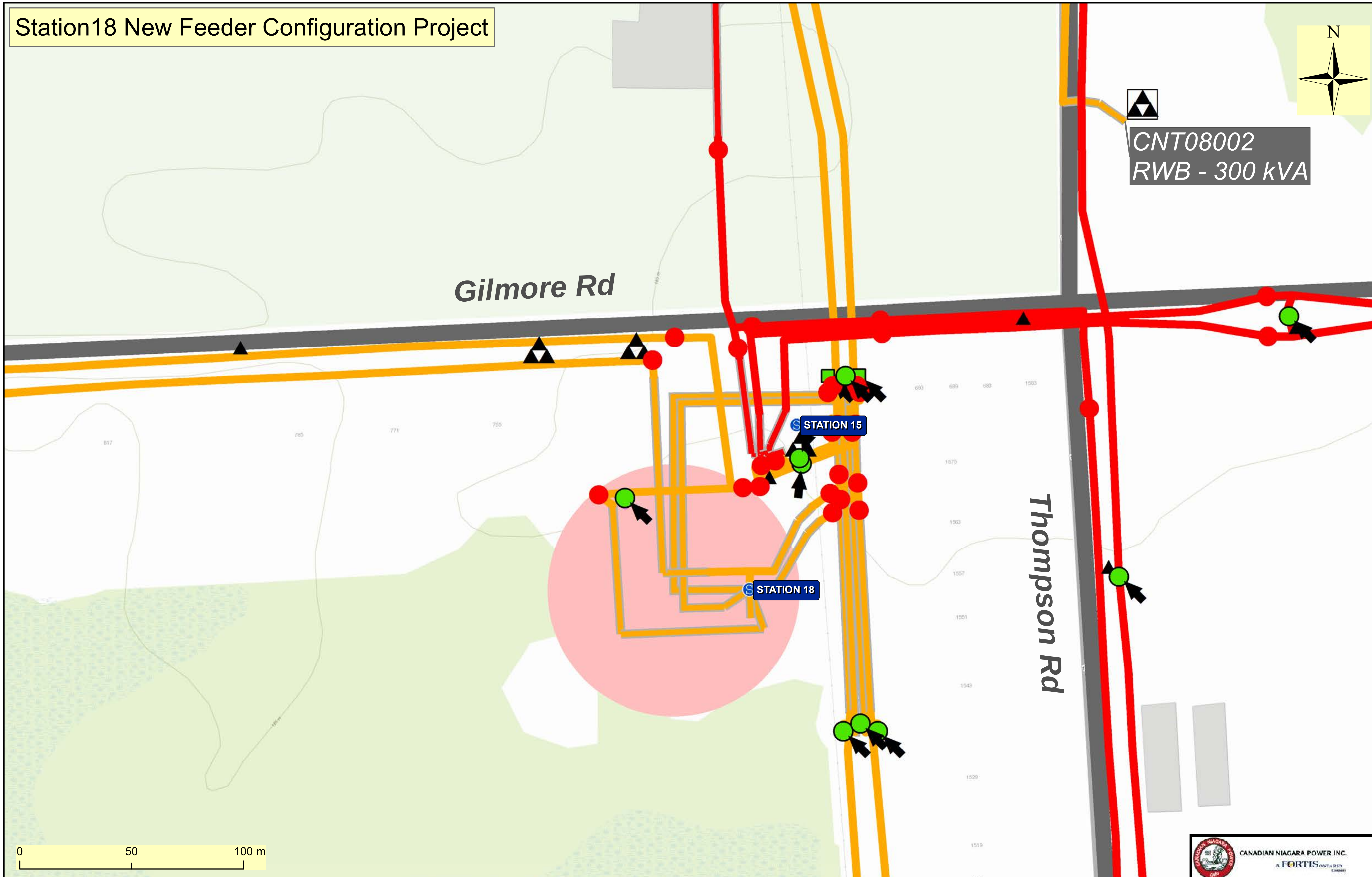
Project Justification (Note that EACH Justification Criterion must be addressed)

1. Efficiency, Customer Value, Reliability - The reconfiguration of Station 18 positively impacted customer value and reliability through the construction of 3 new feeders, reducing individual feeder exposure. These additional 34.5 kV feeders offer additional operational flexibility and load transfer options, minimizing customer interuptions.

Total:	**$ 102,623**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	


Station18 New Feeder Configuration Project
N
CNT08002
RWB - 300 kVA
Gilmore Rd
STATION 15
STATION 18
Thompson Rd
0
50
100 m
CANADIAN NIAGARA POWER INC.
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Capital Expenditure Approval Form - Distribution Lines

Project Name:	18L10 Extension Highway 3
Settlement Account:	102031, 102020, 102027, 102030
OEB Category	○ SYSTEM ACCESS ○ SYSTEM RENEWAL ● SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Reliability
Project Information:	
Number of Circuits:	2
Number of Phases:	3 Phase
Number of Poles Installed:	22
Primary Conductor (Circuit km) Installed:	1.3 km
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	September 2014
Completion Date:	October 2015
Is this a multi-year project?	YES

Project Description:

Build a double circuit pole line, on the North side of Highway 3, from Gorham Rd. to Rosehill Rd and from Centralia Rd. to Ridgemount Rd. Top circuit 34.5 to replace 10 line feed to Station 19 and underbuild to 15kv for future conversion of delta to wye. The lower circuit will also play into the future feeder of Station 19, reducing the size of feeder 1921, which because of the conversion process has become large until other rabbits are eliminated.

Applicable Justification Criteria:	☑ 1. Efficiency, Customer Value, Reliability ☐ 2. SAFETY ☐ 3. Cyber-security, Privacy ☐ 4. Coordination, Interoperability ☐ 5. Economic Development ☐ 6. Environmental Benefits

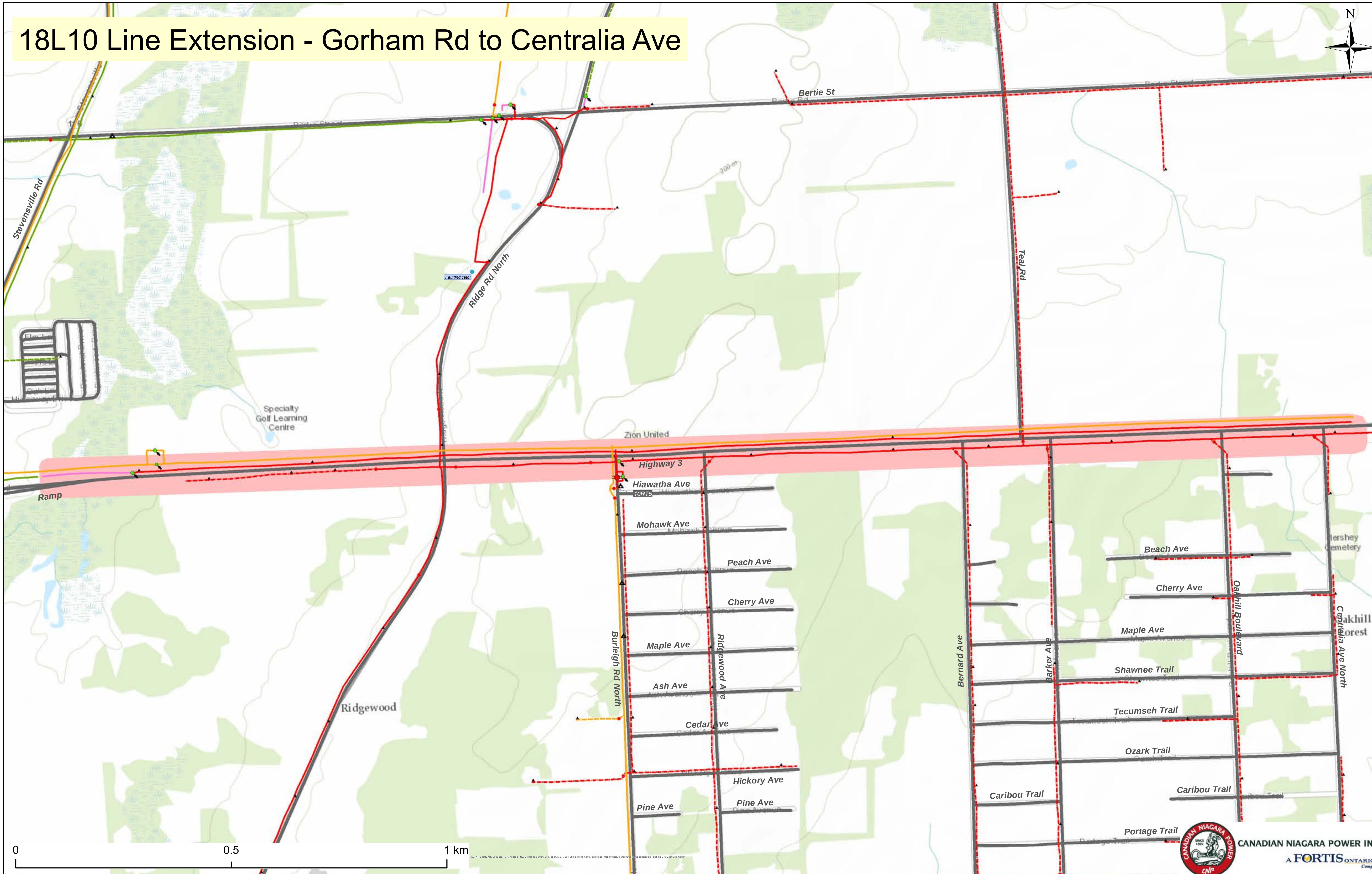
Project Justification (Note that EACH Justification Criterion must be addressed)

1. Efficiency, Customer Value, Reliability - CNPI is improving our customer reliability and efficiency by moving 10 line out of the old right of way, South of Dominion Rd. and relocating it out to Highway 3 from Gorham Rd. to eventually, the Town Hall. The lower circuit will be part of our ongoing conversion work in Ridgeway.

Total:	**2014 - $ 507,744** **2015 - $ 147,429**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	



18L10 Line Extension - Gorham Rd to Centralia Ave
N
Bertie St
Stevensville Rd
Ridge Rd North
FaultIndicator
Teal Rd
Specialty
Golf Learning
Centre
Zion United
Highway 3
Ramp
Hiawatha Ave
10RT5
Mohawk Ave
Peach Ave
Cherry Ave
Maple Ave
Ash Ave
Cedar Ave
Hickory Ave
Pine Ave
Burleigh Rd North
Ridgewood Ave
Ridgewood
Bernard Ave
Barker Ave
Beach Ave
Cherry Ave
Maple Ave
Shawnee Trail
Tecumseh Trail
Ozark Trail
Caribou Trail
Portage Trail
Oakhill Boulevard
Centralia Ave North
Hershey
Cemetery
Oakhill
Forest
0
0.5
1 km
CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Distribution Lines

Project Name:	Houck Crescent Conversion
Settlement Account:	102022, 102027, 102030
OEB Category	○ SYSTEM ACCESS ○ SYSTEM RENEWAL ● SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Reliability
Project Information:	
Number of Circuits:	1
Number of Phases:	1 Phase
Number of Poles Installed:	26
Primary Conductor (Circuit km) Installed:	1.3 km
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	June 2015
Completion Date:	July 2015
Is this a multi-year project?	NO

Project Description:

This project is the second phase of rear lot conversion Niagara Blvd. from Sutherland to Thompson Road in the Fort Erie service territory. Phase one was completed in 2013. Complete rebuild from 4.8kv delta to 19.9kv wye. Installation of new 40ft poles and reconductor. New transformation and secondary bus installed on new neutral. Also included in this project is the reclemation of Right of way.

Applicable Justification Criteria:

- [x] 1. Efficiency, Customer Value, Reliability
- [x] 2. SAFETY
- [ ] 3. Cyber-security, Privacy
- [ ] 4. Coordination, Interoperability
- [ ] 5. Economic Development
- [ ] 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

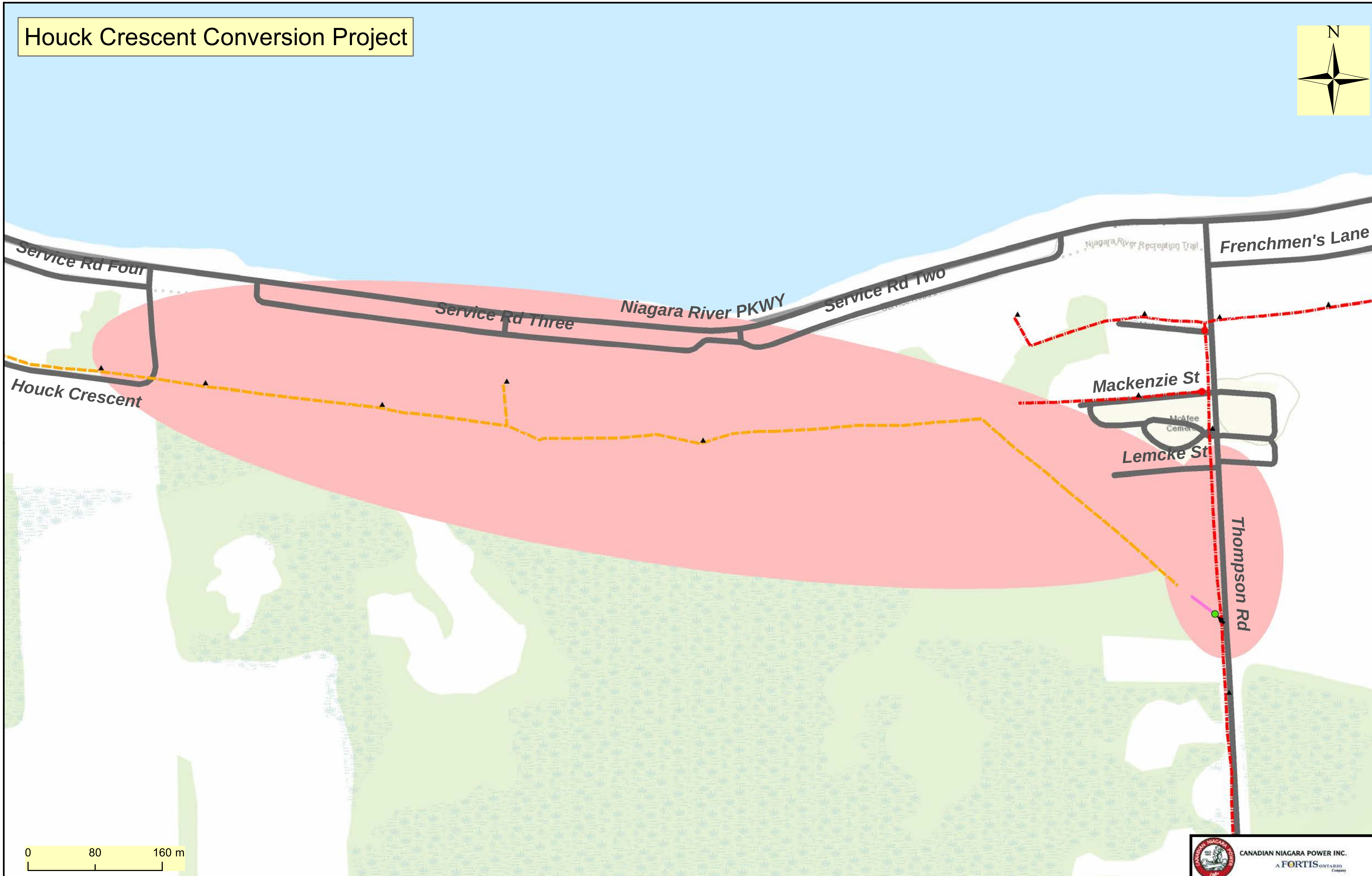
1. Efficiency, Customer Value, Reliability - This line is over 50 years old with undersized conductor. It has been experiened a number of outages in the past years. Also, going from Delta to Wye will reduce the width of the line, therefore reducing the amount of tree trimming required in our right of way.

2. Safety - The conversion of the Delta circuit to Wye will improve public safety.

Total:	**$ 268,338**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	


Houck Crescent Conversion Project
N
Service Rd Four
Service Rd Three
Niagara River PKWY
Service Rd Two
Niagara River Recreation Trail
Frenchmen's Lane
Houck Crescent
Mackenzie St
McAfee
Lemcke St
Thompson Rd
0
80
160 m
CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Distribution Lines

Project Name:	Fort Erie North Conversion
Settlement Account:	102052
OEB Category	○ SYSTEM ACCESS ○ SYSTEM RENEWAL ◉ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	End of Service Life, Risk of Failure
Project Information:	
Number of Circuits:	N/A
Number of Phases:	N/A
Number of Poles Installed:	N/A
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	January 2017
Completion Date:	December 2017
Is this a multi-year project?	NO

Project Description:

Driven by the construction of the new Gilmore Distribution Station, this project will see the conversion of a pocket of customers in North Fort Erie from Delta to Wye. Completion of this project will provide improved safety, customer value, reliability and efficiencies.

Applicable Justification Criteria:	☐ 1. Efficiency, Customer Value, Reliability ☐ 2. SAFETY ☐ 3. Cyber-security, Privacy ☐ 4. Coordination, Interoperability ☐ 5. Economic Development ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

2. Safety - The existing Delta distribution system in this area poses safety risks to the public and CNPI line crews with no return path for single phase to ground faults.

Total:	**$ 156,031**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

CANADIAN NIAGARA POWER INC.
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Capital Expenditure Approval Form - Distribution Lines

Project Name:	SCADA and Communication Projects
Settlement Account:	102019
OEB Category	○ SYSTEM ACCESS ○ SYSTEM RENEWAL ◉ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Replacement of assets at end of useful life
Project Information:	
Number of Circuits:	N/A
Number of Phases:	N/A
Number of Poles Installed:	N/A
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	2014
Completion Date:	2015
Is this a multi-year project?	YES

Project Description:

This provides for the design, specificaltion, procurement, installation, and rollout of a new 2-way radio system.

This requires the complete replacement of the legacy trunking system with:

- Master base station
- Antennae (tower at Operartions Center will be re-used)
- Operator workstation and 'heads-up' master radio console monitor
- 28 truck-mounted mobile radios
- 6 hand-held portable radios

The new system will replace the legacy system before this mission-critical system reaches the end of its useful life, and provides addtional functionality such as 'man-down' detection (when working alone), GPS tracking and integration with the CNPI GOS/OMS system. The new system will allow for greater interoperability with other FortisOntario regions

Note that the use of this asset will be shared between CNPI LDC and CNPI Transmission.
This radio system meets the needs of all applicable NERC Regulations.

Applicable Justification Criteria:

☑ 1. Efficiency, Customer Value, Reliability ☑ 2. SAFETY ☐ 3. Cyber-security, Privacy
☑ 4. Coordination, Interoperability ☐ 5. Economic Development ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

1. Efficiency, Customer Value, Reliability- The new system will replace a mission-critical legacy system before it reaches the end of its useful life. It makes better use of the broadcast spectrum to communicate voice and data as required. There will be improved redundancy of critical components to increase anticipated Mean Time Between Failures (MTBF). The new system should improve power restoration respojnse times, as it will feature an integrated GPS system that will provide constant near-real-time information to the CNPI control room of all truck locations.

2. Safety- The proposed system has improved emergency/MAYDAY functionality which is anticipated to reduce response time in the event of critical injuries. The portable radios canbe equipped with a 'man-down' detection system which provides for improved worker safety, particularly when working alone. All radios are equipped with integrated satellite GPS techonology to better track crew locations and reduce chance of overlooking a crew experiencing difficulties.

6. Coordination, Interoperability- The new system will feature different 'talk groups' as well as a 'master group' to allow for communications with all other workers when necessary and limit calls to specific groups when warranted. This system will be integrated with the CNPI Outage management System and allow staff in the control room to better view the locations of all crews to improve outage and regular task management. The new system will also improve interoperability with other regions of FortisOntario if required.

Total:	**2014 - $ 118,501** **2015 - $ 152,677**
Additional Information on Cost Estimate:	
Manager Responsible:	
Project Approval:	

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Distribution Lines

Project Name:	Herbert Street Feeder Reinforcement
Settlement Account:	101137
OEB Category	○ SYSTEM ACCESS ○ SYSTEM RENEWAL ◉ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Reliability
Project Information:	
Number of Circuits:	One 26kV circuit plus one 4kV underbuilt circuit
Number of Phases:	26kV - 3Phase, 4kV - 3 Phase
Number of Poles Installed:	9 Mainline Poles plus 3 stub poles
Primary Conductor (Circuit km) Installed:	Approx. 500m per circuit
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	2012
Completion Date:	2012
Is this a multi-year project?	NO

Project Description:

Rebuild the existing double circuit pole line along Stone street between Emma Street and Brock Street. A new pole line will be built on the East side of Stone Street allowing the existing pole line on the West side of Stone street to be retired. The scope of this project also includes replacing end of life secondary bus along Georgiana Street and Havelock Alley.

Applicable Justification Criteria:

- [x] 1. Efficiency, Customer Value, Reliability
- [x] 2. SAFETY
- [ ] 3. Cyber-security, Privacy
- [ ] 4. Coordination, Interoperability
- [ ] 5. Economic Development
- [ ] 6. Environmental Benefits

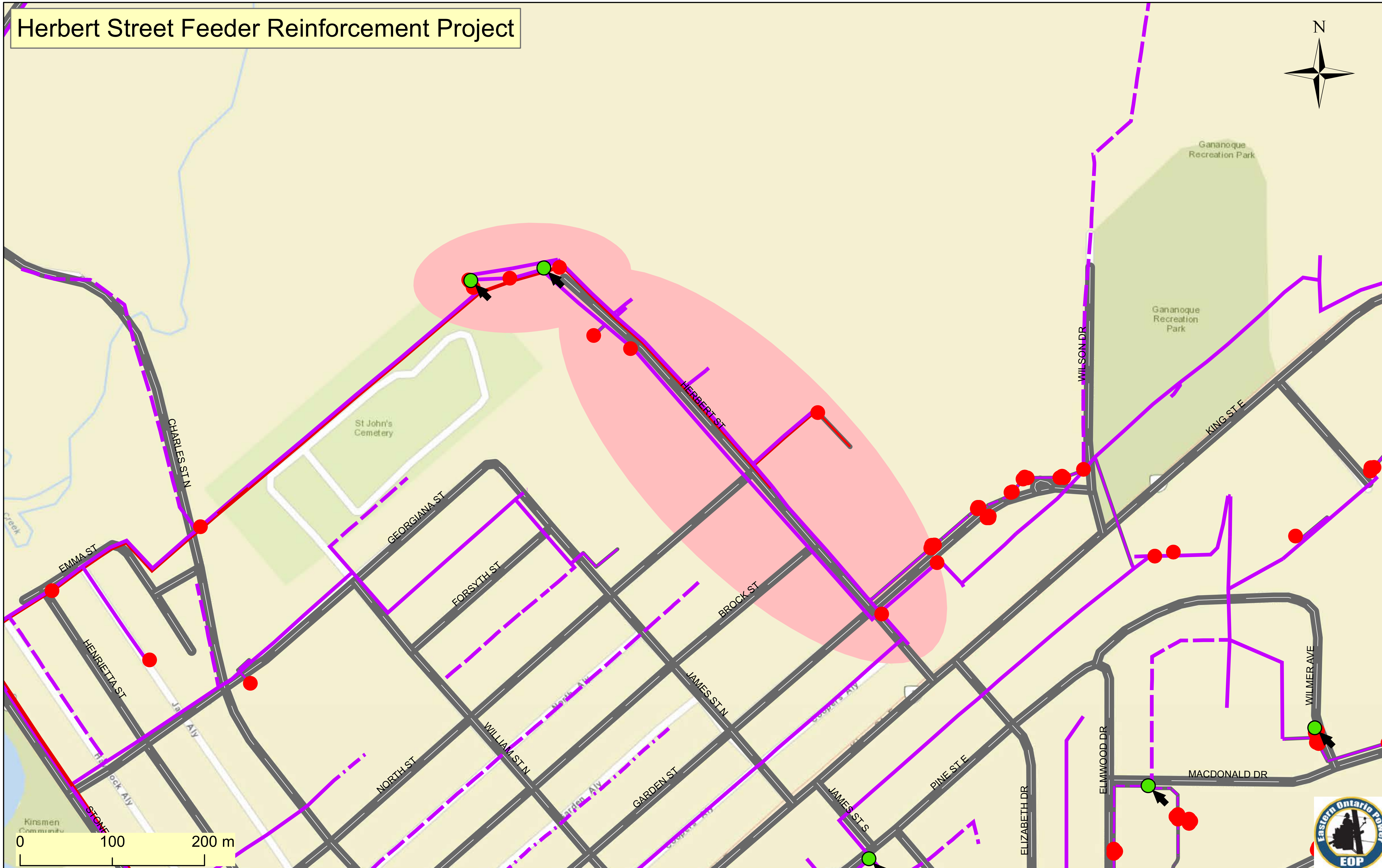
Project Justification (Note that EACH Justification Criterion must be addressed)

The existing pole line is in the order of 40 to 60 years old and is due for replacement. The existing construction standards do not meet the requirements of CSA C22.3 No. 1 in some locations. Clearances are often compromised posing hazards to line crews as well as homeowners in some cases. The reconstruction of the 4 kV circuit will reduce the potential for outages due to potential failures. The reconstruction of the 4 kV circuit will reduce system losses with respect to small wire size losses as well as distribution transformer losses. Relocating the pole line to the East side of the street, will minimize the number of the crossing poles required.

Total:	**$ 178,390**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	



Herbert Street Feeder Reinforcement Project
N
Gananoque Recreation Park
Gananoque Recreation Park
St John's Cemetery
HERBERT ST
WILSON DR
KING ST E
CHARLES ST N
GEORGIANA ST
FORSYTH ST
BROCK ST
EMMA ST
HENRIETTA ST
JAMES ST N
WILLIAM ST N
NORTH ST
GARDEN ST
JAMES ST S
PINE ST E
ELIZABETH DR
ELMWOOD DR
MACDONALD DR
WILMER AVE
Kinsmen Community
0
100
200 m
Eastern Ontario Power
EOP

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Distribution Lines

Project Name:	Main Substation - EOP - Delta to Wye Conversion
Settlement Account:	100921
OEB Category	○ SYSTEM ACCESS ○ SYSTEM RENEWAL ● SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	End of Service Life, Risk of Failure
Project Information:	
Number of Circuits:	N/A
Number of Phases:	N/A
Number of Poles Installed:	N/A
Primary Conductor (Circuit km) Installed:	N/A
Primary U/G cable (Circuit m) Installed:	N/A
Secondary U/G (Circuit m) Installed:	N/A
Starting Date:	January 2017
Completion Date:	December 2017
Is this a multi-year project?	NO

Project Description:

The Gananoque service territory receives its point of supply from HYDRO One 44kV at EOP Main Substation. The current substation consist of two power transformers for n-1 contigency operating as one main (TB2) and one spare (TB1). Although TB2(2006) has a 27.6kV Wye secondary, TB1(1980) has a 26.4kV delta secondary and as such, the system must remain 26.4kV delta to maintain n-1 contigency. EOP is proposing to replace TB1 with a new 15-20MVA, 44kV-27.6kV GRDY, regulating power transformer to facilitate the conversion of the 26.4kV delta system to 27.6kV GRDY. This would require the purchase of a new transformer and all installation costs.

Applicable Justification Criteria:

- [x] 1. Efficiency, Customer Value, Reliability
- [x] 2. SAFETY
- [ ] 3. Cyber-security, Privacy
- [ ] 4. Coordination, Interoperability
- [ ] 5. Economic Development
- [ ] 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed)

1. Efficiency, Customer Value, Reliability-This conversion would also simplify future voltage conversions of remote 4kV distribution to 27.6kV to improve system losses, voltage quality, as well as reduce system complexity. The new transformer winding configuration would allow for parralel operation of the power transformers to eliminate the need for system wide outages when switching between trasnformers.

2. Safety - The existing 3-wire delta distribution poses safety risks to the public and EOP line crews with no return path for single phase to ground faults. Although TB2 is able to operate with a 4-wire secondary, EOP cannot convert to 4-wire system and maintain n-1 contigency without the replacement of TB1. The transformer replacement would faciliate conversion to 4-wire distribution and eliminate safety concerns with the existing delta system.

An alternative approach may be to install a grounding transformer (zig-zag) to provide a neutral reference point on the delta secondary winding but with TB1(built 1980) having only an additional 10-15 years of life remaining, EOP will investigate whether or not this alternative is justifyable from a present value(PV) approach.

Total:	**$ 750,768**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

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Appendix J.

CNPI Capital Expenditure Approval Forms 2018-2021

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CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form

Project Name:	**NIA - Gilmore DS: Construct new 8.3kV (Wye) Substation**		
Settlement Account:		DSP ID:	1
OEB Category	○ SYSTEM ACCESS ◉ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT		
OEB Primary ("Trigger") Driver:	Replacement of assets at end of useful life		

Project Information: **Project Period: 2016**

This project allows for the design, construction, and commisioning of a new 34.5kV : 8.3kV (Wye) substation to provide a new 8.3kV (Wye) source for the associated FE North 4.8Δ to 8.3Y voltage conversion projects (DSP IDs 2 and 3).

This item also provides for the demolition of Station 15, a legacy 4.8Δ DS. Gilmore DS is to be built on the same site, eliminating the need for land acquisition, extensive environmental assessments, and most of the site preparation costs. This station is co-located with CNPI Tx - owned Station 18 TS, and will share the existing TS control building to improve efficiencies and reduce investment and long-term O&M costs.

Gilmore DS will consist of:
- Two 7.5/10 MVA 34.5 : 8.3kV (Wye) power transformers
- Dual 35.5kV source connections
- Dual 8.3kV busses
- Four 8.3kV Feeders c/w Viper reclosers, with provision for two more in the future
- Ancillary Protection and Control Equipment

More detailed information on this project may be found in the CNPI Distribution System Plan.

Applicable Justification Criteria:

- ☑ 1. Efficiency, Customer Value, Reliability
- ☑ 2. SAFETY
- ☐ 3. Cyber-security, Privacy
- ☐ 4. Coordination, Interoperability
- ☐ 5. Economic Development
- ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed. If more space is required, attach separate sheet)

1. Efficiency, Customer Value, Reliability

This new station will be co-located with Station 18, a CNPI Tx-owned TS. This will allow for the sharing of many legacy facilities, reducing costs associated with construction, land aquisition and preparation, and long-term O&M. This station will replace another operating at 4.8kV (Delta) and will allow for the voltage conversion of a large portion of the legacy CNPI 4.8Δ system, resulting in significant long term savings to CNPI customers as a result of reduced line losses.

2. Safety

This project addresses two basic safety concerns. Much of the project areas described previously contains poles in deteriorated condition that might represent a hazard to workers or the public if not replaced as they reach the end of their useful lives. In addition, the legacy three-wire 4.8kV Delta system possesses inherent safety issues, such as difficulty in detecting faults/grounded conditions. Energized conductors can be in direct contact with objects or the ground with no means to detect this condition. Delta distribution systems, although common at one point in the history of the electricity industry, have become quite rare in Ontario, and workers may be less familiar with their operation. CNPI has been engaged in a long-term program to eliminate all of its legacy delta system. This project represents significant progress in achieving that goal.

More detailed information on this project may be found in the CNPI Distribution System Plan

Total Estimated Costs:

Cost Profile:	2016	2017	2018	2019	2020	2021	TOTALS
Contribution in Aid of Construction (CIAC):	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Internal Labour:	$ 128,480	$ -	$ -	$ -	$ -	$ -	**$ 128,480**
External Labour:	$ 703,020	$ -	$ -	$ -	$ -	$ -	**$ 703,020**
Engineering & Planning	$ 88,000	$ -	$ -	$ -	$ -	$ -	**$ 88,000**
Material & External Contracts:	$ 1,204,500	$ -	$ -	$ -	$ -	$ -	**$ 1,204,500**
Total:	**$ 2,124,000**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 2,124,000**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

CANADIAN NIAGARA POWER INC.
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Capital Expenditure Approval Form - Multi-Year Project

Project Name:	**NIA - FE North Voltage Convert 4.8kV Delta to 8.3 Wye SR (Minor SS)**
Settlement Account:	DSP ID: 2 and 3
OEB Category	○ SYSTEM ACCESS ◉ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Replacement of assets at end of useful life

Project Information: Project Period: 2016-2020

This project allows for the conversion of all of the legacy 4.8 kV (Delta) system to 4.8/8.3 kV (Wye) in the town of Fort Erie that lies north of the Queen Elizabeth Highway (QEW). Please refer to map on following page to show area to be rebuilt. It is part of a long term program to eliminate all of the legacy three-wire Delta primary system, with replacement by a modern four wire "Wye" system.

Approximately 36 km of this legacy distribution system will be converted to and energized at 4.8/8.3kV, with a further 3 km converted to and energuized at 19.9/34.5 kV. Both of these higher line voltages are already standard at CNPI.

- 7 km of new double circuit three-phase 8.3kV will be constructed to serve as 'feeder trunks'
- 11 km of overhead line and 1.2 km of underground line (including primary customer services) will be completely rebuilt to address condition concerns.
- 13 km of overhead line will be rebuilt and/or re-framed as required to address asset condition concerns where all components have not reached the end of their useful lives.
- 7 km of overhead line will have a minimum of components replaced (e.g. post insulators) as they are converted to 4.8/8.3kV Wye.

More detailed information on this project may be found in the CNPI Distribution System Plan.

Applicable Justification Criteria:

- ☑ 1. Efficiency, Customer Value, Reliability
- ☑ 2. SAFETY
- ☐ 3. Cyber-security, Privacy
- ☐ 4. Coordination, Interoperability
- ☐ 5. Economic Development
- ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed. If more space is required, attach separate sheet)

1. Efficiency, Customer Value, Reliability

Conversion from 4.8kV Delta to 8.3kV Wye reduces line losses to less than half of their pre-converted values. These savings in line losses are passed on directly to customers via a reduced loss factor. In addition, conversion allows for reducing the number of circuits on many streets and ROWs. This should result in incremental long-term savings in O&M costs.

Much of the project area contains poles in deteriorated condition that have a negative impact on reliability, if not replaced as they reach the end of their useful lives. Once these assets are renewed, there should be an overall reduction in O&M costs.

2. Safety

This project addresses two basic safety concerns. Much of the project area contains poles in deteriorated condition that might represent a hazard to workers or the public if not replaced as they reach the end of their useful lives. In addition, the legacy three-wire 4.8kV Delta system possesses inherent safety issues, such as difficulty in detecting faults/grounded conditions. Energized conductors can be in direct contact with objects or the ground with no means to detect this condition. Delta distribution systems, although common at one point in the history of the electricity industry, have become quite rare in Ontario, and workers may be less familiar with their operation. CNPI has been engaged in a long-term program to eliminate all of its legacy delta system. This project represents significant progress in achieving that goal.

More detailed information on this project may be found in the CNPI Distribution System Plan

Total Estimated Costs:

Cost Profile:	2016	2017	2018	2019	2020	2021	TOTALS
Contribution in Aid of Construction (CIAC):	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Internal Labour:	$ 350,000	$ 449,000	$ 449,000	$ 449,000	$ 449,000	$ -	**$ 2,146,000**
External Labour:	$ 152,000	$ 201,000	$ 201,000	$ 201,000	$ 201,000	$ -	**$ 956,000**
Engineering & Planning	$ 32,500	$ 130,000	$ 130,000	$ 130,000	$ 130,000	$ -	**$ 552,500**
Material:	$ 216,500	$ 260,833	$ 260,833	$ 260,833	$ 260,833	$ -	**$ 1,259,832**
Total:	**$ 751,000**	**$ 1,040,833**	**$ 1,040,833**	**$ 1,040,833**	**$ 1,040,833**	**$ -**	**$ 4,914,332**

Additional Information on Cost Estimate:

Manager Responsible:

Project Approval:

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Multi-Year Project

Project Name:	**NIA - FE - Convert Ridgeway Delta to Wye 2016-2020**		
Settlement Account:		DSP ID:	4 and 5
OEB Category	○ SYSTEM ACCESS ○ SYSTEM RENEWAL ◉ SYSTEM SERVICE ○ GENERAL PLANT		
OEB Primary ("Trigger") Driver:	Elliciency, Safety		

Project Information: **Project Period: 2016-2020**

The Ridgeway area contains approximately 66 circuit-km of the total 191 circuit-km of 4.8kV delta lines within the FE distribution system. A portion of this area has already been rebuilt during the historical investment period to support a wye connected configuration. In order to eliminate the delta system in this area, CNPI estimates the following effort will be required:

Effort Line Length (km):
- Line Rebuild 8.2
- Line Refurbishment 13.8
- Line Conversion 41.8

Based on the schedule for conversion in this area for the period 2016 through to 2020, CNPI estimates the following annual pole replacements:

Year:	2016	2017	2018	2019	2020
Est. Pole Count	94	14	68	56	77

CNPI plans to eliminate the Delta system in the Ridgeway area by the end of 2020.

For more information, please refer to DSP, sections 5.4.6.4 and 5.4.6.5

Applicable Justification Criteria:

- ☑ 1. Efficiency, Customer Value, Reliability
- ☑ 2. SAFETY
- ☐ 3. Cyber-security, Privacy
- ☐ 4. Coordination, Interoperability
- ☐ 5. Economic Development
- ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed. If more space is required, attach separate sheet)

Please refer to DSP sections 5.4.6.4 and 5.4.6.5

Total Estimated Costs:

Cost Profile:	2016	2017	2018	2019	2020	2021	TOTALS
Contribution in Aid of Construction (CIAC):	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Internal Labour:	$ 342,000	$ 181,800	$ 268,200	$ 219,330	$ 324,720	$ -	**$ 1,336,050**
External Labour and Contracts:	$ 332,500	$ 176,750	$ 260,750	$ 213,238	$ 315,700	$ -	**$ 1,298,938**
Engineering & Planning	$ 85,500	$ 45,450	$ 67,050	$ 54,833	$ 81,180	$ -	**$ 334,013**
Material:	$ 190,000	$ 101,000	$ 149,000	$ 121,850	$ 180,400	$ -	**$ 742,250**
Total:	**$ 950,000**	**$ 505,000**	**$ 745,000**	**$ 609,250**	**$ 902,000**	**$ -**	**$ 3,711,250**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

Capital Expenditure Approval Form - Multi-Year Project

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Project Name:	**NIA - FE - 5/8 Line 34.5 kV Distribution Line Rebuild**
Settlement Account:	102022, 102030 — DSP ID: 6
OEB Category	○ SYSTEM ACCESS ◉ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Failure risk, Replacement of end of life assets

Project Information: **Project Period: 2016-2017**

Tower removal project to remove all towers from Bowen Rd. to Switch Rd. in Fort Erie service territory along CNPI right of way.

The legacy line was originally built to carry 25Hz power from the Rankine Generating plant to Buffalo, New York. CNPI has since re-purposed this line to serve as a 34.5kV 60Hz distribution line, but the structures have reached the end of their useful lives.

Applicable Justification Criteria:

- ☑ 1. Efficiency, Customer Value, Reliability
- ☑ 2. SAFETY
- ☐ 3. Cyber-security, Privacy
- ☐ 4. Coordination, Interoperability
- ☐ 5. Economic Development
- ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed. If more space is required, attach separate sheet)

1. Efficiency, Customer Value, Reliability - 5/8 line are ties between Station 17 and Station 18. Without the tie line, the thousands of customers will have no power if Station 17 or 18 is out of service.

2. Safety - The existing tower line was built in early 1900s. The towers were rusty and may have structural weakness.

Total Estimated Costs:

Cost Profile:	2016	2017	2018	2019	2020	2021	**TOTALS**
Contribution in Aid of Construction (CIAC):	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Internal Labour:	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
External Labour and Contracts:	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Engineering & Planning	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Material:	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Total:	**$ 250,000**	**$ 250,000**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 500,000**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form

Project Name:	**EOP - Construct Herbert DS to Gananoque DS Intertie**
Settlement Account:	DSP ID: 7
OEB Category	○ SYSTEM ACCESS ◉ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	End of Service Life, Risk of Failure

Project Information: **Project Period: 2017**

This project focuses on rebuilding end-of-life 4-kV interties between Herbert DS and Gananonque DS. This project has been broken down into two smaller projects as described below.

1. Coopers Alley
Replace existing back lot construction of multiple circuits with new front of lot circuits from the main substation to a previously completed project on Oak Alley. Construction will include the relocation of two 4 kV circuits from back lot to front lot and the relocation of one 26 kV circuit from customer owned lands. All three circuits to be reconfigured to meet today's construction standards.

2. Pine Street
Replace existing 4 kV circuit with new 4 kV and 26 kV circuits from William Street to Herbert Street along Coopers Alley as well as extending 26 kV circuit along existing pole line on Herbert Street. The secondary bus will be replaced as well. The new circuit will be built to meet today's construction standards.

Applicable Justification Criteria:

- ☑ 1. Efficiency, Customer Value, Reliability
- ☑ 2. SAFETY
- ☐ 3. Cyber-security, Privacy
- ☐ 4. Coordination, Interoperability
- ☐ 5. Economic Development
- ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed. If more space is required, attach separate sheet)

1. Efficiency, Customer Value, Reliability
The reconstruction of the 4 kV circuits will reduce the potential for outages due to potential failures. The installation of the 26 kV circuit is part of the overall project to loop the 26 kV circuit through Gananoque to improve reliability and operability on the 26 kV network. The reconstruction of the 4 kV circuits will reduce system losses with respect to small wire size losses as well as increase the capacity of these interties to provide additional flexibility when transferring load between Herbert and Gananoque DS.

2**. Safety**
The existing pole lines are in the order of 50 to 60 years old and due for replacement. The existing construction standards do not meet the requirements of CSA C22.3 No. 1 in numerous locations. Clearances are often compromised posing hazards to line crews as well as homeowners in some cases.

More detailed information on this project may be found in the CNPI Distribution System Plan

Total Estimated Costs:

Cost Profile:	2016	2017	2018	2019	2020	2021	TOTALS
Contribution in Aid of Construction (CIAC):	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Internal Labour:	$ -	$ 255,000	$ -	$ -	$ -	$ -	**$ 255,000**
External Labour:	$ -	$ 15,000	$ -	$ -	$ -	$ -	**$ 15,000**
Engineering & Planning	$ -	$ 15,000	$ -	$ -	$ -	$ -	**$ 15,000**
Material:	$ -	$ 95,000	$ -	$ -	$ -	$ -	**$ 95,000**
Total:	**$ -**	**$ 380,000**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 380,000**

Additional Information on Cost Estimate:

Coopers Alley: $200,000
Pine Street: $200,000

Manager Responsible:	
Project Approval:	

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Multi-Year Project

Project Name:	**NIA - FE - Station 19 Upgrade SS**
Settlement Account:	DSP ID: 13
OEB Category	○ SYSTEM ACCESS ○ SYSTEM RENEWAL ◉ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Reliability: Address "Load-at-risk" and update obsolete P&C Equipment

Project Information: **Project Period: 2017**

This capital project provides for two key things:

Arc Hazard Hardening
CNPI will be making changes to the secondary (8.3kV) configuration such that no single contingency can cause component loss in a manner that prevents delivery from at least one power transformer. Supplemented by external sources, this should remove the 8.3kV service territory around Station 19 from the contingency load-at-risk category.

After 2021, once CNPI has commissioned the new South FE DS described in 5.4.6.20, there could be additional source relief to this service territory, further reducing the chance for a long-term outage to these customers.

Modernization of Protection and Control
This project also provides for:
• Replacement of the legacy high-side primary fuses with two relay-controlled Vipertm reclosers
• Replacement of legacy relaying with modern SEL relays, including modernization of the SCADA RTU.
• Improvements to the protection schema at this station to include more sensitive fault detection, transformer differential protection, and faster clearing of low-current faults often associated with developing arc-flash conditions.

For more information, please refer to DSP, section 5.4.6.13

Applicable Justification Criteria:
☑ 1. Efficiency, Customer Value, Reliability ☐ 2. SAFETY ☐ 3. Cyber-security, Privacy
☐ 4. Coordination, Interoperability ☐ 5. Economic Development ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed. If more space is required, attach separate sheet)

1. Efficiency, Customer Value, Reliability

For more information, please refer to DSP, section 5.4.6.13(a)

Total Estimated Costs:

Cost Profile:	2016	2017	2018	2019	2020	2021	TOTALS
Contribution in Aid of Construction (CIAC):	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Internal Labour:	$ -	$ 75,850	$ -	$ -	$ -	$ -	**$ 75,850**
External Labour and Contracts:	$ -	$ 75,000	$ -	$ -	$ -	$ -	**$ 75,000**
Engineering & Planning	$ -	$ 22,000	$ -	$ -	$ -	$ -	**$ 22,000**
Material:	$ -	$ 175,000	$ -	$ -	$ -	$ -	**$ 175,000**
Total:	**$ -**	**$ 347,850**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 347,850**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

Capital Expenditure Approval Form - Multi-Year Project

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Project Name:	**NIA - PC - Construct Port Colborne South DS (SR)**
Settlement Account:	DSP ID: 14
OEB Category	○ SYSTEM ACCESS ◉ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Reliability: Address "Load-at-risk" and update obsolete P&C Equipment

Project Information: **Project Period: 2017-2018**

This project provides for the complete construction of a new 27.6:4.16kV wye Distribution Substation in the southern area of western Port Colborne.
This station is expected to be a single-element 5.0/6.6MVA station c/w four 4.16kV feeders.

This project scope includes:
• land acquisition, permitting, legal costs, and environmental assements
• site preparation, including grading
• all civil works, inclusing grounding, fencing(if required), lightning protecton, antenna tower (if required), and foundations and structures
• all electrical equipment, inclusing power transformers, switchgear, and cabling
• all P&C equipment, including relaying, SCADA RTU, communications.
• all ancillary equipment, such as AC/DC panels, control wiring, station service, etc.

For more information, please refer to DSP sections 5.4.6.13

Applicable Justification Criteria:

☑ 1. Efficiency, Customer Value, Reliability ☐ 2. SAFETY ☐ 3. Cyber-security, Privacy
☐ 4. Coordination, Interoperability ☐ 5. Economic Development ☑ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed. If more space is required, attach separate sheet)

1. Efficiency, Customer Value, Reliability

The construction of this substation will allow for the eventual retirement of two other Distribution Stations. Both of these substations have legacy concerns (as can be found in DSP section 5.4.6.14). The least-cost means to address all of these concerns is to construct this new substation as replacement.

Employing modern relaying equipment and up-to-date protection philosophies should allow for better detection of system problems and more effective response to such events.

6. Environmental Benefits

The construction of this substation will allow for the eventual retirement of two other Distribution Stations, Jefferson DS and Catharine DS. Neither of these legacy substations has any oil collection system in-place, and the design and layout of these two substations makes any retrofitting of an oil collection system a particular challenge. Both of these substations are located in urban residential neighborhoods.

For more information, please refer to DSP, section 5.4.6.13(a)

Total Estimated Costs:

Cost Profile:	2016	2017	2018	2019	2020	2021	TOTALS
Contribution in Aid of Construction (CIAC):	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Internal Labour:	$ -	$ 12,400	$ 206,000	$ -	$ -	$ -	**$ 218,400**
External Labour and Contracts:	$ -	$ 212,000	$ 320,000	$ -	$ -	$ -	**$ 532,000**
Engineering & Planning	$ -	$ 35,000	$ 44,000	$ -	$ -	$ -	**$ 79,000**
Material:	$ -	$ 150,000	$ 680,000	$ -	$ -	$ -	**$ 830,000**
Total:	**$ -**	**$ 409,400**	**$ 1,250,000**	**$ -**	**$ -**	**$ -**	**$ 1,659,400**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Multi-Year Project

Project Name:	**EOP - North Line Rebuild - 9.3km**
Settlement Account:	DSP ID: 15
OEB Category	○ SYSTEM ACCESS ◉ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	End of Service Life, Risk of Failure

Project Information: **Project Period: 2017-2021**

EOP currently owns an approximately 38km, 26.4 kV, 3-wire distribution circuit (North Line) spanning from EOP's main substation to three remote hydro generation plants. Along with the generation plants, the North line also services 1 residential and 1 commmercial customer. EOP is proposing to rebuild approximately 9.3km of the existing 26.4kV 3-wire line over the course of 5-years. The complete rebuild of the North line will occur over multiple phases with this project being phase one. EOP will also attempt to re-align the North Line where feasible as part of the rebuild to provide easier truck access at various locations.

Applicable Justification Criteria:

- ☑ 1. Efficiency, Customer Value, Reliability
- ☑ 2. SAFETY
- ☐ 3. Cyber-security, Privacy
- ☐ 4. Coordination, Interoperability
- ☐ 5. Economic Development
- ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed. If more space is required, attach separate sheet)

1. Efficiency, Customer Value, Reliability

The existing pole line is in the order of 50 to 60 years old and is due for replacement. The existing pole line traverses over some difficult terrain and through some dense bush limiting truck access in many areas and leaving the line vulnerable to tree/branch contacts even with preventative line clearing. The reconstruction of the 26.4 kV circuit will reduce the potential for outages due to potential failures. The reconstruction of the 26.4 kV circuit will reduce system losses with respect to small wire size losses. Relocating the line to the road allowance will improve the reliability of the line by reducing the likelyhood of tree contacts. It will also provide line-truck access to line to make repairs/maintenance much easier in the future.

2. Safety

The existing pole line traverses through some difficult terrain creating additional risks during repairs and line patroling operations. Relocating the poleline to the road allowance will help minimize these risks.

More detailed information on this project may be found in the CNPI Distribution System Plan

Total Estimated Costs:

Cost Profile:	2016	2017	2018	2019	2020	2021	**TOTALS**
Contribution in Aid of Construction (CIAC):	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Internal Labour:	$ -	$ 12,850	$ 14,000	$ 12,000	$ 9,000	$ 8,000	**$ 55,850**
External Labour:	$ -	$ 170,905	$ 186,200	$ 159,600	$ 119,700	$ 106,400	**$ 742,805**
Engineering & Planning	$ -	$ 8,995	$ 9,800	$ 8,400	$ 6,300	$ 5,600	**$ 39,095**
Material:	$ -	$ 64,250	$ 70,000	$ 60,000	$ 45,000	$ 40,000	**$ 279,250**
Total:	**$ -**	**$ 257,000**	**$ 280,000**	**$ 240,000**	**$ 180,000**	**$ 160,000**	**$ 1,117,000**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

Capital Expenditure Approval Form - Multi-Year Project

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Project Name:	**EOP - Main Substation - Delta to Wye Conversion**
Settlement Account:	DSP ID: 16
OEB Category	○ SYSTEM ACCESS ○ SYSTEM RENEWAL ● SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Safety Hazards associated with Delta System

Project Information: **Project Period: 2017**

EOP receives its point of supply from HYDRO One 44kV at EOP Main Substation. The current substation consist of two power transformers for n-1 contigency. These transformers cannot operate in parrallel due to differing winding configurations and as such operate as one main (TB2) and one spare (TB1). TB1 is nearing end of life and has a 26.4kV delta secondary. EOP is proposing to replace TB1 with a new 15-20MVA, 44kV-27.6kV GRDY, regulating power transformer to facilitate the future conversion of the 26.4kV delta system to 27.6kV GRDY. This would require the purchase of a new transformer and all installation costs.

Applicable Justification Criteria:

- ☑ 1. Efficiency, Customer Value, Reliability
- ☑ 2. SAFETY
- ☐ 3. Cyber-security, Privacy
- ☐ 4. Coordination, Interoperability
- ☐ 5. Economic Development
- ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed. If more space is required, attach separate sheet)

1. Safety

This project addresses one basic safety concerns. The legacy three-wire 26.4kV Delta system possesses inherent safety issues, such as difficulty in detecting faults/grounded conditions. Energized conductors can be in direct contact with objects or the ground with no means to detect this condition. Delta distribution systems, although common at one point in the history of the electricity industry, have become quite rare in Ontario, and workers may be less familiar with their operation. CNPI has been engaged in a long-term program to eliminate all of its legacy delta system. This project represents significant progress in achieving that goal.

2. Efficiency, Customer Value, Reliability

This conversion would also simplify future voltage conversions of the 4kV distribution to 27.6kV to improve system losses, voltage quality, as well as reduce system complexity. The new transformer winding configuration would allow for parrallel operation of the power transformers to eliminate the need for system wide outages when switching between trasnformers.

More detailed information on this project may be found in the CNPI Distribution System Plan

Total Estimated Costs:

Cost Profile:	2016	2017	2018	2019	2020	2021	TOTALS
Contribution in Aid of Construction (CIAC):	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Internal Labour:	$ -	$ 50,000	$ -	$ -	$ -	$ -	**$ 50,000**
External Labour:	$ -	$ 25,000	$ -	$ -	$ -	$ -	**$ 25,000**
Engineering & Planning	$ -	$ 25,000	$ -	$ -	$ -	$ -	**$ 25,000**
Material:	$ -	$ 650,000	$ -	$ -	$ -	$ -	**$ 650,000**
Total:	**$ -**	**$ 750,000**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 750,000**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Multi-Year Project

Project Name:	**NIA - PC - Killaly: Upgrade Protection and Install Redundant Source (SS)**
Settlement Account:	DSP ID: 18
OEB Category	○ SYSTEM ACCESS ○ SYSTEM RENEWAL ◉ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Reliability: Address "Load-at-risk" and update obsolete P&C Equipment

Project Information: **Project Period: 2019**

This project will consist of:

• Installation of a second 27.6kV supply, tapped from the overhead 27.6kV feeder on Killaly St E.

• Installation of two sets of new 28kV station ingress cables with the cable risers on separate poles. The legacy supply cables will also be replaced during this process.

• Replacement of the 27.6kV primary fuses with pole-mount Viper reclosers

• Replacement of the low-side (4.16kV) feeder-breaker switchgear with a combination of dead-front equipment like S&C PME switchgear and G&W Viper padmounted reclosers

• Replacement of the vintage protection and control equipment with modern SEL relaying and SCADA modules.

• Complete review and updating of the protection schema to leverage the capabilities of the new relays.

For more information, please refer to DSP, section 5.4.6.18

Applicable Justification Criteria:

☑ 1. Efficiency, Customer Value, Reliability ☐ 2. SAFETY ☐ 3. Cyber-security, Privacy
☐ 4. Coordination, Interoperability ☐ 5. Economic Development ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed. If more space is required, attach separate sheet)

1. Efficiency, Customer Value, Reliability

Load-at-Risk

Killaly DS is isolated from the rest of the 'urban' 4.16kV substation sources by the Welland Canal. There are no other DS that can supply the load of this station if it were to become unavailable. There is a single three-phase set of submarine cables that is installed under the canal, and a few small pole-mounted ratio banks, but they are insufficient to supply all of the extra load represented by Killaly DS.

There is only a single overhead 27.6kV high-side supply to this DS. It splits into two sets of underground cables to supply each of the two power transformers, but both of these cable 'risers' are installed on a common pole. Some outage scenarios would result in no power to many of CNPI's customers for a prolonged period, well in excess of the 8-hour standard used at CNPI and throughout the industry.

The station also incorporates a double-ended 4.16kV switchgear. The switchgear presents another single point of failure for which significantly limits restoration options under contingency.

Protection

This DS has only power fuses to protect the supply ingress point and the power transformer.

• These transformers would be expensive to replace, and require very long lead times to acquire and install. If one of these transformers required replacement, it might take up to 32 weeks to replace.

• Power fuses can be effective protective devices, but they are not as effective as relay-controlled circuit breakers, complete with current transformers (CT's), in detecting and clearing system faults while minimizing damage to the protected components.

Total Estimated Costs:

Cost Profile:	2016	2017	2018	2019	2020	2021	TOTALS
Contribution in Aid of Construction (CIAC):	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Internal Labour:	$ -	$ -	$ -	$ 116,000	$ -	$ -	**$ 116,000**
External Labour and Contracts:	$ -	$ -	$ -	$ 35,000	$ -	$ -	**$ 35,000**
Engineering & Planning	$ -	$ -	$ -	$ 19,000	$ -	$ -	**$ 19,000**
Material:	$ -	$ -	$ -	$ 240,000	$ -	$ -	**$ 240,000**
Total:	**$ -**	**$ -**	**$ -**	**$ 410,000**	**$ -**	**$ -**	**$ 410,000**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Multi-Year Project

Project Name:	**NIA - FE - Construct New Fort Erie South DS (SR)**
Settlement Account:	DSP ID: 19 & 20
OEB Category	○ SYSTEM ACCESS ◉ SYSTEM RENEWAL ○ SYSTEM SERVICE ○ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Reliability: Address "Load-at-risk" and update obsolete P&C Equipment

Project Information: Project Period: 2020-2021

This project provides for the complete construction of a new 34.5:8.3 wye Distribution Substation in the south-central area of Fort Erie.
This station is expected to be a duel-element 5.0/6.6MVA station c/w four 8.3kV feeders.

This project scope includes:
• land acquisition, permitting, legal costs, and environmental assements
• site preparation, including grading
• all civil works, inclusing grounding, fencing(if required), lightning protecton, antenna tower (if required), and foundations and structures
• all electrical equipment, inclusing power transformers, switchgear, and cabling
• all P&C equipment, including relaying, SCADA RTU, communications.
• all ancillary equipment, such as AC/DC panels, control wiring, station service, etc.

For more information, please refer to DSP, sections 5.4.6.19 and 5.4.6.20

Applicable Justification Criteria:
☑ 1. Efficiency, Customer Value, Reliability ☐ 2. SAFETY ☐ 3. Cyber-security, Privacy
☐ 4. Coordination, Interoperability ☐ 5. Economic Development ☑ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed. If more space is required, attach separate sheet)

1. Efficiency, Customer Value, Reliability
Before the 'Fort Erie South' area of the Fort Erie 4.8kV delta system can be converted to 8.3kV, it will first be necessary to create a new 8.3kV wye source. Once complete, CNPI can do these voltage conversions, resulting in signifigant savings in distribution line-losses.

In addition, the design of the new substaton will be modular and will not include as much maintenance-intensive equipment as the station it will be replacing. This is expected to result in reduced O&M costs.

Employing modern relaying equipment and up-to-date protection philosophies should allow for better detection of system problems and more effective response to such events.

6. Environmental Benefits
The construction of this substation will allow for the eventual retirement of another Distribution Stations, Station 12 DS. This legacy substation has no oil collection system in-place, and the design and layout of this legacy substation makes any retrofitting of an oil collection system a particular challenge

For more information, please refer to DSP, sections 5.4.6.19 and 5.4.6.20

Total Estimated Costs:

Cost Profile:	2016	2017	2018	2019	2020	2021	**TOTALS**
Contribution in Aid of Construction (CIAC):	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Internal Labour:	$ -	$ -	$ -	$ -	$ -	$ 435,000	**$ 435,000**
External Labour and Contracts:	$ -	$ -	$ -	$ -	$ 20,000	$ 305,000	**$ 325,000**
Engineering & Planning	$ -	$ -	$ -	$ -	$ 10,000	$ 110,000	**$ 120,000**
Material:	$ -	$ -	$ -	$ -	$ 220,000	$ 850,000	**$ 1,070,000**
Total:	**$ -**	**$ -**	**$ -**	**$ -**	**$ 250,000**	**$ 1,700,000**	**$ 1,950,000**

Additional Information on Cost Estimate:

Manager Responsible:

Project Approval:

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Multi-Year Project

Project Name:	**Information Technology - Hardware**
Settlement Account:	DSP ID: 22
OEB Category	○ SYSTEM ACCESS ○ SYSTEM RENEWAL ○ SYSTEM SERVICE ◉ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Non-system phyiscal plant

Project Information: **Project Period: 2016-2021**

Workstations:
CNPI maintains approximately 135 workstations (both desktops and laptops) within the Fort Erie, Port Colborne and Gananoque locations. The lifecycle of these assets has been set at five years, which generally coincides with the warranty coverage and useful life of the assets.
The annual cost to replace the workstations has remained relatively consistent using the five-year lifecycle.

Servers:
The server assets are also managed using a five-year lifecycle. CNPI maintains approximately 73 servers. The annual schedule of replacing CNPI servers is in line with the five-year warranties of the systems. Replacement of corporate servers and storage systems. The replacement program is generally consistent year over year with the exception of the following:
- 2016: The SAP hardware landscape is being replaced as it is at end of life (five years). Both front-end host servers and the back-end storage system is included.
- 2017: The non-SAP hardware landscape is being replaced as it is at end of life (five years). This consists of but not limited to email, file/print and utility based servers all residing within a virtualized hardware environment. Both front-end host servers and the back-end storage system is included.
- 2021: The SAP hardware landscape is being replaced as it is at end of life (five years). Both front-end host servers and the back-end storage system is included.

Data Centre Upgrade: Includes replacement of batteries, cooling system or security based controls

Miscellaneous:
The following represents a non exhaustive list of hardware related equipment that is either a compliment to server technology noted above or is independently replaced based on lifecycle or business requirments:
- Network switches
- Wireless technology
- Miscellaneous improvements:
- Network printers
- Phone system upgrades

Applicable Justification Criteria:
- ☑ 1. Efficiency, Customer Value, Reliability
- ☐ 2. SAFETY
- ☑ 3. Cyber-security, Privacy
- ☐ 4. Coordination, Interoperability
- ☐ 5. Economic Development
- ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed. If more space is required, attach separate sheet)

1. Efficiency, Customer Value, Reliability - The primary drivers for replacing any technology based hardware are lifecycle management and response to business needs.

3. Cyber-security, Privacy - Within certain years, it is necessary to replace security based hardware such as firewalls, spam filters, etc. These replacements are consistent with lifecycle parameters stated above but also in response to changing security threats current and/or future. These security based improvements also translate to increased customer privacy.

Total Estimated Costs:

Cost Profile:	2016	2017	2018	2019	2020	2021	TOTALS
Contribution in Aid of Construction (CIAC):	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Internal Labour:	$ 6,000	$ 6,000	$ 4,000	$ 4,000	$ 4,000	$ 6,000	**$ 30,000**
External Labour and Contracts:	$ 5,000	$ 5,000				$ 5,000	**$ 15,000**
Engineering & Planning							**$ -**
Material:	$ 589,000	$ 343,000	$ 246,000	$ 196,000	$ 196,000	$ 389,000	**$ 1,959,000**
Total:	**$ 600,000**	**$ 354,000**	**$ 250,000**	**$ 200,000**	**$ 200,000**	**$ 400,000**	**$ 2,004,000**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

CANADIAN NIAGARA POWER INC. A FORTIS ONTARIO Company

Capital Expenditure Approval Form - Multi-Year Project

Project Name:	**Information Technology - Software**
Settlement Account:	DSP ID: 23
OEB Category	○ SYSTEM ACCESS ○ SYSTEM RENEWAL ○ SYSTEM SERVICE ◉ GENERAL PLANT
OEB Primary ("Trigger") Driver:	Business operations efficiency

Project Information: **Project Period: 2016-2021**

Function Specific Software:
The following applications are maintained in support of ongoing business operations and improvements to service delivery:
- GIS/OMS/SAP specific: representing the interfacing, automations and general improvements provided by in-house programmers
- Environment Health & Safety specific: representing the ongoing improvements in support of document control, audit/inspection management and compliance requirements
- Vegetation Management specific: representing the ongoing improvements in support of document control, audit/inspection management and compliance requirements
- Service Desk Application: Replacement of existing service desk product
- Information Security Project: Review existing and introduce new/improved controls in respect of business and customer information

Annual Software Licensing:
For software approved and utilized within the organization for the foreseeable future a portion of the license fees have been assigned to capital expenditures. The two products are SAP and the Microsoft Enterprise Agreement.

Miscellaneous:
The following represents a non exhaustive list of hardware related equipment that is either a compliment to server technology noted above or is independently replaced based on lifecycle or business requirments:
- ADP HR Resource Partner
- ADP Payroll
- Z-Option (Excel/SAP interface)
- Adobe
- SharePoint intranet upgrade

Applicable Justification Criteria:

☑ 1. Efficiency, Customer Value, Reliability ☐ 2. SAFETY ☑ 3. Cyber-security, Privacy
☐ 4. Coordination, Interoperability ☐ 5. Economic Development ☐ 6. Environmental Benefits

Project Justification (Note that EACH Justification Criterion must be addressed. If more space is required, attach separate sheet)

1. Efficiency, Customer Value, Reliability - The primary drivers for replacing any technology based hardware are lifecycle management and response to business needs.

3.Cyber-security, Privacy - Within certain years, it is necessary to replace security based hardware such as firewalls, spam filters, etc. These replacements are consistent with lifecycle parameters stated above but also in response to changing security threats current and/or future. These security based improvements also translate to continued controls related to customer privacy.

Total Estimated Costs:

Cost Profile:	2016	2017	2018	2019	2020	2021	TOTALS
Contribution in Aid of Construction (CIAC):							**$ -**
Internal Labour:	$ 1,117,000	$ 960,000	$ 705,000	$ 756,000	$ 766,000	$ 766,000	**$ 5,070,000**
External Labour and Contracts:	$ 160,000	$ 100,000	$ 50,000	$ 10,000	$ 10,000	$ 10,000	**$ 340,000**
Engineering & Planning							**$ -**
Material:	$ 214,000	$ 214,000	$ 249,000	$ 234,000	$ 224,000	$ 224,000	**$ 1,359,000**
Total:	**$ 1,491,000**	**$ 1,274,000**	**$ 1,004,000**	**$ 1,000,000**	**$ 1,000,000**	**$ 1,000,000**	**$ 6,769,000**

Additional Information on Cost Estimate:

Manager Responsible:	
Project Approval:	

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Appendix K.

CIA Applications from CNPI to HONI re. North Line

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483 Bay Street, Toronto, Ontario M5G 2P5

DETAILED TECHNICAL CONNECTION ASSESSMENT

Washburn GS
Canadian Niagara Power Inc.
0.1875 MW Hydraulic Generation
Project ID 22040

June 7, 2013

NOTE: ***The Detailed Technical Connection Assessment (DTCA) for project ID 22040 was performed by Hydro One Networks Inc. ("Hydro One") using Hydro One's Distributed Generation Technical Interconnection Requirements: Interconnections at Voltages 50kV and Below" (the "TIR") in effect at the time the DTCA was performed and based on the system conditions at the time the DTCA was performed under the assumptions and key project and connection data contained in this DTCA report. This DTCA is valid for a period of no more than 6 months from the date first written above. Any future modifications to the TIR, assumptions and key project and connection data could affect the DTCA results, and a new DTCA may need to be performed at the Customer's expense. Where there is a new DTCA and that new DTCA (a) is performed as a result of any material revisions to the design, planned equipment or plans for the embedded generation facility and connect and the new DTCA differs in a material respect from this DTCA, that Section 6.2.4.1ii. of the Distribution System Code will apply; and (b) does not differ in a material respect from this DTCA, this may result in the scope of the Hydro One Connection Work required to be performed on Hydro One's distribution system and/or any work to be performed on Hydro One's transmission system in order for the project to connect to Hydro One's distribution system to change substantially which could affect the in-service date and/or the actual cost of the work actually required to be performed by Hydro One in order for the project to connect to Hydro One's distribution system.***

Generation Connections Department
Hydro One Networks Inc.

DISCLAIMER

Hydro One Networks Inc.'s ("Hydro One") liability to any party with respect to the use of this Detailed Technical Connection Assessment is limited to damages that arise directly out of the negligence or the willful misconduct of Hydro One. Under no circumstances whatsoever will Hydro One be liable for any indirect or consequential damages, loss of profit or revenues, business interruption losses, loss of contract or loss of goodwill, special damages, punitive or exemplary damages, whether any of the said liability, loss or damages arises in contract, tort or otherwise. In any event, the total liability of Hydro One will not exceed the amounts paid by the Customer under the terms of the Study Agreement made between Hydro One and the Customer under which this Detailed Technical Connection Assessment was performed.

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1.0 Background and Objective of the Connection Assessment

The following is a Detailed Technical Connection Assessment ("DTCA") study report for the connection of the proposed generation project, as per the scope of work (the "Work") outlined in the Study Agreement made between Canadian Niagara Power Inc. (the "Customer"), and Hydro One dated February 14, 2013.

This DTCA considered the impact of proposed project ID 22040 connection only on the Hydro One distribution system and the Hydro One supply station, Frontenac Transformer Station (TS). The impact of this project on any part of the distribution system that belongs to other Local Distribution Companies (LDC), those are embedded within Hydro One distribution system or a customer of Hydro One transmission, was not included in the scope of this DTCA.

Please note the following:

1. This DTCA study for project ID 22040 was performed using the DTCA Study Data and Assumptions listed in section 3.0 of this report. Any future modifications to the Assumptions and DTCA Study Data could affect the DTCA results and the DTCA may need to be redone at the Customer's expense.

2. Interface protection settings will be reviewed during the implementation phase of this project.

3. This DTCA was performed in compliance with the Ontario Energy Board (OEB) Distribution System Code (DSC).

2.0 Executive Summary

This DTCA considered the impact of proposed project ID 22040 connection only on the Hydro One distribution system and the Hydro One supply station, Frontenac TS. The impact of this project on any part of the distribution system that belongs to other LDCs, who are embedded within Hydro One distribution system or a customer of Hydro One transmission, was not included in the scope of this DTCA.

The following items were discovered during the assessment of this project and shall be addressed to facilitate interconnection of the DG facility to Hydro One's distribution system. Details regarding these items can be found in the appropriate sections of this report.

- A 3-ph load interrupter with visible separation is required at the PCC.
- Provision for monitoring is required.

3.0 DTCA Study Data and Assumptions

Below is the list of assumptions made about the distribution system for this DTCA.

3.1. Assumptions

a) The information submitted in the application package (e.g. Single Line Diagram, generator characteristics, connection point, et al.) and in subsequent supporting information from the Customer

b) There are no transmission system constraints (e.g. capacity, stability, etc.)

3.2. Present and Planned System

This DTCA is performed based on present and planned configuration of the subject distribution system and supply station. The system configuration may change at any time and such change could result in a revision to this DTCA.

3.3. List of Connected or Capacity Allocated Projects

The following connected or capacity allocated DG projects were considered in this DTCA to assess the subject distribution system and the supply station, Frontenac TS:

- Connected generation: 0.05 MW on M1
  7.5 MW on M4
  7.5 MW on M5
  7.35 MW on M8

- Capacity Allocated Project ID 22130: 0.068 MW on M8

- MicroFIT: 0.416 MW on M1
  0.224 MW on M3
  0.139 MW on M8

3.4. Definitions

“Point of Common Coupling” or “PCC” or “Point of Supply” means the point where the generation facility is to connect to Hydro One’s distribution system.

“Point of Connection” or “POC” means the point where the new Customer’s connection assets or new line expansion assets will be connected to the existing Hydro One’s distribution system.

3.5. Point of Connection to Hydro One

The PCC is the Point of Connection where the Customer taps into the existing Hydro One distribution system as shown in the attached map (Appendix A) and DG Interconnection Schematic (Appendix B). The Customer has confirmed in writing that the proposed tap line of 0.06 km Phase #2 Copper, Neutral #2 ACSR will be owned by the Customer.

3.6. DTCA Study Data

The following data were used in the study.

Project and Connection Data

A. Project Identification	
1. Project ID	ID 22040
2. Project Name	Washburn GS
3. Project Type	Hydraulic
4. DG Single Line Drawing No.:	WB-SLD-1 Rev.0
B. Information for Connection to Hydro One Distribution System	
1. Name of Hydro One Distribution Station	Joyceville DS (44 kV /12.5 kV)
2. Nominal Voltage	12.5 kV
3. Feeder Operating Designation	F3
4. Approximate Distance from Station to PCC	2.8 km
5. Approximate length of Customer's owned tap line	0.06 km
6. Comments: I. The 44 kV distribution system is 3-phase, 3-wire, and grounded at the TS. II. For study and cost estimate purposes, only the normal supply, through M1 breaker position at Frontenac TS, will be considered. III. Normal operating conditions will be considered for Frontenac TS for this DTCA. IV. For study and cost estimate purposes, only the normal supply, through F3 recloser position at Joyceville DS, will be considered. V. The 12.5 kV distribution system is 3-phase, 4-wire, grounded at the DS.	
7. Information for Upstream Station Supplying the DS Listed Above	
a) Name of Hydro One Upstream Supply Station	Frontenac TS (115 kV / 44 kV)
b) Nominal Voltage	44 kV
c) Feeder Operating Designation	M1
d) Approximate Distance from Supply Station to DS	22.2 km
C. Generator Data	
1. Generator Type	Synchronous
2. Manufacturer of Generator	NEC
3. Generator Size	187.5 kW
4. Number of Generating Units	1
5. Total Output of DG Facility	187.5 kW
6. Number of Phases	3
7. Rated Frequency	60 Hz
8. Rated Voltage of the Generating Unit	2300 V
D. DG Interface Transformer Data	
1. Rating	200 kVA
2. Number of Interface Transformer Units	1
3. Number of Phases	3
4. Winding Connection & Voltage	Star(12.5 kV) / Delta (2.3 kV)

5. High Voltage Neutral Grounding Reactor (if applicable)	777.5 ohms Based on Hydro One TIR Section 2.1.10 to avoid unacceptable TOV.
6. Reactance, X (p.u. on 200 kVA base)	0.06 p.u.
7. Resistance, R (p.u. on 200 kVA base)	0.006 p.u.

4.0 Impacts to Hydro One Distribution System at 44 kV

4.1. Feeder Power Flow

The power flow on the feeder was studied to determine the impact on the thermal loading of feeder voltage regulating devices, metering devices, protection devices and feeder conductor with connection of this project. Reverse power flow impacts on all the above devices were also investigated.

Study Conditions and Criterion:
Thermal loading and impacts of reverse power flow were studied under feeder light loading conditions with maximum generation at all DG facilities on the feeder once this project is connected.

Assessment Findings and Remarks:

a) ***Feeder Conductor:***

The feeder loading and reverse power flow on the feeder is acceptable and the current due to power flow is expected to remain within the feeder conductor ampacity limits with connection of this project.

4.2. Impact of DG Fault Current Contribution on Feeder Equipment Short Circuit Limitations

Short circuit studies were carried out to determine the fault contribution of this project and the impact on feeder equipments.

Study Conditions and Criterion:
The short circuit study was carried out under maximum fault conditions.

Assessment Findings and Remarks:

Acceptable

5.0 Impacts to Frontenac TS (Hydro One Supply Station)

5.1. Power Flow at Supply Station

The power flow at the supply station was studied to determine the impact on the transformers, voltage regulating devices and metering infrastructure with connection of this DG facility. Reverse power flow impact on the supply station was also investigated. For detailed criterion please review the TIR.

Study Conditions and Criterion:
The power flow at the supply station was studied under light loading condition with maximum generation at all DG facilities on the concerned feeders once the project is connected.

Assessment Findings and Remarks:

Acceptable

5.2. Impact of DG Fault Current Contribution on Short Circuit Limitations at Supply Station

Short circuit studies were carried out to determine the fault contribution of this project and the impact on station equipments and on Transmission System Code (TSC) limits.

Study Conditions and Criterion:
The short circuit study was carried out under maximum fault condition with all DG facilities on the supply station in service.

Assessment Findings and Remarks:

The DG fault contribution is acceptable.

Based on Hydro One TIR Section 2.1.10 to avoid unacceptable TOV, the Customer is required to have 777.5 ohms Neutral Grounding Reactor on the Interface Transformer.

5.3. Feeder Protection at Supply Station

5.3.1. Direct Transfer Trip Signal from Station Feeder Breaker to the DG Facility

The conditions for the requirement of the T/T are outlined in the TIR.

Study Conditions and Criterion:
The need for direct T/T signal from the station feeder breaker to the DG facility was studied using:

- The aggregate generation on the feeder that is without T/T. Auto reclosing timings, with auto reclosing assumed on all feeders.

Assessment Findings and Remarks:

Direct T/T signal from the M1 feeder protection at Frontenac TS to the DG facility is not required.

DGEO signal from the DG facility to M1 feeder protection at Frontenac TS is not required.

5.3.2. Directioning of Feeder Protection

Study Conditions and Criterion:
The study was done to determine if existing feeder protections trip at faults on adjacent feeders due to DG fault contribution.

The short circuit study was carried out under maximum fault condition with all DG facilities on the supply station in service.

Assessment Findings and Remarks:

Phase and Ground relay Directioning are not required for M1 feeder protection.

5.3.3. Magnetizing Inrush Current Caused by DG Interface/Intermediate Transformer(s)

Inrush currents resulting from energization of all DG interface transformer(s) on the feeder once project ID 22040 is connected shall not cause inadvertent operation of the feeder breaker.

Study conditions and Criterion:
The DG interface transformer(s) are energized simultaneously with feeder at nominal system voltage.

Assessment Findings and Remarks:

The impact of inrush currents resulting from energization of the DG interface transformer(s) is acceptable and is not expected to cause inadvertent operation of the feeder breaker.

5.4. Telecommunication, Telemetry and SCADA

Study Conditions and Criterion:
The criteria for determining the need for DG monitoring and identifying the requirements for telecommunications, telemetry and SCADA facilities for DG monitoring are outlined in the TIR.

Assessment Findings and Remarks:

Provision of monitoring is required.

6.0 Impacts to Hydro One Distribution System at 12.5 kV

6.1. Feeder Steady State Voltage Performance

Study Conditions and Criteria:
The impact on voltage along the entire feeder due to the change in power flow with connection of the proposed DG facility was studied. The study was conducted on a system model consisting of snapshots of light and peak feeder loading conditions. The following criteria ("The DG Voltage Performance Criteria") must be respected under all operating conditions:

a. Impact of DG connection on voltage regulation of the feeder and compliance with CSA Standard CAN3-C235-83 "Preferred Voltage Levels for AC Systems, 0 to 50,000 V Electric Power Transmission and Distribution" was considered. The voltage at the PCC and over the entire feeder shall remain between 0.94p.u and 1.06p.u of the nominal system voltage.
b. PCC voltage shall not be lower than pre-connection voltage
c. DG shall not contribute to short-term voltage fluctuation anywhere on the feeder exceeding 1%

Assessment Findings and Remarks:

6.1.1. Power Factor Performance

The assessment showed that to meet the DG Voltage Performance Criteria, the DG facility shall operate such that power factor of the contribution of the DG facility to Hydro One distribution system, at the PCC, must be at all times within the tolerances specified below in Table 1. In Table 1, the specified power factors are either at unity or leading (i.e. absorbing reactive power from the Hydro One distribution system) and Hydro One's preferred power factor is the 'target' power factor.

The DG facility must be capable of power factor set-point changes (i.e. field adjustable). Hydro One reserves the right to require changes to the power factor set-point from time to time.

A power factor of unity is acceptable at the PCC.

6.2. Feeder Voltage Dip and Abrupt Voltage Change

Voltage dip and abrupt voltage change at the PCC, at the distribution station and along the feeder were studied to ensure that they meet the requirements outlined in the TIR with connection of this project.

Study Conditions and Criterion:
The voltage dip study was done for the following:

- Connection and start up of the single largest DG unit and/or the DG unit with the largest inrush current for project ID 22040. The voltage dip at the PCC must be less than 4% upon start-up of the largest single DG unit and/or the DG unit with largest inrush current.

Assessment Findings and Remarks:

DG unit start up
The DG facility start up must not cause unacceptable voltage dip on the Hydro One distribution system.

The voltage dip at PCC is acceptable with the start-up of the largest single DG unit (one 0.1875 MW unit & assuming inrush current of 1 p.u.).

6.3. Feeder Power Flow

The power flow on the feeder was studied to determine the impact on the thermal loading of feeder voltage regulating devices, metering devices, protection devices and feeder conductor with connection of this project. Reverse power flow impacts on all the above devices were also investigated.

Study Conditions and Criterion:
Thermal loading and impacts of reverse power flow were studied under feeder light loading conditions with maximum generation at all DG facilities on the feeder once this project is connected.

Assessment Findings and Remarks:

a) ***Feeder Conductor:***

The feeder loading and reverse power flow on the feeder is acceptable and the current due to power flow is expected to remain within the feeder conductor ampacity limits with connection of this project.

b) ***Recloser:***

The continuous rating of the recloser OCR9600 is acceptable and the feeder loading and reverse power flow is expected to remain within the recloser’s continuous rating.

6.4. Impact of DG Fault Current Contribution on Feeder Equipment Short Circuit Limitations

Short circuit studies were carried out to determine the fault contribution of this project and the impact on feeder equipments.

Study Conditions and Criterion:
The short circuit study was carried out under maximum fault conditions.

Assessment Findings and Remarks:

Acceptable

6.5. Protection Requirements of Upstream Line Recloser(s) on the Feeder

6.5.1. Direct Transfer Trip Signal from Line Recloser to the DG facility

The conditions for the requirement of T/T are outlined in the TIR.

Study Conditions and Criterion:
The need for Direct T/T signal from the upstream line recloser to the DG facility was studied using the aggregate generation on the feeder that is without T/T. Auto re-closing timings, with auto-reclosing assumed on all feeders.

Assessment Findings and Remarks:

The Customer shall install anti-islanding as per section 2.3.12 (iv) of the Hydro One TIR.

6.5.2. Directioning of Line Recloser

Study Conditions and Criterion:
The study was done to determine if the line recloser trips at faults on the upstream sections of the feeder due to DG fault contribution.

The short circuit study was carried out under maximum fault contribution from all DG facilities downstream of the recloser to an upstream fault.

Assessment Findings and Remarks:

Phase and Ground relay Directioning are not required for OCR9600 line recloser.

6.5.3. Magnetizing Inrush Current Caused by DG Interface Transformer(s)

Inrush currents resulting from energization of all DG interface transformer(s) on the feeder once project ID 22040 is connected shall not cause inadvertent operation of the line recloser.

Study conditions and Criterion:
The DG interface transformer(s) are energized simultaneously with feeder in line recloser at nominal system voltage.

Assessment Findings and Remarks:

The impact of inrush currents resulting from energization of the DG interface transformer(s) is acceptable and is not expected to cause inadvertent operation of the line recloser.

6.6. Interrupting/Isolating Device for Proposed Tap Line

The Customer has confirmed the 0.06 km Phase #2 Copper, Neutral #2 ACSR of tap line will be built from the PCC to DG site in order to accommodate this generation connection, and it will be owned by the Customer.

A 3 Ø load interrupter device with visible separation of contacts in compliance with Ontario Electrical Safety Code (OESC) is required at the PCC.

7.0 Impacts to Joyceville DS (Hydro One Distribution Station)

7.1. Power Flow at Distribution Station

The power flow at the distribution station was studied to determine the impact on the transformers as well as voltage regulating and metering devices with connection of this DG facility. Reverse power flow impact on the distribution station was also investigated. For detailed criterion please review the TIR.

Study Conditions and Criterion:
The power flow at the distribution station was studied under light loading condition with maximum generation at all DG facilities on the concerned feeder once the project is connected.

Assessment Findings and Remarks:

Acceptable

7.2. Impact of DG Fault Contribution on Distribution Station Short Circuit Limitations

Short circuit studies were carried out to determine the fault contribution of this project and the impact on distribution station equipments.

Study Conditions and Criterion:
The short circuit study was carried out under Maximum Fault Condition with all DG facilities on the distribution station in service.

Assessment Findings and Remarks:

The DG fault contribution is acceptable.

Based on Hydro One TIR Section 2.1.10 to avoid unacceptable TOV, the Customer is required to have 777.5 ohms Neutral Grounding Reactor on the Interface Transformer.

7.3. Feeder Protection at Distribution Station

7.3.1. Direct Transfer Trip Signal from Station Recloser to the DG facility

The conditions for the requirement of the T/T are outlined in the TIR.

Study Conditions and Criterion:
The need for Direct T/T signal from the station feeder recloser to the DG facility was studied using:

- The aggregate generation on the feeder that is without T/T. Auto re-closing timings, with auto-reclosing assumed on all feeders.

Assessment Findings and Remarks:

The Customer shall install anti-islanding as per section 2.3.12 (iv) of the Hydro One TIR.

7.3.2. Directioning of Feeder Protection

Study Conditions and Criterion:
The study was done to determine if existing feeder protections trip at faults on adjacent feeders due to DG fault contribution.

The short circuit study was carried out under maximum fault condition with all DG facilities on the station in service.

Assessment Findings and Remarks:

Phase and Ground relay Directioning are not required for F3 feeder protection.

7.3.3. Magnetizing Inrush Current Caused by DG Interface Transformer(s)

Inrush currents resulting from energization of all DG interface transformer(s) on the feeder once project ID 22040 is connected shall not cause inadvertent operation of the feeder recloser.

Study conditions and Criterion:
The DG interface transformer(s) are energized simultaneously with feeder at nominal system voltage.

Assessment Findings and Remarks:

The impact of inrush currents resulting from energization of the DG interface transformer(s) is acceptable and is not expected to cause inadvertent operation of the feeder recloser.

8.0 Other Requirements and Considerations

8.1. Interconnection Requirements

The DG facility must comply with all applicable interconnection requirements specified in the "Hydro One Distributed Generation Technical Interconnection Requirements - Interconnections at Voltages 50kV and Below" (the "TIR").

8.2. Power Quality

The DG facility must conform to the Power Quality requirements of the Hydro One's Conditions of Service.

If at any time before or after the in-service date, additional filters, other equipments, Or modifications are needed to meet current power quality requirements outlined in Hydro One's Conditions of Service or any future specifications, the Customer shall take the necessary steps to meet Hydro One requirements and will be responsible for all associated costs to resolve any problem.

8.3. Revenue Metering at DG Site

Revenue metering installation including the installation of a dedicated phone line at the DG site is a contestable work that can be done by any licensed Meter Service Provider (MSP) including Hydro One. However, please note that Hydro One will provide the meter at the Customer's cost and Hydro One will own, operate and maintain the metering facilities once the proposed DG is in service. As such, the revenue metering facilities must be in accordance with Hydro One's requirements. The requirement for DG metering arrangements must be approved by Hydro One Technical Services.

Hydro One's Revenue Metering requirements are detailed in the TIR which is available on the Hydro One website. If you have questions related to Hydro One's revenue metering requirements, please contact:

Business Customer Centre
E-mail: Business.Customer.Centre@HydroOne.com
Phone: 1-877-447-4412

8.4. Protection Setting Review

A final protection setting review will be required during the implementation phase of the project.

9.0 Signature Block

Role	Name	Signature
Prepared by	Cecilia Pang	
Reviewed by	Muhammed Ali	
Approved by	Viktor Maksimovic	Viktor Maksimovic

Appendix A: Distribution Operating Map

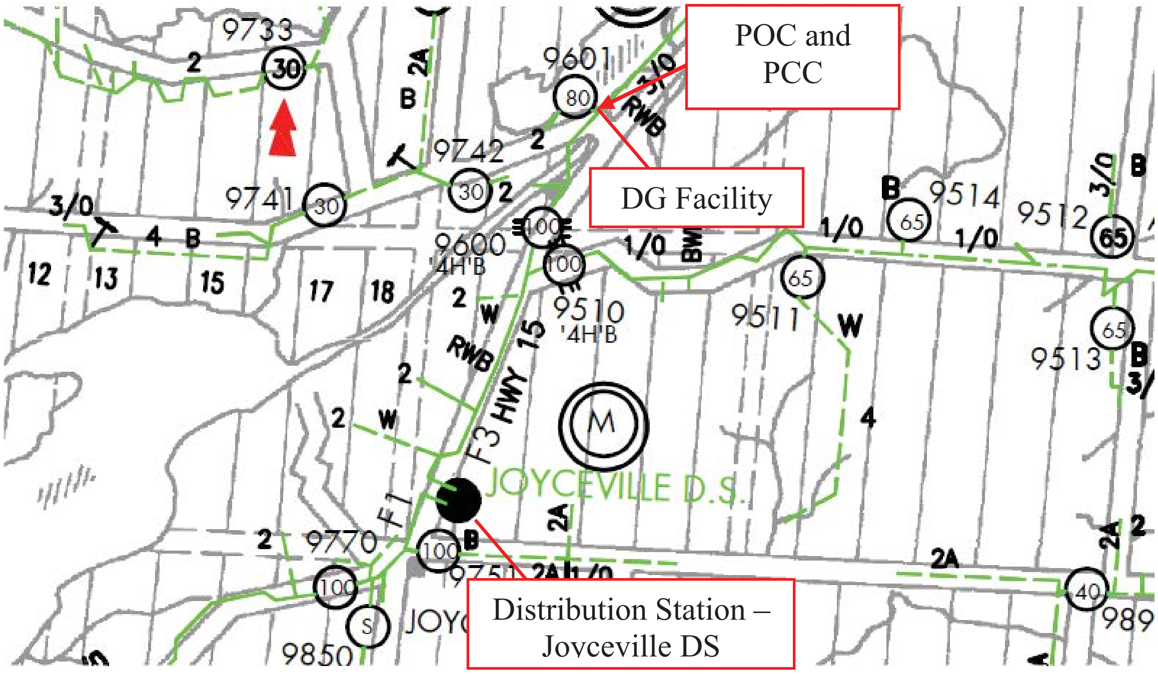

Figure A1: DG Location – Distribution Operating Map

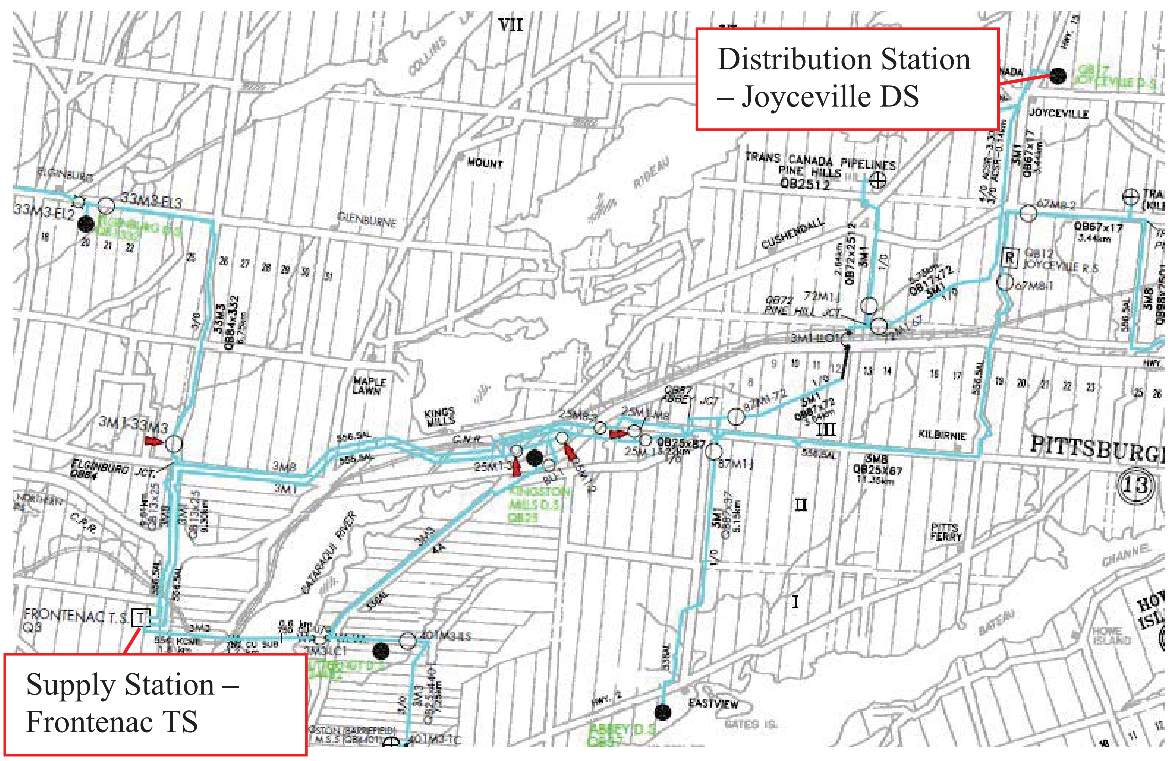

Figure A2: DG Location – High Level View

Appendix B: Interconnection Schematic

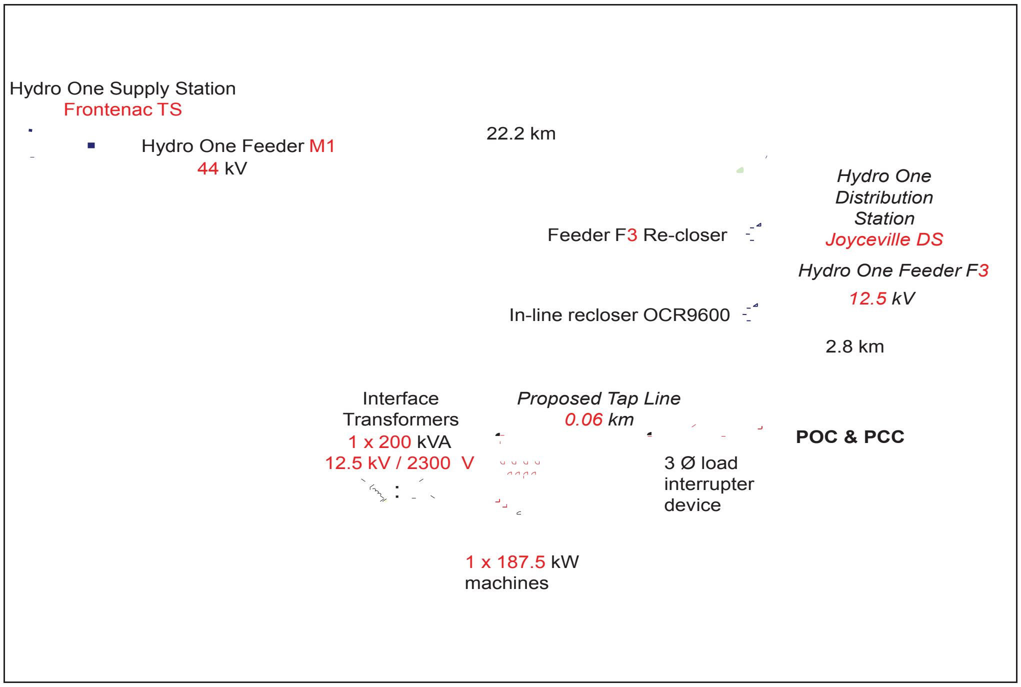

Figure B1: Distribution System Interconnection Schematic

Appendix C: System Data

Fault Levels and Thevenin Impedance at the PCC

Condition	Fault Type			Thevenin Impedance (ohms)				X / R Ratio	
	3 Phase (A)	Phase-Ground (A)	Phase-Phase (A)	R1	X1	R0	X0	X1/R1	X0/R0
No Generation Connected	1946	1725	1685	1.27	3.68	1.80	5.07	2.9	2.82
Connected Generation In Service	1953	1729	1691	1.26	3.66	1.80	5.07	2.9	2.82
Capacity Allocated Generation In Service	1953	1729	1691	1.26	3.66	1.80	5.07	2.9	2.82

Table C1: Fault Levels and Thevenin Impedance at the PCC

Station	Joyceville DS
Feeder	F3
Nominal Feeder Voltage	12.5 kV
Operating Voltage at Source Station	13.125 kV
Conditions under which values were obtained	Maximum source No Load

Feeder Impedance from Distribution Station to the PCC

Impedance (ohms)			
R1	X1	R0	X0
0.68	1.19	1.68	3.64

Table C2: Feeder Impedance from Distribution Station to the PCC

Notes:

1. Fault levels and thevenin impedances were calculated under normal operating conditions at the station with the all DGs disconnected.
2. The values given in the tables were calculated by using a CYME model.
3. Some tolerances apply to the values given above.
4. Values given above can change with system operating conditions.

Low-voltage (LV) bus short-circuit levels at Frontenac TS

Condition	Fault Type	
	3 Phase (A)	**Phase-Ground (A)**
No Generation Connected	7632	5297
Capacity Allocated Generation In Service	9113	5728

Table C3: LV bus short-circuit levels at Frontenac TS

Station	Frontenac TS
Nominal LV Bus Voltage	44 kV
Operating LV Bus Voltage	46.2 kV
Conditions under which values were obtained	Maximum source No Load

Notes:
1. The values given in the table were calculated by using a CYME model.
2. Some tolerances apply to the values given above.
3. Values given above can change with system operating conditions.

Appendix D: Customer Contact Information

This DTCA was issued to the following individual(s):

SINGLE POINT OF CONTACT

Name	Dale Williston
Title	Consultant
Organization	Williston & Associates Inc.
Mailing Address	3324 Gregoire Road, RR2 Russell, Ontario K4R 1E5
Email Address	dale.williston@sympatico.ca

483 Bay Street, Toronto, Ontario M5G 2P5

DETAILED TECHNICAL CONNECTION ASSESSMENT

Brewers Mills GS
Canadian Niagara Power Inc.
0.9 MW Hydraulic Generation
Project ID 22050

June 7, 2013

NOTE: ***The Detailed Technical Connection Assessment (DTCA) for project ID 22050 was performed by Hydro One Networks Inc. ("Hydro One") using Hydro One's Distributed Generation Technical Interconnection Requirements: Interconnections at Voltages 50kV and Below" (the "TIR") in effect at the time the DTCA was performed and based on the system conditions at the time the DTCA was performed under the assumptions and key project and connection data contained in this DTCA report. This DTCA is valid for a period of no more than 6 months from the date first written above. Any future modifications to the TIR, assumptions and key project and connection data could affect the DTCA results, and a new DTCA may need to be performed at the Customer's expense. Where there is a new DTCA and that new DTCA (a) is performed as a result of any material revisions to the design, planned equipment or plans for the embedded generation facility and connect and the new DTCA differs in a material respect from this DTCA, that Section 6.2.4.1ii. of the Distribution System Code will apply; and (b) does not differ in a material respect from this DTCA, this may result in the scope of the Hydro One Connection Work required to be performed on Hydro One's distribution system and/or any work to be performed on Hydro One's transmission system in order for the project to connect to Hydro One's distribution system to change substantially which could affect the in-service date and/or the actual cost of the work actually required to be performed by Hydro One in order for the project to connect to Hydro One's distribution system.***

Generation Connections Department
Hydro One Networks Inc.

DISCLAIMER

Hydro One Networks Inc.'s ("Hydro One") liability to any party with respect to the use of this Detailed Technical Connection Assessment is limited to damages that arise directly out of the negligence or the willful misconduct of Hydro One. Under no circumstances whatsoever will Hydro One be liable for any indirect or consequential damages, loss of profit or revenues, business interruption losses, loss of contract or loss of goodwill, special damages, punitive or exemplary damages, whether any of the said liability, loss or damages arises in contract, tort or otherwise. In any event, the total liability of Hydro One will not exceed the amounts paid by the Customer under the terms of the Study Agreement made between Hydro One and the Customer under which this Detailed Technical Connection Assessment was performed.

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1.0 Background and Objective of the Connection Assessment

The following is a Detailed Technical Connection Assessment ("DTCA") study report for the connection of the proposed generation project, as per the scope of work (the "Work") outlined in the Study Agreement made between Canadian Niagara Power Inc. (the "Customer"), and Hydro One dated February 14, 2013.

This DTCA considered the impact of proposed project ID 22050 connection only on the Hydro One distribution system and the Hydro One supply station, Frontenac Transformer Station (TS) . The impact of this project on any part of the distribution system that belongs to other Local Distribution Companies (LDC), those are embedded within Hydro One distribution system or a customer of Hydro One transmission, was not included in the scope of this DTCA.

Please note the following:

1. This DTCA study for project ID 22050 was performed using the DTCA Study Data and Assumptions listed in section 3.0 of this report. Any future modifications to the Assumptions and DTCA Study Data could affect the DTCA results and the DTCA may need to be redone at the Customer's expense.

2. Interface protection settings will be reviewed during the implementation phase of this project.

3. This DTCA was performed in compliance with the Ontario Energy Board (OEB) Distribution System Code (DSC).

2.0 Executive Summary

This DTCA considered the impact of proposed project ID 22050 connection only on the Hydro One distribution system and the Hydro One supply station, Frontenac TS. The impact of this project on any part of the distribution system that belongs to other LDCs, who are embedded within Hydro One distribution system or a customer of Hydro One transmission, was not included in the scope of this DTCA.

The following items were discovered during the assessment of this project and shall be addressed to facilitate interconnection of the DG facility to Hydro One's distribution system. Details regarding these items can be found in the appropriate sections of this report.

- 1.5 km of 3/0ASR conductor is required to be upgraded to meet the voltage performance criteria.
- LSBS is required from the DG facility to feeder recloser F3.
- LSBS is required from the DG facility to line recloser OCR9600.
- Transfer Trip and DGEO is required
    - Between the DG facility and line recloser OCR9600;
    - Between station feeder recloser F3 and the DG facility;
    - Between station feeder breaker M1 and the DG facility.
- Phase relay Directioning is required for OCR9600 line recloser.
- Phase relay Directioning is required for F3 feeder protection.
- A 3-ph load interrupter with visible separation is required at the PCC.
- An automatic isolating device is required at the PCC.
- Metering device for F3 feeder shall be bi-directional.
- The voltage regulating and metering devices of the station transformer at Joyceville DS are required to be compatible for reverse flow.
- Full monitoring is required.

3.0 DTCA Study Data and Assumptions

Below is the list of assumptions made about the distribution system for this DTCA.

3.1. Assumptions

a) The information submitted in the application package (e.g. Single Line Diagram, generator characteristics, connection point, et al.) and in subsequent supporting information from the Customer

b) There are no transmission system constraints (e.g. capacity, stability, etc.)

3.2. Present and Planned System

This DTCA is performed based on present and planned configuration of the subject distribution system and supply station. The system configuration may change at any time and such change could result in a revision to this DTCA.

3.3. List of Connected or Capacity Allocated Projects

The following connected or capacity allocated DG projects were considered in this DTCA to assess the subject distribution system and the supply station, Frontenac TS:

- Connected generation: 0.2375 MW on M1
  7.5 MW on M4
  7.5 MW on M5
  6.45 MW on M8

- Capacity Allocated Project ID 22130: 0.068 MW on M8

- MicroFIT: 0.416 MW on M1
  0.224 MW on M3
  0.139 MW on M8

3.4. Definitions

"Point of Common Coupling" or "PCC" or "Point of Supply" means the point where the generation facility is to connect to Hydro One's distribution system.

"Point of Connection" or "POC" means the point where the new Customer's connection assets or new line expansion assets will be connected to the existing Hydro One's distribution system.

3.5. Point of Connection to Hydro One

The PCC is the Point of Connection where the Customer taps into the existing Hydro One distribution system as shown in the attached map (Appendix A) and DG Interconnection Schematic (Appendix B). The Customer has confirmed in writing that the proposed tap line of 0.3 km Phase #2 Copper, Neutral #2 ACSR will be owned by the Customer.

3.6. DTCA Study Data

The following data were used in the study.

Project and Connection Data

A. Project Identification	
1. Project ID	ID 22050
2. Project Name	Brewers Mills GS
3. Project Type	Hydraulic
4. DG Single Line Drawing No.:	BM-SLD-1 Rev.0
B. Information for Connection to Hydro One Distribution System	
1. Name of Hydro One Distribution Station	Joyceville DS (44 kV /12.5 kV)
2. Nominal Voltage	12.5 kV
3. Feeder Operating Designation	F3
4. Approximate Distance from Station to PCC	5.6 km
5. Approximate length of Customer's owned tap line	0.3 km
6. Comments: I. The 44 kV distribution system is 3-phase, 3-wire, and grounded at the TS. II. For study and cost estimate purposes, only the normal supply, through M1 breaker position at Frontenac TS, will be considered. III. Normal operating conditions will be considered for Frontenac TS for this DTCA. IV. For study and cost estimate purposes, only the normal supply, through F3 recloser position at Joyceville DS, will be considered. V. The 12.5 kV distribution system is 3-phase, 4-wire, grounded at the DS.	
7. Information for Upstream Station Supplying the DS Listed Above	
a) Name of Hydro One Upstream Supply Station	Frontenac TS (115 kV / 44 kV)
b) Nominal Voltage	44 kV
c) Feeder Operating Designation	M1
d) Approximate Distance from Supply Station to DS	22.2 km
C. Generator Data	
1. Generator Type	Synchronous
2. Manufacturer of Generator	CGE / ATB
3. Generator Size	300 kW
4. Number of Generating Units	3
5. Total Output of DG Facility	900 kW
6. Number of Phases	3
7. Rated Frequency	60 Hz
8. Rated Voltage of the Generating Unit	600 V
D. DG Interface Transformer Data	
1. Rating	1000 kVA
2. Number of Interface Transformer Units	1
3. Number of Phases	3
4. Winding Connection & Voltage	Star(12.5 kV) / Delta (0.6 kV)

5. High Voltage Neutral Grounding Reactor (if applicable)	155.5 ohms Based on Hydro One TIR Section 2.1.10 to avoid unacceptable TOV.
6. Reactance, X (p.u. on 1000 kVA base)	0.06 p.u.
7. Resistance, R (p.u. on 1000 kVA base)	0.006 p.u.

4.0 Impacts to Hydro One Distribution System at 44 kV

4.1. Feeder Power Flow

The power flow on the feeder was studied to determine the impact on the thermal loading of feeder voltage regulating devices, metering devices, protection devices and feeder conductor with connection of this project. Reverse power flow impacts on all the above devices were also investigated.

Study Conditions and Criterion:
Thermal loading and impacts of reverse power flow were studied under feeder light loading conditions with maximum generation at all DG facilities on the feeder once this project is connected.

Assessment Findings and Remarks:

a) ***Feeder Conductor:***

The feeder loading and reverse power flow on the feeder is acceptable and the current due to power flow is expected to remain within the feeder conductor ampacity limits with connection of this project.

4.2. Impact of DG Fault Current Contribution on Feeder Equipment Short Circuit Limitations

Short circuit studies were carried out to determine the fault contribution of this project and the impact on feeder equipments.

Study Conditions and Criterion:
The short circuit study was carried out under maximum fault conditions.

Assessment Findings and Remarks:

Acceptable

5.0 Impacts to Frontenac TS (Hydro One Supply Station)

5.1. Abrupt Voltage Change at Supply Station Low Voltage Bus

Abrupt voltage change at the supply station low voltage bus was studied to ensure that the requirements outlined in the TIR are met with connection of project ID 22050.

Study Conditions and Criterion:
Tripping of all DG facilities on the concerned feeder is studied. The resulting steady state voltage must be within 90% to 110% of nominal.

Assessment Findings and Remarks:

The abrupt voltage change at the supply station low voltage bus is acceptable upon tripping of all the DG facilities on the concerned feeder once the project is connected and operating at the power factor specified in section 6.1.

5.2. Power Flow at Supply Station

The power flow at the supply station was studied to determine the impact on the transformers, voltage regulating devices and metering infrastructure with connection of this DG facility. Reverse power flow impact on the supply station was also investigated. For detailed criterion please review the TIR.

Study Conditions and Criterion:
The power flow at the supply station was studied under light loading condition with maximum generation at all DG facilities on the concerned feeders once the project is connected.

Assessment Findings and Remarks:

Acceptable

5.3. Impact of DG Fault Current Contribution on Short Circuit Limitations at Supply Station

Short circuit studies were carried out to determine the fault contribution of this project and the impact on station equipments and on Transmission System Code (TSC) limits.

Study Conditions and Criterion:
The short circuit study was carried out under maximum fault condition with all DG facilities on the supply station in service.

Assessment Findings and Remarks:

The DG fault contribution is acceptable.

Based on Hydro One TIR Section 2.1.10 to avoid unacceptable Temporary Over Voltage (TOV), the Customer is required to have 155.5 ohms Neutral Grounding Reactor on the Interface Transformer.

5.4. Feeder Protection at Supply Station

5.4.1. Direct Transfer Trip Signal from Station Feeder Breaker to the DG Facility

The conditions for the requirement of the T/T are outlined in the TIR.

Study Conditions and Criterion:
The need for direct T/T signal from the station feeder breaker to the DG facility was studied using:

- The aggregate generation on the feeder that is without T/T. Auto reclosing timings, with auto reclosing assumed on all feeders.

Assessment Findings and Remarks:

Direct T/T signal from the M1 feeder protection at Frontenac TS to the DG facility is required.

DGEO signal from the DG facility to M1 feeder protection at Frontenac TS is required.

5.4.2. Directioning of Feeder Protection

Study Conditions and Criterion:
The study was done to determine if existing feeder protections trip at faults on adjacent feeders due to DG fault contribution.

The short circuit study was carried out under maximum fault condition with all DG facilities on the supply station in service.

Assessment Findings and Remarks:

Phase and Ground relay Directioning are not required for M1 feeder protection.

5.4.3. Magnetizing Inrush Current Caused by DG Interface/Intermediate Transformer(s)

Inrush currents resulting from energization of all DG interface transformer(s) on the feeder once project ID 22050 is connected shall not cause inadvertent operation of the feeder breaker.

Study conditions and Criterion:
The DG interface transformer(s) are energized simultaneously with feeder at nominal system voltage.

Assessment Findings and Remarks:

The impact of inrush currents resulting from energization of the DG interface transformer(s) is acceptable and is not expected to cause inadvertent operation of the feeder breaker.

5.5. Telecommunication, Telemetry and SCADA

Study Conditions and Criterion:
The criteria for determining the need for DG monitoring and identifying the requirements for telecommunications, telemetry and SCADA facilities for DG monitoring are outlined in the TIR.

Assessment Findings and Remarks:

Full Monitoring is required.

6.0 Impacts to Hydro One Distribution System at 12.5 kV

6.1. Feeder Steady State Voltage Performance

Study Conditions and Criteria:

The impact on voltage along the entire feeder due to the change in power flow with connection of the proposed DG facility was studied. The study was conducted on a system model consisting of snapshots of light and peak feeder loading conditions. The following criteria ("The DG Voltage Performance Criteria") must be respected under all operating conditions:

a. Impact of DG connection on voltage regulation of the feeder and compliance with CSA Standard CAN3-C235-83 "Preferred Voltage Levels for AC Systems, 0 to 50,000 V Electric Power Transmission and Distribution" was considered. The voltage at the PCC and over the entire feeder shall remain between 0.94p.u and 1.06p.u of the nominal system voltage.
b. PCC voltage shall not be lower than pre-connection voltage
c. DG shall not contribute to short-term voltage fluctuation anywhere on the feeder exceeding 1%

Assessment Findings and Remarks:

6.1.1. Power Factor Performance

The assessment showed that to meet the DG Voltage Performance Criteria, the DG facility shall operate such that power factor of the contribution of the DG facility to Hydro One distribution system, at the PCC, must be at all times within the tolerances specified below in Table 1. In Table 1, the specified power factors are either at unity or leading (i.e. absorbing reactive power from the Hydro One distribution system) and Hydro One's preferred power factor is the 'target' power factor.

The DG facility must be capable of power factor set-point changes (i.e. field adjustable). Hydro One reserves the right to require changes to the power factor set-point from time to time.

Percentage Power (P) Output	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Less Lead	0.991	0.971	0.964	0.959	0.957	0.956	0.954	0.953	0.953	0.952
Target	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
More Lead	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95

Table 1: Range of Acceptable Power Factor at the PCC

6.1.2. Maintaining Steady State Voltage Performance

The impact of the DG facility on the voltage performance of the existing distribution system is not acceptable. In order to maintain acceptable voltage performance and power quality of the exiting Hydro One distribution system, approximately 1.5 km of 3/0ASR conductor must be upgraded to 336ASR conductor.

6.2. Feeder Voltage Dip and Abrupt Voltage Change

Voltage dip and abrupt voltage change at the PCC, at the distribution station and along the feeder were studied to ensure that they meet the requirements outlined in the TIR with connection of this project.

Study Conditions and Criterion:
The voltage dip study was done for the following:

- Connection and start up of the single largest DG unit and/or the DG unit with the largest inrush current for project ID 22050. The voltage dip at the PCC must be less than 4% upon start-up of the largest single DG unit and/or the DG unit with largest inrush current.

The abrupt voltage change study was done for the following:

- Tripping of all DG facilities on the feeder once project ID 22050 is connected. In this case, the voltage change at the PCC and along the feeder must be such that the resulting steady state voltage remains within 10% of the nominal voltage (i.e. between 90% and 110% of nominal voltage).

Assessment Findings and Remarks:

DG unit start up
The DG facility start up must not cause unacceptable voltage dip on the Hydro One distribution system.

The voltage dip at PCC is acceptable with the start-up of the largest single DG unit (one 0.3 MW unit & assuming inrush current of 1 p.u.).

The starting of multiple generating units shall be staggered in order to reduce the start-up impact on the Hydro One system voltage.

Tripping of all DG facilities on the Feeder
Abrupt voltage change is acceptable when the DG facility is operating at the power factor specified in Section 6.1.

6.3. Feeder Power Flow

The power flow on the feeder was studied to determine the impact on the thermal loading of feeder voltage regulating devices, metering devices, protection devices and feeder conductor with connection of this project. Reverse power flow impacts on all the above devices were also investigated.

Study Conditions and Criterion:
Thermal loading and impacts of reverse power flow were studied under feeder light loading conditions with maximum generation at all DG facilities on the feeder once this project is connected.

Assessment Findings and Remarks:

a) ***Feeder Conductor:***

The feeder loading and reverse power flow on the feeder is acceptable and the current due to power flow is expected to remain within the feeder conductor ampacity limits with connection of this project.

b) *Recloser:*

The continuous rating of the recloser OCR9600 is acceptable and the feeder loading and reverse power flow is expected to remain within the recloser's continuous rating.

6.4. Impact of DG Fault Current Contribution on Feeder Equipment Short Circuit Limitations

Short circuit studies were carried out to determine the fault contribution of this project and the impact on feeder equipments.

Study Conditions and Criterion:
The short circuit study was carried out under maximum fault conditions.

Assessment Findings and Remarks:

Acceptable

6.5. Protection Requirements of Upstream Line Recloser(s) on the Feeder

6.5.1. Direct Transfer Trip Signal from Line Recloser to the DG facility

The conditions for the requirement of T/T are outlined in the TIR.

Study Conditions and Criterion:
The need for Direct T/T) signal from the upstream line recloser to the DG facility was studied using the aggregate generation on the feeder that is without T/T. Auto re-closing timings, with auto-reclosing assumed on all feeders.

Assessment Findings and Remarks:

T/T Signal from OCR9600 line recloser to DG facility is required.

DGEO Signal from DG Facility to OCR9600 line recloser is required.

The recloser must be upgraded to be capable of sending and receiving T/T signals.

6.5.2. Directioning of Line Recloser

Study Conditions and Criterion:
The study was done to determine if the line recloser trips at faults on the upstream sections of the feeder due to DG fault contribution.

The short circuit study was carried out under maximum fault contribution from all DG facilities downstream of the recloser to an upstream fault.

Assessment Findings and Remarks:

Phase relay Directioning is required for OCR9600 line recloser.

6.5.3. Magnetizing Inrush Current Caused by DG Interface Transformer(s)

Inrush currents resulting from energization of all DG interface transformer(s) on the feeder once project ID 22050 is connected shall not cause inadvertent operation of the line recloser.

Study conditions and Criterion:
The DG interface transformer(s) are energized simultaneously with feeder in line recloser at nominal system voltage.

Assessment Findings and Remarks:

The DG facility shall mitigate the inadvertent trips by sending LSBS to block the recloser low set instantaneous protection, such that magnetizing inrush currents due to transformer(s) will not cause tripping of the line recloser.

6.6. Interrupting/Isolating Device for Proposed Tap Line

The Customer has confirmed the 0.3 km Phase #2 Copper, Neutral #2 ACSR of tap line will be built from the PCC to DG site in order to accommodate this generation connection, and it will be owned by the Customer.

A 3 Ø load interrupter device with visible separation of contacts in compliance with Ontario Electrical Safety Code (OESC) is required at the PCC.

The Customer is also responsible for the installation, operation, and ownership of an automatic isolating device at the PCC to isolate the proposed tap line for faults in that section.

7.0 Impacts to Joyceville DS (Hydro One Distribution Station)

7.1. Abrupt Voltage Change at Distribution Station LV Side

Abrupt voltage change at the LV side of the distribution station was studied to ensure that they meet the requirements outlined in the TIR with connection of project ID 22050.

Study Conditions and Criterion:
Tripping of all DG facilities on the concerned feeder is studied. The resulting steady state voltage must be within 90% to 110% of nominal.

Assessment Findings and Remarks:

The abrupt voltage change at the LV side of the distribution station is acceptable upon tripping of all the DG facilities on the concerned feeder once the project is connected and operating at the power factor specified in section 6.1.

7.2. Power Flow at Distribution Station

The power flow at the distribution station was studied to determine the impact on the transformers as well as voltage regulating and metering devices with connection of this DG facility. Reverse power flow impact on the distribution station was also investigated. For detailed criterion please review the TIR.

Study Conditions and Criterion:
The power flow at the distribution station was studied under light loading condition with maximum generation at all DG facilities on the concerned feeder once the project is connected.

Assessment Findings and Remarks:

Due to the reverse power flow at Joyceville DS:

- The voltage regulating and metering devices at the DS transformer are required to be compatible for reverse flow.
- Metering device for the F3 feeder needs to be bi-directional.

7.3. Impact of DG Fault Contribution on Distribution Station Short Circuit Limitations

Short circuit studies were carried out to determine the fault contribution of this project and the impact on distribution station equipments.

Study Conditions and Criterion:
The short circuit study was carried out under Maximum Fault Condition with all DG facilities on the distribution station in service.

Assessment Findings and Remarks:

The DG fault contribution is acceptable.

Based on Hydro One TIR Section 2.1.10 to avoid unacceptable TOV, the Customer is required to have 155.5 ohms Neutral Grounding Reactor on the Interface Transformer.

7.4. Feeder Protection at Distribution Station

7.4.1. Direct Transfer Trip Signal from Station Recloser to the DG facility

The conditions for the requirement of the T/T are outlined in the TIR.

Study Conditions and Criterion:
The need for Direct T/T signal from the station feeder recloser to the DG facility was studied using:

- The aggregate generation on the feeder that is without T/T. Auto re-closing timings, with auto-reclosing assumed on all feeders.

Assessment Findings and Remarks:

Direct Transfer Trip (T/T) signal from the F3 feeder protection at Joyceville DS to the DG facility is required.

DGEO signal from the DG facility to F3 feeder protection at Joyceville DS is required.

7.4.2. Directioning of Feeder Protection

Study Conditions and Criterion:
The study was done to determine if existing feeder protections trip at faults on adjacent feeders due to DG fault contribution.

The short circuit study was carried out under maximum fault condition with all DG facilities on the station in service.

Assessment Findings and Remarks:

Phase relay Directioning is required for F3 feeder protection.

7.4.3. Magnetizing Inrush Current Caused by DG Interface Transformer(s)

Inrush currents resulting from energization of all DG interface transformer(s) on the feeder once project ID 22050 is connected shall not cause inadvertent operation of the feeder recloser.

Study conditions and Criterion:
The DG interface transformer(s) are energized simultaneously with feeder at nominal system voltage.

Assessment Findings and Remarks:

The DG facility shall mitigate the inadvertent trips by sending LSBS to block feeder low set instantaneous protection, such that magnetizing inrush currents due to transformer(s) will not cause tripping of feeder recloser.

8.0 Other Requirements and Considerations

8.1. Interconnection Requirements

The DG facility must comply with all applicable interconnection requirements specified in the “Hydro One Distributed Generation Technical Interconnection Requirements - Interconnections at Voltages 50kV and Below” (the “TIR”).

8.2. Power Quality

The DG facility must conform to the Power Quality requirements of the Hydro One’s Conditions of Service.

If at any time before or after the in-service date, additional filters, other equipments, Or modifications are needed to meet current power quality requirements outlined in Hydro One’s Conditions of Service or any future specifications, the Customer shall take the necessary steps to meet Hydro One requirements and will be responsible for all associated costs to resolve any problem.

8.3. Revenue Metering at DG Site

Revenue metering installation including the installation of a dedicated phone line at the DG site is a contestable work that can be done by any licensed Meter Service Provider (MSP) including Hydro One. However, please note that Hydro One will provide the meter at the Customer’s cost and Hydro One will own, operate and maintain the metering facilities once the proposed DG is in service. As such, the revenue metering facilities must be in accordance with Hydro One’s requirements. The requirement for DG metering arrangements must be approved by Hydro One Technical Services.

Hydro One’s Revenue Metering requirements are detailed in the TIR which is available on the Hydro One website. If you have questions related to Hydro One’s revenue metering requirements, please contact:

Business Customer Centre
E-mail: Business.Customer.Centre@HydroOne.com
Phone: 1-877-447-4412

8.4. Protection Setting Review

A final protection setting review will be required during the implementation phase of the project.

9.0 Signature Block

Role	Name	Signature
Prepared by	Cecilia Pang	Cecilia
Reviewed by	Muhammed Ali	[illegible]
Approved by	Viktor Maksimovic	Viktor Maksimovic

Appendix A: Distribution Operating Map

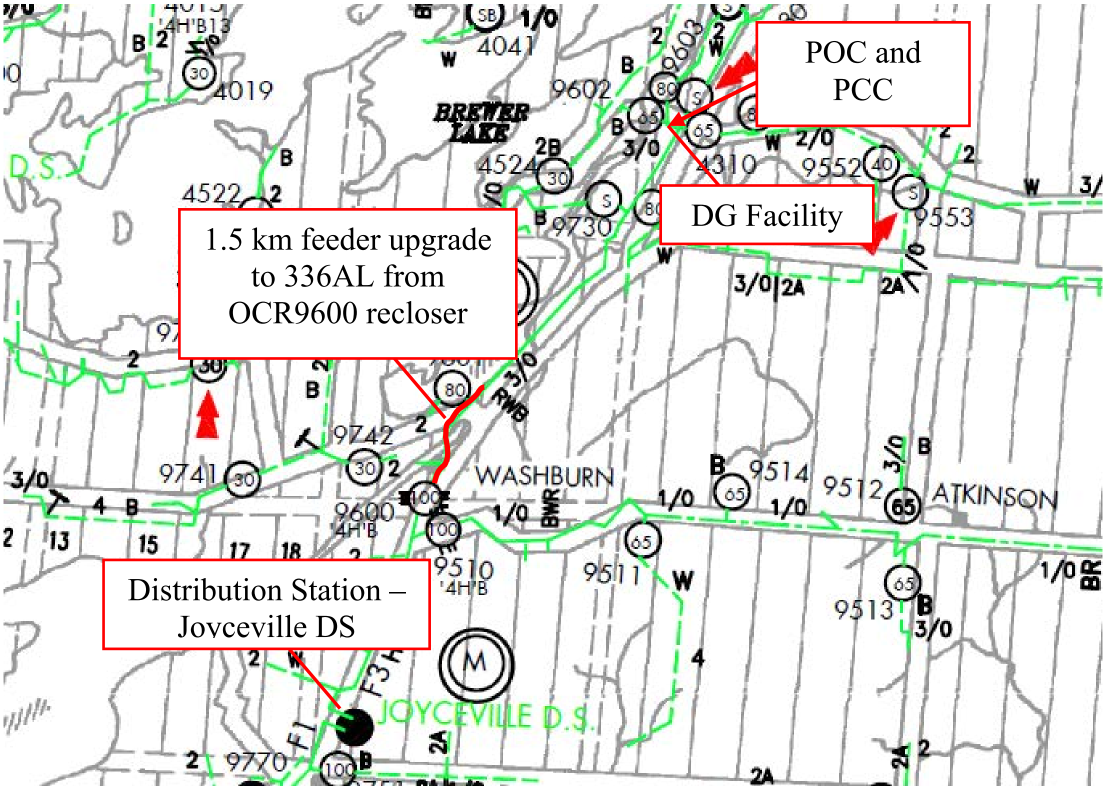

Figure A1: DG Location – Distribution Operating Map

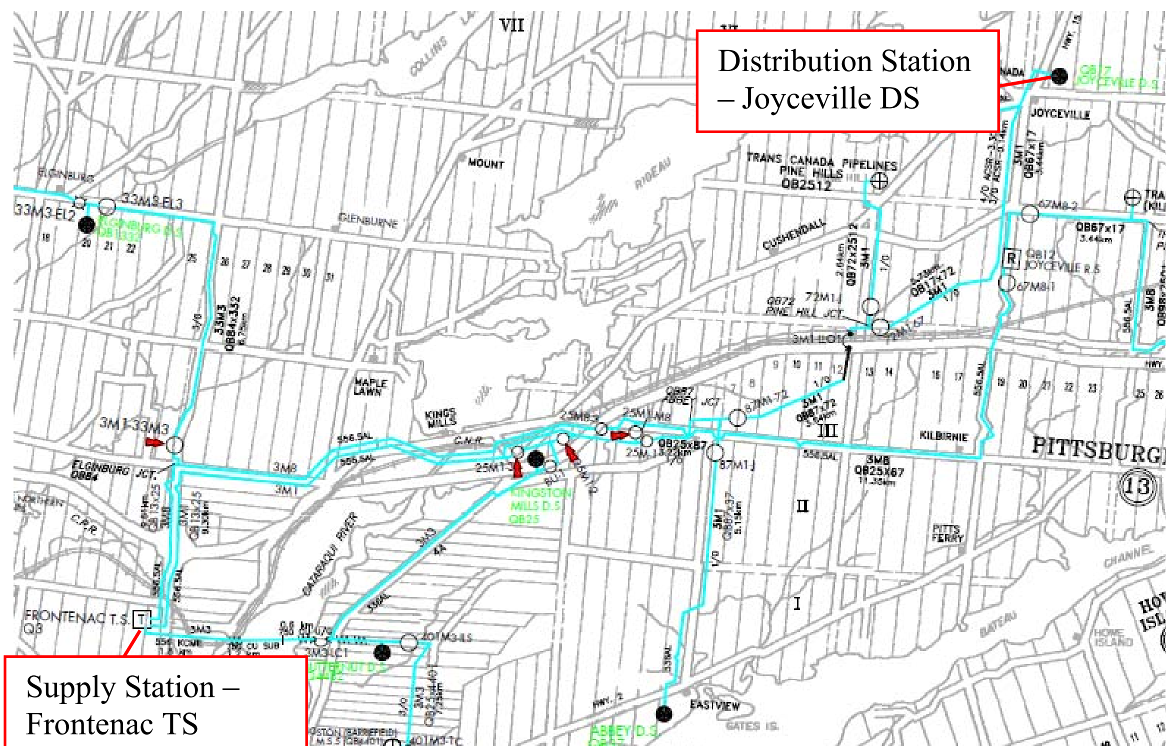

Figure A2: DG Location – High Level View

Appendix B: Interconnection Schematic

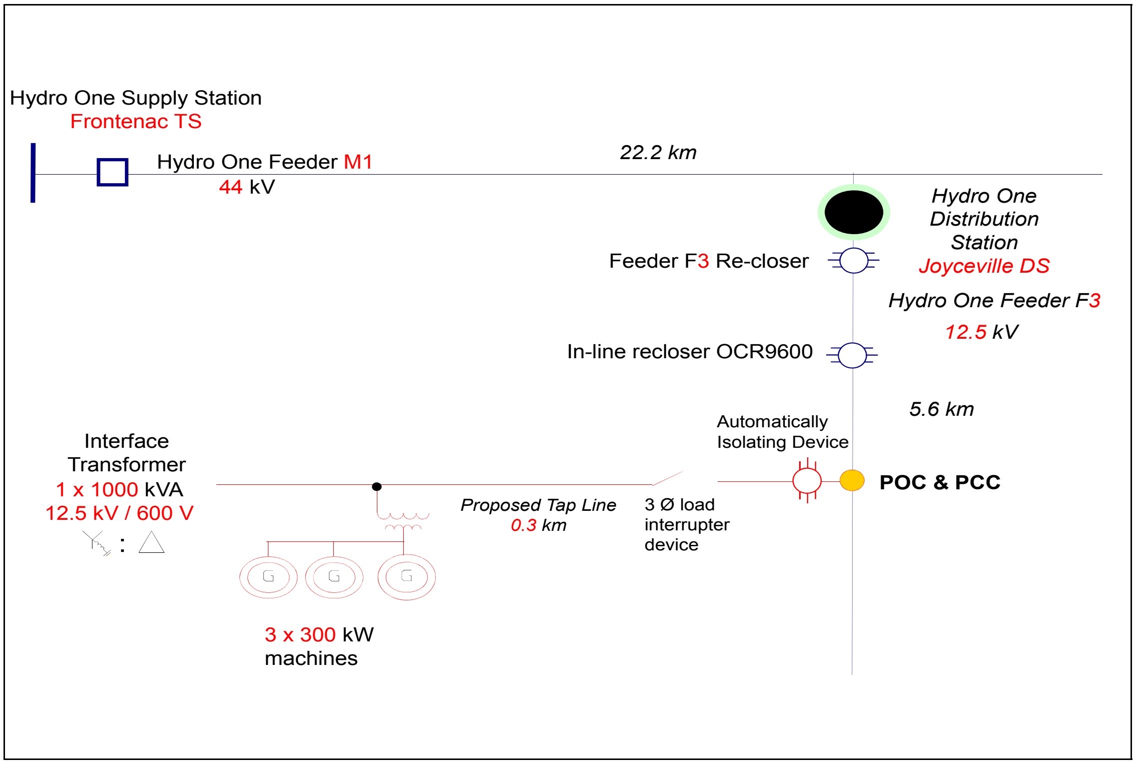

Figure B1: Distribution System Interconnection Schematic

Appendix C: System Data

Fault Levels and Thevenin Impedance at the PCC

Condition	Fault Type			Thevenin Impedance (ohms)				X / R Ratio	
	3 Phase (A)	Phase-Ground (A)	Phase-Phase (A)	R1	X1	R0	X0	X1/R1	X0/R0
No Generation Connected	1440	1142	1247	2.01	4.86	3.56	8.66	2.41	2.43
Connected Generation In Service	1444	1144	1250	2.01	4.84	3.56	8.66	2.41	2.43
Capacity Allocated Generation In Service	1475	1158	1278	1.95	4.74	3.55	8.65	2.44	2.44

Table C1: Fault Levels and Thevenin Impedance at the PCC

Station	Joyceville DS
Feeder	F3
Nominal Feeder Voltage	12.5 kV
Operating Voltage at Source Station	13.125 kV
Conditions under which values were obtained	Maximum source No Load After conductor upgrade

Feeder Impedance from Distribution Station to the PCC

Impedance (ohms)			
R1	X1	R0	X0
1.42	2.37	3.44	7.23

Table C2: Feeder Impedance from Distribution Station to the PCC

Notes:

1. Fault levels and thevenin impedances were calculated under normal operating conditions at the station with the all DGs disconnected.
2. The values given in the tables were calculated by using a CYME model.
3. Some tolerances apply to the values given above.
4. Values given above can change with system operating conditions.

Low-voltage (LV) bus short-circuit levels at Frontenac TS

Condition	Fault Type	
	3 Phase (A)	Phase-Ground (A)
No Generation Connected	7632	5297
Capacity Allocated Generation In Service	9097	5723

Table C3: LV bus short-circuit levels at Frontenac TS

Station	Frontenac TS
Nominal LV Bus Voltage	44 kV
Operating LV Bus Voltage	46.2 kV
Conditions under which values were obtained	Maximum source No Load

Notes:

1. The values given in the table were calculated by using a CYME model.
2. Some tolerances apply to the values given above.
3. Values given above can change with system operating conditions.

Appendix D: Customer Contact Information

This DTCA was issued to the following individual(s):

SINGLE POINT OF CONTACT

Name	Dale Williston
Title	Consultant
Organization	Williston & Associates Inc.
Mailing Address	3324 Gregoire Road, RR2, Russell, Ontario, K4R 1E5
Email Address	dale.williston@sympatico.ca

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Appendix L.
Letter from HONI regarding Jones Falls

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Hydro One Networks Inc.
Business Customer Centre
185 Clegg Road
Markham, Ontario L6G 1B7

December 5, 2013

Dale Williston
Williston & Associates Inc.
3324 Gregoire Rd. RR2
Russell, Ontario
K4R 1E5

Re: Jones Falls GS, ID # 23,620

Dear Mr. Williston**,**

Hydro One received your Connection Impact Assessment (CIA) study application for a planned 2.3 MW hydraulic generating facility to connect to the 8.3 kV feeder F2 for Elgin DS.

Hydro One has assigned a Project Identification Number 23,620 for your project and all communications regarding this project should reference this project ID. To ensure the confidentiality of your project, Hydro One will use only this ID number in all publicly displayed documents and in all Hydro One communications with other projects proponents.

Your application is ineligible for a CIA for the following required reasons:

1. The largest project size connecting to a voltage less than or equal to 13.8 kV is 1 MW. Your project is 2.3 MW which exceeds this limit.
2. There is insufficient thermal capacity in the upstream Crosby TS DESN1 to accommodate your 2.3 MW project. Please refer to Hydro One's List of Station Capacity and List of Applications located at: http://www.hydroone.com/Generators/Pages/AvailableCapacity.aspx

For additional information on distribution-connected generation, please visit our website at http://www.hydroone.com/Generators/Pages/Distribution-connected.aspx. For any further questions or inquiries, please call the Business Customer Centre at 1-877-447-4412 or email us at dxgenerationconnections@HydroOne.com.

Yours truly,

HYDRO ONE NETWORKS INC

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Appendix M.
CNPI Distribution Asset Management Plan (DAMP)

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CANADIAN NIAGARA POWER INC.

A FORTIS ONTARIO Company

Distribution Asset Management Program

Release	3
Revision:	3.16
Release Date:	April 26, 2016

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CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

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1 Introduction

1.1 Non-Disclosure

This document does not contain private customer information or confidential future business plans.

1.2 Objective

The fundamental objective of the Canadian Niagara Power Inc. (CNPI) Distribution Asset Management Program (DAMP) is to prudently and efficiently manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement of all distribution assets in a sustainable manner that maximizes safety and customer reliability, while managing costs.

This objective is met through the application of thorough and sound planning, prudent and justified budgeting, and ongoing oversight, documentation, and review of all efforts and expenditures while implementing the documented capital and operating plans.

CNPI will maintain a comprehensive Distribution Asset Management Plan which outlines the operating and capital processes, activities, and expenditures that are necessary to ensure that CNPI continues to provide the safe, reliable, and efficient distribution of electricity to its customers.

There are three key principles that are integral to the CNPI Distribution Asset Management Plan:

(1) Provide for the growth needs of the customers in the various service territories

(2) Provide safe, reliable, and high-quality service to all of the customers of CNPI

(3) Satisfy the first two principles in a sustainable manner while managing costs to be borne by the ratepayers of CNPI

These key principles are derived from safety considerations; acts, regulations, codes and guidelines; Good utility practice; and Customer expectations.

The DAMP is reviewed annually and adjustments to the plan are made based on changes in legislation, codes and regulations, system performance reviews, safety assessments, infrastructure studies, and customer feedback.

The table below illustrates how the asset management objectives and principles identified above, as well as CNPI's core values, relate to each other and to the Renewed Regulatory Framework for Electricity (RRFE) performance outcomes established by the Board.

Performance Outcome	Asset Management Objective	Core Values
Customer Focus	• Provide for growth needs of customers • Provide safe, reliable, and high-quality service • Manage costs borne by ratepayers	• Customer Service • Respect for People • Community Involvement • Safety and the Environment
Operational Effectiveness	• *Prudently and efficiently* manage the planning and engineering, design, addition, inspection, maintenance, replacement, and retirement of all distribution assets in a sustainable manner in accordance with standards, codes, and good utility practices	• Customer Service • Productivity
Public Policy Responsiveness	• Principles are derived from safety considerations; *acts, regulations, codes and guidelines*	• Safety and the Environment
Financial Performance	• Prudently and efficiently manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement *of all distribution assets in a sustainable manner*	• Productivity • Financial Success

Table 1: Asset Management Objectives in Relation to Performance Outcomes

1.3 Scope

The scope of the CNPI Distribution Asset Management Program (DAMP) includes the long-term management of all distribution assets owned by CNPI. CNPI serves customers in the areas of Fort Erie, Port Colborne, and Gananoque.

These areas will be described in greater detail in Section 3 of this document.

The CNPI Distribution DAMP deals with all assets that are regulated by the Province of Ontario through the Ontario Energy Board (OEB) and the distribution licenses granted to its affiliates by the OEB.

This document is intended to provide a synopsis of the Asset Management Program at CNPI with sufficient detail to supply an overall understanding of CNPI's Asset Management efforts.

1.4 Acts, Regulations, Codes and Guides

The following is a partial listing of the acts, regulation, codes and guidelines that direct CNPI's operations:

(1) The principal regulator guiding CNPI's practices is the OEB. Under the guiding principles set out in the *Electricity Act, 1998* (the Electricity Act), the OEB has established a Distribution System Code (DSC) that defines how and under what conditions, a utility is to provide service and interact with its customers. It is prescriptive in nature and deals with virtually every aspect of utility operations including such things as: connections and expansions, standards of business practice and conduct, quality of supply (reliability), infrastructure inspections, metering and conditions of service. The licensed distributor's conditions of service are set out by the distributor in a document that is filed with the OEB and posted on the distributor's web site.

(2) A second entity is the Electrical Safety Authority (ESA). The ESA derives its authority from the Electricity Act. The ESA is responsible for ensuring the safety of all electrical installations in the province of Ontario for systems operating at a voltage less than 50kV under Ontario Regulation 22/04. Under the regulations, every electrical installation and associated equipment must be installed in accordance with a design or standard approved by a professional engineer. Every year there is a compliance audit conducted by an outside agency and the utility is required to sign a regulatory declaration stipulating that it has complied with the regulations.

(3) The Occupational Health and Safety Act (OHSA) governs how work is performed and is enforced by the Ministry of Labour. The act is comprehensive and forms part of every job. At CNPI the health and safety of employees and customers is given top priority and there is an active joint health and safety committee that oversees operational activities. There is also a Central Environmental and Safety Committee (CESC) to centrally coordinate safety and reporting activities. Extensive training programs ensure that staff is competent to perform their duties. Every effort is made to make sure that employees have the right tools and protective equipment to do their job safely. The CESC and the Joint Health and Safety Committee (JHSC) at CNPI report to the Executive Environment and Safety Team (EEST). The EEST meets regularly to develop and communicate corporate health, safety, and environmental philosophy, policies, and goals. The EEST develops corporate strategies to achieve these goals and continually monitors performance.

(4) The Ministry of Environment (MOE) is responsible for regulating how hazardous waste is handled. CNPI has registered hazardous waste storage sites in its service territories and deals with a variety of substances in the course of building, operating and maintaining the electric distribution system.

(5) Measurement Canada (MC) regulates CNPI's revenue metering activities.

(6) The Ministry of Transportation (MTO) is the governing body with respect to activities associated with the fleet. It also mandates the requirements for traffic control at worksites that are near or on roadways.

(7) CNPI is an engineering focused company and as such is governed in its activities by the *Professional Engineers Ontario Act* (PEO). The PEO regulates codes of practice and ethics within the engineering staff at the utility.

(8) CNPI owns distribution system assets in a number of municipalities across Ontario. The needs, rules and by-laws of these municipalities must be respected.

(9) There are a host of other entities that mandate rules, programs and work practices. These include, but are not limited to: the Electrical Utility Safety Association (E&USA); the Independent Electric System Operator (IESO); the Canadian Coast Guard; the St. Lawrence Seaway Authority, CN and CP Rails; various Conservation Authorities; and the Canadian Standards Association (CSA).

All of the above impact planning, and ensure that CNPI follows “Good Utility Practice” in providing exceptional customer service.

1.5 Documents that Support the Asset Management Plan

CNPI has completed various internal infrastructure studies and refers to other relevant sources of information in order to develop and sustain the Asset Management Plan. The following are examples of reports and studies supporting the Asset Management Plan with a short description of each:

1.5.1 Area Planning Study(Regional)

A comprehensive Area Planning Study (APS) is conducted for each region of CNPI. The foundation of these studies is CNPI’s comprehensive Geographic Information System (GIS) data repository. CNPI leverages engineering analysis tools integrated with the GIS as a fundamental input to the APS. The APS reports for each region contain 10-year forecast analysis, including projected load growth and municipally-identified land use projections and are used to develop a detailed forecast on a substation and feeder basis that is compared to the long term growth trend using regression techniques. Any identified system shortcomings (present and projected) are addressed through the use of least-cost cumulative present-worth alternative analysis. The results are used as a primary input to the asset management planning process. The APS models are updated annually and validated with actual peak load data from recent years, with appropriate adjustments made to regional spending priorities.

1.5.2 The CNPI Construction Verification Program (CVP)

As required by Ontario Regulation 22/04, CNPI performs all material procurement, project design, construction, and follow-up inspections in accordance with ESA-approved CVP, utilizing only professionally approved construction standards. This process is reviewed and updated on an ongoing basis.

1.5.3 Housing Market Outlook Reports

This is a collection of reports produced by the Canada Mortgage and Housing Corporation which are available from public sources. These reports speak to the housing starts for single family residences and multi-unit housing. CNPI uses these reports, as one resource, in the development of capital projects.

1.5.4 Distribution System and Substation Assessments

These assessments are a key component of the DAMP. A comprehensive review of system and substation equipment and performance indicators is used to optimize preventative maintenance programs and to drive future capital plans.

1.5.5 Predictive Maintenance Reports

Results from predictive maintenance techniques such as infrared scanning, oil testing and insulation testing are used to assess the condition of individual system components. The overall assessment forms the basis for the development of maintenance, refurbishment, intervention, and equipment retirement strategies.

1.5.6 Third Party Studies

A variety of third party studies are performed in order to provide supporting data and information to CNPI's planning process and asset management strategies. An example is the 15kV XPLE Cable Condition Assessment (refer to Appendix K). This report and condition assessment conclusions provide valuable input to CNPI's APS. Another example is the Emerald Ash Borer (EAB) impact assessment. This report provides an overview of the impact of the EAB infestation on trees in the vicinity of distribution plant, affording CNPI the opportunity to mitigate associated operational and reliability risk. The EAB impact assessment can be found in Appendix M.

1.5.7 Technical Studies

Various technical reports are prepared on an as-needed basis and are incorporated into the DAMP as required. An example would be a Connection Impact Assessment (CIA) prepared for a distributed generation applicant under Ontario's Feed-In-Tariff (FIT) program.

1.5.8 Distribution System Information

CNPI uses an integrated GIS which incorporates its distribution asset and maintenance records in a spatial data environment. The GIS is integrated with the corporate Systems, Applications and Products (SAP) system, which is used by CNPI to perform financial, project work flow, materials management, metering, billing, and customer information system (CIS) activities.

CNPI supplements the GIS with linkages to legacy data repositories such as relational databases, Computer Aided Design (CAD) drawings, Global Positioning System (GPS) records, and electronic spreadsheets. Additionally, CNPI manages a variety of paper-based maintenance and inspection records.

2 Asset Management Process

2.1 Asset Management Strategy

Prudent and timely planning lies at the core of any sustainable asset management program. At CNPI, planning is a continuous and evolving process designed to meet the present and changing needs of a variety of stakeholders. CNPI's high level asset management process is illustrated in Figure 1.

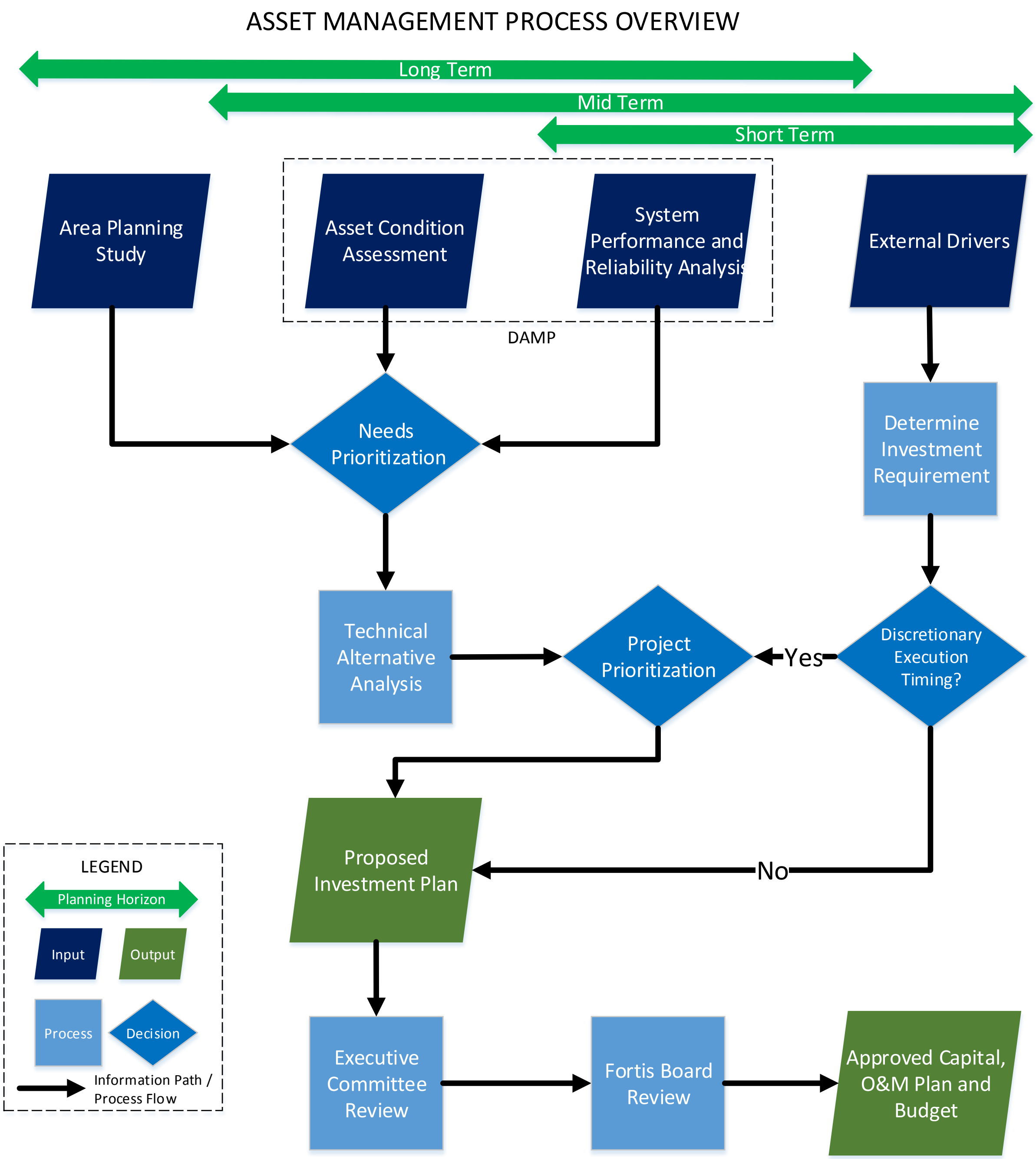


Figure 1: Asset Management Process Overview

2.1.1 Planning Horizons

At CNPI, planning is divided into three general categories, with ongoing interaction between all three.

2.1.1.1 Long Term Planning (Forecast Horizon Typically 10 Years)

Long range planning at CNPI is generally performed through the preparation and periodic review of Area Planning Studies (APS), load growth projections, governmental initiatives, and changes to standards, guidelines, and codes.

The APS analyzes the existing distribution system and anticipated customer load (and generation) changes over a planning horizon of ten years.

A long-term load (and distributed generation) forecast is prepared, using the best information available at the time of the study. Input is sought from all relevant stakeholders, including customers and developers, municipalities, internal corporate departments, and various Provincial organizations.

Technical issues like component capacities, ability to operate within voltage requirements, and basic contingency analysis are reviewed, and system deficiencies (present and predicted through the load forecast period) are identified.

Various alternatives and solutions are proposed, and then analysed to ensure that they address all predicted deficiencies. Recommendations are then made based on a Least-Cost Cumulative Present-Worth methodology.

APS’ do not attempt to identify or address all asset condition issues, as these concerns are more immediate in nature and are resolved through a 5-year (medium term) budget planning process. However, if some distribution assets are known to be approaching the end of their useful lives, this information is taken into account when proposing alternative solutions.

Generally, a complete APS for each region of CNPI will be performed at regular intervals of five years, with periodic reviews to ensure that the information and conclusions in each study are still reasonably accurate and valid as more-recent data becomes available.

Major unforeseen events may require a shorter interval between studies. For example, a request for service from a large load or generation customer may trigger the need for a comprehensive study, if the proposed change is outside the parameters of the most recent full study.

2.1.1.2 Medium Term Planning (5 Year Planning Horizon)

CNPI uses results from its strategic planning and other reports, such as asset condition reports, to perform ‘tactical’ planning which covers a five-year period.

Medium-Term planning is performed each year, to incorporate new information that may arise, such as new regulations, longer-term individual customer needs, or updated asset condition reports. Typical inputs to medium term planning include:

- Customer-driven needs

- Municipal-driven needs
- Regulatory requirements
- Reliability analysis
- Asset evaluation and renewal requirements
- Expansion requirements identified through long-term planning
- Extraordinary initiatives, such as FIT, Smart-Grid and Smart Meters

The results of this medium term planning set priorities, goals and targets to define optimal and sustainable levels of activity in all areas of the LDC.

The outcomes of tactical planning contribute directly to the corporate five-year fiscal plan.

2.1.1.3 Short Term Planning (One Year Planning Horizon)

Short term or operational planning involves developing specific plans to implement the projects defined in next year's budget as well as operate the distribution system(s) in a safe and reliable manner.

It also addresses short-term needs, such as connection of a customer that was not identified previously during medium term planning, or reaction to external events such as a severe ice storm. Typical inputs to the short term planning process include:

- Next Year Budget and Project Design Based on the Investment Plan
- Known Customer-Driven Asset Development
- Known Municipal and Developer-Driven Asset Development
- Other Short-term Projects

The general process followed in the Short Term Planning Horizon is depicted in Figure 2.

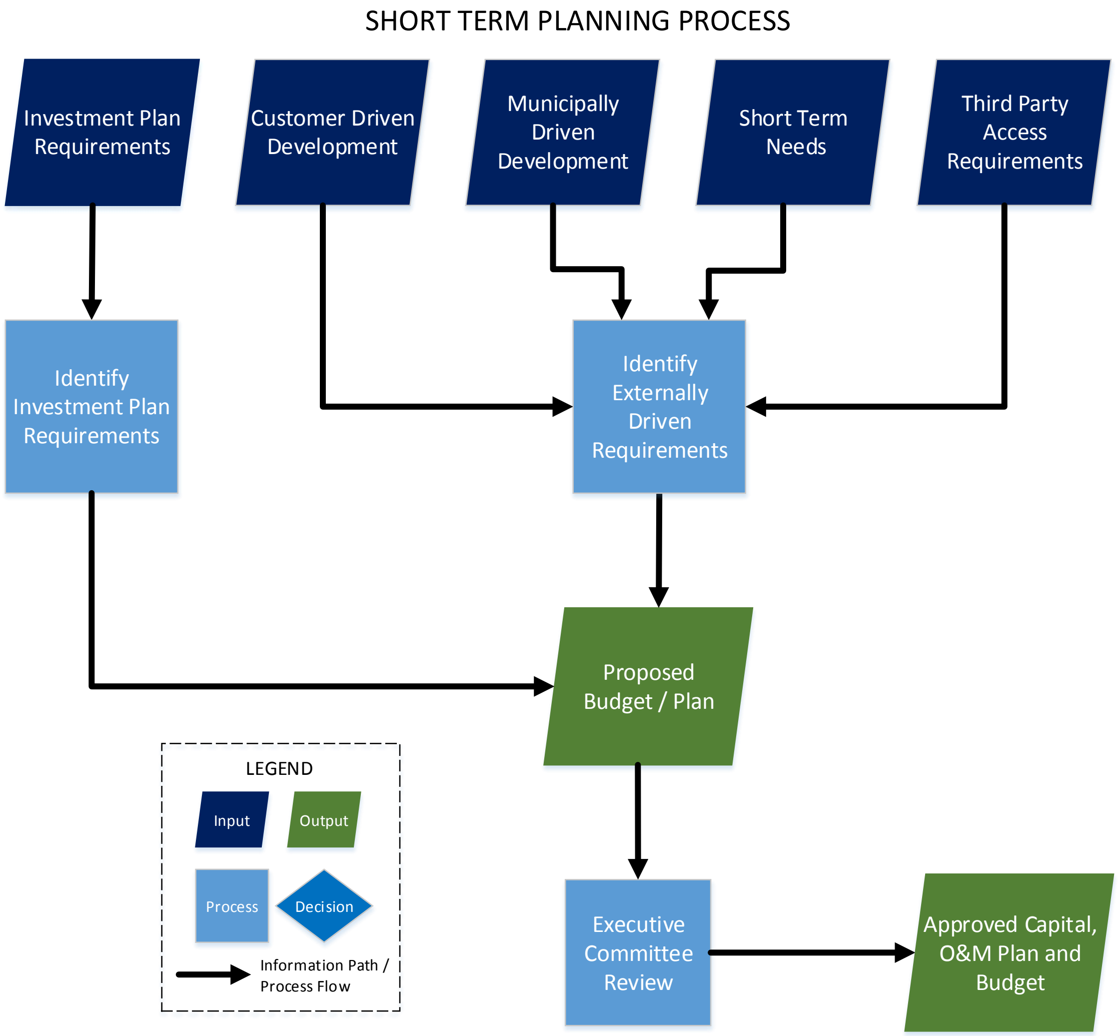


Figure 2: Short Term Planning Process

2.2 Process Inputs

2.2.1 Area Planning Study

The results of the regional APS' identify internally driven needs aimed at achieving the performance outcomes detailed earlier in this document (Customer Focus, Operational Effectiveness, Public Policy Responsiveness, and Financial Performance).

Factors that the APS considers include:

- Overloaded conductors and equipment
- Substandard voltages and voltage balance
- Fault levels exceeding design parameters
- Predicted reliability
- n-1 contingency analysis

- Safety concerns, such as ungrounded delta systems, arc hazard identification
- Distribution loss savings
- Retirement of aged assets

One of the major considerations of the APS is to address the safety and operational challenges associated with CNPI's significant delta distribution system. The APS gives consideration to the technical, regulatory, and financial constraints associated with mitigation of these negative impacts associated with this system. It identifies technical alternatives and associated performance outcomes as key inputs to the planning process.

2.2.2 Asset Condition Assessment

Asset condition analysis results are a key input to CNPI's asset management process. Section 6 of this document contains an assessment of CNPI'S managed assets for which condition data is available. Currently, CNPI manages asset condition data for major equipment such as substations, poles, and transformers. These assets represent approximately 78% of CNPI's overall rate base.

2.2.3 System Performance and Reliability Analysis

CNPI monitors system reliability indices System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) on a monthly, quarterly, and annual basis. Section 9 of this document describes the process that CNPI follows. The section also contains an analysis of historical reliability data from both system and feeder performance perspectives.

The results of CNPI's system reliability analyses are reviewed annually to identify year over year trending in poor performance. Feeders or feeder sections identified as having recurring poor performance levels are reviewed. Potential mitigation options are explored and feasible technical investments solutions are identified.

2.2.4 External Drivers

External drivers are primarily comprised of:

- Regulatory requirements such as accommodation of distributed generation
- Customer developments, new connection requests
- Municipally/Regionally driven development such as roadway widening or reconfiguration
- Third party system access requirements

These drivers can result in either discretionary or non-discretionary investment requirements.

Non-discretionary investments are typically required in order to maintain compliance with the requirements of the Distribution System Code (DSC). Typically this type of investment (such as accommodation of a new connection request) is such that a short term project execution is required. The asset management process is designed to anticipate and accommodate this type of investment in order to meet the narrow execution timing requirements, Certain externally driven investment requirements are discretionary from a timing perspective. In these cases, the investment is evaluated against internally driven investment requirements. This allows appropriate sequencing of the investment in the overall plan and may result in incremental benefits. For example, certain municipally or regionally driven projects such as a road widening have a longer term execution horizon. In these cases, CNPI can coordinate the timing of execution with internally driven project needs.

2.3 Technical Alternative Analysis

Once internally driven needs are identified, investment requirements are prioritized based on alignment with CNPI's desired asset management objectives. Technical alternatives aimed at addressing needs are developed with consideration given to the overall impact on performance outcomes: Customer Focus, Operational Effectiveness, Public Policy Responsiveness, and Financial Performance.

Technical alternatives identify:

- Applicable Justification Criteria
- Estimated Level of Expenditure
- Project / Program Scope
- Execution Timing

Technical alternatives to address a given need are evaluated based on a benefit vs cost analysis. Technical alternatives identified as potential capital investments are used to formulate a high level project scope.

2.4 Project Prioritization

Capital investments are selected for execution based on priority. Projects or programs developed to address a need stemming from an external driver are prioritized based on execution timing requirements and resource availability. These projects are typically customer, municipally / regionally, or third party driven. In order to meet the regulatory requirements associated with these types of projects, these investments are considered to be non-discretionary.

Internally driven projects and programs based on asset condition analysis are typically non-discretionary in nature. For these projects the prioritization focuses on asset replacement timing based on risk of asset failure and the customer impact associated with the potential loss of service.

Projects or programs stemming from internal drivers are prioritized based on the identified benefit vs. cost of execution and alignment with asset management objectives. The benefit of a given project or program execution is evaluated based on the adherence to CNPI's project justification criteria. CNPI identifies a primary "trigger" or driver for selected project alternatives but also, identifies the applicable justification criteria.

The justification criteria identifies whether the project positively impacts:

- Safety
- Customer Value

- Operational Efficiency
- Reliability
- Coordination / Interoperability
- Economic Development
- Cyber-Security / Privacy
- Environmental Objectives

Use of this criteria promotes project selection that provides a balanced approach toward meeting CNPI's asset management objectives. Projects and programs directed at replacement of end-of-life assets in advance of failure are given higher priority due to impact on safety and reliability. CNPI's long and medium term planning processes identify program based system renewal investments aimed at levelizing year over year expenditure maximizing the efficient use of resources.

Investments with primary drivers related to the system service category are typically discretionary. The discretionary nature of these types of investments tends to rank associated projects and programs with lower priority compared to system access and system renewal based investments. The selection criteria for discretionary projects are based on incremental analysis. CNPI's historical and forecast investment profile indicates that system service based projects tend to account for a small component of annual expenditure.

2.5 Investment Plan

CNPI produces a five year investment plan based on the prioritized registry of projects and programs. This investment plan is updated on an annual basis. The five year investment plan is reviewed by the Executive Committee of CNPI to ensure alignment with asset management objectives as they relate to the performance outcomes identified above. The Executive Committee also ensures that appropriate risk mitigation strategies are deployed within the investment portfolio.

On an annual basis, the five year plan is also reviewed and approved by the Board of Directors of CNPI to ensure alignment with strategic goals and to benchmark against historical investments.

CNPI derives an annual budget as part of its short term planning process. The annual budget is derived from the five year investment plan but also takes into account any new and previously unforeseen requirements. These are typically externally driven such as:

- Customer Requirements
- Regulatory Changes
- Municipal / Regional Initiatives
- Third Party Access Requests
- Reliability Driven Requirements

The annual budget is reviewed and approved by the Executive Committee to ensure adherence and alignment with long and medium term investment plan requirements.

3 Distribution System Overview

3.1 General

Canadian Niagara Power Inc. (CNPI) is a Licensed Local Distribution Company (LDC) in Ontario, and supplies electricity to over 25,200 customers in Fort Erie (FE) and Port Colborne (PC) and over 3,500 customers in the Gananoque area.

CNPI is an amalgamation of three former distinct LDCs:

- Canadian Niagara Power, serving the Town of Fort Erie
- Port Colborne Hydro, serving the City of Port Colborne
- Eastern Ontario Power, serving the Town of Gananoque and some surrounding area

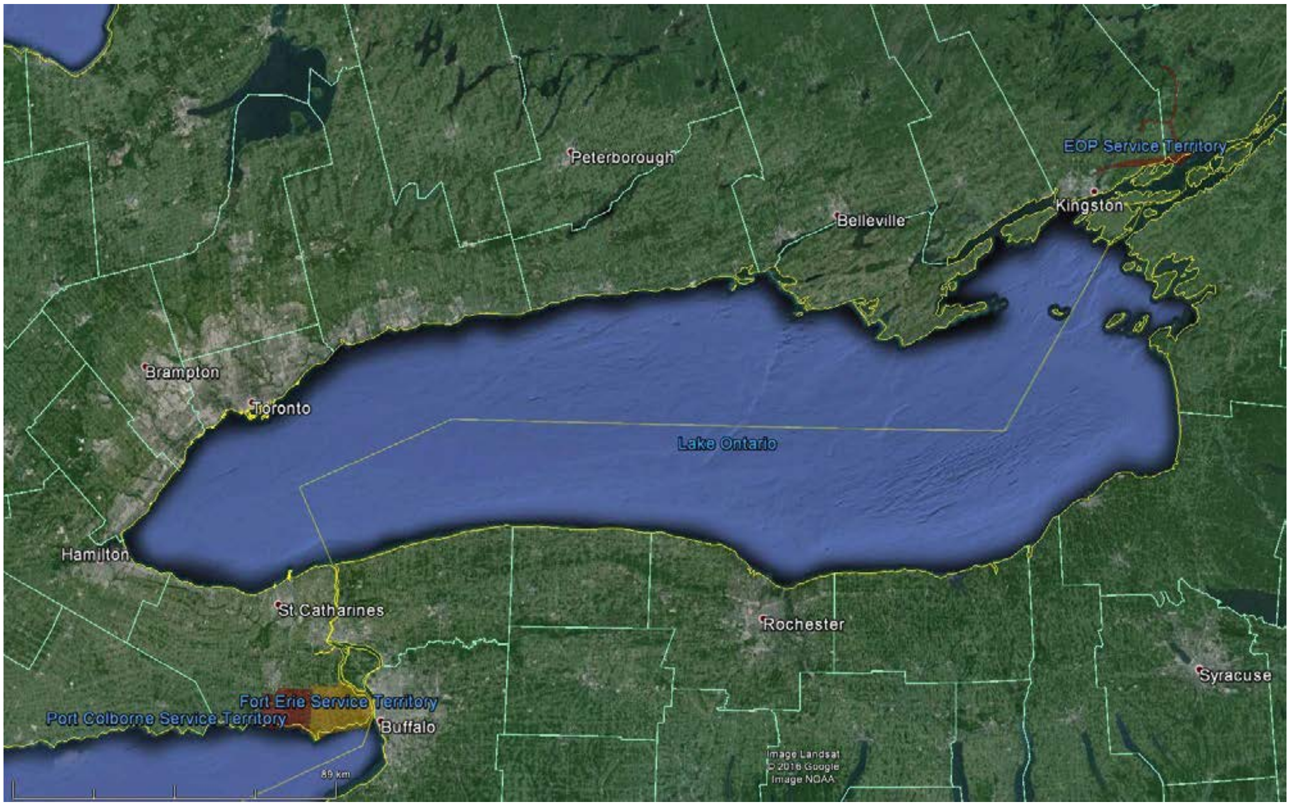


Figure 3: Service Territory for CNPI

CNPI operates as Canadian Niagara Power Inc. in Port Colborne and Fort Erie. However, it operates as Eastern Ontario Power for the portion of its service territory in and around Gananoque.

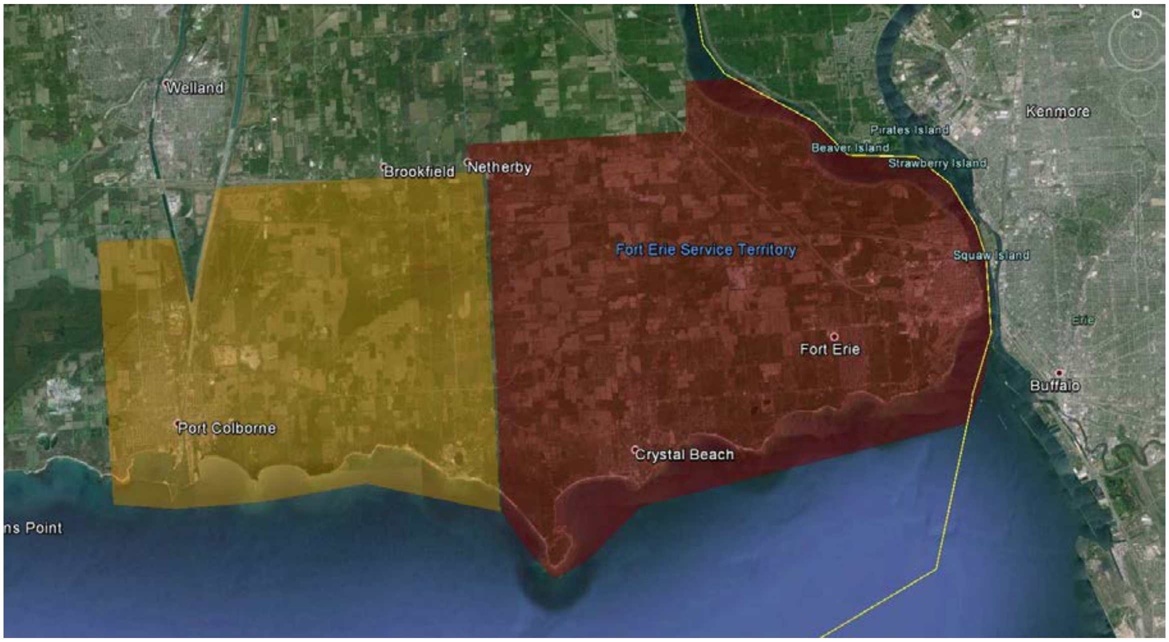


Figure 4: Service Territory in the Municipality of Fort Erie (shown in red)

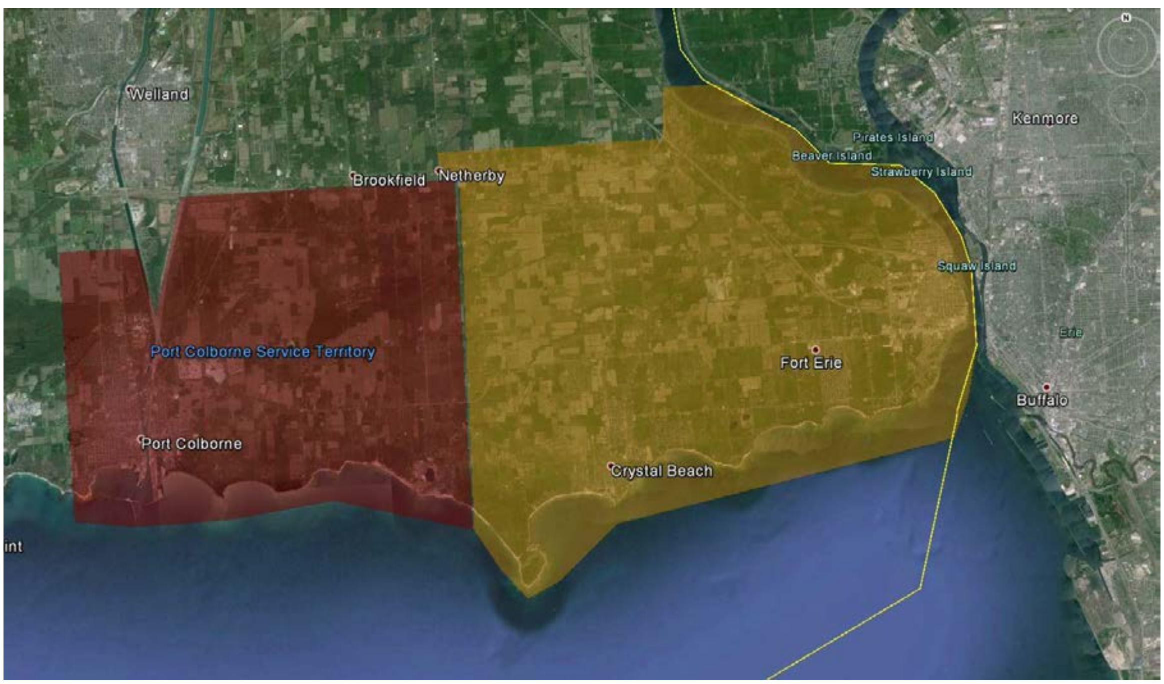


Figure 5: Service Territory in the Municipality of Port Colborne (shown in red)

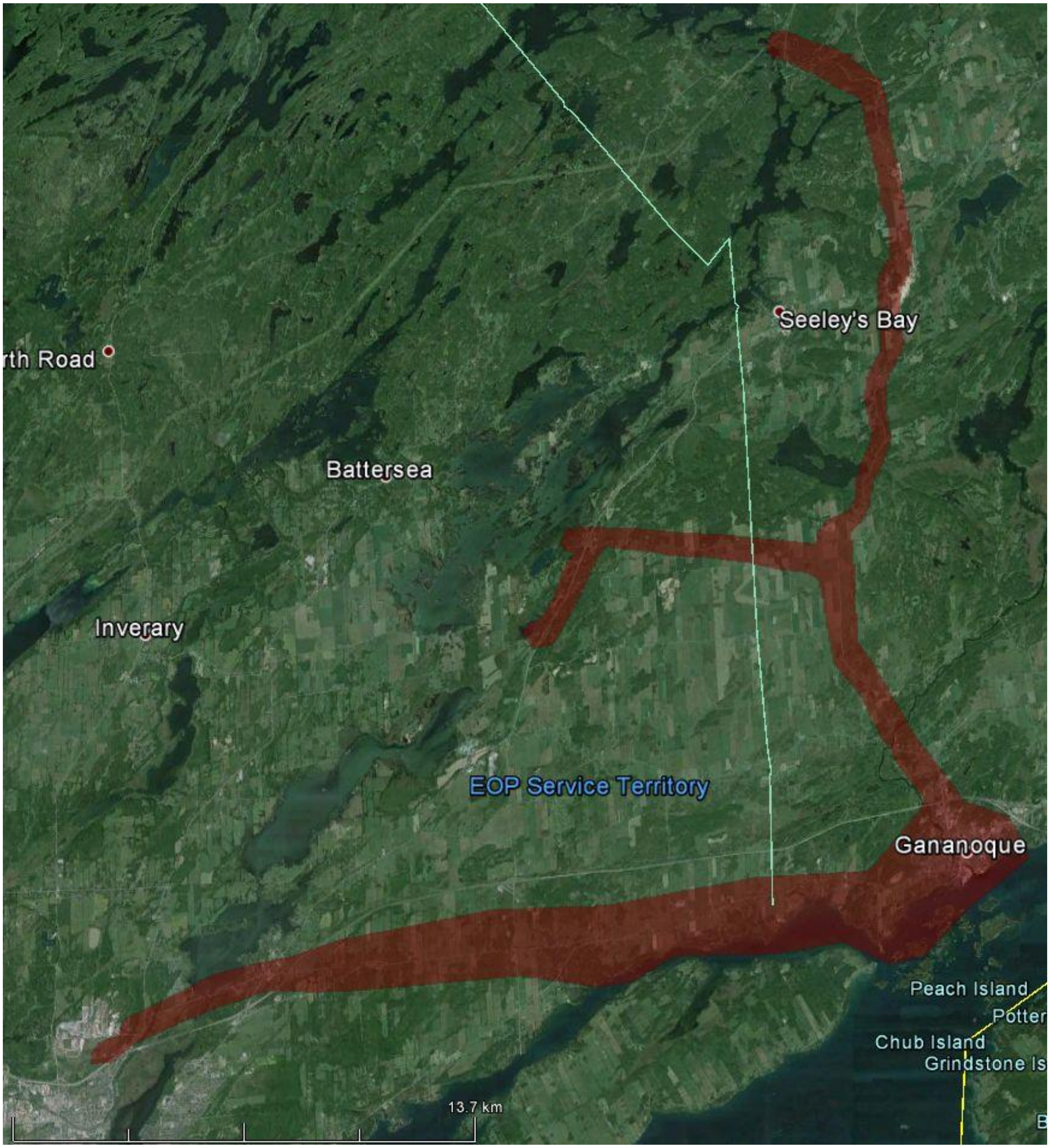


Figure 6: Service Territory for Gananoque (EOP)

Each of the three former LDCs that now comprise CNPI existed and operated completely independently for many years until recent times. As a result, through a series of different planning decisions, operating philosophies, and construction standards, the three systems have very distinct characteristics. They all have different legacy primary system voltages.

3.2 Service Area Features

CNPI serves over 28,000 customers. The majority of CNPI's distribution assets are overhead. CNPI's service area of 357 sq. km is approximately 80% urban. There are approximately 28.3 customers per kilometer of line. This information can be found in Table 7, Section 3.6.

The service areas in both Niagara and Gananoque are exposed on Northern Great Lake shorelines making the areas quite susceptible to significant weather events. Severe wind and snow storms are common events along the windward shoreline of Lake Erie. In recent years, wind events have involved significant gusts exceeding 100km/h and occurring over multiple consecutive hours. Wind events are also common of the Northern shore of Lake Ontario impacting reliability in the Gananoque area. Section 9 of CNPI's DAMP provides a summary of the impact of major events on SAIDI and SAIFI indices in recent history.

CNPI has operated in an economy with declining demand over recent years. Peak demand in each region is primarily influenced by weather and conservation efforts. CNPI's demand profile can be characterized as summer peaking.

Fort Erie service area is supplied by a single transmission line at 115kV owned and operated by CNPI's transmission company. The 115kV system can be supplied from the United States via National Grid under loss of normal supply conditions. It should be noted that the intertie is not synchronized. This can lead to significant loss of supply durations during contingencies. The Port Colborne and Gananoque service areas are also supplied by a single source via Hydro One. The majority of Port Colborne is supplied from Port Colborne Transformer Station (TS) which is radially fed at 115kV. The Eastern Ontario Power (EOP) main substation is supplied by a single 44kV circuit.

A significant portion of the Fort Erie and EOP systems are configured in a delta distribution configuration. This presents a significant challenge from a safety and operational perspective. These system consist primarily of assets at or nearing end of life. A significant component of CNPI's asset management investments are aimed at replacement of these systems with a four wire grounded solution.

The remainder of this section provides details of the distribution system in each of the three regions.

3.3 Fort Erie (FE)

3.3.1 Distribution System

CNPI owns and operates the electricity distribution system in the Fort Erie service area, serving over 16,000 customers. The service area includes an area of approximately 170 square kilometers, 455 km of overhead lines, and 45 km of underground cables. There are approximately 12,500 poles and 2,300 distribution transformers in the Fort Erie service area.

The CNPI distribution system in Fort Erie is supplied from the CNPI-owned 115kV transmission system that feeds Stations 17 and 18, the two transmission substations in Fort Erie. Both supply 19.9/34.5kV distribution feeders that provide all of the electricity for the Fort Erie distribution system. The 34.5kV feeders supply three step-down distribution substations (Stations 12, 15, and 19), twenty step-down ratio banks ("Ratio Banks" or

"Rabbits"), large commercial/industrial customers, large residential subdivisions, and rural customers. The distribution substations and ratio banks transform to voltages of 4.8kV delta, 4.8/8.3kV, and 2.4/4.16kV. The variety of distribution voltages used in the Fort Erie distribution system and the uncommon nature of some of the voltage classes present challenges to the planning and operation of the system.

A summary of the distribution system in Fort Erie is shown in Figure 7.

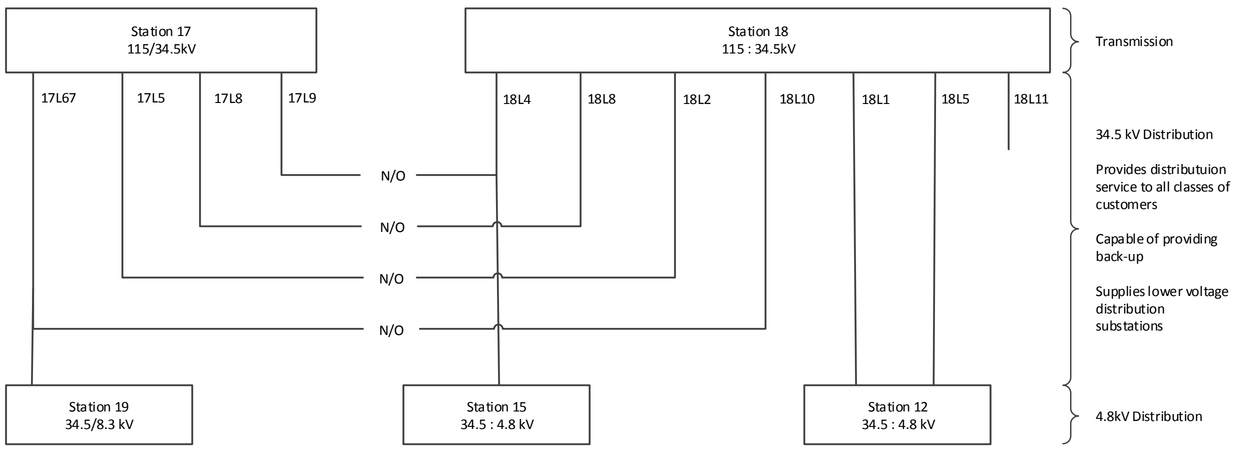


Figure 7: Fort Erie Distribution System Overview

Due to historical changes in planning and construction policies, and as a result of historical service area amalgamations, CNPI employs a wide variety of distribution voltages. Appendix A1 contains maps for the Fort Erie system. The distribution systems associated with the various voltage classes are summarized in the remainder of this section.

3.3.1.1 19.9/34.5kV (Wye)

The 34.5kV distribution system is shown in orange on the system map in Appendix A1. This voltage was introduced to serve as a higher-voltage distribution system to add capacity and efficiently supply distribution substations and larger load centers. The 34.5kV feeders from each transmission station are radially operated, but are installed with several normally open feeder interties to facilitate load transfers under planned or emergency conditions. The distribution system is designed to allow the entire Fort Erie load to be served by either Transmission Station 17 (with four available feeders) or 18 (with six available feeders). This configuration provides significant operating flexibility to allow for planned system maintenance to be carried out with minimal or no disruption to customers. In forced outage situations, the feeder interties facilitate isolation of faulted components and the speedy restoration of the majority of affected customers.

The 34.5kV voltage level is rare in Ontario. Purchase costs for equipment in this voltage class are higher than the 27.6kV systems that are more common in Ontario. This is particularly true on underground portions of the system. Switching and isolation issues are also more complex than those found on lower voltages.

Conversely, the 34.5kV feeders provide a high degree of 'reach' and capacity. A typical non-emergency rating for these feeders is approximately 28MVA. At moderate load levels, these feeders can run longer distances (>25km) while maintaining acceptable voltage levels and minimizing losses. Conductor sizes have been standardized at 336.4 aluminum for all new main 34.5kV lines

The expansion of this voltage has generally focused on:

- Supply of the step-down substations and ratio banks.
- Servicing large commercial/industrial customers

After allowing for contingencies, these existing 10 feeders have a theoretical combined capacity of at least 112 MVA, although downstream voltage correction would be required if loads reached these levels.

3.3.1.2 4.8kV (Three-Wire Delta)

The 4.8kV delta distribution system is shown in red on the system map in Appendix A1. Historically, this was the earliest 60Hz distribution voltage in Fort Erie and for many years was the sole distribution system. A delta configuration involves three single-phase transformers (or in the case of a three phase transformer, the three windings) connected together without a neutral. As loads increased and feeders were extended, the 34.5kV distribution system was introduced to serve distribution substations and larger loads, thereby relieving the overloaded 4.8kV delta system, improving voltage regulation, and reducing system losses.

By count, the 4.8kV delta system supplies the majority of customers in Fort Erie. Generally, the majority of the 4.8kV delta system components are aged, and in need of replacement. There are disadvantages to operating a 4.8kV delta system. The absence of a system neutral raises significant challenges for system protection/relaying and the effective balancing of loads across phases. The most significant risk with the delta system is the inability to detect single phase faults as there is no ground reference on this system. This presents a safety risk to both the public and workers in downed conductor scenarios.

Based on the risks associated with operating a delta distribution system, for several years one of the primary objectives of the CNPI capital program has been the conversion of the 4.8kV delta system to an 4.8/8.3kV system, and in some cases to 19.9Y/34.5kV. A wye configuration involves three single-phase transformers (or, in the case of a three-phase transformer, the three windings) connected together along with a neutral. Two distribution substations continue to supply 4.8kV delta loads; Stations 12 and 15. Load previously supplied from Station 13 was either converted to 8.3kV wye or was transferred to 4.8kV ratio banks in the area. Current conversion efforts are focused on converting loads supplied from these ratio banks to 4.8/8.3kV.

3.3.1.3 4.8/8.3kV (Four-Wire Wye)

The 8.3kV distribution system is shown in green on the system map in Appendix A1. This voltage was introduced as an economic option for converting the legacy 4.8kV delta system to a wye system. Although not a particularly high distribution voltage by modern standards, the 8.3kV system provides the advantage of being able to re-use transformers and other line components of the existing 4.8kV delta system, with the exception of lightning arresters and three-phase pad-mount transfers. This improves the feasibility of systematic voltage conversion from the delta system. In practice, voltage conversions from 4.8kV delta system to 8.3kV wye often necessitate extensive pole and framing replacements, as the legacy 4.8kV delta lines tend to use obsolescent standards and are supported by vintage wooden poles.

Presently, only Station 19 in Ridgeway in the southwest sector of the Fort Erie service area supplies this voltage and the systematic conversion of the 4.8kV delta system commenced in that area. The stand-alone nature of Station 19 is a concern from a contingency standpoint, especially as load served from this substation continues to increase as more load is converted from 4.8kV delta to 8.3kV wye. Feeders served from Station 19 are also increasing in length to beyond optimal levels as more loads are converted.

Starting in 2016, this system voltage will be introduced in the Northeast portion of the Fort Erie service territory. This expands conversion work on the 4.8kV delta system and targets replacement of end of life station, structure, and conductor assets.

3.3.1.4 2.4/4.16kV (Wye)

The 4.16kV distribution system is shown in magenta on the system map in Appendix A1. This voltage class is found only in Stevensville, located in the northwest portion of Fort Erie. This area was inherited from the former Ontario Hydro when the franchise boundary was amended to match the municipal boundary. In the Stevensville area, ratio banks are used to supply the 4.16kV distribution system covering a large rural geographical area with low customer density.

3.3.1.5 7.6kV (1 phase, Wye)

There are three pockets of this voltage at FE:

- Crescent Road, near Woodside Court
- Dodd's Court
- Gorham Road, near Wellington and Brewster

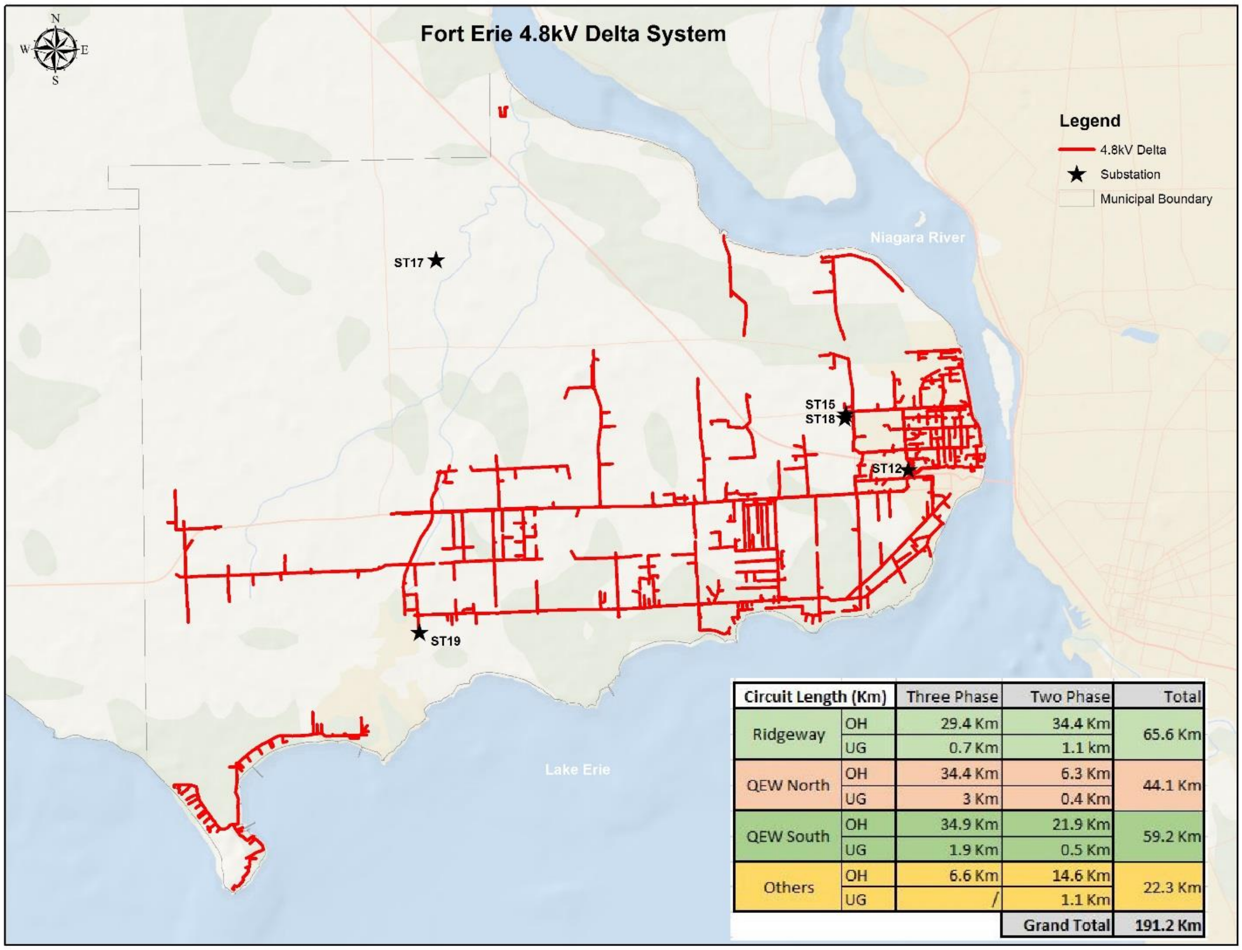
Each of these is a relatively small single-phase underground residential system. The first of these is supplied by a single ratio transformer, whereas the others have two installed ratio transformers that can each supply the entire load.

3.3.1.6 13.8kV (Three-Wire Delta)

There is a single Ratio Bank transformer (5RT1) supplying 13.8kV delta to a commercial customer located on Concession Ave., South of Gilmore Rd. in Fort Erie.

3.3.2 Delta Distribution System

A significant portion of Fort Erie's primary distribution system is delta connected. In the Fort Erie area, approximately 191 circuit kilometers of 500 total circuit kilometers is delta connected (as of the end of 2015). The following maps illustrate the significance of this system in the Fort Erie area:



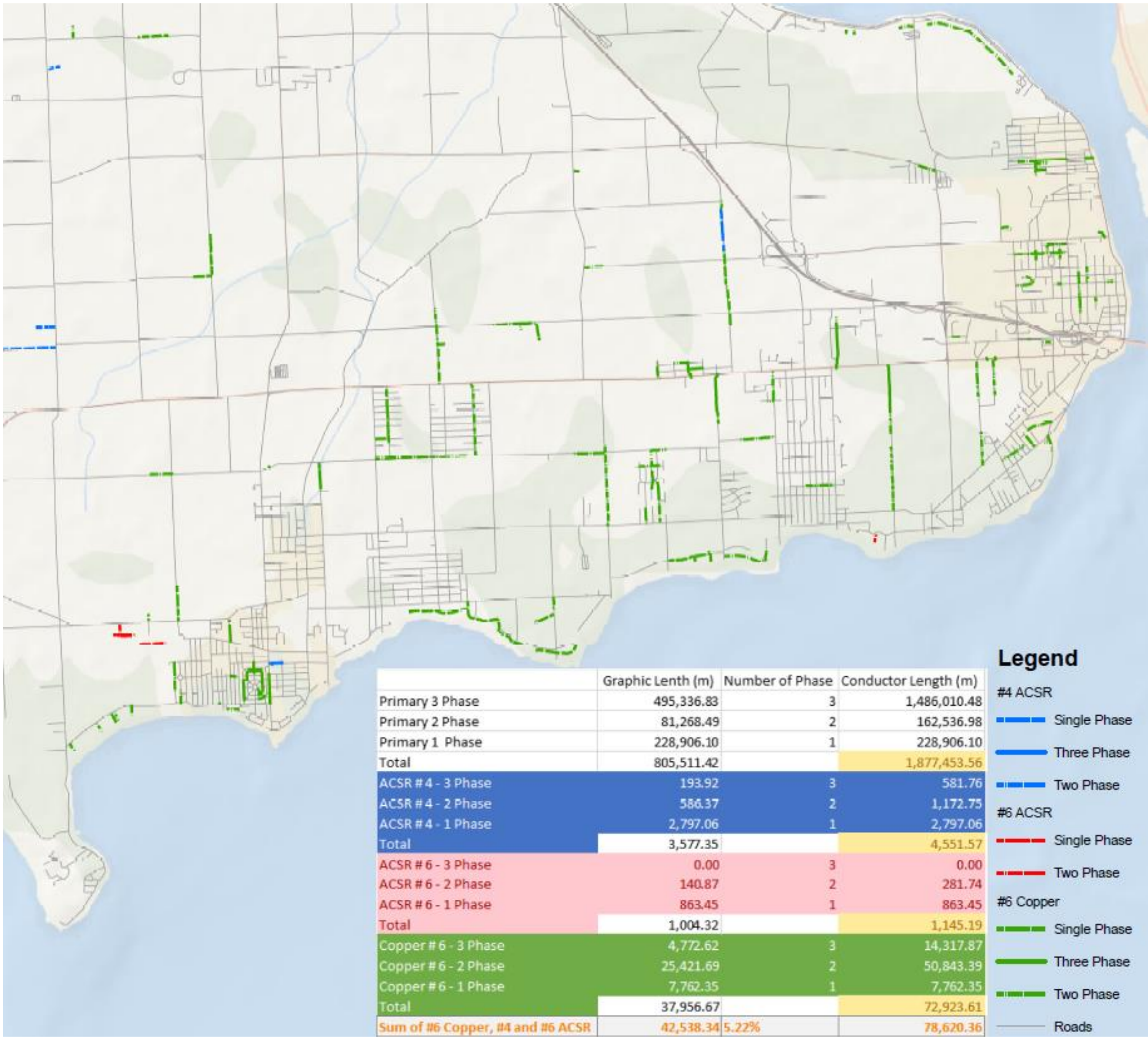
Circuit Length (Km)		Three Phase	Two Phase	Total
Ridgeway	OH	29.4 Km	34.4 Km	65.6 Km
	UG	0.7 Km	1.1 km	
QEW North	OH	34.4 Km	6.3 Km	44.1 Km
	UG	3 Km	0.4 Km	
QEW South	OH	34.9 Km	21.9 Km	59.2 Km
	UG	1.9 Km	0.5 Km	
Others	OH	6.6 Km	14.6 Km	22.3 Km
	UG	/	1.1 Km	
			Grand Total	191.2 Km

Figure 8: FE Delta Distribution System

The aging primary delta distribution system presents fundamental safety and operational concerns. From a safety perspective, the limited ability to detect a downed line or grounded phase presents a public and worker safety hazard.

From an operational perspective, substations servicing the delta system consist of legacy relay controlled breakers with negligible ground fault detection capability. The lack of ground fault detection limits CNPI's ability to determine fault locations contributing to lengthy response and restoration durations during unplanned events. As indicated elsewhere in this document, the substations supplying the 4.8kV delta system are at or nearing end of life.

Another concern with the delta primary distribution system is that a significant portion of the conductor is considered "restricted" from any live line operation. Wire sizes smaller than (and inclusive of) #4 ACSR and #6 copper are considered "restricted" due to known safety issues associated with brittle conductor shearing and separation during handling. This also contributes to operational inefficiency as significant sections of line must be de-energized in order to perform any planned or unplanned work in the identified areas. Figure 9 indicates the presence of restricted conductor on sections of the delta distribution system.



	Graphic Lenth (m)	Number of Phase	Conductor Length (m)
Primary 3 Phase	495,336.83	3	1,486,010.48
Primary 2 Phase	81,268.49	2	162,536.98
Primary 1 Phase	228,906.10	1	228,906.10
Total	805,511.42		1,877,453.56
ACSR # 4 - 3 Phase	193.92	3	581.76
ACSR # 4 - 2 Phase	586.37	2	1,172.75
ACSR # 4 - 1 Phase	2,797.06	1	2,797.06
Total	3,577.35		4,551.57
ACSR # 6 - 3 Phase	0.00	3	0.00
ACSR # 6 - 2 Phase	140.87	2	281.74
ACSR # 6 - 1 Phase	863.45	1	863.45
Total	1,004.32		1,145.19
Copper # 6 - 3 Phase	4,772.62	3	14,317.87
Copper # 6 - 2 Phase	25,421.69	2	50,843.39
Copper # 6 - 1 Phase	7,762.35	1	7,762.35
Total	37,956.67		72,923.61
Sum of #6 Copper, #4 and #6 ACSR	42,538.34	5.22%	78,620.36

Figure 9: FE Delta System Restricted Conductor

In addition to restricted conductor, 4.57km of the overhead circuit installations incorporate lashed aerial cable. Seven of the main circuit installations supplied from Station 12 utilize this aerial cable which is reaching the end of its predicted useful life. The cables have been in service for approximately 30 years. A cross section of this cable is shown in the figure below.

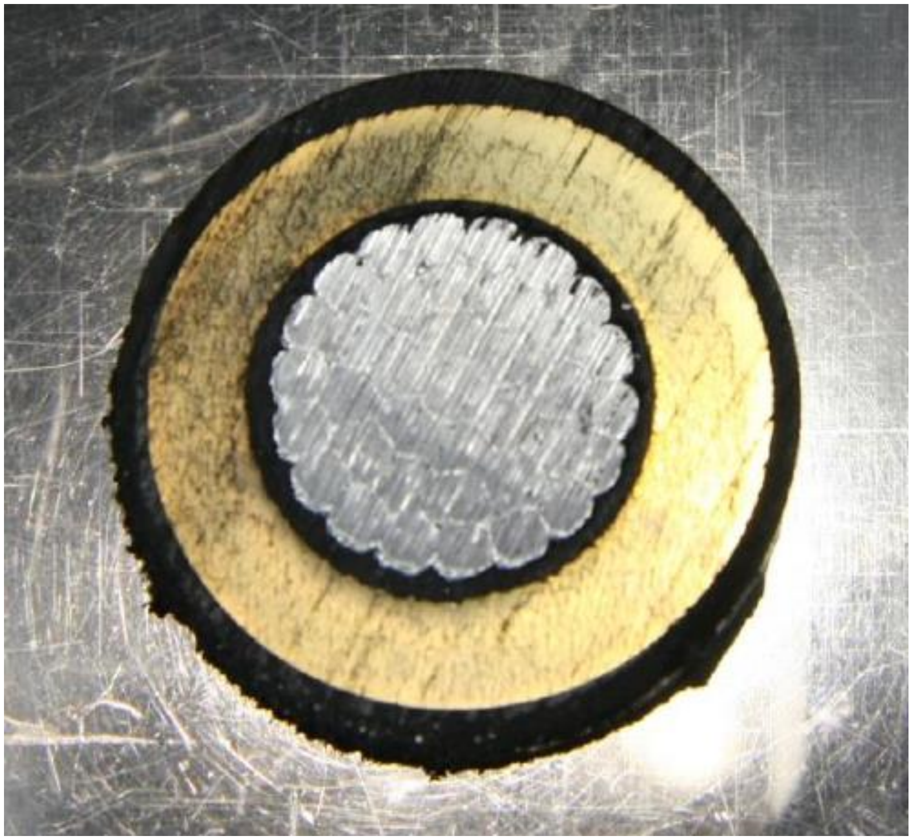


Figure 10: Cross-section of Station 12 Feeder Cables

In 2015, CNPI had an independent review of samples of this 350 kcMIL, XLPE cable completed by Kinectrics. The report determined that the cables could have an approximate remaining in service life of no more than 10 years under normal conditions.

CNPI also had Kinectrics review the suitability of this cable on an 8.3kV wye connected system. The analysis and resulting conclusions indicate that the remaining useful life could be reduced to 5 years in such service conditions.

The full report on this aerial cable can be found in Appendix K.

Due to the safety and operational concerns with the delta primary system and associated asset condition, CNPI is directing a significant component of forecast investment towards its inevitable elimination. While some line rebuilds have occurred, particularly in the Ridgeway area, the majority of the pole installations are approaching end of life conditions.

In the long term plan, CNPI intends to convert most of the 4.8kV delta system to 8.3kV wye or, in some cases, to 34.5kV wye over the next 10 years.

3.3.3 Distribution Substations (DS) and Step Down Ratio Banks

Distribution substations in Fort Erie are generally of an older vintage, apart from Station 19 that is approximately 15 years old. Station 12 serves the bulk of the 4.8kV load and is over 60 years old, while Station 15 is over 40 years old. Because of the long-term nature of the voltage conversion program, Station 12 will be required to serve 4.8kV delta loads for several more years. Therefore, capital initiatives in Fort Erie over the next few years will also include upgrading and modernizing Station 12 to ensure it remains in good operating condition. The table below shows pertinent information about the distribution substations in Fort Erie. All distribution substations are supplied at 19.9/34.5kV.

St. #	Secondary Voltage	Year Installed	# of TX's	Total Capacity (MVA)	TX Protection	# of Feeders	Feeder Protection
12	4.8kV (delta)	1952	3	25	Breakers	12	Breakers
15	4.8kV (delta)	1975	1	6.75	Breaker	3	Breakers
19	4.8/8.3kV (wye)	2001	2	26.7	Fuses	6	Breakers

Table 2: Summary of Fort Erie Distribution Substations

A summary of each of these DS's as well as the deployment of aerial step-down ratio banks is outlined as follows:

3.3.3.1 Station 12

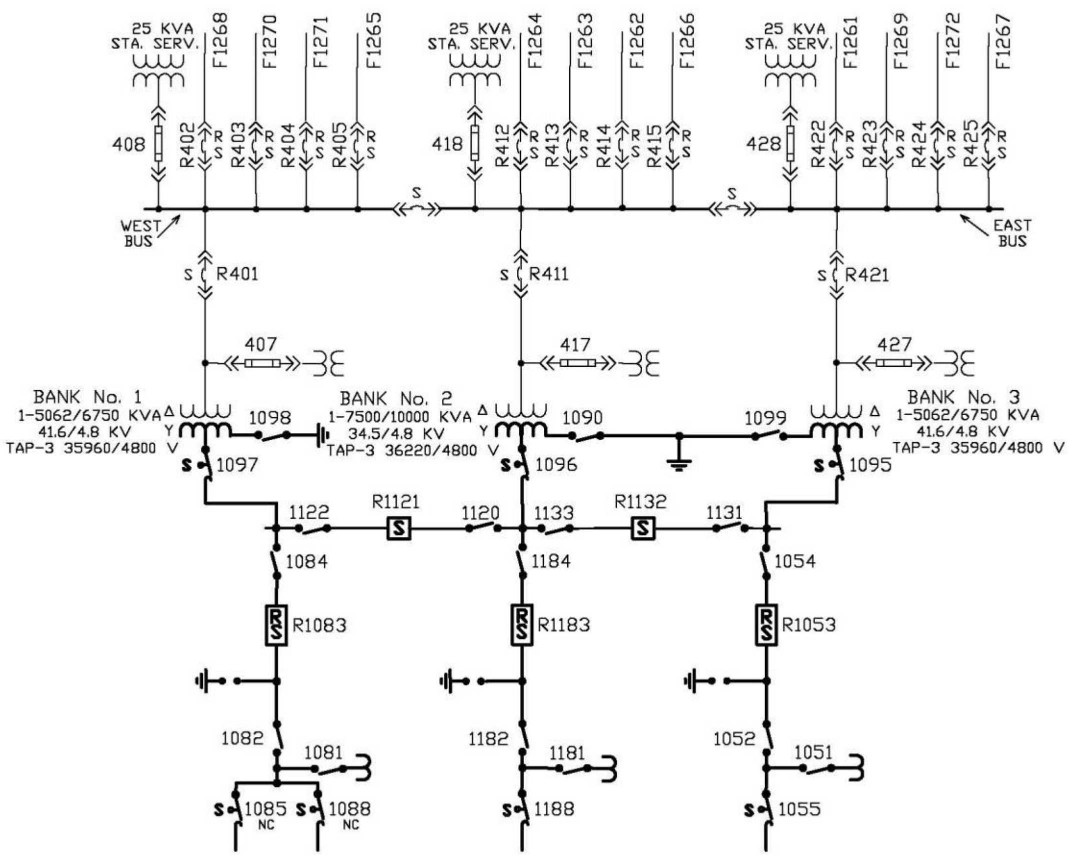


Figure 11: Station 12 SLD

- This is FE's largest step-down substation, by peak load, in 2015. The peak load was ~10.1MW in August of that year.
- Two different 34.5kV feeders (18L1, 18L5) fed from Station 18 are presently available to service this station. The peak station load can be carried by either circuit if required, as the non-emergency capacity of each 34.5 feeder is approximately 28MVA.
- The station has three 34.5Y:4.8∆ transformers, each supplying four 4.8kV ∆ feeders. Turns-ratio mismatches between these transformers means that long-term paralleling of these transformers is undesirable.
- Station service is available from each of the three 4.8kV buses.

3.3.3.2 Station 15

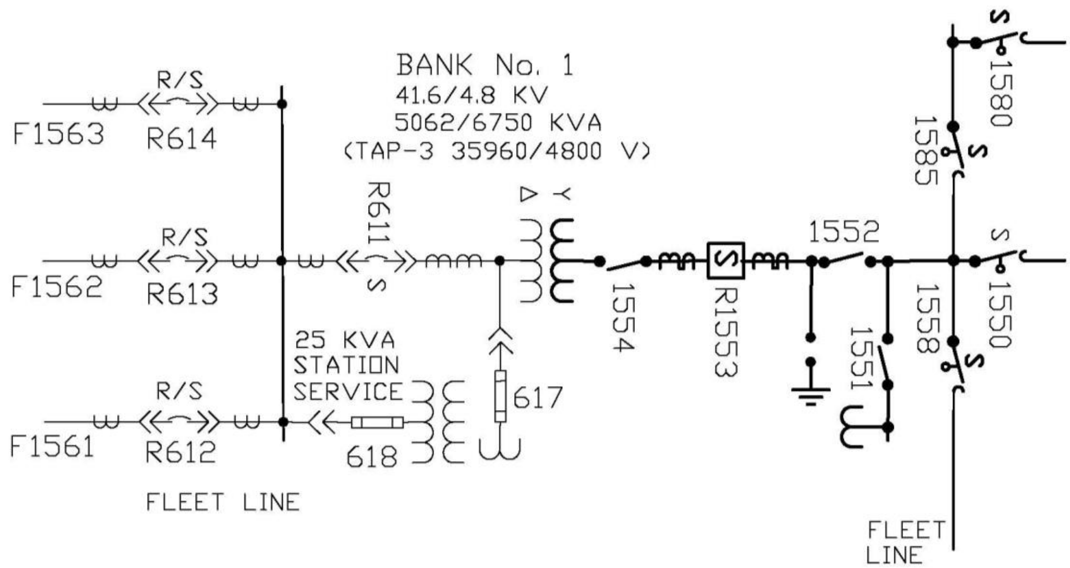


Figure 12: Station 15 SLD

- This station is located immediately adjacent to Station 18, and has two 34.5kV feeders available to supply it.
- A single 5.1/6.75MVA transformer supplies three 4.8kV ∆ feeders. The peak load for this station in 2015 was about 2.4MW.
- There is only a single source for station service.
- This station will be replaced by Gilmore DS in 2016. Gilmore DS will be implemented in the same location as Station 15 and will provide an 8.3Y source to the general area. This new station will facilitate additional conversion work on the 4.8∆ system.

3.3.3.3 Station 19

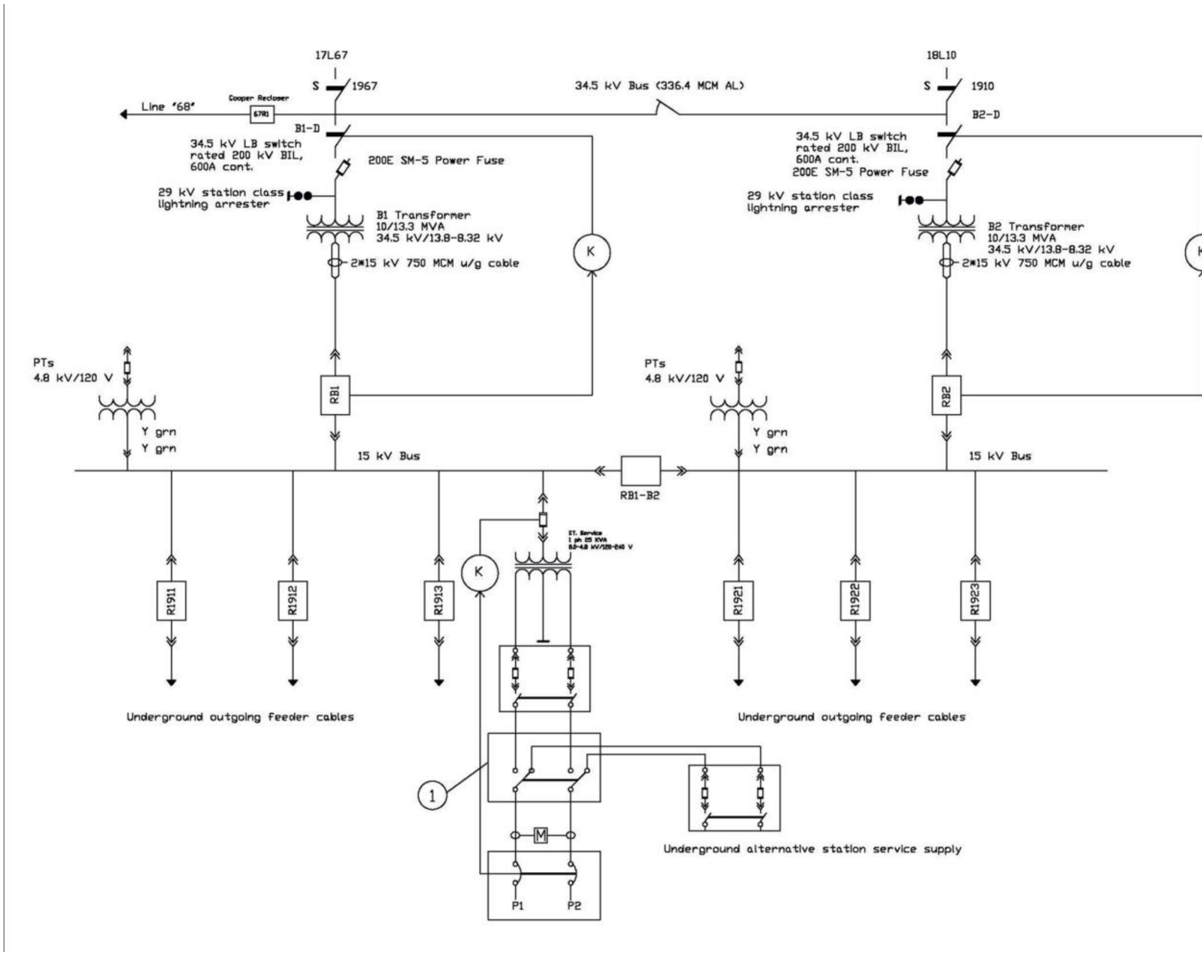


Figure 13: Station 19 SLD

- This acts as the source for the south-western portion of CNPI's system. The load on this station has increased steadily as 4.8Δ-to-8.3Y voltage conversion programs are completed. This is one of CNPI's newest stations.
- This station is supplied by two 34.5kV feeders (17L67 and 18L10), either of which can provide this station's entire anticipated load.
- Two 10/13.3MVA 34.5:8.3kV transformers each supply three 4.8/8.3kV (wye) feeders. Either transformer is able to carry the entire load.
- There is a single station service on Bus 1. However, an alternative station service supply is available from the overhead distribution system in the vicinity.
- As the only significant source of 4.8/8.3kV in FE at present, there is some concern about contingency planning. This has been mitigated by ensuring redundancy of major components within the station.
- The peak load for this station in 2015 was 8.7MW.

3.3.3.4 Step-Down Ratio Banks ("Rabbits")

There are presently 21 Ratio Banks deployed on the Fort Erie distribution system. These Ratio Banks have been installed to address some distribution substation overload and contingency issues, plus to supply low-density rural and underground subdivision loads. These Ratio Banks are connected on the primary side to the 34.5kV system and supply either 4.8kV delta or 8.3kV wye. These units are introduced on a temporary basis to supply 8.3kV wye secondary to facilitate voltage conversion. Three Ratio Banks in Stevensville supply 2.4/4.16V loads.

A few Ratio Banks supply only single-phase loads, but the majority supply three-phase circuits. All Ratio Bank transformers are protected with fuses on the primary side and either with fuses or reclosers on the secondary side.

There are some disadvantages of using Ratio Banks compared to distribution substations, including the following:

- Ratio banks increase system complexity because they result in scattered load-serving centers, compared to a distribution substation that would provide a concentrated load-serving point. With Ratio Banks there is more line equipment to operate and maintain and potential failure points.
- Each Ratio Bank installation requires a certain "footprint" and are also aesthetically displeasing. This limits the potential locations where they can be deployed. Ratio Banks result in higher transformation losses compared to a distribution station.
- Platform-mounted ratio banks generally have higher failure rate and result in lower reliability compared with ground-mounted and fenced solutions.

However, Ratio Banks have low initial costs and quick installation times. Accordingly, they provide an economic and flexible interim measure as longer term voltage conversion is carried out. They are particularly cost-effective in rural areas with low-density and widely scattered load centres.

Table 3 shows a summary of the ratio banks installed in the Fort Erie service area.

Ratio Bank	Phases	Source Feeder	Primary Voltage (Volts)	Config.	Secondary Voltage (Volts)	Nameplate Rating (kVA)	Location
5RT1	3	5RT1	34500	Y-Δ	13800	500	Concession Ave., South of Gilmore Rd.
5RT4	1	5RT4	19900	Y-Δ	4800	500	Black Creek Rd., North of Baker Rd.
5RT5	1	5RT5	19900	Y-Δ	4800	500	Sussex Dr., West of River Tr.
5RT6	1	5RT6	19900	Y-Δ	4800	500	Thompson Rd., North of Phipps St.
5RT7	1	5RT7	19900	Y-Δ	4800	500	Sutherland Dr. South of Cairns Cres.
8RT1	3	17L8	34500	Y-Y Grd	4160	1500	Eagle St., East of Stevensville Rd.
8RT2	3	17L8	34500	Y-Y Grd	4160	1500	Fox Rd., West of Ott Rd.
9RT1	3	17L9	34500	Y-Y Grd	4160	1500	Netherby Rd., West of Winger Rd.
9RT2	3	17L9	34500	Y-Δ	4800	1500	Ridgemount Rd., South of Bowen Rd.
9RT3	1	17L9	19900	Y-Y Grd	4800	500	Bowen Rd., West of Ridgemount Rd.
10RT1	3	18L10	34500	Y-Δ	4800	1500	Rosehill Rd., South of Dominion Rd.
10RT2	1	10RT2	19900	Y-Y Grd	4800	500	Albert St., North of Albany St.
10RT3	3	18L10	34500	Y-Δ	4800	1500	Stonemill Rd., South of Dominion Rd.
10RT4	3	18L10	34500	Y-Δ	4800	1500	Burleigh Rd., North of Dominion Rd.
10RT5	3	18L10	34500	Y-Δ	4800	1500	Burleigh Rd., South of Highway 3
11RT1	3	18L4	34500	Y-Δ	4800	500	Pettit Rd., North of Gilmore Rd.
67RT3	3	17L67	34500	Y-Δ	4800	1500	Erie Rd., West of Derby Rd.
67RT5	1	67RT3	4800	Δ-Y Grd	19900	167	Abino Dunes Rd., South of Point Abino Rd. S.
1268RT1	1	F1268	4800	Δ-Y Grd	4800	250	Albert St., North of Lakeshore Rd.
1268RT2	1	F1268	4800	Δ-Y Grd	4800	250	Bardol Ave., South of Dominion Rd.
1563RT1	1	F1563	4800	Δ-Y Grd	7620	167	Crescent Rd., North of Philips St.

Table 3: Summary of Fort Erie Ratio Banks

3.3.4 SCADA

CNPI remotely monitors and controls its distribution system via its Supervisory Control and Data Acquisition System (SCADA). The SCADA system is monitored from the Fort Erie-based System Control Centre, which is staffed 8 hours per day, 5 days a week. All substations are remotely monitored and controlled via SCADA, as are several Ratio Banks using electronic reclosers. Line reclosers and motor controlled gang-operated switches are also remotely monitored and controlled via SCADA. CNPI uses a variety of communication technologies for SCADA, including data lines and wireless radio transmission.

3.3.5 Map of Fort Erie System

See Appendix A1

3.4 Port Colborne (PC)

3.4.1 Distribution System

CNPI operates the electricity distribution system in Port Colborne, serving approximately 9,200 customers. The service territory includes an area of approximately 125 square kilometers, approximately 320 kilometers of overhead line, and 24 kilometers of underground cables. There are approximately 7,400 poles and 1,450 distribution transformers in the Port Colborne service area.

The Port Colborne distribution system is supplied mainly from Hydro One's Port Colborne Transformer Station (TS), located in the south end of the city. This substation transforms the power supply from Hydro One's 115kV transmission voltage down to the distribution voltage of 27.6kV. Port Colborne TS supplies four 27.6kV distribution feeders that serve the majority of the territory's load. These feeders are owned by CNPI, with the ownership demarcation generally at the outer perimeter of Port Colborne TS. A small portion of the supply to Port Colborne is delivered to the north-west sector of the city by one 27.6kV feeder that originates from Hydro One's Crowland TS in Welland. CNPI owns the section of this feeder that is located in the Port Colborne service territory, while Hydro One owns other sections of the feeder. The maps in Appendix A2 show the extent of these five feeders.

CNPI owns and operates several Distribution Substations (DS's) that transform the 27.6kV down to 4.16kV, generally used to supply the 'urban core' of the system.

CNPI also operates 27.6kV - 4.16kV (three-phase) or 16kV - 2.4kV (single-phase) ratio banks to supply the remainder of the 4.16kV system. These are generally isolated pockets of the original 2400/4160V system still awaiting voltage conversion.

Port Colborne is dominated geographically by the Welland Canal, which makes it difficult and expensive (technically and politically) to have circuits passing from east to west over/under the canal. As a result, there is only a single usable 4.16kV feeder crossing (submarine cable, at Clarence St.). However, there are four 27.6kV crossings of the canal, all underground, at three distinct points.

3.4.1.1 27.6kV:

The 27.6kV distribution system is shown in orange on the system map in Appendix A2. The five 27.6kV feeders in Port Colborne act as the trunk distribution system supplying five step-down Distribution Substations (DS's), thirteen step-down "Ratio Banks" or "Rabbits", several larger commercial/industrial customers, residential subdivisions, and rural customers. The distribution substations and Ratio Banks transform electricity down to a distribution voltage of 4.16kV. The five 27.6kV feeders are radially configured, but are interconnected at several locations via "Normally Open" points to facilitate load transfers under planned or emergency conditions. This provides significant operating flexibility on the 27.6kV system to allow for planned system maintenance to be carried out with minimal or no disruption to customers. In forced outage situations, it facilitates isolation of faulted components along with the expedient restoration of the majority of affected customers.

The Welland Canal runs generally north-south and forms a major geographical barrier within the City of Port Colborne. The canal presents significant challenges and expense, because feeder crossings must be routed under the canal. Presently, there are four 27.6kV and one

4.16kV feeder crossings at three locations along the canal in Port Colborne. Three of the distribution substations in Port Colborne are on the west side of the Welland Canal and only two, Killally DS and Sherkston DS, are on the east side. There are several 4.16kV interconnections among the DS's on the West side of the canal. However, there are no interconnections between the two substations of the East side of the canal, and only a single 4.16kV interconnection of limited capacity between the east and west sides of the canal.

Nearly all of the 27.6kV system is overhead, and the 'main lines' are generally constructed of large gauge conductor, typically 336 Aluminum.

3.4.1.2 4.16kV:

The 4.16kV distribution system is shown in magenta on the system map in Appendix A2. It supplies the urban core and rural areas of Port Colborne. It is an older system and is generally in poorer condition compared to the 27.6kV system. While there is at present generally sufficient transformation capacity at the distribution substations on the west side of the canal in order to meet normal and emergency needs, there are some instances of 4.16kV lines having conductors that are too small to pick up other loads in emergency situations. This limits the ability to effect inter-feeder or interstation load transfers, and presents challenges to maintaining system reliability. Capital programs in recent years have partly focused on upgrading the 4.16kV system to provide additional capacity and enhance transfer capability between feeders and distribution substations.

There are isolated pockets of 4.16kV supplied by Ratio Banks. Generally, the loading on these 'rabbits' is less than those employed in Fort Erie, with the largest bank rated at 750kVA.

3.4.2 Distribution Substations (DS) and Step-Down Ratio Banks

The table below shows pertinent information about the Port Colborne distribution substations. All Port Colborne DS's transform voltage from 16.0/27.6kV to 2.4/4.16kV.

Barrick DS was decommissioned in 2015, as it was the oldest substation on the system. Equipment was nearing the end of its useful life, with primary concern of the switchgear equipment. The expansion of Fielden DS, which was completed in 2015, allowed Fielden DS to accept a portion of Barrick's load. Fielden DS originally had a single 6.5/8.67MVA transformer with four feeders. The expansion included a 6.5MVA transformer with padmounted switchgear, facilitating three new feeders with interties to the existing station on poles directly external of the station.

In 2008, CNPI purchased a used mobile transformer from a neighbouring LDC and refurbished the unit using internal resources. This unit provides additional security to the Port Colborne system by making available transformation capacity that can be deployed to avoid or reduce outages during planned or emergency situations. For example, the mobile transformer was utilized during the construction and commissioning of Sherkston DS to avoid lengthy outages to customers.

A summary of each of these DS's as well as the deployment of aerial step-down ratio banks is outlined in the following sub-sections.

Substation	Year Installed	# of TX's	Total Capacity (MVA)	TX Protection	# of Feeders	Feeder Protection
Jefferson	1952	3	5.0	Breakers	3	Breakers
Catharine	1975	1	6.6	Breaker	3	Breakers
Killaly	2001	2	10	Fuses	6	Breakers
Fielden	2004/2015	2	15.2	Fuses and Breakers	7	Breakers
Sherkston	2009	2	15	Breakers	4	Reclosers

Table 4: Summary of Port Colborne Distribution Substations

3.4.2.1 Jefferson DS

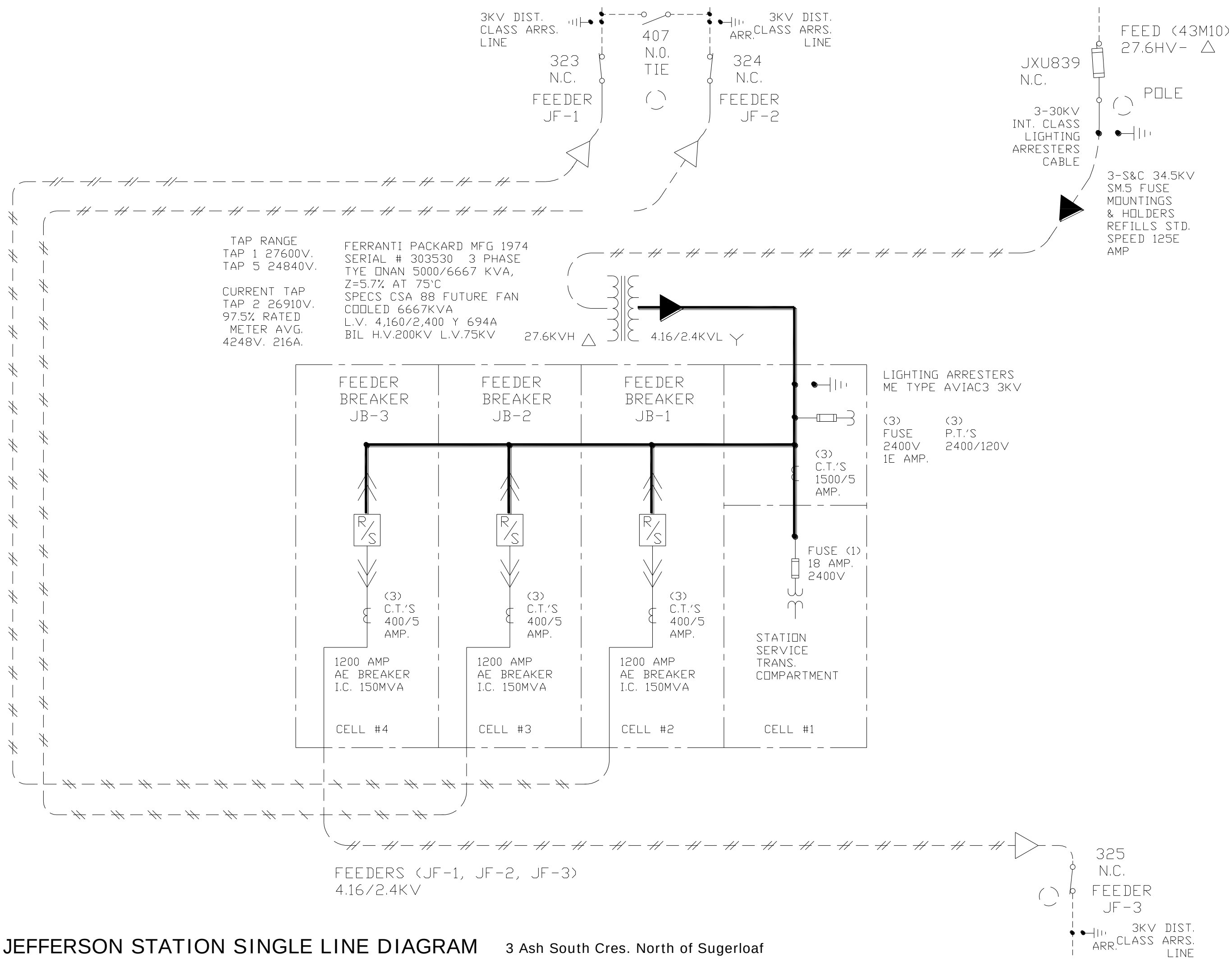


Figure 14: Jefferson Station SLD

- Jefferson DS was commissioned in 1952.
- This station contains a single 5000kVA transformer which is at end of life.
- The legacy switchgear and associated protection elements are at end of life and replacement parts are not readily available.
- Three feeders (JF1, JF2, and JF3) are supplied by this transformer.
- Peak loading was 4.1MW in 2015.
- Based on asset condition and the limitations of protection elements at this location, CNPI plans to implement a new distribution substation to supply load customers connected to the 4.16kV system in the Southern area of Port Colborne.

3.4.2.2 Catharine DS

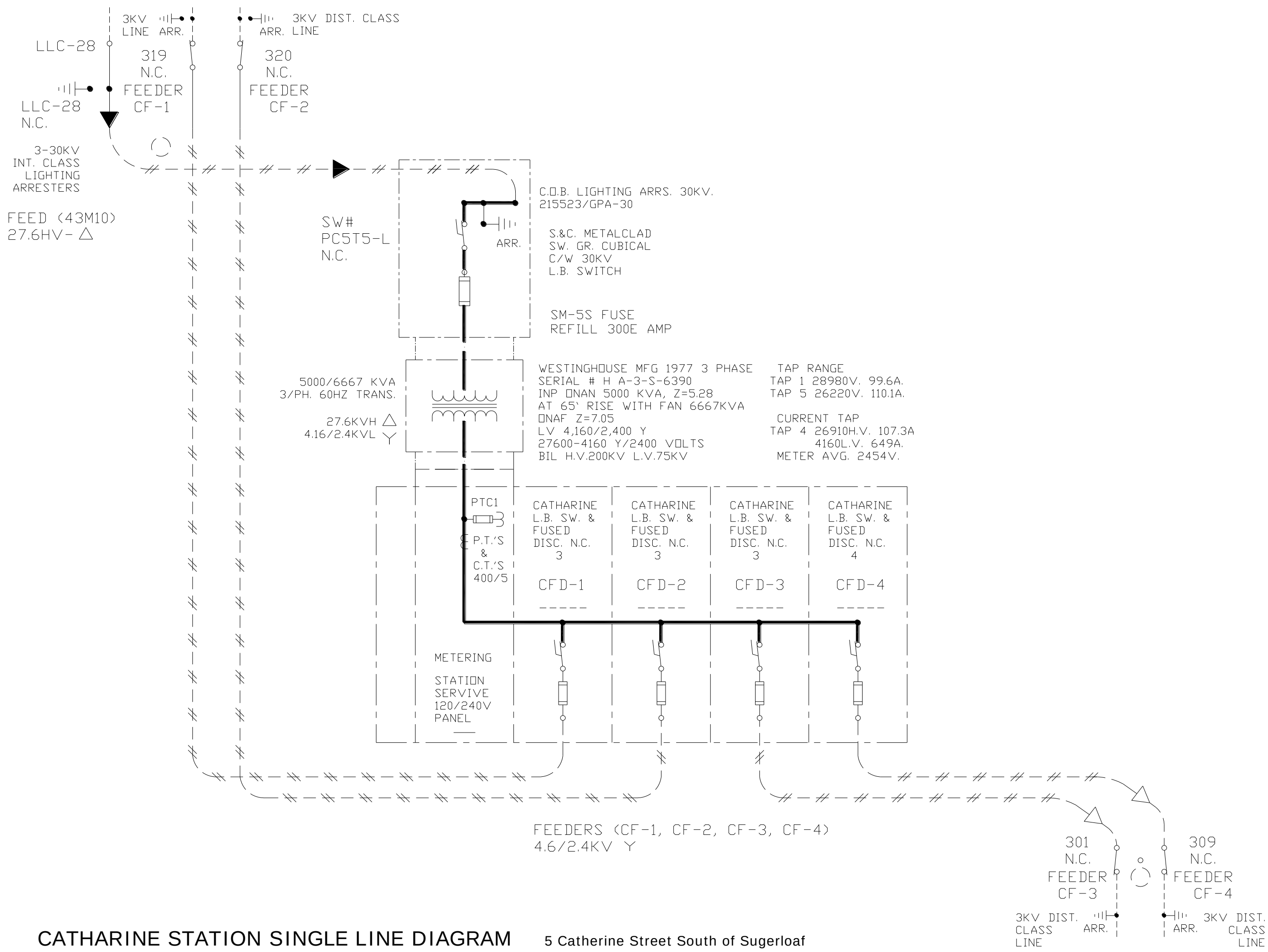


Figure 15: Catharine Station SLD

- Catherine DS is a single element station that was commissioned in 1975.
- The station incorporates fused protection with no automation.
- The legacy switchgear is approaching end of life.
- This station contains a single 5000kVA transformer. It is nameplate rated for 5000/6667kVA ONAF, but is not equipped with fans. This unit is approaching end of life.
- Four feeders (CF1, CF2, CF3 and CF4) are supplied by this transformer.
- Peak loading was about 3.2MW in 2015.
- Based on asset condition and the limitations of protection elements at this location, CNPI plans to implement a new distribution substation to supply load customers connected to the 4.16kV system in the Southern area of Port Colborne.

3.4.2.3 Killaly DS

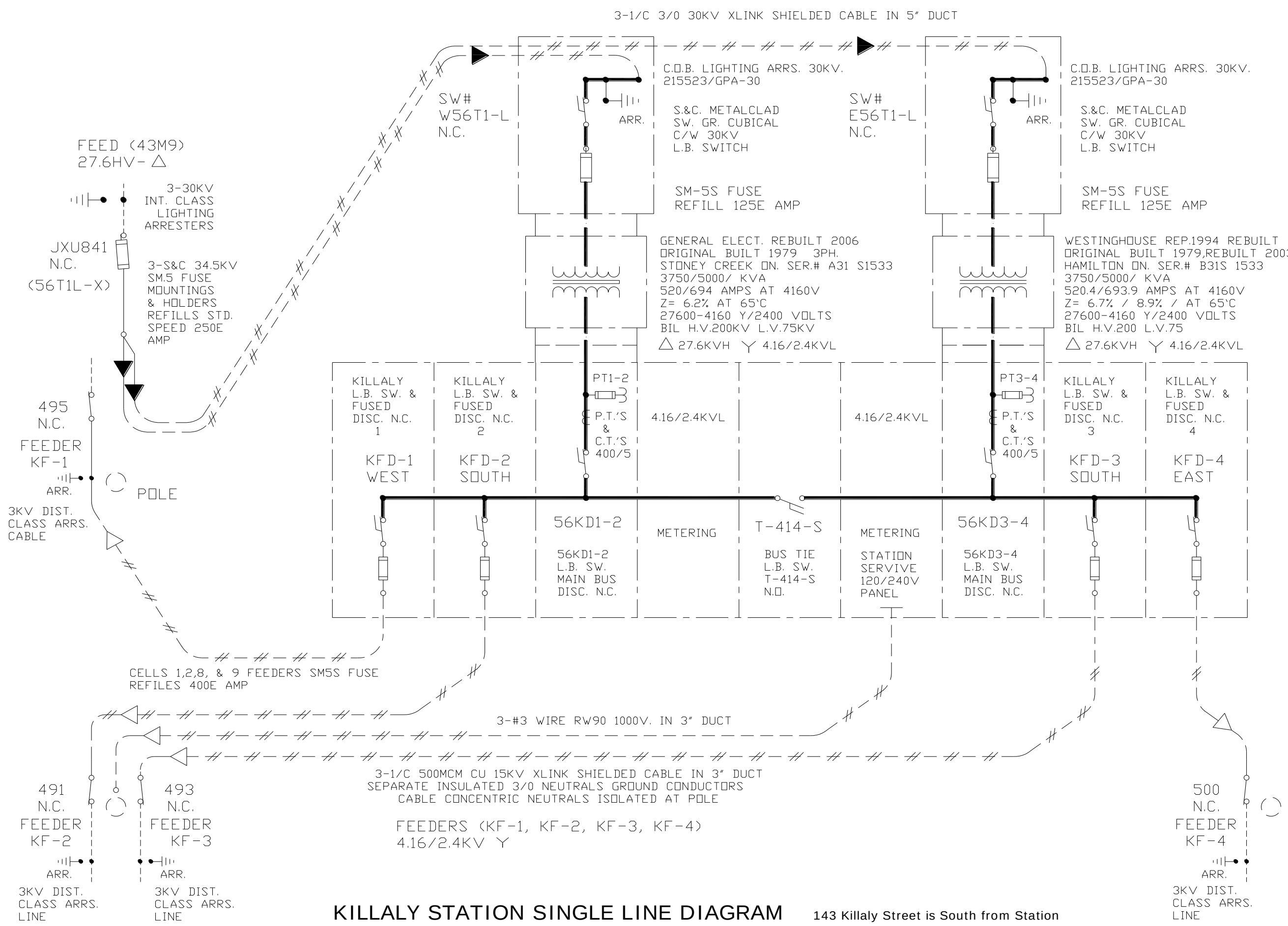


Figure 16: Killaly Station SLD

- The Killaly station supplies most of the 4.16kV 'urban' area on the east side of the river/canal.
- The station contains two 27.6kV - 4.16kV transformers:
  - a. The "east" unit is rated at 3750/5000kVA.
  - b. The "west" unit is rated at 3750/5000kVA.
- BOTH transformers are supplied from a common overhead 27.6kV "tap", with individual cable risers originating at the same pole outside of the substation.
- A total of four 4.16kV feeders originate at this substation:
  - a. KF1 and KF2 are normally supplied by the West transformer
  - b. KF3 and KF4 are normally supplied by the East transformer
  - c. There is a 4.16kV "Tie" switch that allows either transformer to supply all four feeders, assuming load levels allow.
- The peak load for this station in 2015 was 2.9MW.

3.4.2.4 Fielden DS

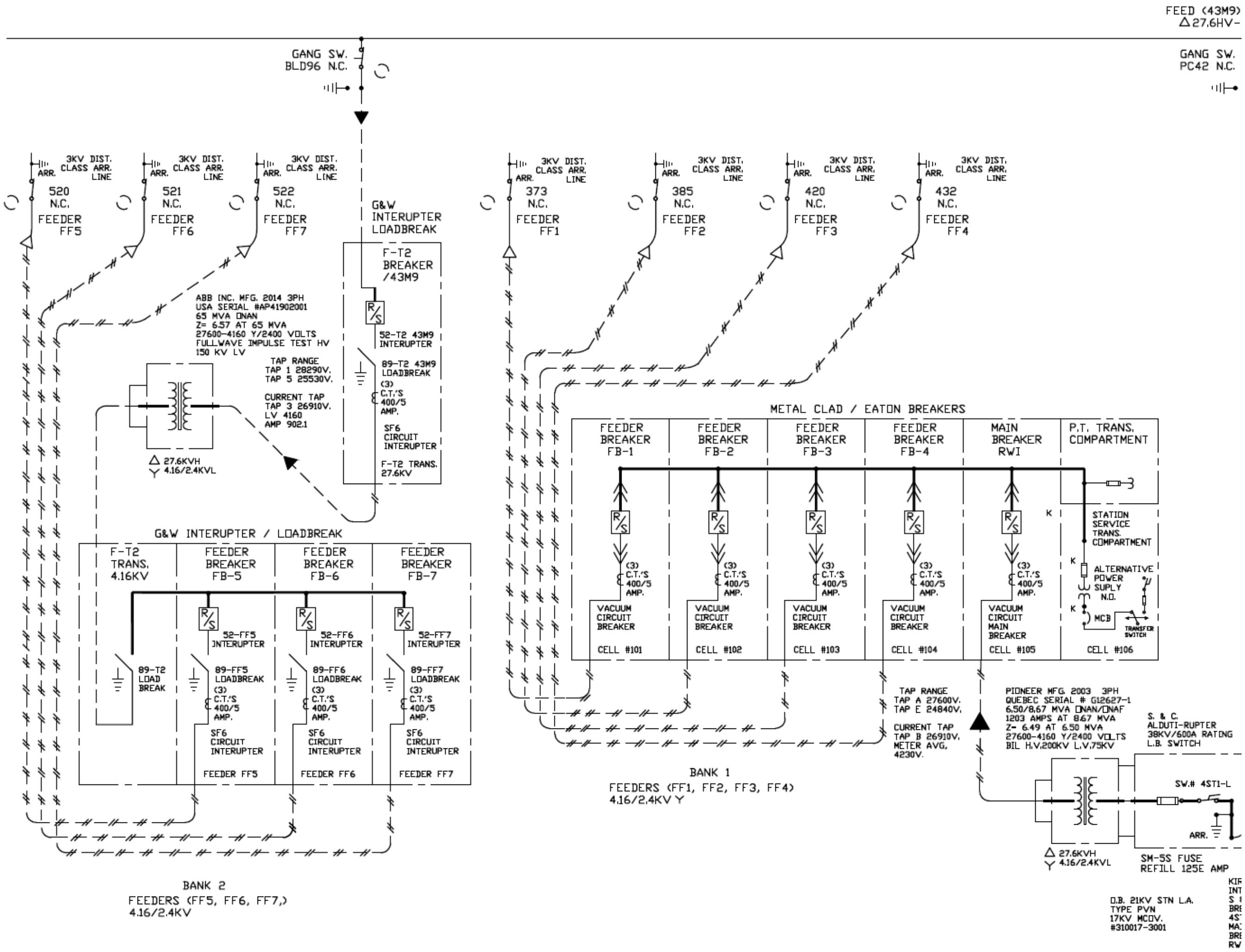


Figure 17: Fielden Station SLD

- The T1 side of this substation was commissioned in the 4th Quarter of 2004.
- The T2 side of this substation was commissioned in the 3rd Quarter of 2015. This essentially eliminated the requirement for Barrick DS which has been decommissioned.
- T1 is a 6.5/8.67MVA transformer, equipped with automatic fan cooling. T2 is a 6.5MVA transformer without fan cooling.
- There are seven 4.16kV feeders (FF1, FF2, FF3, FF4, FF5, FF6 and FF7), which had a peak load in 2015 of 4.4MW.

3.4.2.5 Sherkston DS

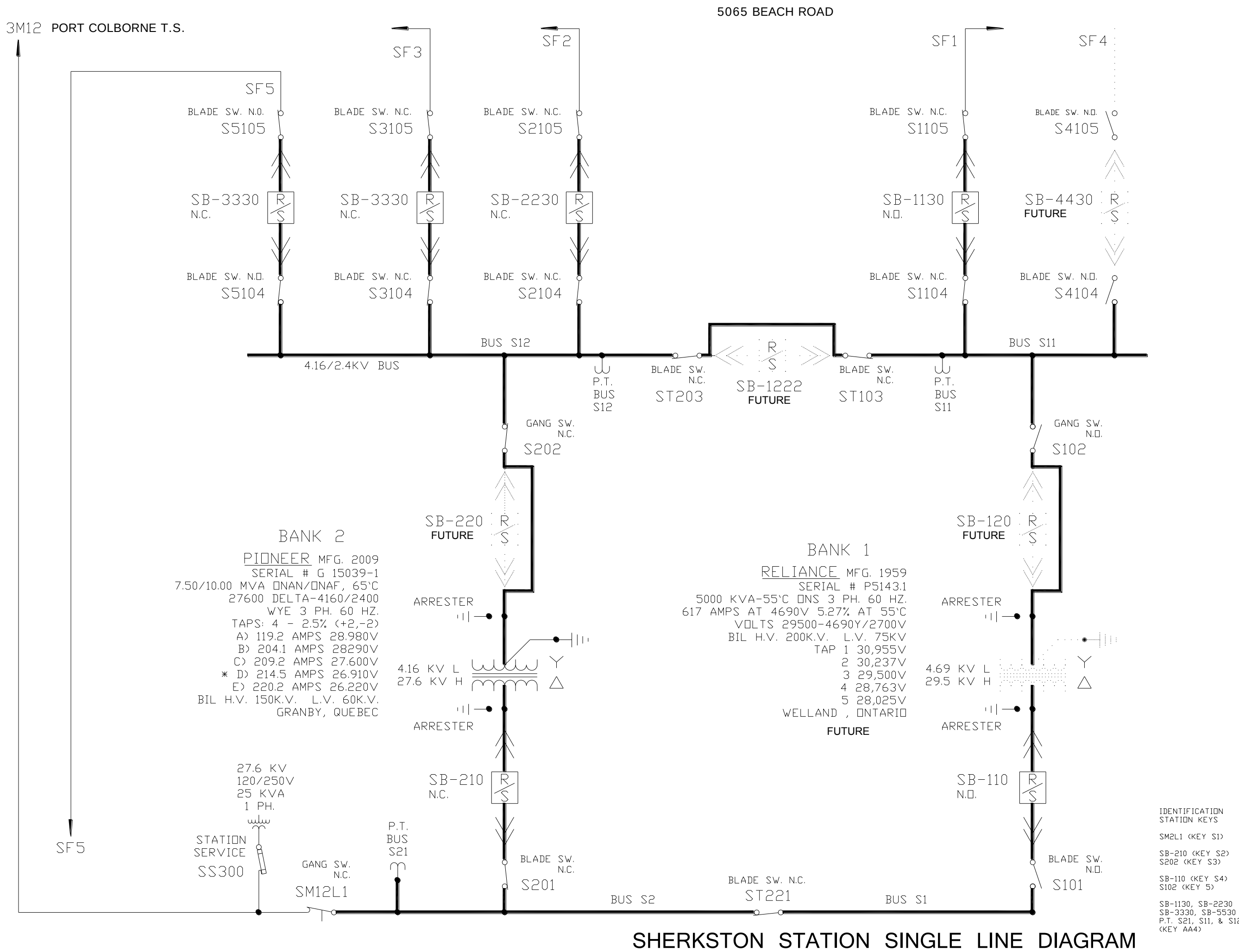


Figure 18: Sherkston Station SLD

- Sherkston DS was commissioned in 2009
- It is radially supplied by a single 27.6kV feeder (43M12). Some switching can be done to allow another 27.6kV feeder to act as source if a problem develops in or near the source at Port Colborne TS.
- It contains two 27.6kV - 4.16kV transformers, a new 7.5/10MVA unit and a 5MVA unit intended to act as an energized backup.
- Presently, three 4.16kV feeders (SF1, SF2, SF3) are constructed, with provision for a fourth feeder when and if load growth requires it.
- This station was constructed to serve CNPI customers in the south-east portion of Port Colborne as well as to provide dedicated 4.16kV supply to Sherkston Shores, which is a largely warm-weather seasonal spot load.
- Peak loading was 3.7MW in 2015.

3.4.2.6 Ratio Banks:

The CNPI distribution system in Port Colborne includes thirteen Ratio Banks installed mostly in rural areas. These units are connected on the primary side at 27.6kV and provide 4.16 kV on the secondary side. Several banks supply three-phase power on the secondary side, while the remainder provide single-phase power only. There are some disadvantages to using Ratio Banks compared to distribution substations, namely:

- Ratio banks increase system complexity because they result in scattered load-serving centers, compared to a distribution substation that would provide a concentrated load-serving point. Furthermore, with Ratio Banks, there is more equipment to operate and maintain and potential failure points.
- Each Ratio Bank installation requires a certain "footprint" and they are also aesthetically displeasing. This limits the potential locations where they can be deployed.
- Compared to a distribution station, Ratio Banks result in higher transformation losses.
- Platform-mounted ratio banks generally have higher failure rates and result in lower reliability compared with ground-mounted, fenced substations.

However, ratio banks incur low initial costs and quick installation times. Accordingly, they provide an economic and flexible means of supplying rural areas with low-density, widely scattered loads.

The following table shows some data for these ratio banks:

Ratio Bank	Phases	Source Feeder	Primary Voltage (Volts)	Config.	Secondary Voltage (Volts)	Nameplate Rating (kVA)	Location
M9RT3	1	43M9	16000	Y-Y Grd	2400	100	Chippawa Rd., North of Main St. E
M9RT16	3	43M9	27600	Y-Y Grd	4160	750	Amelia St., East of Canal Bank Rd.
M10RT6	3	43M10	27600	Y-Y Grd	4160	750	Welland St., North of Mellanby Ave.
M11RT1	1	43M11	16000	Y-Y Grd	2400	250	Barrick Rd., West of Hawthorne Blvd.
M11RT2	1	43M11	16000	Y-Y Grd	2400	250	Steele St., North of Donlea Dr.
M11RT3	1	43M11	16000	Y-Y Grd	2400	250	Steele St., South of Royal Rd.
M12RT1	1	M12RT1	16000	Y-Y Grd	2400	100	Weaver Rd. South of Firelane 1
M12RT4	3	43M12	27600	Y-Y Grd	4160	300	Cedar Bay Rd., South of Killaly St. E
M12RT5	3	43M12	27600	Y-Y Grd	4160	750	Killaly St. E, East of Lorraine Rd.
M12RT7	1	43M12	16000	Y-Y Grd	2400	100	Second Conc., West of White Rd.
M12RT8	3	43M12	27600	Y-Y Grd	4160	750	Forks Rd., East of Yager Rd.
M12RT11	1	43M12	16000	Y-Y Grd	2400	100	White Rd., North of Forks Rd.
M12RT12	1	43M12	16000	Y-Y Grd	2400	100	Michael Rd., South of Carpy's Ln.
M12RT14	1	43M12	16000	Y-Y Grd	2400	100	Forks Rd., West of South Brookfield Rd.
M12RT17	1	43M12	16000	Y-Y Grd	2400	100	Forks Rd., West of Snider Rd.

Table 5: Summary of Port Colborne Ratio Banks

3.4.3 SCADA

The CNPI distribution system is remotely monitored and controlled via the CNPI Supervisory Control and Data Acquisition (SCADA) system. The SCADA system is operated from the

CNPI System Control Centre (SCC) located in Fort Erie. All Port Colborne substations are monitored by SCADA, and all of the monitored substations except two are also remotely controlled via SCADA. The two substations that are not remotely controlled (Killally DS and Catherine DS) do not contain controllable devices such as circuit breakers. CNPI has also extended SCADA to strategic locations on its distribution system. Over the past few years, several electronic line reclosers were installed to improve feeder sectionalizing, fault isolation, and outage response. These reclosers were connected to SCADA to provide remote monitoring and control. Over the next several years, CNPI plans to continue the expansion of its SCADA system by deploying more line reclosers and automating gang-operated switches. CNPI uses a variety of communication technologies for SCADA communications, including data lines and radio transmission.

3.4.4 Map of Port Colborne System

See Appendix A2

3.5 Eastern Ontario Power (EOP) – Gananoque

3.5.1 Distribution System

A map of the Gananoque distribution system can be found in Appendix A3.

CNPI owns and operates the distribution system in its service territory of Gananoque, serving over 3,500 customers. The service territory includes an area of approximately 65 square kilometres, approximately 172 kilometers of overhead line, and 11 kilometers of underground cables. There are approximately 2,950 poles, and 880 distribution transformers in the Gananoque service territory.

The electricity supply to CNPI in Gananoque originates at the Hydro One 44kV subtransmission system. The territory is supplied from a single Hydro One 44kV feeder that is stepped down to 26.4kV delta at CNPI's EOP Main Substation, which then supplies the 26.4kV delta distribution system.

A delta configuration involves three single-phase transformers (or, in the case of a three-phase transformer, the three windings) connected together without a neutral.

The 26.4kV system supplies three customer owned transformer stations (larger industrial customers), three 26.4kV-2.4/4.16kV distribution substations (DS's), three 26.4kV-2.4/4.16kV ratio banks (RB's) and also connects to five customer owned embedded hydro-electric generating plants.

The 26.4kV and 4.16kV distribution systems in Gananoque are generally of older vintage and some sections are in poor condition. Capital programs in Gananoque in recent and future years have been and will continue to focus on upgrading the system to replace aged components, increase capacity, and improve system reliability.

The legacy 26.4kV delta system also presents challenges to system planning and operation. There are inherent disadvantages to the delta system because the absence of a system neutral presents challenges to effective protection and control and the efficient balancing of load across phases. There are also cost disadvantages because of the unique nature of transformation equipment required to connect to the 26.4kV delta.

CNPI's plan is to convert the 26.4kV delta system to the more common 16.0/27.6kV voltage in 2017. A wye configuration involves three single-phase transformers or, in the case of a three-phase transformer, the three windings connected together along with a neutral. The EOP Main Substation (commissioned in 2007) was constructed with 27.6kV transformation equipment to facilitate the conversion of the 26.4kV delta system to 27.6kV wye.

3.5.1.1 Point of Supply Main Substation

The EOP Main Substation serves as the point of supply from Hydro One's 44kV subtransmission system, where it is stepped down to supply CNPI's 26.4kV delta distribution system. The current substation consists of two power transformers operating as one main (TB2) and one spare (TB1). Although TB2 (2006) has a 27.6kV wye secondary, TB1 (1980) has a 26.4kV delta secondary and as such, the system must remain 26.4kV delta to maintain n-1 transformer contingency. CNPI is proposing to replace TB1 with a new 15-20MVA, 44kV-27.6 GRDY transformer to facilitate a system voltage conversion from 26.4kV delta to a more conventional 27.6kV grounded wye system. The single line diagram shown below represents the EOP main substation:

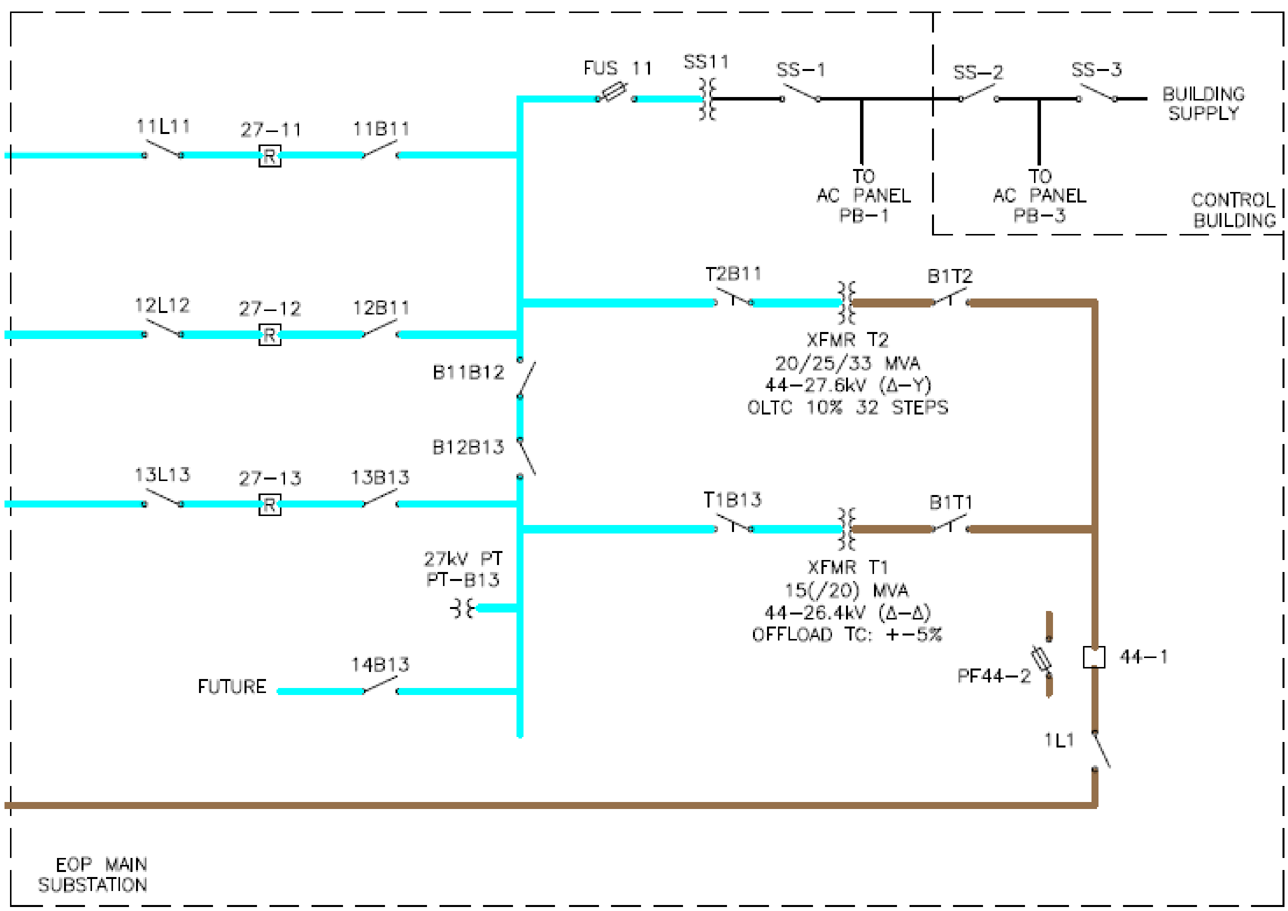


Figure 19: EOP Main Substation SLD

- Peak loading on the EOP Main Substation was approximately 12.0 MVA in 2015.

3.5.1.2 26.4kV Delta System

The 26.4kV delta system serves as the higher-voltage distribution, or trunk distribution system, in Gananoque. It was introduced to efficiently supply distribution substations, larger load centers, and widely scattered rural loads. The 26.4kV distribution system is shown in Red in Appendix A3.

Three 26.4kV delta feeders originate from the Main Substation, and these feeders serve the entire load in Gananoque. The 26.4kV system serves three distinct components: the "Town Loop", the "West Line" and the "North Line" as described below.

Town Loop

The Town Loop supplies the bulk of the Town of Gananoque's urban commercial and residential load by supplying power to the downtown distribution substations – Herbert Street DS and Gananoque DS.

The Town Loop originates at the Main Substation and runs along two separate paths generally referred to as the "East side" and the "West side". The "East side" route follows highway and street right-of-ways, while the "West side" route follows an abandoned Canadian National Railway (CNR) right-of-way into the Town. Both the "East Side" and "West side" of the loop eventually make their way down to Gananoque DS where they are tied together providing a redundant supply to the substation as well as any additional taps/loads along their path.

A tap off of the "East side" of the loop supplies power to Herbert Street DS leaving the substation with a radial point of supply along its length. Efforts have been made and will continue to be made provide a second point of supply to Herbert Street DS from the "West side" of loop. These efforts line up well with system renewal projects along Oak Alley (2013), Cooper's Alley (2016) and Pine Street (2016).

The West Line

The West Line is a 23-kilometre long radial 26.4kV distribution line that runs between the Gananoque DS and the Kingston Mills DS. Along with Kingston Mills DS, the West Line also supplies three ratio banks along the way – Leaky Creek, Ratio Bank #1, and Ratio Bank #2. The conductor size over most of the length of the line is 3/0 ACSR.

The line is alongside road allowances and is readily accessible by line truck. An embedded hydro-electric generator, Kingston Mills Generating Station, also feeds into the West Line. The three ratio banks and one distribution substation step down the voltage to 2.4/4.16kV, which is then distributed to rural customers.

The 26.4kV West Line is underbuilt over its entire length with a 4.16kV line that is supplied at different sections from one of the aforementioned distribution substation and ratio banks. Being radially fed, faults along the West Line must be isolated and repaired before power can be restored to customers. Depending on the location of the fault, varying numbers of customers would be affected.

The North Line

The North Line is a 38.5-kilometre long radial 26.4kV distribution line that runs from the Main Substation North to three embedded hydro-electric generating plants and a few residential customers. The circuit designation for the North Line is feeder 26-1.

Most of this line was constructed in the 1940's and the conductor size over the majority is #2 copper that is in deteriorating condition. The route of the line is well away from the road, running cross-country through fields and forested areas. Therefore, much of the line is inaccessible by vehicular traffic, which raises operational challenges. The inaccessibility of the line and the forested environment for much of its length creates challenges to its ongoing operation and maintenance. Because the line is a radial configuration with no interties to other feeders, faults must be isolated and repaired before power can be restored to customers.

Capital Investments will be made beginning in 2017, to rebuild portions of the North Line. The primary focus of these investments will be to rebuild the most deteriorated portions of the line. CNPI will also investigate the possibility of relocating portions of the line to the road side to provide easier access where feasible.

3.5.1.3 4.16Y/2.4kV system

The 4.16kV distribution system is shown in purple in Appendix A3. The 4.16kV system in Gananoque is a traditional 2.4/4.16kV grounded-wye system that serves mostly commercial and residential loads in the urban and rural areas.

At present, there is a limitation on the number and capacity of feeder interties in the urban 4.16kV distribution system. Consequently, there is no capability to supply the full load of one of the downtown distribution stations (Gananoque or Herbert Street) should the second distribution substation be offline under planned or emergency circumstances under peak load condition.

With the aged infrastructure in the urban distribution system, CNPI has taken advantage of system renewal projects to increase the backup capacity of the 4.16kV feeder interties at a reasonable incremental cost. These improvements will increase operating flexibility and improve system capacity and reliability. Much of the downtown core contains assets at or near end of life. Significant capital investments will be required over the foreseeable future years to replace/rebuild these assets.

The 4.16kV system presents some challenges in itself and is inefficient in a lot of ways. Some challenges are that there is limited capacity on any given feeder due to constraints on voltage drop and conductor size. This poses challenges when connecting large loads and typically requires an extension of the 26.4kV system (depending on location) in order to connect these loads.

Inefficiencies can be seen on the 4.16kV system as the lower system voltage results in line-losses however additional inefficiency exist due to the increased complexity of the system. Upon conversion of the 26.4kV delta distribution to a 16.0/27.6kV system, CNPI would take advantage of this by converting end of life 4.16kV assets to the 27.6kV system at their time of replacement with the intent of eventually eliminating the 4.16kV distribution system. Additional conversions may take place ahead of end-of-life if the incremental benefits exceed the incremental costs.

3.5.2 Distribution Substations (DS) and Step Down Ratio Banks

The table below shows pertinent information for the Gananoque distribution substations and ratio banks:

Substation	Year Installed	# of TX's	TX Protection	# of Feeders	Feeder Protection
Main	2007	2	Breaker	3	Reclosers
Gananoque DS	1945	2	Fuses	6	Breakers
Herbert Street DS	1992	1	Fuses	3	Breakers
Kingston Mills DS*	1956	1	Fuses	2	Fuses
Leaky Creek RB	2013	3 x 1 phase	Fuses	2	Fuses
RB1	2013	3 x 1 phase	Fuses	2	Fuses
RB2	2013	3 x 1 phase	Fuses	2	Fuses

Table 6: Summary of Gananoque Stations and Ratio Banks

*To be retired and replaced with new Ratio Bank in early 2016

3.5.2.1 Gananoque DS

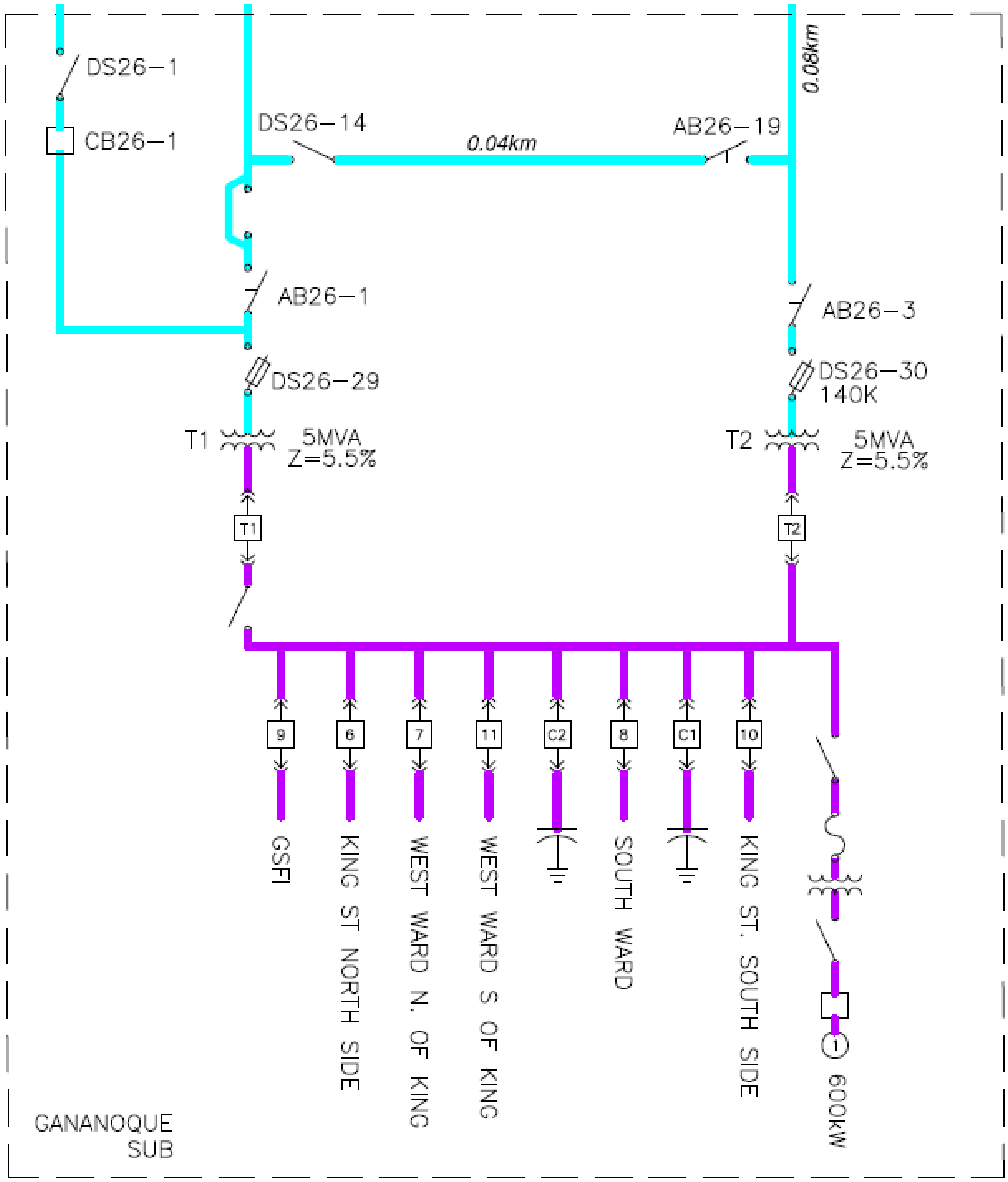


Figure 20: Gananoque Station SLD

Gananoque DS is located in the downtown core of Gananoque where it transforms its 26.4kV delta supply to 2.4/4.16kV grounded wye. With six distribution feeders, Gananoque DS serves as the normal point of supply for the South and West portions of the downtown distribution system. It is configured with two 5MVA transformers operating in parallel for an effective capacity of 10MVA. Should one of the power transformers become unavailable, 4kV load may be transferred as necessary to Herbert Street DS to avoid overloading the remaining transformer. One of the two 5MVA power transformers is 60 years old and will require capital investments to replace/remove it from service in the near future.

- Peak loading on Gananoque DS was approximately 5.9 MVA in 2015.

3.5.2.2 Herbert Street DS

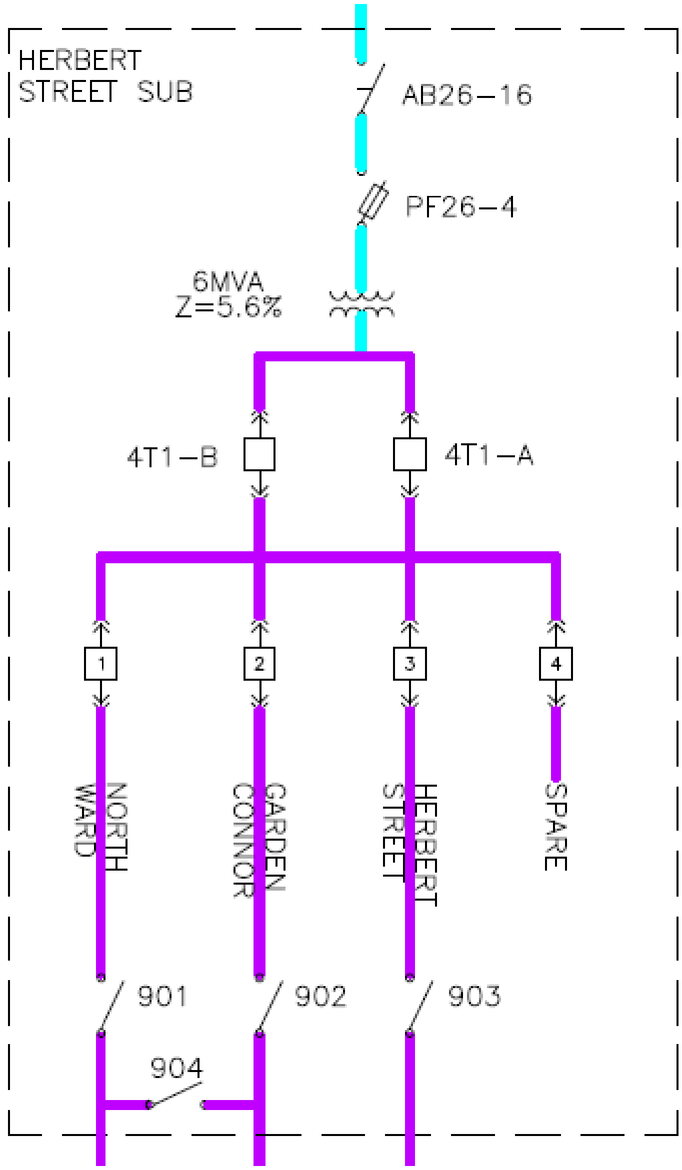


Figure 21: Herbert Station SLD

Herbert Street DS is located in the North East corner of the town of Gananoque where it transforms its radially fed 26.4kV delta supply to 2.4/4.16kV grounded wye. With three distribution feeders, Herbert Street DS serves as normal point of supply for the North and East portions of the downtown distribution system. Consisting of a single power transformer and being radially fed, Herbert Substation's only means of back-up should this transformer or the supply feeder fail or require maintenance is from Gananoque DS through the use of 4kV interties. Investments have been made and will continue to be made to upgrade/replace old assets along these interties to maintain reliability and improve backup capability within them.

- Peak loading on Herbert DS was approximately 4.7 MVA in 2015.

3.5.2.3 Kingston Mills

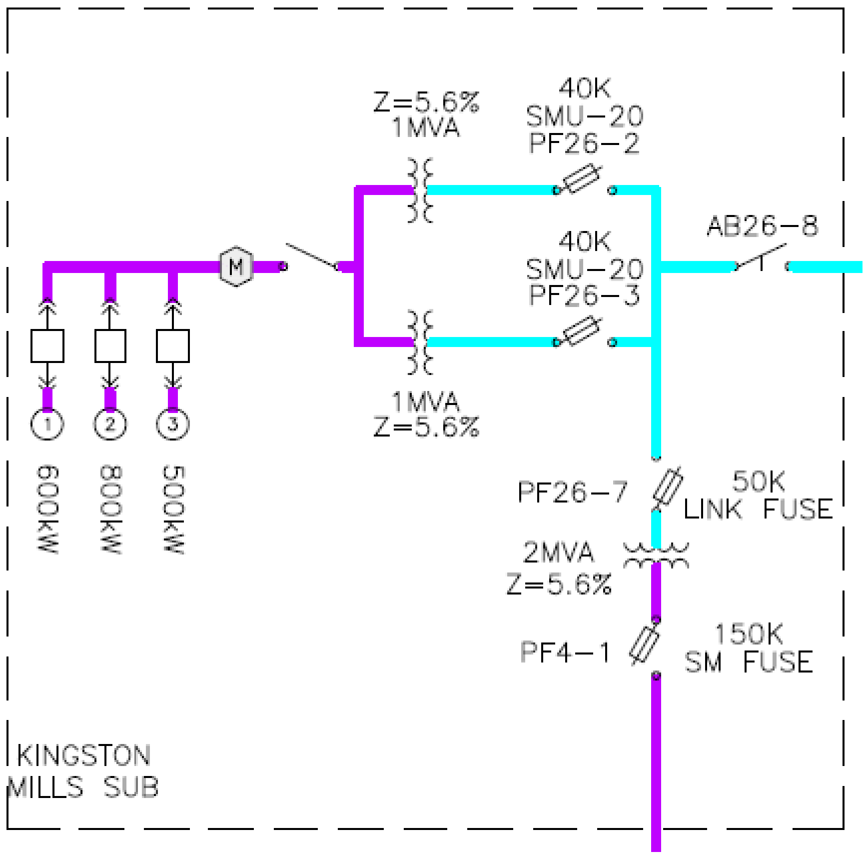


Figure 22: Kingston Mills Station SLD

Located at the West most point of CNPI's 26.4kV distribution system, Kingston Mill's Generating Station (GS) is owned and operated by the interconnected connected generation operator. CNPI owns the 2 MVA power transformer installed at the facility which provides a 4.16kV source for CNPI owned distribution along the "West Line". The existing infrastructure in the facility is in the order of 60+ years old. Construction began in 2015 (to be completed in 2016) to install a new 1 MVA ratio bank along the road side to retire the legacy power transformer installation at Kingston Mills GS. Once commissioned, all CNPI load will be transferred from the GS to this new supply.

3.5.3 Ratio Banks

In 2013, CNPI installed three, 1MVA, single phase ratio banks (Leaky Creek, Ratio Bank 1, and Ratio Bank 2) along the "West Line" to replace/retire legacy distribution stations "Leaky Creek", "Substation 1", and "Substation 2" respectively. The legacy substations contained aged equipment including power transformers with potential PolyChlorinated Biphenyl (PCB) content which could not be verified without destructive testing of the transformer bushings. This, coupled with the age of the transformers, led to the retirement of these stations and the installation of the ratio banks. Ratio Banks have low initial costs and quick installation times which provided an economical solution to the retirement of the distribution stations.

3.5.4 SCADA

The Gananoque distribution system is controlled by the Control Room at CNPI's affiliate company; Cornwall Electric. In 2010, SCADA was implemented at the Main Substation to enable its remote monitoring and control. Over the next several years, SCADA will be expanded into other substations in Gananoque as well as strategic components on the distribution system. SCADA expansions will yield the operational and system planning benefits of access of real-time system information and the ability to operate devices remotely.

3.5.5 Map of Gananoque System

See Appendix A3.

3.6 Summary of Key Statistics

The following table summarizes some key statistics for the three operating areas that comprise CNPI in December of 2015:

	Niagara Area	Gananoque Area	Total
	Operating as CNPI	Operating as EOP	
Customers			
Residential	22,836	3,144	25,980
General Service	2,276	419	2,695
Distribution Line Assets			
Poles, owned by CNPI	19,918	2,954	22,872
Distribution Transformers	5,282	886	6,168
Service Area (km^2)	292	65	357
Total Overhead Line (km)	775	172	947
Total Underground Line (km)	69	11	80
Ratio (step-down) banks	36	3	39
Distribution Substations	8	4	12
power transformers	14	6	20
circuit breakers	54	20	74
distribution feeders	43	17	60

Table 7: Summary of Key Statistics

4 Distribution Assets

4.1 Categories of Assets

The distribution assets of CNPI can be broken down into various categories and definitions:

(1) **Financial (Fixed) Asset**: This is the 'traditional' accounting/finance view of assets, falling into different accounts, focusing on financial information such as original cost, current book value, and depreciation amounts.

(2) **Physical Assets (Components):** This is the 'traditional' operations view of assets, which are actual material parts such as a 45 foot class 4 wood pole, a cross-arm, or a section of 28kV underground primary cable.

(3) **Managed Asset (MA)**: For purposes of the CNPI DAMP, a *Managed Asset* (MA) is an assembly of one or more components tracked and managed as a single entity. For example a single 'Pole' MA might consist of the pole itself in addition to any supporting components such as guy wires and anchors, A framing MA may contain a cross-arm, three 28kV insulators, plus the sundry other approved hardware required.

CNPI's DAMP will focus almost entirely on *Managed Assets* as the effective meaning of 'assets' in the context of this document.

4.2 Identification of Managed Assets

4.2.1 Process

CNPI has had a program underway for some time to identify and assess the condition of all of its MAs. The information has been collected from a variety of sources:

4.2.1.1 Field Inventory and General Condition Assessment

CNPI has a comprehensive inventory of MA in its asset management database for all regions of the company. CNPI conducts a general condition assessment on MA through either a holistic approach or strategic sampling.

4.2.1.2 Periodic Scheduled Inspections

Prior to the issue of the DSC, CNPI performed regular inspections of its MA's. Since the DSC came into force, CNPI has continued with these inspections while ensuring that the content, frequency, and recordkeeping of these inspections are consistent with Appendix C of the DSC. Inspection data is captured using a primarily paper based system. Historical data is maintained in CNPI's asset management database where practicable.

4.2.1.3 Identification during Project Planning and Construction

As sections of distribution line are evaluated due to internally or externally-driven projects, the type and condition of CNPI's assets are captured into the asset management database.

4.2.1.4 Technical Programs

This type of program can include such technical programs as

(1) Infra-red or thermographic imaging of all current-carrying components of the distribution system to identify hot-spots that can signify imminent or near-term failure of MAs.

(2) Pole testing using one of several non-destructive or low-impact intrusive testing techniques to directly measure and assess the present condition of wooden poles. These tests have been proven in the industry to be a cost effective and accurate predictor of remaining pole life.

Although critical condition issues are dealt with as soon as practicable, all information collected during these programs is stored and will be evaluated for incorporation into corporate information systems.

4.2.1.5 Ad-hoc Assessments during Unplanned Construction

Often, a condition assessment of one or more MA's is performed by a line-crew performing unplanned construction, such as responding to a report of a vehicle accident or as a result of a Third Party report from customers. Where practicable, information gained from these assessments is incorporated into the asset management database.

4.3 Geographic Information Systems (GIS)

Information regarding CNPI's Managed Assets is maintained in CNPI's asset management database. The database is an integration of GIS, SAP, and other relational database systems.

CNPI's GIS consists of a complete electrical model for all of its regions. Although some paper-based files, Microsoft Access databases, Microsoft Excel spreadsheets, and AutoCAD drawings pertaining to MA still exist, CNPI makes every effort practicable to manage information in the asset management database.

CNPI's GIS is the corporate data repository supporting outage management, engineering analysis, and field based data capture systems.

4.4 Overhead Distribution Managed Assets

The following is a listing and brief description of each type of Managed Asset (MA) at CNPI:

4.4.1 Poles

Constructed of wood, steel, and occasionally concrete or resin composites, these form the 'backbone' of the overhead distribution system. Wooden poles are used in over 90 percent of all cases.

For distribution purposes, these range in height from 25' (7.6m) to 75' (22.8m). A typical height for a single-circuit three-phase pole is 45' (13.7m).

Poles come in several standard 'strengths' known as classes, as defined by CSA specifications.

4.4.2 Framing Assemblies

This MA is the assorted hardware components installed on a pole that provide mechanical support and clearances, and electrical isolation / insulation for the various conductors and equipment required on an overhead distribution line.

It can include cross arms, insulators, brackets, bolts, washers, nuts, and sundry other hardware. Note that Framing Assemblies will include guying and anchors as required.

It should be noted that the specific choice of some of these components, such as insulators, will vary depending on the required voltage of the system.

4.4.3 Transformers and Voltage Regulators (Pole Top)

Used to transform electricity from one voltage to another. Typically, this will be from a primary voltage (such as 16,000V) to a secondary voltage (such as 120/240V) useful to one or more customers.

These aerial devices can be found in a variety of sizes, ranging from 3kVA to 333kVA.

Most distribution transformers change a high-voltage primary voltage (2400V or greater) to one of CNPI's three standard secondary voltages:

(1) 120/240V single phase

(2) 120/208V three phase

(3) 347/600V three phase

Some specialized units, known as step-downs or ratio banks (otherwise known as 'rabbits'), provide a smaller, yet still primary, voltage, and are generally used to supply a small portion of CNPI's existing system that still requires a legacy voltage.

Voltage regulators are a form of transformer that automatically maintains line voltages within a narrow specified range and allows CNPI to maintain CSA standard voltages on long feeders or feeders with larger than typical loads.

4.4.4 Overhead Switches

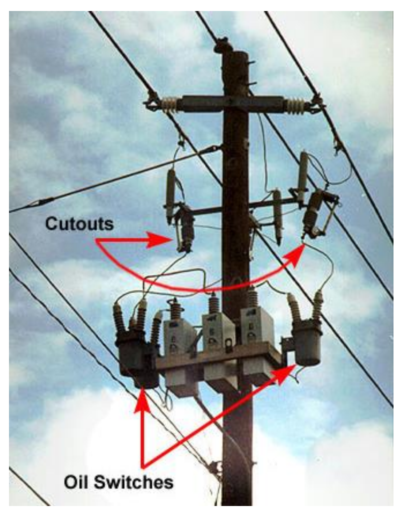
This type of MA, as the name implies, allows for opening and closing of current-carrying components, which either prevents or allows the flow of electricity. Switches can have different characteristics:

(1) Gang-operated or single-phase operated: A gang-operated switch, generally a three-phase device, allows all three phases of the switch to be opened or closed at once, often from the ground.

(2) Load-break or Non-load-break: A Load-break switch allows for the interruption of power flow even when a significant amount of current is flowing.

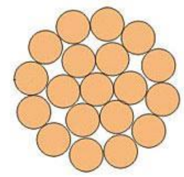
(3) Remote-controlled or locally operated

(4) Dielectric: the medium used by the switch to interrupt or insulate can vary. Most use air (such as the 'Cutouts' in the picture), while others use oil, vacuum, or SF_6.



4.4.5 Overhead Conductor

Conductors, also called wires, or cables run from pole to pole, or pole to building, and carry the current from the source to the customers. Overhead conductor has several different characteristics:



(1) Metal or alloy: older conductors were mostly copper, but most modern applications use aluminum, or aluminum alloys to save weight and cost

(2) Size / Gauge: the size of the wire is matched to the expected maximum current required. Larger conductors cost more, weigh more, and can take longer to install, but carry more current ('higher ampacity') and can have longer useful lives

(3) Insulation: some conductors have one or more layers of insulation on them, if they are bundled together or are installed in a location where they can be expected to be contacted by vegetation or the public. The bundled cable shown at right has two insulated and one bare conductor, and is used for supplying a typical 'house service'. Most primary / high voltage conductors are bare, as this saves costs and weight.

(4) Single or Bundled: At lower voltages, to save space and add strength, more than one conductor may be twisted or lashed into a 'bundle'. This is most common for secondary or service wires.

4.4.6 Protective and System Devices

Aggregated into this MA group are:

(1) reclosers (a type of aerial circuit breaker),

(2) capacitors, of two types:

  (i) Fixed (always 'on')

  (ii) Switches (only 'on' under specific conditions)

(3) current sensors

(4) voltage sensors

(5) primary (pole-mounted) instrument transformers

4.5 Underground Distribution Managed Assets

4.5.1 Pad-mounted Transformers

Used to transform electricity from one voltage to another in surface-mount applications. These devices range in sizes from 50kVA to 100kVA in residential subdivisions and from 75kVA to 1000kVA in commercial installations.

This type of transformer incorporates integral protection elements typically consisting of a bay-o-net style fuse with a partial range current limiting back up fuse. The transformer also typically incorporates primary winding and bushing isolation switches.

4.5.2 Switchgear

Pad-mounted switchgear are used in underground applications to provide a point of switching and or circuit protection. The installations contain provisions for terminal connection of up to four sets of cables.

Each of the four terminal connection points or “ways” can incorporate either a load break disconnecting switch or a protection element (power fuse or interrupter).

Electrical insulation within the switchgear enclosure is achieved by air or SF6 gas.

4.5.3 Civil Structures

This MA group consists of:

(1) Foundations / Pads

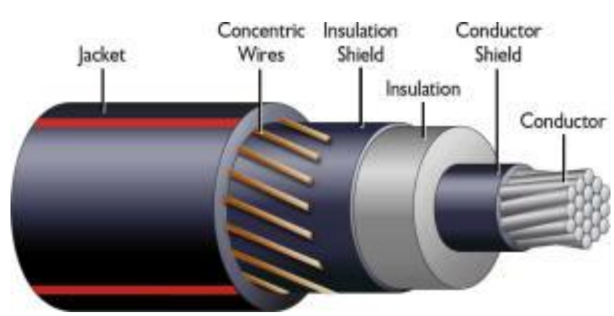
(2) Manholes

(3) Vaults

(4) Conduit

4.5.4 Cable

4.5.4.1 Primary Cable



Primary cables are typically installed for feeder cable exits in substations, and commercial or residential subdivisions with underground servicing. These cables are built to CSA Standard C68.5 and consist of a copper or aluminum phase conductor with a copper stranded concentric neutral conductor.

Sizes of conductor range from 1/0 to 1000 kcmil. Modern cables are typically insulated with cross linked polyethylene (XLPE) with a linear low-density polyethylene (LLDPE) jacket.

4.5.4.2 Secondary Cable

Secondary cables are used to supply low voltage (<=600V) to customers from a distribution transformer. These cables typically range in size from #6 to 1250 kcmil and can be aluminum or copper.

The conductors can be directly buried or installed in conduit. They can also be bundled to save space and simply the installation methodology.

4.6 Substation Managed Assets

4.6.1 Power Transformers

Power transformers installed in distribution substations are used to transform electricity from a higher primary voltage (such as 34.5kV) to a lower primary voltage (such as 8.32kV).

These devices range in size from 2MVA to 33MVA within CNPI's substations. The transformers are oil filled for electrical insulation and cooling purposes.

Conductor terminal connections are established with either overhead exposed conductor, underground cable in an enclosed compartment or a combination of both.

Integral to the power transformer are components such as insulated bushings, cooling systems, gauges, tap changing equipment, etc. that require routine inspection and maintenance.

4.6.2 Protection Elements

4.6.2.1 Breakers

Many of CNPI's distribution station assets and feeders are protected by relay controlled circuit breakers. Circuit breakers are rated from 5kV to 35.4kV and are situated in switchgear or outdoor structures.

Breakers are designed to clear overcurrent, differential, and distance faults with response times ranging from three to eight cycles. Breakers are insulated with either air, oil, or SF6.

Isolation devices are typically installed to permit these devices to be removed from service for maintenance or replacement.

4.6.2.2 Reclosers

Solid dielectric three phase reclosers have been introduced into many of CNPI's newer distribution stations to provide transformer and feeder protection. These devices incorporate vacuum interrupters with a limited maintenance requirement.

The devices are designed for applications at 4.16kV through to 34.5kV and have continuous current carrying capability in excess of 600A. These devices are relay controlled and can be supplied form DC station service systems. Fault response times are typically in the range of five to eight cycles.

Reclosers can be pole or structure mounted and are also available in a pad-mounted configuration.

4.6.3 Switchgear

Substation metal-clad switchgear located in CNPI's DS locations typically contains multiple cells (or compartments) which house protection elements such as breakers or fuses. The cells may also contain instrument transformers for metering or relaying requirements.

Protection elements incorporated into DS switchgear are for the purposes of feeder, bus, or transformer protection.

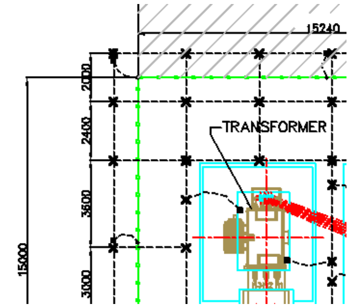
Metal-clad switchgear can be located in an indoor building or an outdoor environment.

4.6.4 Structures

Distribution substations can utilize structure mounted, outdoor rated equipment. Structures typically consist of steel or concrete materials and are fabricated based on the dimensional, weight, and clearance requirements of the equipment that must be supported.

Structures must be bonding to the substation grounding system. The deployment of these structures must be such that equipment access for maintenance or replacement purposes can be maintained while minimizing operational constraints.

4.6.5 Grounding Systems



Grounding systems are required to maintain safe touch and step potentials as required by the Ontario Electrical Safety Code. These systems typically incorporate a conductive ground grid consisting of copper conductor and electrodes. Metallic components such as fencing, structures, and equipment are bonded to this grid to minimize touch potential hazards under fault conditions.

4.6.6 SCADA and Communications Equipment

CNPI leverages a mature Supervisory Control and Data Acquisition (SCADA) system which provides monitoring of CNPI's substation elements and field automation devices. The SCADA system uses communication mediums such as leased telephone line, spread spectrum radio, and fiber optics for connectivity with endpoint devices. The SCADA system is integral to CNPI operations and provides real time access and control of critical infrastructure improving response and restoration times. Endpoint deployment continues as part of CNPI's distribution automation program in order to mitigate feeder performance issues.

4.7 Revenue Metering

This item includes

(1) revenue meters that measure, store and report electricity usage

(2) instrument transformers

(iii) current transformers (CTs)

(iv) potential or voltage transformers (PTs)

(3) any communications or data aggregation equipment owned by CNPI used to facilitate the revenue metering process (collectors, antennae, etc)

4.8 Fleet Assets

CNPI operates a variety of vehicles including passenger vehicles, bucket trucks, and digger derricks. Currently CNPI has a fleet of 53 vehicles that range in age from 1999 to 2015.

Generally, CNPI maintains its fleet of vehicles in accordance with manufacturer's guidelines.

CNPI considers a number of condition factors to determine a schedule for replacement of vehicles which include but not limited to:

- Vehicle age
- Mileage
- Engine hours
- Power Take Off (PTO) hours
- Chassis condition
- Body condition
- Boom condition
- Technical assessment

4.9 Tools and Test Equipment

CNPI owns and maintains a variety of tools and test equipment required to efficiently operate a distribution system.

These assets are generally tracked as individual items, with regular assessments of their operability and condition. Typically, these assessments are performed prior to each use.

In the event that a tool or test equipment is not in adequate condition, it is removed from service immediately. It is then repaired or replaced, as may be appropriate.

CNPI budgets for and purchases such tools each year in a planned program to update obsolescent items as well as deal with unexpected breakages.

4.10 CNPI Owned Properties and Leasehold Improvements

CNPI owns and maintains buildings within its service territories. Building assessments have been conducted to establish life expectancy and aid in asset management. CNPI has also completed a number of leasehold improvements including the construction of additional office space to accommodate current staffing levels as a result of the consolidation of the Port Colborne and Fort Erie service centers.

In an effort to minimize operating expenses, CNPI actively pursues any reasonable opportunity to sell unused property and lands. CNPI also owns a number of lands including decommissioned substation properties and Rights-Of-Ways.

Ongoing, regularly scheduled inspection and monitoring is conducted on both CNPI owned properties and lands. These inspections and monitoring activities occur in accordance with operating system inspection programs, vegetation management program and any Health, Safety and Environment management system obligations.

5 Inspection and Maintenance Programs

5.1 Inspection and Maintenance (General)

Expenditures on inspection and maintenance programs are an integral aspect of any Asset Management program and good utility practice. Effectively maintaining existing line and substation equipment is necessary to keep equipment in good working condition, maximize equipment lifespan, and improve reliability by reducing the probability of failure. Maintenance programs optimize the value of capital investments. Maintaining equipment in proper working condition reduces the probability of equipment failure, enhances safety and increases reliability of supply to customers.

Maintenance activities at CNPI are performed with a combination of internal personnel and qualified outside contractors and consultants.

Maintenance activities can be subdivided into <u>four basic categories</u>:

5.1.1 Predictive Maintenance:

This is the identification of equipment deficiencies that may lead to failure. Examples of predictive maintenance activities are visual inspections, equipment testing, and substation transformer dissolved gas analysis. Thorough inspections are the chief mechanism used at CNPI for predictive maintenance, although other methodologies are used, such as pole condition testing.

5.1.2 Corrective Maintenance:

This is the repair equipment as a result of deficiencies identified through visual inspections or testing.

5.1.3 Preventive Maintenance:

The routine servicing or repair of equipment on a regular schedule to ensure that equipment remains in good working condition. Maintenance is undertaken at specific time intervals and is applied regardless of equipment condition. Examples of preventive maintenance activities are load-break switch maintenance, protective device maintenance, and substation equipment maintenance.

5.1.4 Certification Maintenance

Certain assets require periodic certification or re-certification. This generally involves testing, calibration, and documentation (such as a ‘seal’ or ‘sticker’) by a third-party accredited or industry-accepted expert group. Examples of managed assets requiring certification:

(1) revenue meters and instrument transformers (residential, commercial / industrial, and bulk)

(2) Insulated booms on Bucket Trucks

(3) Working grounds used by power line workers

5.2 Line Maintenance Activities (General)

CNPI establishes its various maintenance cycles to achieve a number of objectives:

(1) Maintenance cycles for inspections will meet or exceed the minimum regulatory requirements.

(2) Critical assets may be inspected more frequently and may make use of more sophisticated inspection methods (e.g. thermographic scans at substations).

(3) Preventive maintenance activities are scheduled on cycles that attempt to optimize the life-cycle costs of equipment considering manufacturer's recommendations, good utility practice as well as CNPI past experience.

(4) To the extent possible, scheduling of preventive maintenance activities on cycles greater than one year will be scheduled with a goal of levelling the amount of work assigned to each service centre from year-to-year. This ensures adequate resource availability to complete the planned program and minimizes travel costs associated with crews traveling between service centers.

The three major types of maintenance activity are described as follows:

5.2.1 Predictive Maintenance

5.2.1.1 Visual Inspections

Predictive maintenance on overhead and underground distribution systems in the CNPI service area generally takes the form of visual inspections. Most overhead and underground line components are normally inspected on a 3-year or 6-year cycle. This conforms to the inspection cycles laid out in the OEB Distribution System Code, Appendix C, *and Minimum Inspection Requirements*.

All overhead and underground lines scheduled to be inspected during that year are patrolled and detailed inspections carried out on all major equipment. This includes poles, cross-arms, guy wires, transformers (overhead and pad-mounted), conductors and cables, insulators, arrestors, bushings, terminations, switching devices (fused cut-outs, load-break and disconnect switches, live-line openers, etc). Civil facilities, such as transformer pads and cable chambers, are also inspected.

The results of these inspections and any identified deficiencies are documented for follow-up and are archived. Deficiencies are assessed on the basis of the potential for failure and consequential impact on safety or reliability. They are then prioritized for corrective action as follows:

(1) Major deficiencies, where repair or replacement is required to address a pending failure or safety hazard. Examples of major deficiencies would be broken poles and cross-arms.

(2) Minor deficiencies, where the deficiency is of a nature where action can be deferred for a time. An example would be a blown lightning arrestor. Repairs to less critical deficiencies are typically planned so that a group of deficiencies within a given area can be addressed by a single crew in a short timeframe to achieve operational efficiency.

Visual inspections are conducted following the requirements of CNPI's Distribution System Inspection Program (DSIP), implemented in 2007. The DSIP outlines the specific manner in which the distribution system inspection is performed. The DSIP can be found in Appendix G.

A sample of a line inspection document may be found in Appendix C1.

5.2.1.2 Inspections using Specialized equipment

In addition to the cycle inspections described above, various line components are inspected using specialized equipment, with any deficiencies being noted and prioritized for correction. Thermographic scans of substations and critical distribution line components are also conducted regularly. The 2015 thermographic scan inspection report is included in Appendix H. Deficiencies observed outside of scheduled line patrols are also recorded and corrected.

In 2011, CNPI performed a detailed, non-destructive random testing on approximately 11% of its pole population. The result of this testing provided CNPI with the condition of poles tested, the pole strength, and the expected remaining life of the pole population. The main objective of this program was to identify the overall condition of CNPI's pole population. CNPI has changed many of the deficient, higher priority poles over the last few years.

In 2016, CNPI is implementing a Detailed Pole Inspection and Testing Program. All poles owned by CNPI and older than 15 years will be tested. This program will form part of the foundation for line rebuilds and pole replacement programs over a number of years. CNPI is estimating that it will take approximately six years to analyze the entire pole population based on alignment to existing distribution inspection area boundaries.

This inspection program will commence in 2016 for Zone 1 in the Fort Erie area. This area covers the Fort Erie delta conversion area, North of the QEW, and a portion of the conversion area South of the QEW. CNPI will leverage this data to confirm the line sections targeted for rebuild and refurbishment as part of the Fort Erie delta conversion program.

5.2.2 Corrective Maintenance

Any deficiencies identified during or outside of scheduled inspections are recorded and prioritized as described above. Repairs or replacements are carried out accordingly and completion is tracked through the corporate work management systems.

Sample records of line correction maintenance forms may be found in Appendices C2 and C3.

Often, corrective maintenance is performed on an ad-hoc basic, as problems are identified by employees or members of the public on an ongoing basis. Some of these problems result in an unplanned (forced) outage /service interruption.

Sample forms used to document these ad-hoc maintenance activities may be found in Appendixes C5, C6, and D2.

5.2.3 Preventive Maintenance

Four major preventive maintenance activities are conducted on distribution lines and equipment:

5.2.3.1 Vegetation Management

CNPI's Integrated Vegetation Management Program has been developed to align with its Health Safety and Environmental Management System (HSEMS) consistent with ISO 14001 standard, OHSA 18001 standard, the North American Electric Reliability Corporation (NERC) Compliance Program, American National Standards Institute (ANSI) A300 - Standard Practices for Trees, Shrubs and other Woody Plant Maintenance, the Electrical Safety Authority (ESA) Guidelines for Tree Trimming Around Power Lines and Planting Under or Around Power Lines and Electrical Equipment. These management systems, standards and guidelines provide the framework for ensuring adequate processes such as governance and oversight.

CNPI performs its vegetation management in the following manner:

(1) 3-year periodic limb and branch removal or trimming along the entire overhead distribution system.

(2) Spot trimming or branch removal in any specific areas where faster-than-typical growth has occurred or one or more damaged branches have entered the minimum clearance zone from outside the vegetation control space.

The sample maps on the following pages graphically represents the specific areas of CNPI's systems that are trimmed in each annual program. In 2015, CNPI trimmed "Zone 3", with "Zone 1" scheduled for 2016, and "Zone 2" most recently completed in 2014, and scheduled to be completed again in 2017:

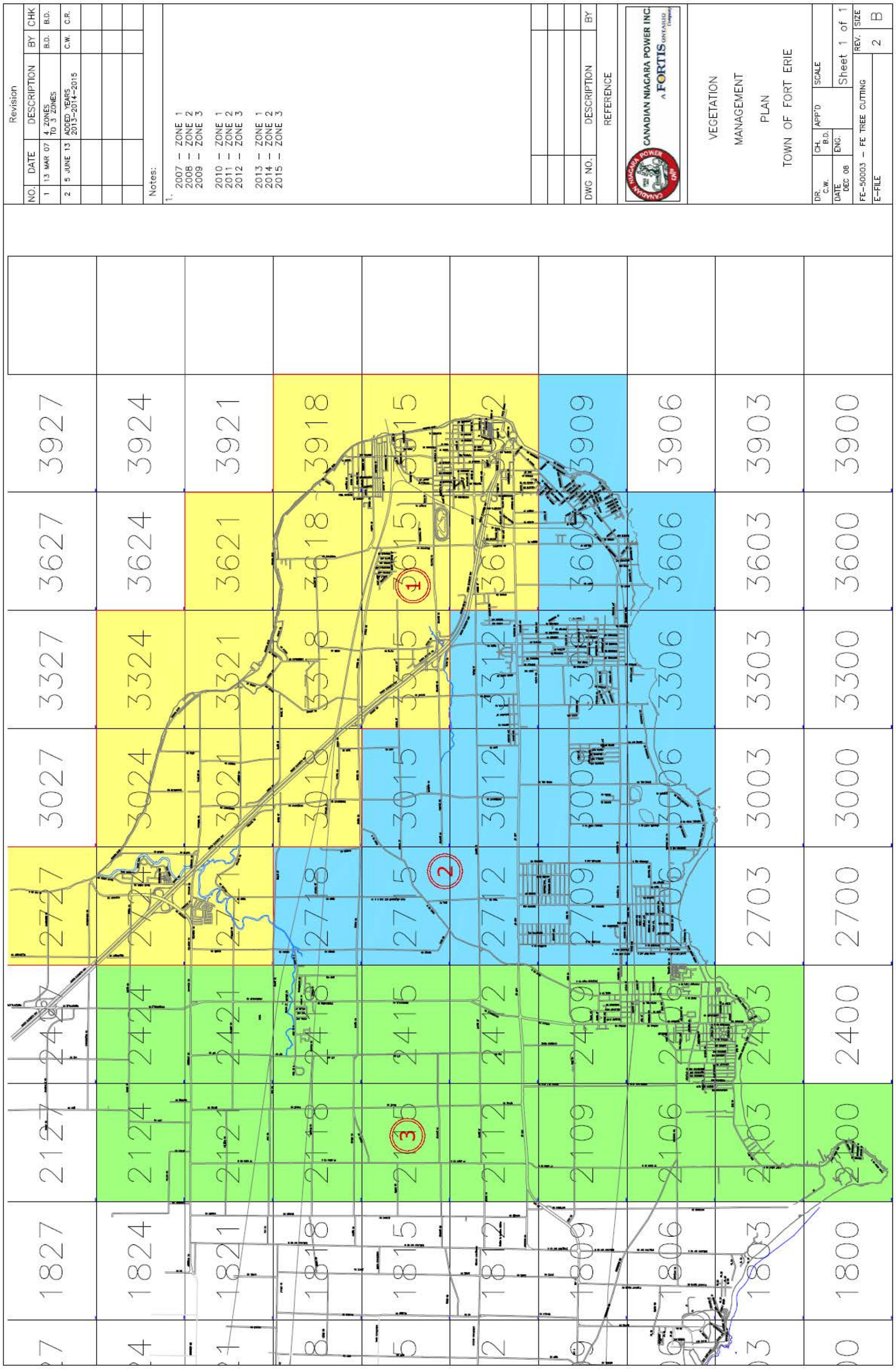


Figure 23: Vegetation Management Zones Fort Erie

The trimming is generally performed by an outside contractor, who must certify completion and no undue hazards on each portion of their work. A CNPI inspector then verifies the work completed.

Sample work complete and inspected document:

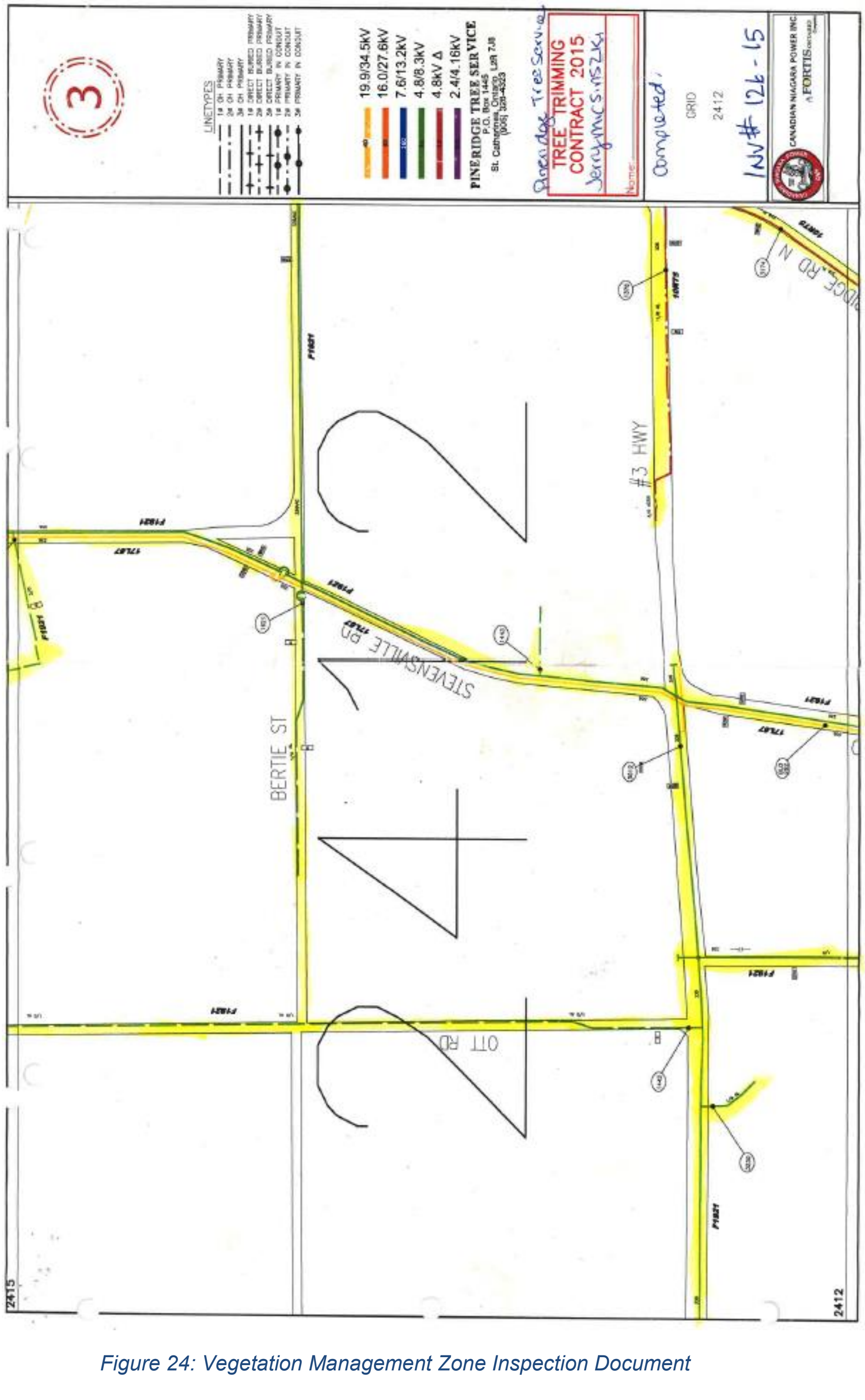


Figure 24: Vegetation Management Zone Inspection Document

In areas that are rural in nature, or areas where CNPI-owned distribution lines do not lay on the edge of a municipal right-of-way, the approach is generally to clear-cut a corridor near line assets to allow for longer periods between vegetation control efforts (referred to as "Grubbing"). This is more cost-effective in the long run. The 2016 area covered in Zone 1 is include in Appendix L.

5.2.3.2 Emerald Ash Borer (EAB)

Based on the results of a third party EAB impact assessment, CNPI has developed an EAB program. The program is designed to manage burdens associated with the invasive emerald ash borer species impacting the ash tree population within CNPI's service territory. The program is focused on sustaining service reliability by proactively eliminating risks associated with this infestation.

Mitigation strategies include:

(1) Removal of infested trees on CNPI owned land

(2) Assisting Stakeholders:

- Creation of electrically safe work zones
- Additional ash tree trimming in support of require clearances for the purpose of removal

(3) Asset repairs as a result of ash tree failure

A copy of the EAB Impact Assessment Report can be found in Appendix M.

5.2.3.3 Switch Maintenance

CNPI maintains switches located in its substations and on its sub-transmission feeders on a 3-year cycle. This minimizes the likelihood of widespread outages due to switch failure and ensures that switches will operate reliably in the event of planned or forced outages elsewhere on the system. Switch maintenance includes the following main activities:

(1) Visual inspection of switch components, such as contacts, insulators and arc horns, to identify any broken or deteriorated parts and evidence of surface tracking or corrosion.

(2) Opening and closing switches to verify proper and efficient operation of blades and gang-operating mechanisms, where applicable.

(3) Cleaning and lubrication of electrical connections and moving parts.

(4) Replacement of worn components, or the entire switch if necessary.

5.2.3.4 Protective Device and Voltage Regulator Maintenance

CNPI performs routine maintenance of its Reclosers, Sectionalizers and Voltage Regulators. Maintenance activities are typically performed on a six-year cycle (or based on manufacturer's recommendation cycle, if more frequent), and include the following main activities:

(1) Determination of number of operations since date of last maintenance to verify that existing maintenance intervals are adequate.

(2) Visual inspection of tanks, bushings, contacts, operating mechanisms, control boxes, etc. to identify any broken or deteriorated parts and evidence of surface tracking or corrosion.

(3) Testing of operations, both manually and using electrical test equipment to ensure proper operation.

(4) Electrical testing (ratio, resistance, etc.) to verify electrical integrity of device and all components.

The results of any tests performed are documented on equipment test forms and kept on file for trending and comparison purposes.

5.3 Distribution Substation Maintenance Activities (General)

5.3.1 Predictive Maintenance

Predictive substation maintenance is integral to maintaining reliability and detecting potential equipment failure. Since substation equipment typically requires large investments for installation and since failure of substation components can affect large numbers of customers, detecting potential failures before they occur is very important. There are presently three key predictive maintenance activities conducted in CNPI substations:

5.3.1.1 Visual Inspections

Visual Inspections are essential for assessing the condition of substation components and identifying deterioration or areas where attention is required. The OEB Distribution System Code provides for different inspection intervals for substations based on various criteria and location.

(1) CNPI conducts detailed inspections on each of its rural distribution substations at least once every 6 months.

(2) CNPI conducts detailed inspections on each of its urban distribution substations every month.

Substation buildings, fences, and electrical components (bus-work, switches, insulators, batteries, transformers, ground conductors, etc.) are inspected and any deficiencies recorded. In addition, data such as relay targets, breaker counters, direct current system voltage, and power transformer gauge readings are recorded. The condition of ancillary equipment such as lighting, eyewash stations, first-aid kits, and oil spill kits is also inspected.

CNPI also performs monthly inspections of its oil containment facilities. During these monthly inspections of oil containment, the remainder of the substation is visually inspected at a high level and deficiencies requiring immediate correction are identified.

Any deficiencies noted during inspections are recorded, reported, and are then prioritized for corrective action.

Samples of inspections may be found in Appendices B1, B2, and B3.

5.3.1.2 Transformer Dissolved Gas Analysis

Dissolved Gas Analysis (DGA) is an effective tool for assessing the condition of power transformers and identifying deterioration in transformer oil or insulation. DGA can also identify whether arcing or acid build up is occurring inside the transformer. DGA tests for the presence of dissolved gas and water in transformer insulating oil, and based on the level of gas(es) or moisture present, assess the condition of the transformer. An important aspect of DGA is the trend analysis, which reviews the history of dissolved gas levels in the transformer.

DGA is scheduled regularly on all power transformers and in CNPI substations, whether in-service or spare. CNPI uses a qualified contractor to perform the analysis, provide reports on transformer condition, and recommend any required actions if gassing is above normal levels or if acids are detected. Corrective action to deal with abnormalities is essential to prevent failure and extend the life of the transformer.

A sample DGA analysis may be found in Appendix B4.

5.3.1.3 Thermographic Scanning

Thermographic (infra-red) scanning is scheduled annually for all distribution substations. Thermography captures the temperature of components compared to surrounding equipment and ambient temperature, and high relative temperatures can be indicative of overloaded or deteriorated components.

5.3.2 Corrective Maintenance

Corrective maintenance is a reactive activity that takes place when deficiencies in substation components are identified. Defective components are prioritized for repair or replacement on the basis of the severity of the condition, the criticality of the equipment, and the potential impact of failure on safety or service reliability.

5.3.3 Preventive Maintenance

Preventive maintenance on substation components is conducted on a regularly scheduled basis and is integral to keeping equipment in good working condition. Substation components typically undergo preventive maintenance on a 6-year cycle, including inspecting, cleaning, lubricating, and testing. The following major activities are included in this program:

(1) Transformers (power and instrument) – inspection and cleaning, DGA, Doble testing, oil refurbishment as required, inspection and cleaning of gauges, access ways, bushings, and connections.

(2) Breaker / Recloser / Circuit Switcher maintenance – inspection, cleaning of bushings, connections, contacts and moving parts, contact resistance and insulation testing.

(3) Switch maintenance – inspection and cleaning of bushings, connections, contacts, arc horns, and operating mechanisms, insulation testing.

(4) Relays and SCADA systems – testing to ensure appropriate response, and recalibration of electronic and electromechanical relays as required.

(5) Oil renewal – replacing insulating oil in power transformers and oil-insulated circuit breakers and potential transformers as needed ensuring insulating oil is clear of contaminants.

(6) Accessories – other equipment such as motor operators and heating elements are inspected, cleaned, and maintained.

5.4 Substation Equipment Maintenance Methodologies (Type-Specific)

5.4.1 Predictive Maintenance:

5.4.1.1 Overhead Switches

Types LLO, LLC, MSO, JX, JXU

(1) Inspect the insulators for breaks, cracks, burns, or cement deterioration. If necessary clean the insulators particularly where abnormal conditions such as salt deposits, cement dust, or acid fumes exist. This is important to minimize the possibility of flashover as a result of the accumulation of foreign substances on the insulator surfaces.

(2) Inspect all live parts for scarring, gouging, or sharp points that could contribute to excessive radio noise and corona.

(3) Check for JX and JXU cut-outs check for damaged fuses and replace if necessary

(4) Scan the switch with an infrared scanner to check for further defects

5.4.1.2 Underground Switches and Junction Units

(1) Scan the switch with an infrared scanner to check for defects.

5.4.1.3 Surge Arrestors

(1) Check for cracked, contaminated, or broken porcelain; loose connections to line or ground terminals; and corrosion on the cap or base.

(2) Check for pitted or blackened exhaust parts or other evidence of pressure relief.

5.4.1.4 Buses and Shield Wire

(1) Inspect bus supports for damaged porcelain and loose bolts, clamps, or connections.

(2) Observe the condition of flexible buses and shield wires.

(3) Inspect suspension insulators for damaged porcelain (include line entrances).

5.4.1.5 Structures

(1) Inspect all structures for loose or missing bolts and nuts.

(2) Observe any damaged paint for galvanizing or signs of corrosion.

(3) Inspect for deterioration, buckling, and cracking.

5.4.1.6 Grounding System

(1) Check all above-grade ground connections at equipment, structures, fences, etc.

(2) Observe the condition of any flexible braid type connections.

5.4.1.7 Control and Metering Equipment

(1) Check current and potential transformers for damage to cases, bushings, terminals, and fuses.

(2) Verify the integrity of the connections, both primary and secondary.

(3) Observe the condition of control, transfer, and other switch contacts; indicating lamps; test blocks; and other devices located in or on control cabinets, panels, switchgear, etc. Look for signs of condensation in these locations.

(4) Examine meters and instruments externally to check for loose connections and damage to cases and covers. Note whether the instruments are reading or registering.

(5) Open and close each potential switch on the test block to determine whether the speed of the meter disk is affected. Repeat the process with the current switches. Changes of speed should be approximately the same for each meter element.

(6) Check the status of relay targets (where applicable).

(7) Make an external examination of relays, looking for damaged cases and covers or loose connections.

(8) Check the station battery for loose connections and battery cells for low level or low specific gravity of the electrolyte. Record the electrolyte temperature.

(9) Inspect the station battery charger. Check the charging current and voltage. Observe the ground detector lamps for an indication of an undesirable ground on the dc system.

(10) Check the annunciator panel lights.

5.4.1.8 Metal-Clad Switchgear

(1) Inspect for damage to enclosures, doors, latching mechanisms, etc.

(2) Inspect bus supports for signs of cracking.

(3) Verify that all joints are tight.

(4) Check the alignment of all disconnect devices, both primary and secondary, including those for potential transformers.

(5) Inspect terminal connections and the condition of wiring.

(6) Check rails, guides, rollers, and the shutter mechanism.

(7) Inspect cell interlocks, cell switches, and auxiliary contacts.

(8) Inspect control, instrument, and transfer switches.

(9) Inspect for broken instrument and relay cases, cover glass, etc, and check for burned-out indicating lamps.

5.4.1.9 Cables

(1) Inspect exposed sections of cable for physical damage.

(2) Inspect the insulation or jacket for signs of deterioration.

(3) Check for cable displacement or movement.

(4) Check for loose connections.

(5) Inspect shield grounding (where applicable), cable support, and termination.

5.4.1.10 Foundations

(1) Inspect for signs of settlement, cracks, spalling, honeycombing, exposed reinforcing steel, and anchor bolt corrosion.

5.4.1.11 Substation Area-General

(1) Verify the existence of appropriate danger and informational warning signs.

(2) Check indoor and outdoor lighting systems for burned-out lamps or other component failures.

(3) Verify that there is an adequate supply of spare parts and fuses.

(4) Observe the condition of hook sticks.

(5) Inspect the fire protection system and the provisions for drainage in the event of leaking oil.

(6) Check for bird nests or other foreign materials in the vicinity of energized equipment, buses, or fans.

(7) Observe the general condition of the substation yard, noting the overall cleanliness and the existence of low spots that may have developed.

(8) Observe the position of all circuit breakers in the auxiliary power system and verify the correctness of this position.

(9) Inspect the area for weed growth, trash, and unauthorized equipment storage.

5.4.1.12 Substation Fence

(1) Check for minimal gap under the fence or under the gate. Ensure that all gaps are less than 50mm at any point under the fence and less than 100mm at any point under the gate.

(2) Ensure the fence fabric is intact and there is no rust.

(3) Check that the barbed wire is taut.

(4) Ensure the gate latches are operable.

(5) Ensure flexible braid-type connections are intact.

(6) Verify that no wire fences are tied directly to the substation fence.

5.4.2 Preventive Maintenance Methodologies

5.4.2.1 Blade (BLD) or Inline Switches (Non-Gang Operated)

(1) Open /Close the switch several times, periodic operation of the switch is recommended as this ensures the hinge pivot point is operating smoothly and helps clean any oxide from the jaw contacts, which may have formed since the last maintenance.

(2) Check for simultaneous closing of all blades and for proper seating in the closed position.

(3) Check the switch for alignment, contact pressure, eroded contacts, corrosion, and mechanical malfunction.

(4) Inspect the insulators for breaks, cracks, burns, or cement deterioration. If necessary clean the insulators particularly where abnormal conditions such as salt deposits, cement dust, or acid fumes exist. This is important to minimize the possibility of flashover as a result of the accumulation of foreign substances on the insulator surfaces.

(5) Inspect all live parts for scarring, gouging, or sharp points that could contribute to excessive radio noise and corona.

(6) If the switch blade has been left open for an extended period of time, if necessary the jaw and blade contacts should be wiped clean of any dirt particles to ensure that there will be no plating damage to the contacts and that they will properly mate. If necessary Thinners or Acetone may be used to clean the contacts and if the contacts are heavily coated use a fine Scotch-Brite® pad.

(7) For FIRON inline switches read the attached maintenance recommendations for further maintenance instructions.

(8) Scan the switch with an infrared scanner to check for further defects

(9) In addition to the above perform the switch maintenance that is specified in the CNPI maintenance report

5.4.2.2 Gang-Operated Switches

(1) The switch should be disconnected from all electric power sources before servicing.

(2) Ground leads or their equivalent should be attached to both sides of the switch, Local and applicable OSHA regulations should be followed.

(3) Inspect the insulators for breaks, cracks, burns, or cement deterioration. Clean the insulators particularly where abnormal conditions such as salt deposits, cement dust, or acid fumes exist. This is important to minimize the possibility of flashover as a result of the accumulation of foreign substances on the insulator surfaces.

Check the switch for alignment, contact pressure, eroded contacts, corrosion, and mechanical malfunction. Replace damaged or badly eroded components. If contact pitting is of a minor nature, smooth the surface with clean, fine sandpaper (not emery) or as the manufacturer recommends. If recommended by the manufacturer, lubricate the contacts.

(4) Inspect arcing horns for signs of excessive arc damage and replace if necessary.

(5) For all S&C Alduti-Rupter switches perform the outlined continuity check and additional maintenance as out lined in the Alduti-Rupter Switch, General-Maintenance Outline.

(6) Check the blade lock or latch for adjustment.

(7) Inspect all live parts for scarring, gouging, or sharp points that could contribute to excessive radio noise and corona. Check corona balls and rings for damage that could impair their effectiveness.

(8) Inspect inter phase linkages, operating rods, levers, bearings, etc., to assure that adjustments are correct, all joints are tight, and pipes are not bent. Clean and lubricate the switch parts only when recommended by the manufacturer. Check for simultaneous closing of all blades and for proper seating in the closed position. Check gear boxes for moisture that could cause damage due to corrosion or ice formation. Inspect the flexible braids or slip-ring contacts used for grounding the operating handle. Replace braids showing signs of corrosion, wear, or having broken strands.

(9) Power-operating mechanisms for switches are usually of the motor-driven, spring, hydraulic, or pneumatic type. The particular manufacturer's instructions for each mechanism should be followed. Check the limit switch adjustment and associated relay equipment for poor contacts, burned out coils, adequacy of supply voltage, and any other conditions that might prevent the proper functioning of the complete switch assembly.

(10) Inspect overall switch and working condition of operating mechanism. Check that the bolts, nuts, washers, cotter pins, and terminal connectors are in place and in good condition. Replace items showing excessive wear or corrosion. Inspect all bus cable connections for signs of overheating or looseness.

(11) Inspect and check all safety interlocks while testing for proper operation.

5.4.2.3 Oil Circuit Breakers

(1) Check compressor operation, including operation of all pneumatic switches and their operating set point.

(2) Check for air leaks.

(3) Check the compressor belts.

(4) Check the latching mechanisms, relay contacts, and fuse clips (for secureness).

(5) Check pole units, contacts, bayonets, interrupters, and resistors for signs of heating.

(6) Inspect the hardware and wiring connections for Current Transformers (CTs).

(7) Inspect the alignment of contacts.

(8) Inspect the operating mechanism and leakage.

(9) Inspect the lift rod and toggle assembly.

(10) Check for loose, contaminated, or damaged bushings; loose terminals; oil leaks; and proper gas pressures.

(11) Check the oil level in bushings and the main tank (if applicable).

(12) Check the anti-condensation heaters.

(13) Read and record the number of operations indicated. If the breaker has not operated during the preceding year, bypass the breaker or otherwise take it out of the circuit for testing.

(14) Inspect contact areas on the main plug-in assembly for signs of overheating or arcing.

(15) Read and record compressor operating hours as shown on the indicator.

(16) In addition to the above perform the oil breaker maintenance that is specified in the CNPI maintenance report

5.4.2.4 Air Blast and SF6 Circuit Breakers

(1) Check compressor operation, including operation of all pneumatic switches and their operating set point.

(2) Check for air leaks.

(3) Check the compressor belts.

(4) Check the latching mechanisms, relay contacts, and fuse clips (for secureness).

(5) Check pole units, contacts, bayonets, interrupters, and resistors for signs of heating.

(6) Inspect the hardware and wiring connections for CTs.

(7) Inspect the alignment of contacts.

(8) Inspect the operating mechanism and leakage.

(9) Inspect the lift rod and toggle assembly.

(10) Inspect the compressor system, including belts, pneumatic switches, contactors, relays, and other auxiliary devices.

(11) Inspect the gas or air piping for signs of deterioration.

(12) Inspect all air or gas seals and o-rings.

(13) Check for loose, contaminated, or damaged bushings; loose terminals and proper gas pressures.

(14) Check the anti-condensation heaters.

(15) Read and record the number of operations indicated. If the breaker has not operated during the preceding year, bypass the breaker or otherwise take it out of the circuit for testing.

(16) Inspect contact areas on the main plug-in assembly for signs of overheating or arcing.

(17) Read and record compressor operating hours as shown on the indicator.

SF6 gas used in circuit breakers is subject to contamination as a result of the products released during the interruption of current. This contamination increases with the severity of the fault and with the deterioration of the breaker contacts. Specific tests are not normally performed since the gas should be reconditioned on a regular basis in accordance with the manufacturer's recommendation.

5.4.2.5 Air Circuit Breakers

(1) Inspect contacts for visual signs of overheating. Check contact clearance, contact wipe, toggles, latches, position indicator, auxiliary contacts, etc.

(2) Inspect hardware and check wire connections for secureness.

(3) Inspect arc interruption chambers.

(4) Inspect relay contacts.

(5) Check fuse clips for secureness.

(6) Check the condition of bushings, porcelains, and contact surfaces.

(7) Check the load conductor terminations.

(8) Check the current transformer connections.

(9) Check the grounding connections.

(10) Check the lifting or racking mechanism (if applicable).

(11) Check for loose, contaminated, or damaged bushings; loose terminals; and proper gas pressures.

(12) Check the anti-condensation heaters. Read and record the number of operations indicated. If the breaker has not operated during the preceding year, bypass the breaker or otherwise take it out of the circuit for testing.

(13) Inspect contact areas on the main plug-in assembly for signs of overheating or arcing.

(14) Read and record compressor operating hours as shown on the indicator

(15) In addition to the above perform the air breaker maintenance that is specified in the CNPI maintenance report

5.4.2.6 Vacuum Circuit Breakers

(1) Check for loose, contaminated, or damaged bushings; loose terminals; oil leaks; and proper gas pressures.

(2) Check the anti-condensation heaters.

(3) Read and record the number of operations indicated. If the breaker has not operated during the preceding year, bypass the breaker or otherwise take it out of the circuit for testing.

(4) Read and record compressor operating hours as shown on the indicator.

5.4.2.7 Power Transformers

(1) Inspect the control cabinet, control relays, contactors, indicators, and the operating mechanism.

(2) Look for loose, contaminated, or damaged bushings; loose terminals; and oil leaks.

(3) Check oil levels in main tanks, tap changer compartment, and bushings.

(4) Inspect the inert gas system (when applicable) for leakage, proper pressure, etc.

(5) Read and record the operations counter indicator reading associated with the load tap changer.

(6) Observe oil temperature. Oil temperature should not exceed the sum of the maximum winding temperature as stated on the nameplate plus the ambient temperature (not to exceed 40C) plus 10C. Generally, oil temperature does not exceed 95 and 105C for 55 and 65C winding temperature rise units, respectively; since the ambient temperature rarely exceeds 30C for periods long enough to cause an oil temperature rise above these points.

(7) Perform the power factor test

(8) Perform the turns ratio test

(9) Perform the winding resistance test

(10) Perform the excitation current test

(11) Perform the insulation resistance test

(12) Send sample to lab for Dissolved Gas Analysis (DGA)

(13) In addition to the above perform the transformer maintenance that is specified in the CNPI maintenance report

5.4.2.8 Potential and Current Transformers

(1) Perform the transformer maintenance that is specified in the CNPI maintenance report

5.4.2.9 Station Service Transformers

(1) Perform the transformer maintenance that is specified in the CNPI maintenance report

(2)

5.5 Revenue Metering and Instrument Transformer Maintenance

This type of Managed Assets requires additional Certification Maintenance in addition to the typical ‘physical’ maintenance (predictive, corrective, and preventative) required by most other types of Managed Assets.

Typically, each class of revenue meter and instrument transformer (current transformers and potential / voltage transformers) must be re-certified by an accredited testing organization on a recurring basis.

The frequency and nature of these recertification are dictated by regulations enforced by Measurement Canada (Industry Canada), a Federal regulator.

In the past, these regulations have allowed for sample testing and inter-LDC ‘family’ testing of entire groups of revenue meters rather than full testing of each and every individual meter.

Whatever method is used to re-certify a group of meters, meticulous and detailed records must be maintained for every individual meter and retained throughout the life of the meter. At CNPI, these records are managed within SAP.

6 Assessment of Asset Condition

6.1 Distribution Substations

The nature of distribution substation (DS) equipment does not lend itself to purely quantitative evaluation of its condition. In addition, the relatively low quantity of each type of DS asset ensures that each item can receive regular inspection, maintenance, and qualitative assessment.

Since each piece of substation equipment is also relatively expensive to replace, it is generally cost effective to perform regular maintenance on it rather than relying on run-to-failure techniques which make more sense for low-value items like line insulators or cross-arms.

The table below summarizes the substations in service at CNPI:

Station	Pri. Voltage	Sec. Voltage	Year Installed	# of TX's	Total Capacity (MVA)	TX Prot.	# of Feeders	Feeder Prot.
12	34.5kV	4.8kV - Δ	1952	3	25	Breakers	12	Breakers
15	34.5kV	4.8kV - Δ	1975	1	6.75	Breaker	3	Breakers
19	34.5kV	8.3kV	2001	2	26.7	Fuses	6	Breakers
Jefferson	27.6kV	4.16kV	1952	3	5	Breakers	3	Breakers
Catharine	27.6kV	4.16kV	1975	1	6.6	Breaker	3	Breakers
Killaly	27.6kV	4.16kV	2001	2	10	Fuses	6	Breakers
Fielden	27.6kV	4.16kV	2004	2	15.2	Fuses and Breaker	7	Breakers
Sherkston	27.6kV	4.16kV	2009	2	15	Breakers	4	Reclosers
EOP Main Sub.	44kV	26.4kV	2007	2	33	Breaker	3	Breakers
Gananoque	26.4kV	4.16kV	1945	2	10	Fuses	3	Breakers
Herbert	26.4kV	4.16kV	1992	1	6	Fuses	2	Breakers
Kingston Mills	26.4kV	4.16kV	1956	1	2	Fuses	2	Fuses

Table 8: Summary of CNPI's Distribution Stations

In this table, the year installed correlates to the date the distribution station was placed in service. In some cases, power transformers and/or other ancillary equipment may have been refurbished or replaced since the station was originally commissioned. The total capacity is stated in terms of full cool installed capacity at the station. In some circumstances such as a Sherkston DS, the transformers are not capable of parallel operation. As such, the total installed capacity is not available to service load at any given time.

The table below summarizes the (n-1) capacity at each station. In some instances, the station is only configured for single element operation. In most cases, these stations have distribution intertie capability to adjacent stations to be able to supply load during contingencies.

Station	Pri. Voltage	Sec. Voltage	# of TX's	Installed Capacity (MVA)	n-1 Capacity
12	34.5kV	4.8kV - Δ	3	25	13.5
15	34.5kV	4.8kV - Δ	1	6.75	n/a
19	34.5kV	8.3kV	2	26.7	13.3
Jefferson	27.6kV	4.16kV	3	5	5
Catharine	27.6kV	4.16kV	1	6.6	n/a
Killaly	27.6kV	4.16kV	2	10	5
Fielden	27.6kV	4.16kV	2	15.2	6.5
Sherkston	27.6kV	4.16kV	2	15	5
Main	44kV	26.4kV	2	33	13.5
Gananoque	26.4kV	4.16kV	2	10	5
Herbert	26.4kV	4.16kV	1	6	n/a
Kingston Mills	26.4kV	4.16kV	1	2	n/a

Table 9: Summary of CNPI's Distribution Station (n-1) Capacity

The table below summarizes CNPI's deployment of power transformers in Distribution Substations:

Station	Unit	Pri. Voltage	Sec. Voltage	Manufacturer	Year of Mfg.	Total Capacity (MVA)
12	T1	34.5kV	4.8kV - Δ	General Electric	1963	6.75
12	T2	34.5kV	4.8kV - Δ	Pioneer	2009	11.87
12	T3	34.5kV	4.8kV - Δ	Moloney	1977	6.75
15	T1	34.5kV	4.8kV - Δ	Moloney	1973	6.75
19	T1	34.5kV	8.3kV	Northern	1999	13.3
19	T2	34.5kV	8.3kV	Northern	1999	13.3
Jefferson	T1	27.6kV	4.16kV	Ferranti Packard	1974	5
Catharine	T1	27.6kV	4.16kV	Westinghouse	1977	6.6
Killaly	T1	27.6kV	4.16kV	Westinghouse	2003	5
Killaly	T2	27.6kV	4.16kV	General Electric	2006	5
Fielden	T1	27.6kV	4.16kV	Pioneer	2003	8.67
Fielden	T2	27.6kV	4.16kV	ABB	2014	6.5
Sherkston	T1	27.6kV	4.16kV	Reliance	1959	5
Sherkston	T2	27.6kV	4.16kV	Pioneer	2009	10
Main	T1	44kV	26.4kV	Moloney	1980	20
Main	T2	44kV	27.6	Northern	2006	33
Gananoque	T1	26.4kV	4.16kV	General Electric	1995	5
Gananoque	T2	26.4kV	4.16kV	General Electric	1956	5
Herbert	T1	26.4kV	4.16kV	Northern	1992	6
Kingston Mills	T1	26.4kV	4.16kV	Northern	1994	2

Table 10: Summary of CNPI's Power Transformers in Distribution Substations

The following sections provide a summary of CNPI's distribution substation equipment and asset assessments:

6.1.1 FE-Station 12

(1) Two of the power transformers (Bank 1 and Bank 3) will soon be reaching the end of their predicted useful lives. Bank 1 is the oldest power transformer in Fort Erie's distribution substations with an age of 53.

(2) The masonry control building is showing signs of early stages of structural damage, due to aging. CNPI had an external audit of the station control building, switchgear building, and station yard elements to confirm asset condition. The audit was conducted in 2014 and the resulting report is included in Appendix I. The audit report indicated that the remaining service life of the building is less than 20 years and "that it is not worth spending additional money to repair the noted problems."

(3) The audit of the station yard elements indicated that many of the concrete piers require replacement.

(4) CNPI also had the outdoor structural steel reviewed by AECOM which indicated the need for structural re-enforcement. This report is included in Appendix J.

(5) Seven of the feeder exit cables are over 40 years old consisting of 750kcmil aluminum 15kV cable. Three of these cables share a legacy common civil infrastructure with a significant length (approximately 400m). The overall length and age of this civil installation, which incorporates a crossing under the QEW, makes cable replacement unfeasible.

(6) Five of the feeder exit cables are approaching 20 years old and consist of 750kcmil aluminum 15kV cable. The feeder cables egress through manhole structures with very limited separation between circuits. A splice or cable failure in these structures could potentially compromise multiple circuits, placing the assets and connected load at risk.

(7) The transformer protective relaying is electromechanical and at end of life. The feeder protection relay consists of a combination of electronic and electromechanical relaying which is also at end of life.

(8) CNPI's long term plan is to convert the 4.8kV system in the FE downtown area over the next 10 years and Station 12 will be replaced during this time frame.

6.1.2 FE–Station 15

(1) Station 15 consists of the originally deployed transformation, switchgear, and protection elements.

(2) This station is scheduled for replacement in 2016. The site of station 15 will be utilized for the new Gilmore DS as part of the introduction of an 8.32kV wye grounded distribution system in North Fort Erie downtown area. A significant amount of feeders in this area are presently supplied by Station 12.

(3) The power transformer at this station has experienced a low level of utilization throughout its service life. Oil analysis results on this station have also trended

favourably. This power transformer will be relocated to Station 12 to replace Bank 1 once Station 15 is decommissioned.

6.1.3 FE–Station 19

(1) This station is more recently commissioned than the other DS's in FE.

(2) The station consists of two 10/13.3 MVA power transformers which have experienced moderate utilization during their service life. Annual oil analysis results trend positively for these two units.

(3) This station utilizes power fuses for 34.5kV transformer protection. The station also incorporates a double ended switchgear. Since there are no external 8.32kV ties to this substation, the switchgear presents a single point of failure which significantly limits restoration options under contingency. There is risk of sustained load loss should there be an arc-flash event within the switchgear.

(4) CNPI's forecast investment plan includes a project to address this deficiency and an allocation to add transformer and bus differential protection to mitigate asset failure risk.

(5) Feeder relaying is at end of life. The forecast investment plan includes replacement of relays at this substation in the next five years.

6.1.4 PC-Catherine

(1) Catherine DS is a single element substation which incorporates fuse element protection for feeders, bus and transformation.

(2) The power transformer and switchgear are original equipment and are approaching end of life.

(3) This station relies on load transfer capabilities to Fielden DS and/or Jefferson DS under contingency.

(4) There is no oil collection system at this DS which is problematic given the proximity to a residential and recreational area.

(5) CNPI's five year investment plan includes replacement of Catherine and Jefferson DS with a new 27.6kV to 4.16kV stepdown station.

6.1.5 PC–Fielden

(1) This DS was commissioned in 2004, is of modern design and relatively new condition.

(2) In 2015, the T2 transformer was commissioned adding 6.5MVA of capacity to the station. This enabled replacement of end of life assets at Barrick DS.

(3) The station design incorporates physically separated T1 and T2 associated switchgear, mitigating the possibility of single point failure risk.

(4) Transformer T1 incorporates high side fuse element protection. CNPI has included an allocation for implementation of differential protection relaying in its five year forecast investment plan.

6.1.6 PC-Jefferson

(1) This DS is of similar construction and vintage as the recently retired Barrick DS. The transformation and switchgear are original equipment and are at end of life.

(2) This station relies on load transfer capability to Fielden DS and/or Catherine DS under contingency.

(3) There is no oil collection system at this DS which is problematic given the proximity to a residential area.

(4) CNPI's five year investment plan includes replacement of Catherine and Jefferson DS with a new 27.6kV to 4.16kV stepdown station.

6.1.7 PC-Killaly

(1) Killaly DS is a two element station. The station has no external tie capability and relies on redundancy within the DS under contingencies.

(2) The station consists of two recently refurbished 3.75/5 MVA power transformers which have experienced significant utilization during their service life. Annual oil analysis trending is poor for the T2 transformer which will require attention in the near future.

(3) This station utilizes power fuses for transformer and feeder protection. The station also incorporates a double ended switchgear. Since there are no external ties to this substation, the switchgear presents a single point of failure for which significantly limits restoration options under contingency. CNPI's forecast investment plan includes an allocation to add transformer and bus differential protection to mitigate asset failure risk.

(4) The forecast investment plan also includes deployment of relay controlled feeder protection elements.

6.1.8 PC-Sherkston

(1) This DS was commissioned in 2004 and is of modern design and relatively new condition.

(2) The station incorporates redundant transformation with significant capability to accommodate load growth.

(3) The transformer and feeder protection scheme incorporates modern SCADA controlled relaying and associated reclosers.

6.1.9 EOP-Main Substation

(1) This DS was commissioned in 2007 and is of similar design to PC-Sherkston DS.

(2) The backup transformer (T1) is the legacy 26.4kV delta secondary transformer and cannot be paralleled with T2. The forecast investment plan includes allocation for conversion of the 26.4kV delta system to 27.6kV grounded wye. This necessitates the need for replacement of T1 with a second 44kV to 27.6kV wye transformer. The forecast investment plan includes allocation for this transformer replacement.

(3) The station incorporates a modern protection scheme with electronic relaying and transformer differential protection.

6.1.10 Gananoque Substation

(1) The T2 transformer and switchgear at this station is approaching end of life. Under loss of a transformer element at this station, load can be transferred to adjacent Herbert DS.

(2) This station is located on the bank of Gananoque River with very limited room for rebuild or expansion. The long term plan to convert the 4.16kV system supplied by this station to the 27.6kV system and eventually eliminate this station.

6.1.11 Herbert Substation

(1) Herbert DS is of relatively newer vintage. Feeder and bus protection relaying were upgraded in 2015.

(2) This is a single element station which has transfer capability to Gananoque substation.

(3) The transformer protection element consists of fusing and there are no current plans to upgrade this in the forecast period.

6.1.12 Kingston Mills Station

(1) This substation is owned by the Kingston Mills Generation plant. CNPI's power transformer is located in this legacy substation.

(2) In 2015, an agreement was reached that CNPI will retire and remove this transformer out of the customer owned substation by 2016. The customer will contribute $150K towards relocation of the transformer.

(3) CNPI will construct a Ratio Bank on the public right-of-way due to the small amount of distribution load supplied by this transformer.

6.2 Delta Distribution System

6.2.1 Fort Erie

CNPI's Fort Erie delta distribution system can be categorized into four logical sections which are summarized in the following table.

Circuit Length (km)		Three Phase	Two Phase	Total (km)
Ridgeway	OH	29.4	34.4	65.6
	UG	0.7	1.1	
QEW North	OH	34.4	6.3	44.1
	UG	3	0.4	
QEW South	OH	34.9	21.9	59.2
	UG	1.9	0.5	
Other	OH	6.6	14.6	22.3
	UG	0	1.1	

Table 11: Summary of Delta System Areas

6.2.1.1 Ridgeway

The introduction of the wye configured Station 19 in 2001 was a major step towards elimination of the delta primary system in the Ridgeway area. Although this source was introduced, a significant portion of the area remains delta distribution. These areas are supplied via structure mounted ratio bank transformers that have delta connected secondary.

The ratio bank transformers have contributed to a decline in reliability during lightning events. The transformers are susceptible to impulse related failures due to their high impedance characteristic. The following figure illustrates the remaining delta distribution system in the Ridgeway area:

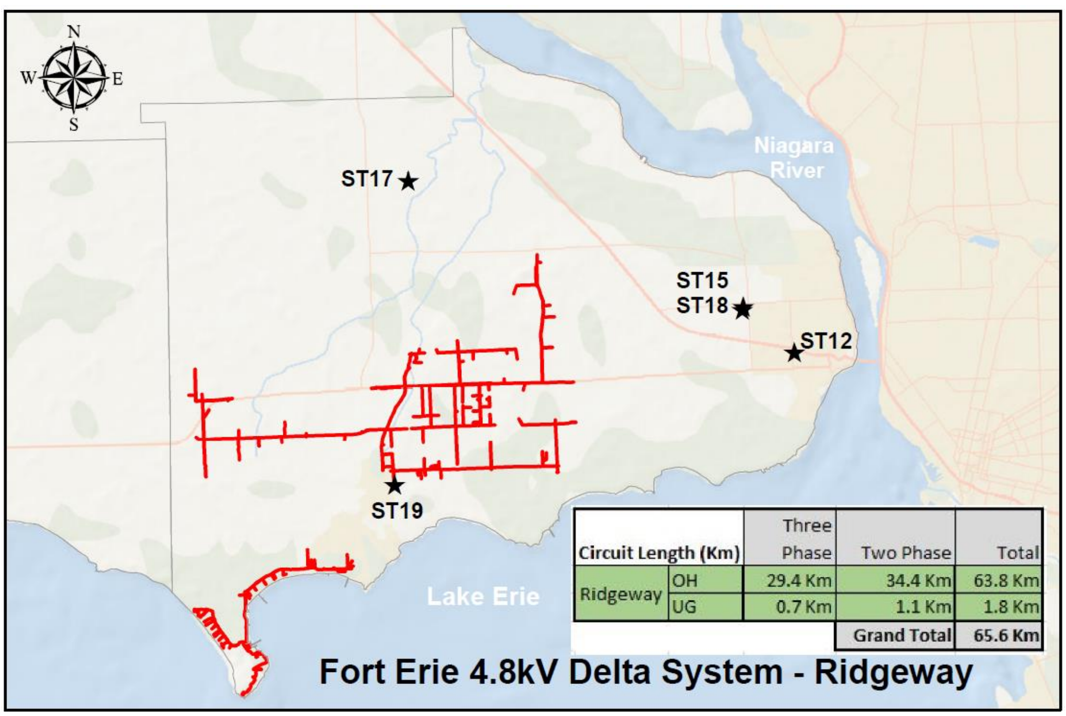


Figure 25: Ridgeway Delta Distribution System

The Ridgeway area contains approximately 66 circuit-km of the total 191 circuit-km of 4.8kV delta distribution lines within the FE distribution system. A portion of this area has already been rebuilt during the historical investment period to support a wye connected configuration. In order to eliminate the delta system in this area, CNPI estimates the following effort will be required:

Effort	Line Length (km)
Line Rebuild	8.2
Line Refurbishment	13.8
Line Conversion	41.8

Table 12: Estimated Effort – Elimination of Ridgeway Delta System

CNPI targets a line for holistic rebuild when over 60% of the poles in the line section require replacement due to poor conditions. Line refurbishment requires a smaller number of pole changes and minor component replacement to support conversion. Line conversion is simply the replacement of minor components (such as arresters, switches, etc.), in order to connect the section to a wye source.

Based on the schedule for conversion in this area for the period 2016 through to 2020, CNPI estimates the following annual pole replacements:

Year	2016	2017	2018	2019	2020
Est. Pole Count	94	14	68	56	77

Table 13: Estimated Pole Replacements – Ridgeway Delta System

CNPI plans to eliminate the Delta system in the Ridgeway area by the end of 2020.

6.2.1.2 QEW North

The introduction of Gilmore DS in 2016 will commence the delta to wye conversion for the area North of the QEW currently serviced by Station 12 and Station 15. The following figure illustrates the delta distribution system in this area:

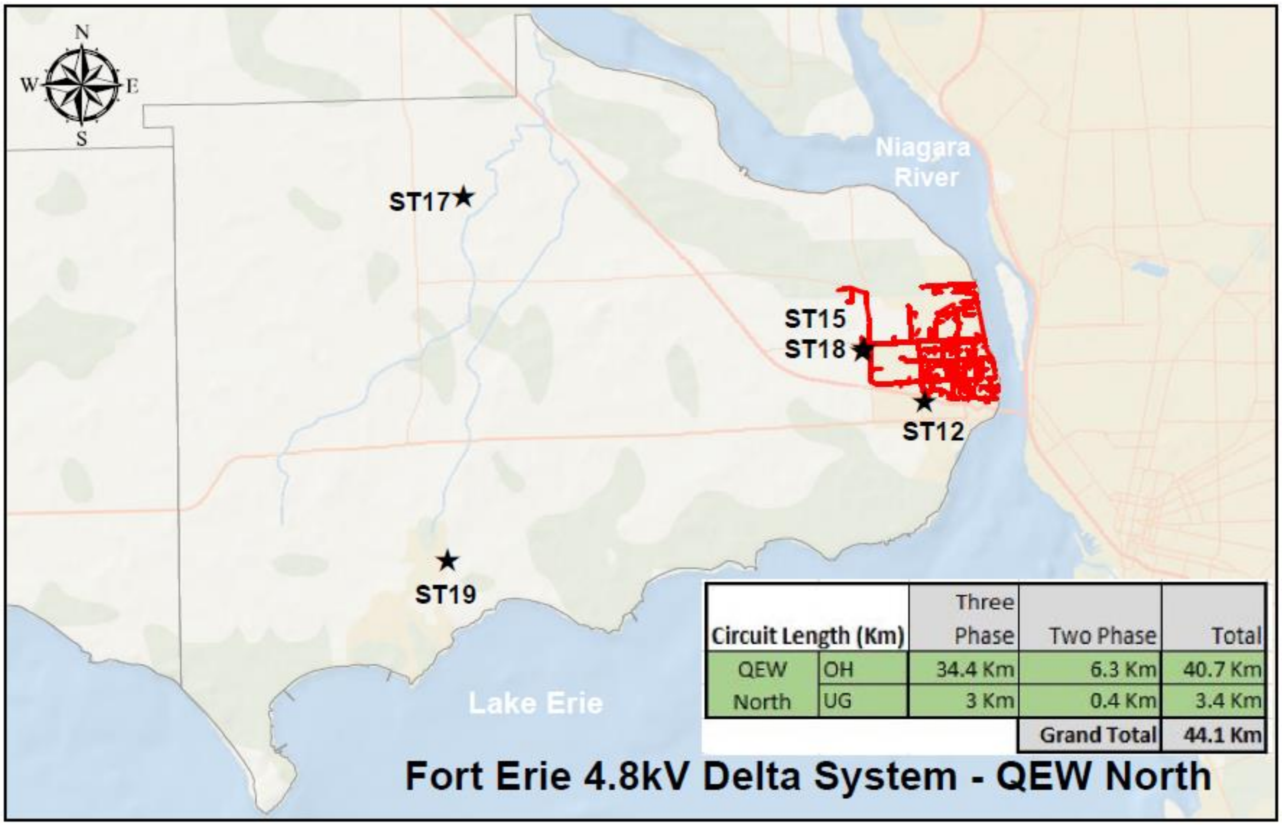


Figure 26: QEW North Delta Distribution System:

This area North of the QEW contains approximately 44 circuit-km of the total 191 circuit-km of 4.8kV delta distribution lines within the FE distribution system.

A significant portion of the distribution system in this area utilizes aerial cable having a circuit kilometer length of approximately 4km. This cable is approaching end of life. Based on a third party assessment of this cable, replacement is required in the next five to ten year period. The condition assessment report is provided in Appendix K.

In order to eliminate the delta system in this area, CNPI estimates the following effort will be required:

Effort	Line Length (km)
Line Rebuild	19.7
Line Refurbishment	8
Line Conversion	12.5

Table 14: Estimated Effort – Elimination of QEW North Delta System

Based on the schedule for conversion in this area for the period 2016 through to 2020, CNPI estimates the following annual pole replacements in this area:

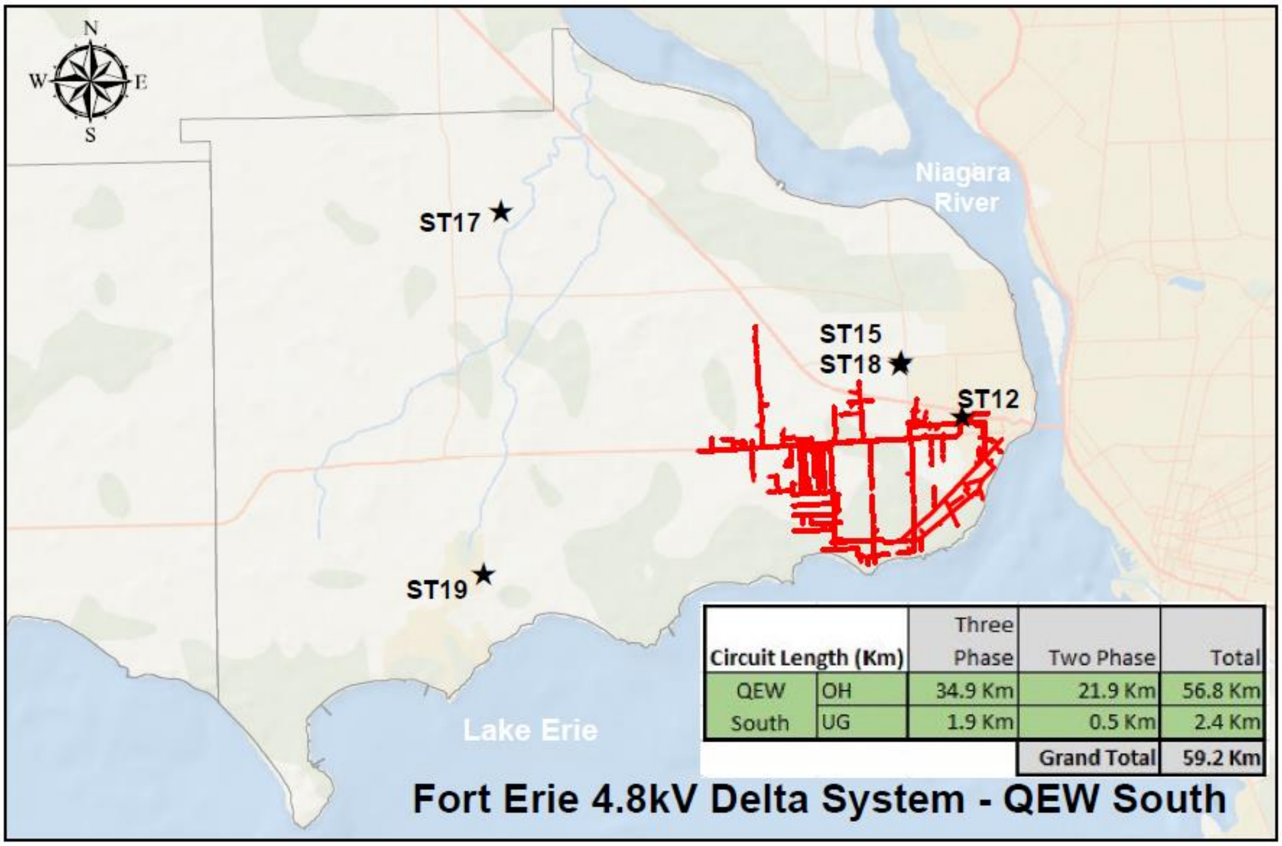
Year	2016	2017	2018	2019	2020
Est. Pole Count	106	117	117	117	117

Table 15: Estimated Pole Replacements – QEW North Delta System

CNPI plans to eliminate the delta system in the QEW North area by 2020.

6.2.1.3 QEW South

Conversion South of the QEW will require the introduction of distribution substation investments in that area. There is an additional 600 meter of aerial cable in this portion of the delta system that is approaching end of life. CNPI forecasts distribution substation investments in 2021 in order to establish a wye source for loads in the area. Based on the implementation of this wye source, the second phase of conversion for loads currently supplied by Station 12 and Station 15 will commence in approximately 2022. The following figure illustrates the delta distribution system in this area:



Circuit Length (Km)		Three Phase	Two Phase	Total
QEW South	OH	34.9 Km	21.9 Km	56.8 Km
	UG	1.9 Km	0.5 Km	2.4 Km
			Grand Total	59.2 Km

Figure 27: QEW South Delta Distribution System

This area accounts for 59 circuit-km of the total 191 circuit-km of 4.8kV delta distribution lines within the FE distribution system.

Although specific conversion efforts have not yet been determined for this area, CNPI anticipates conversion efforts in this area will require approximately 28km of line rebuild and 11km of line refurbishment. This would result in the replacement of an estimated 780 poles. CNPI will adjust the anticipated effort required once pole testing results are available to be analyzed for this target area.

6.2.1.4 Other Delta Distribution

In addition to the 3 areas identified above, there remains ancillary delta load supplied by ratio banks connected to the 34.5kV distribution system. Like the ratio banks that exist in the Ridgeway area, these are structure mounted ratio bank transformers that have delta connected secondary. Again in these areas, the ratio transformers are susceptible to impulse related failures due to their high impedance characteristic. The following figure illustrates the remainder of the delta distribution system in the Fort Erie area:

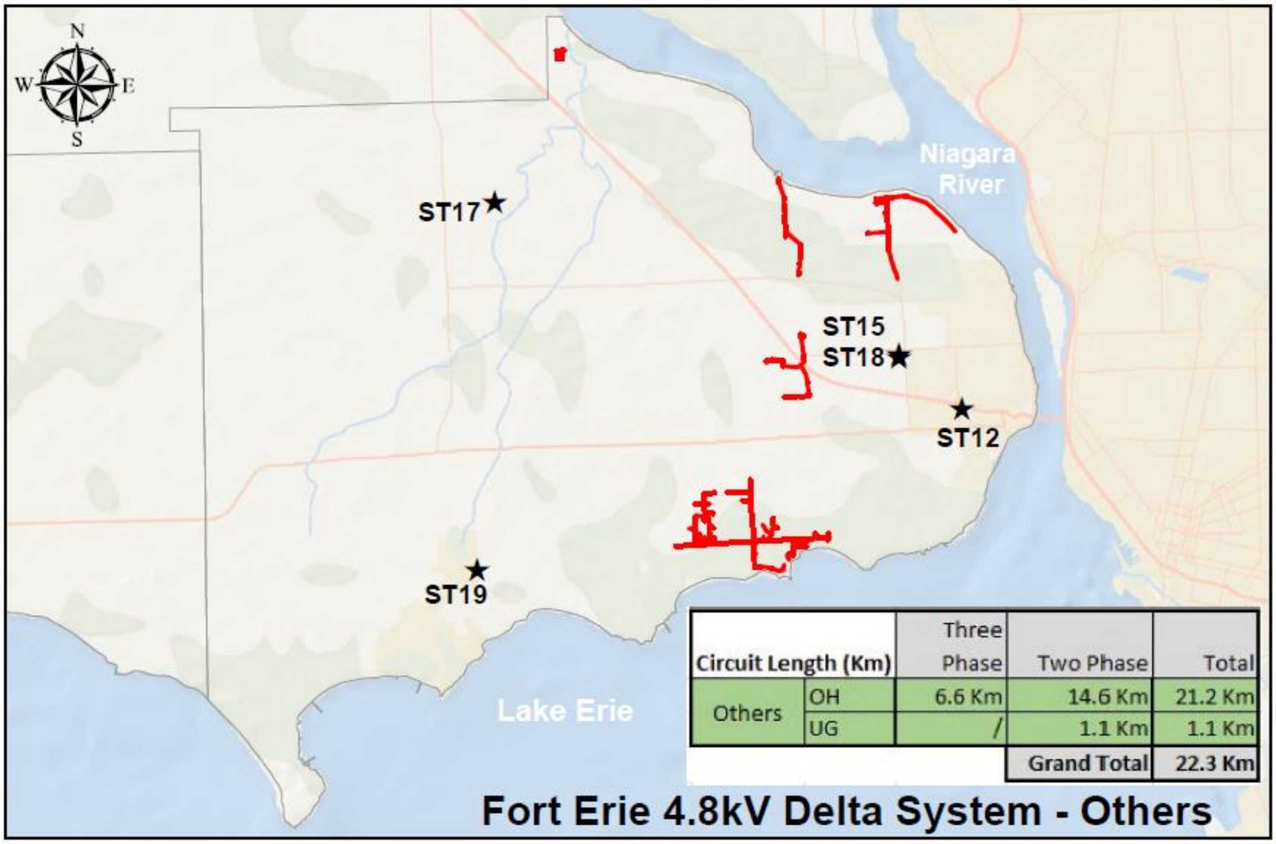


Figure 28: Fort Erie – Balance of FE Delta Distribution System

These remaining areas contain approximately 22 circuit-km of the total 191 circuit-km of 4.8kV delta distribution line.

The majority of this area requires only line conversion efforts. CNPI has allotted investment for conversion of these sections between 2016 and 2021. In 2021, there will be some conversion required in the southern portion of this area with legacy pole installations. CNPI estimates the following effort to complete conversion in these areas:

Effort	Line Length (km)
Line Rebuild	1.4
Line Refurbishment	2.4
Line Conversion	17.4

Table 16: Estimated Effort – Elimination of Remaining FE Delta System

Approximately 55 pole replacements will be required due to rebuild and refurbishment in 2021 based on currently available condition data.

6.2.2 Gananoque

CNPI's investment plan includes conversion of the three wire 26.4kV delta distribution system in Gananoque to a four wire 27.6kV grounded wye system. CNPI started this process in 2006 by implementing a power transformer (TB2) in the EOP Main Substation with a 27.6kV wye secondary. This transformer normally supplies the entire distribution load in the Gananoque area. The legacy TB1 transformer remains on potential as a backup during TB2 contingencies. The legacy transformer is 26.4kV and cannot be paralleled with TB1. The transformer is also considered to be in poor condition with substandard oil analysis results.

The requirements to achieve conversion include the replacement of the TB1 transformer with a 27.6kV wye secondary. CNPI's investment plan includes this scope of work in 2017. The introduction of the transformer will solidify a four wire wye grounded source point at the EOP Main Substation, permitting load transformer between units without an outage.

Additionally, the 2017 conversion project includes the installation of approximately 600m of neutral conductor starting from the feeder egress at the EOP Main Substation on the double circuit sourcing the "Town Loop". The figure below depicts the section of line requiring this neutral conductor installation:

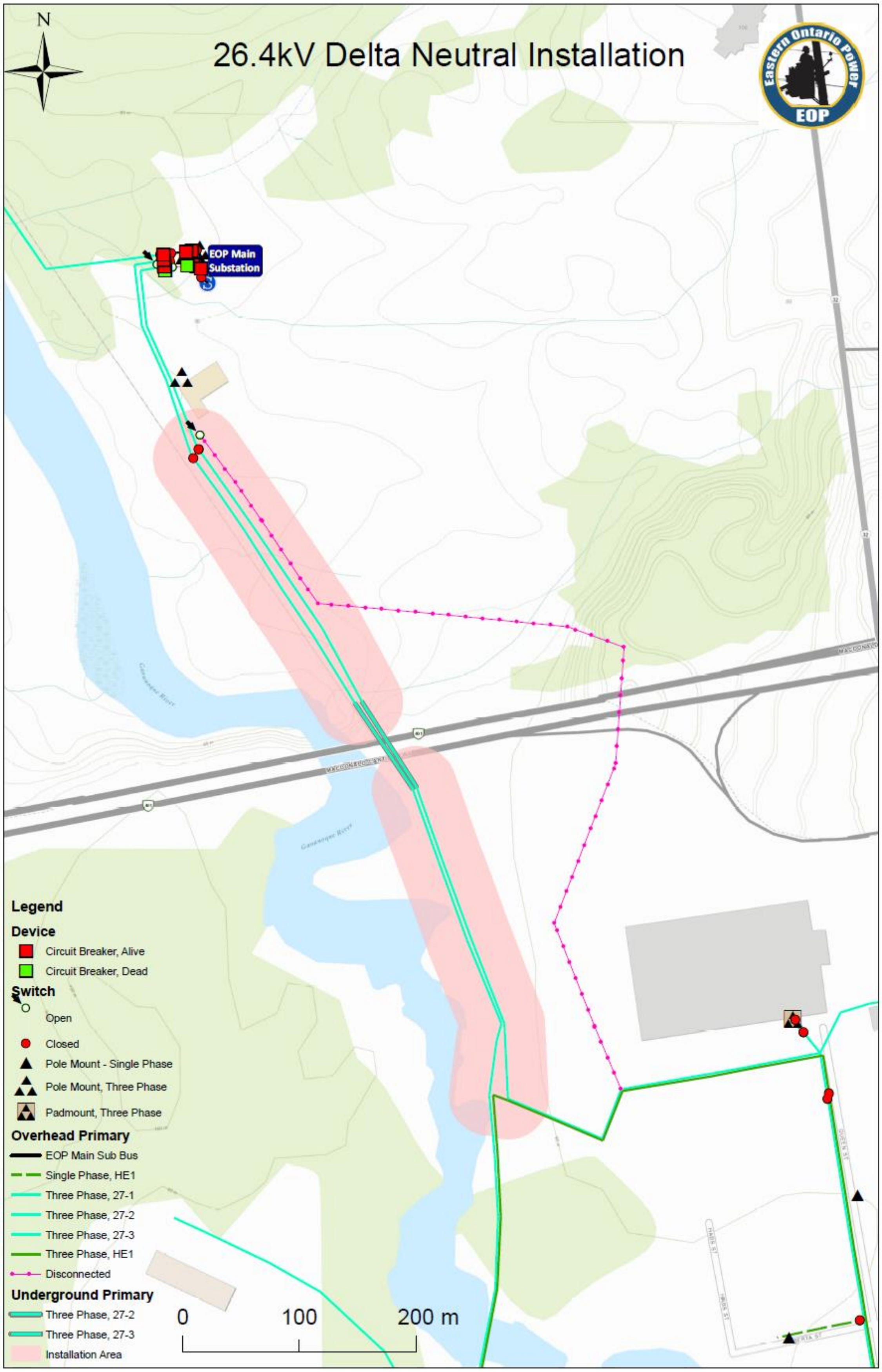


Figure 29: Gananoque – Required Neutral Conductor Installation

6.3 Poles

6.3.1 Defining Asset Condition

A wooden utility pole generally remains useful until:

(1) It fails (breaks or collapses) due to severe weather, vehicles, or loss of strength associated with advanced aging.

(2) New requirements necessitate a pole change-out. These needs might be for a taller or stronger pole to support more equipment.

(3) The pole is no longer required at its legacy location.

(4) Though a gradual process of loss of wood fibre and loss of fibre strength, the strength of the pole decreases until it reaches the point where it no longer satisfies required safety factors under worst-case conditions. At this point, inspections and/or testing will identify the need to replace this pole.

Like many other types of distribution assets, distribution poles are expected to last for a long time. Technical lives of 45 years are expected.

It should be noted that the actual mean 'in-service' life of utility poles is usually less than 45 years, as many are removed or upgraded due to such factors as road realignments or a need to upgrade to a taller or stronger pole as part of a distribution line upgrade.

Individually, the replacement value of these assets ranges from $2,000 to over $15,000. CNPI has approximate 22,872 poles in service.

Because of the high Mean Time Between Failures (MTBF) value, relatively low installed cost, and large installed base of poles, it would be extremely impractical or impossible to closely monitor and maintain each pole in the same fashion as a Substation steel structure, and the expense of such a program would far exceed its utility.

Instead, CNPI manages its pole assets through a combination of:

(1) Industry-standard purchasing specifications

(2) Review of manufacturers' QA/QC efforts

(3) Inspection of new distribution poles as they are received

(4) Periodic inspection and testing of poles while they are retained in stores as spares

(5) In-situ inspections and periodic testing of poles whenever they are installed and/or visited during fieldwork. Visual inspections are performed every three years as part of CNPI's Inspection Program.

(6) Intake inspection whenever a previously-used pole is returned to storage from the field. Occasionally, a pole in near-perfect condition is re-issued to the field.

Documentation is maintained for each of these processes.

6.3.2 Measuring Asset Condition

Monitoring the condition of CNPI's individual poles has been an ongoing process for many years.

In 2011, CNPI performed an evaluation of the overall asset condition of poles. These were evaluated through a methodology of random sampling of the entire installed pole population. Approximately 11 percent of CNPI's pole population was evaluated. Poles were visually evaluated for a variety of factors which impact on pole condition. Maps of the pole test areas and sample inspection form are shown in Appendix F. In addition, the remaining wood fibre strength of the pole was measured.

The results of this testing was analyzed and the Probably Remaining Life (PRL), or the number of years until replacement is projected to be required, was calculated for each pole in the sample test group. The pole test results were then extrapolated to predict the asset condition for all of CNPI's poles.

CNPI maintains a current version of this asset condition report. The current report takes into account the asset replacements that have occurred since the pole population was last evaluated.

The results reveal an expected outcome. In general, older poles are expected to need replacement sooner than younger poles. There is projected to be approximately 1,843 of 22,872 poles that require replacement over the next five years. This represents approximately 8.1 percent of the pole population. The following two histograms show CNPI's pole age distribution as well as the number of years until asset replacement is recommended:

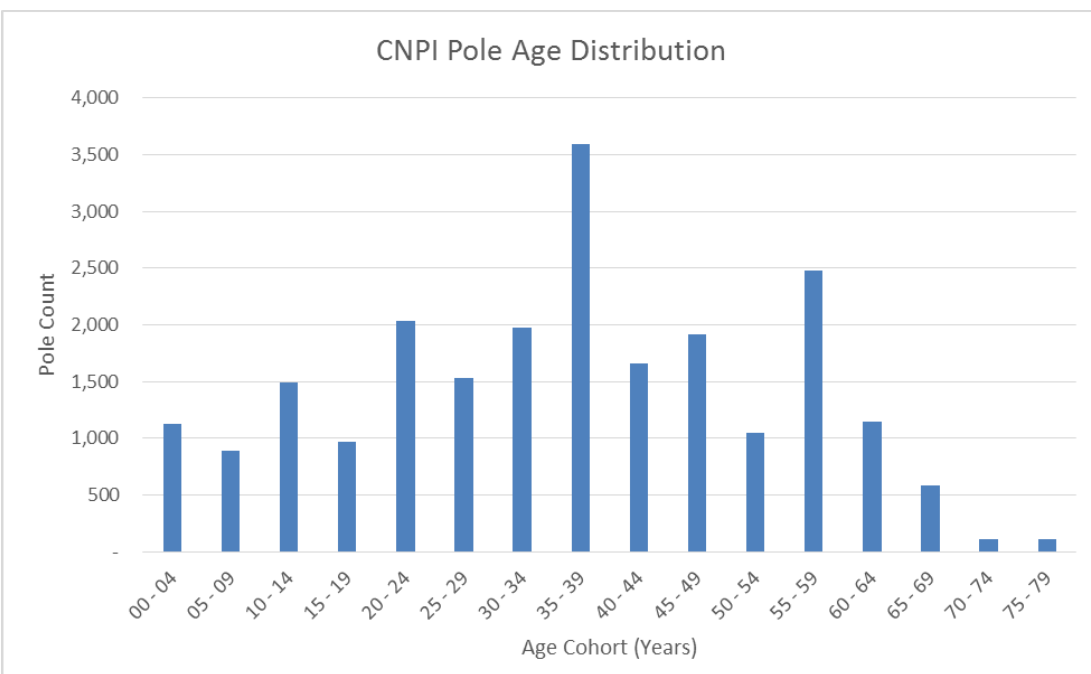


Figure 30: CNPI Pole Age Distribution

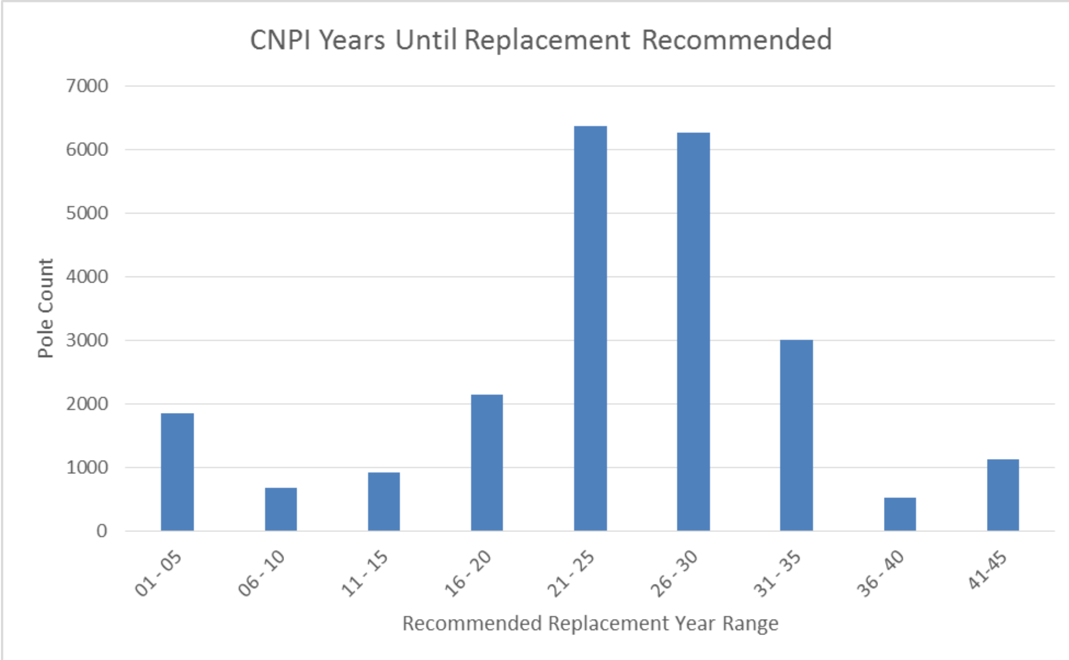


Figure 31: CNPI Years Until Replacement Recommended

CNPI is undergoing implementation of a Detailed Pole Inspection and Testing program to perform a more thorough evaluation of the overall asset condition of CNPI's poles. A six year cyclical approach has been included in CNPI's expenditure forecast through to 2021.

6.4 Distribution Transformers

6.4.1 Defining Asset Condition

Like many other types of distribution assets, distribution transformers are expected to last for 40 years under typical conditions. The maintenance-free Mean Time Between Failures (MTBF) is on the order of 300,000 hours. Individually, the replacement value of these assets ranges from $1,500 to over $40,000. CNPI has over 6,100 such transformers.

Because of the high MTBF value, relatively low cost, and large installed base of distribution transformers, it would be extremely impractical or impossible to closely monitor and maintain each transformer in the same fashion as a Substation power transformer, and the expense of such a program would far exceed its utility.

Instead, CNPI manages its distribution transformer assets through a combination of

(1) Industry-standard purchasing specifications

(2) Review of manufacturers' QA/QC efforts

(3) Examination of the manufacturer's technical drawings and data for each distribution transformer order placed

(4) Inspection and testing of new distribution transformer as they are received

(5) Periodic inspection and technical testing of distribution transformers while they are retained in stores as spares

(6) In-situ inspections and testing of transformers whenever they are installed and/or visited during fieldwork

(7) Intake inspection whenever a previously-used distribution transformer is returned to storage from the field. This is particularly important if the distribution transformer was removed from service because it is suspected to be not in good working order.

(8) Exceptional programs may be initiated if an unforeseen issue arises. For example, the entire CNPI inventory was tested for Polychlorinated Byphenol (PCB) content in the mid-1980's once concerns were raised about environmental issues associated with these chemicals.

Documentation is maintained for each of these processes.

6.4.2 Measuring Asset Condition

For the reasons discussed in the previous section, CNPI does not regularly measure the condition of each distribution transformer while it is in service. Instead, CNPI makes replacement and purchase projections based on

(1) the age of existing distribution transformer

(2) historical trends in actual distribution transformer usage

(3) historical and forecasted trends in expansion of CNPI's system due to customer growth and service changes

(4) specific planned programs that will require an unusual number of new distribution transformer, such as voltage conversions and overhead-to-underground street conversions.

(5) on-hand inventory of replacement spares and anticipated lead times for new orders

The typical reasons why a distribution transformer becomes in a non-working condition include:

(1) Aging

(2) Foreign interference (e.g. vegetation, squirrels and other wildlife)

(3) Vehicle accidents

(4) Vandalism

(5) Adverse environmental conditions (e.g. environmental or chemical contamination)

The following chart illustrates the CNPI's Transformer Age Distribution:

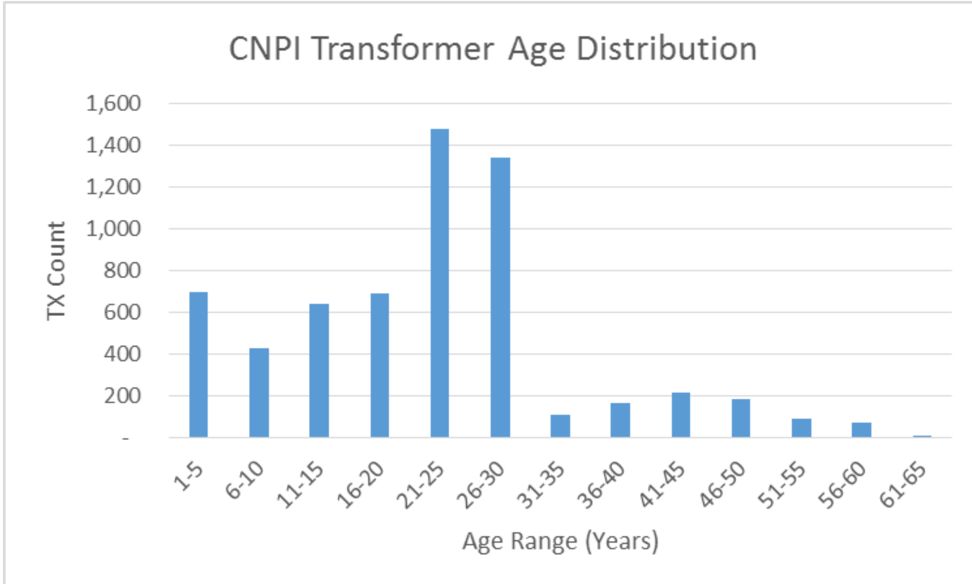


Figure 32: CNPI Transformer Age Distribution

6.5 Other Distribution Assets

For other types of distribution assets, CNPI uses probabilistic techniques to anticipate when they are nearing the end of their useful lives and plans to replace them before that time.

In the event of a premature or other failure of an asset or asset component, CNPI uses well established and industry-typical emergency response plans to replace them in a timely and cost effective manner.

7 Asset Utilization Assessment

7.1 Transformer Station Capacity

CNPI's Fort Erie service area is supplied from a single 115kV transmission circuit with a backup supply from National Grid in the New York State. The CNPI operated 34.5kV system is supplied from two 115kV transformer stations residing within Fort Erie.

The Port Colborne service area is suppled from a single 115kV transmission circuit owned and operated by Hydro One Networks Inc. The circuit supplies the Hydro One owned and operated Port Colborne TS. Port Colborne TS supplies the majority of load at 27.6kV. Additionally, there are some CNPI customers supplied at 27.6kV from the Hydro One owned M13 circuit fed from Crowland TS.

The Gananoque service area is supplied from a single 44kV circuit fed from Frontenac TS. The 44kV circuit is owned and operated by Hydro One Networks Inc.

The following table summarizes transformer station capacities and utilization:

Delivery Point	Service Area	Rating (MVA)	Maximum Load MVA (2015)
Station 17	Fort Erie	62.5	15.7
Station 18	Fort Erie	62.5	36.2
Port Colborne TS	Port Colborne	42	35.7
Crowland 41M13	Port Colborne	N/A-H1	10.3
Frontenac Q3M8	Gananoque	N/A-H1	12.0

Table 17: Transformer Station Utilization

The rating values stated in the above table are the full transformation ratings under full cooling with a single element in service.

7.2 Distribution Station Capacities

The following table summarizes distribution substation capacities and utilization:

Station	Pri. Voltage	Sec. Voltage	# of TX's	Installed Capacity (MVA)	Rating (MVA)	2015 Utilization
12	34.5kV	4.8kV - Δ	3	25	13.5	11.2
15	34.5kV	4.8kV - Δ	1	6.75	6.75	2.7
19	34.5kV	8.3kV	2	26.7	13.3	9.7
Jefferson	27.6kV	4.16kV	3	5	5	4.6
Catharine	27.6kV	4.16kV	1	6.6	6.6	3.6
Killaly	27.6kV	4.16kV	2	10	5	3.2
Fielden	27.6kV	4.16kV	2	15.2	6.5	4.9
Sherkston	27.6kV	4.16kV	2	15	5	4.1
Main	44kV	26.4kV	2	33	13.5	12.0
Gananoque	26.4kV	4.16kV	2	10	5	5.9
Herbert	26.4kV	4.16kV	1	6	6	4.7

Table 18: Distribution Substation Utilization

Again, the Rating values stated in the above table are the transformation ratings under full cooling with a single element in service.

8 Asset Replacement Program

8.1 Asset Lifecycle Optimization Policy and Practices

CNPI's asset management strategies focus on maximizing the service life of distribution assets at the lowest lifecycle cost of ownership. CNPI uses cyclical inspection programs that as described in the DAMP Section 5 as an input to the asset condition assessment process.

Inspection and testing results are reviewed by CNPI operations and planning departments and resulting deficiency records are created. As described in Section 5, deficiencies are prioritized based on the risk of asset failure.

Section 4.4 of the DAMP provides an overview of the CNPI's managed assets on the distribution system. The following table summarizes the asset management strategies for each:

Managed Asset	Replacement Strategy
Power Transformers	Proactive
Poles	Proactive / Reactive
Framing Assemblies	Reactive
Transformers (Pole-Top)	Reactive
Transformers (Pad-Mounted)	Proactive
Voltage Regulators (Pole-Top)	Proactive
Overhead Switches	Proactive/Reactive
Overhead Conductor	Reactive
Protective and Sensory Devices	Reactive
Revenue Metering	Reactive
Fleet	Proactive
Tools and Test Equipment	Proactive

Table 19: Replacement Strategy for Managed Assets

Assets that have a low consequence of failure vs. a high cost of replacement are generally managed through a reactive approach. In some cases, a run to failure approach is utilized when the replacement cost does not outweigh the consequence of asset failure. In these cases, CNPI has an appropriate level of resources to manage replacement in an acceptable time frame.

Assets that have a high consequence of failure such as power transformers, poles, etc., are managed proactively. These assets are critical components necessary to maintain the reliability and operational flexibility of the distribution system.

Where asset deficiencies are identified, CNPI evaluates the feasibility to extend life through maintenance or refurbishment. In some cases, maintenance or refurbishment is a lower cost alterative than asset replacement. This is the basis for CNPI's switch maintenance program. Assets are routinely maintained and components replaced as necessary to maximize usable service life.

Where managed asset replacement is the lowest cost alternative, CNPI incorporates replacement programs into its investment plan. The replacement programs are based on a levelized approach to keep pace with assets approaching end of service life. The annual levelized quantities are the basis for the identified annual investment levels in the forecast period.

Once certain assets are identified for replacement, incremental analyses are carried out to identify opportunities to improve operational efficiency. For example, when a section of distribution line is identified to be rebuilt due to poor condition, incremental analysis to evaluate the benefit of larger gauge conductor or different circuit routing is considered. Construction to higher system voltage standards (such as 27.6kV in an existing 4.16kV area) to prepare for conversion at a later date is considered when the incremental cost if minimal. The inevitable conversion in these cases can lead to substantial energy loss savings.

Transformer and pole replacement rates are covered in further detail for the remainder of this section.

8.2 Recent Historical Replacement Rates

8.2.1 Poles

The following table and chart shows the number of wooden poles actually installed and/or changed out over the last five years:

Year	Quantity	2.2% Sustainment Level	Surplus (Deficit)
2011	132	508	-376
2012	276	508	-232
2013	338	508	-170
2014	195	508	-313
2015	320	508	-188

Table 20: CNPI Historical Pole Replacements

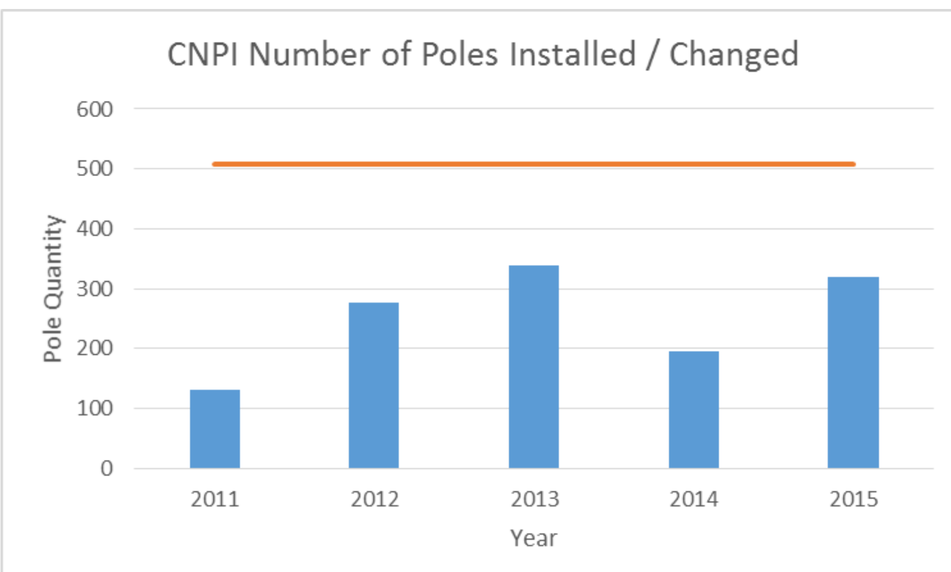


Figure 33: CNPI Pole Replacements 2011 to 2015

With 22,872 poles in service and an expected technical life of 45 years, one would expect an average replacement rate of 508 poles / year is required in order to achieve a sustainable average pole age.

Since a few of these poles were installed in 'fresh ground' to facilitate new customer connections rather than replacement of an aging pole, the number of removed poles may be somewhat less than the totals shown above.

The average 'replacement deficit' in recent years has been about 256 poles. The CNPI 5-year forecast investment plan includes targeted pole replacements and area rebuilds aimed at reaching sustainment levels.

A significant objective of CNPI's asset management plan is elimination of the delta distribution system in Fort Erie and Gananoque. As described in Section 6, a number of pole replacements will be required in the conversion areas in order to achieve this objective.

A summary of the estimated pole replacements required to support delta to wye conversion efforts is shown in the table below.

Year	2016	2017	2018	2019	2020	2021
Estimate of Pole Replacements	200	131	185	173	194	55

Table 21: CNPI Conversion Based Pole Replacements

In addition CNPI will utilize pole asset condition data to prioritize replacements outside of the conversion areas. This targeted pole replacement program will result in the following pole replacements based on a levelized investment strategy:

Year	2016	2017	2018	2019	2020	2021
Estimated Targeted Pole Replacements	138	138	138	138	138	138

Table 22: CNPI Targeted Program Based Pole Replacements

Finally, CNPI's Distribution System Upgrade Program contains a component of investment for replacement of end of life pole assets. In areas of the distribution system being expanded or upgraded, exclusive of conversion and targeted pole replacement programs, a number of end of life pole assets are replaced. This program will result in the following estimated pole replacement from 2016 through to 2021:

Year	2016	2017	2018	2019	2020	2021
Estimated Upgrade and Expansion Based Pole Replacements	41	102	124	196	187	225

Table 23: CNPI Upgrade and Expansion Based Pole Replacements

The total quantity of pole replacements achieved through CNPI's conversion, targeted pole replacements and system upgrades and expansions are forecasted in the table below.

Year	Estimated Replacements	2.2% Sustainment Level	Surplus (Deficit)
2016	379	508	-129
2017	371	508	-137
2018	447	508	-61
2019	507	508	-1
2020	519	508	11
2021	418	508	-90

Table 24: CNPI Combined Forecast Pole Replacements

8.2.2 Distribution Transformers

The following table and chart shows the number of distribution transformers actually installed and/or changed out over the last five years:

Year	Installed Quantity	2.5% Sustainment Level	Surplus (Deficit)
2011	124	155	-31
2012	137	155	-18
2013	138	155	-17
2014	190	155	35
2015	112	155	-43

Table 25: CNPI Historical Transformer Replacements

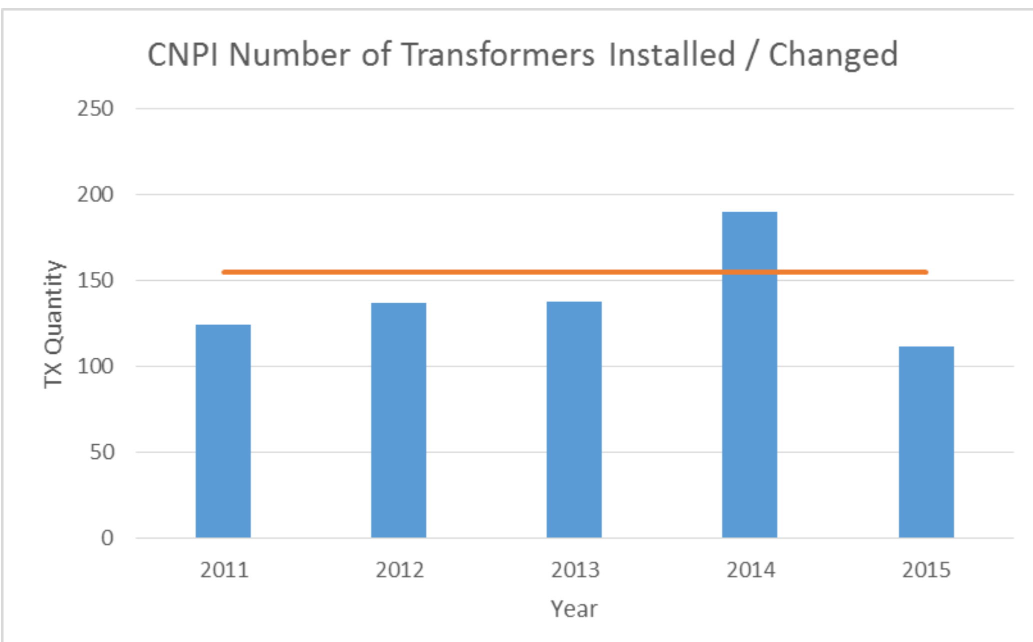


Figure 34: CNPI Transformer Replacements 2011 to 2015

With approximately 6200 transformers in service and an expected technical life of 40 years, one would expect an average replacement rate of 155 transformers / year is required in order to achieve a sustainable average transformer age and condition.

Since some of these transformers were installed as new banks to facilitate new customer connections rather than replacement of an aging or failed unit, the number of 'removed' transformers may be somewhat less than the totals shown above.

In some years CNPI has installed transformers at a rate exceeding the average sustainable rate, and in some years it has not. The overall five year average rate is 140 units per year, which is reasonable compared with the 'optimal target' rate of 155 transformers / year.

9 System Performance and Reliability

9.1 General

CNPI takes operational performance seriously and does not rely solely on regulation as the impetus to maintain performance levels. CNPI subscribes to the philosophy that meeting customer expectation for system performance is part of its mission as a corporation. As part of this objective, CNPI prepares reports on a monthly, quarterly, and annual basis for all service quality indicators. These reports are then analysed to assess system performance. Reports are also filed with the OEB at the prescribed intervals.

In terms of performance, CNPI monitors the metrics to determine what trends, if any, are developing. The reliability indicators assist in developing the programs within the Asset Management Plan through Cause Analysis. Significant work has taken place in specific areas where the infrastructure was visibly aging, or where trend analysis indicated deficiencies.

Notwithstanding that there are yearly fluctuations; the overall trend is positive in that the frequency (SAIFI), duration (SAIDI) are trending lower provided consideration is given to significant events. Yearly fluctuations can result from variations in weather such as extreme lightning, excessive snowfalls, and ice storms.

9.2 Reliability Analysis

9.2.1 Distribution System Level Analysis

A key objective of the CNPI DAMP is to maintain a high level of distribution system reliability. Capital investments are aimed at improving or maintaining reliability by proactively upgrading deteriorating facilities and adding system capacity to avoid overloads. Investments are also made to ensure that sufficient system redundancy exists so that customers can be supplied from alternate paths in emergency or planned outage situations. Investments in technology such as SCADA monitoring and control provide real-time system information that facilitates the rapid identification of system problems and remote switching that improves the efficiency of outage response.

In addition to the capital investments, maintenance programs and operational practices are also aimed at reliability. For example, in its service territories CNPI maintains industry-standard systematic vegetation management programs to ensure that appropriate clearances are maintained between power lines and surrounding vegetation. In forced outage situations, outage response efforts focus on locating and isolated faulted areas promptly so that most affected customers can be restored from alternate paths. When system components must be taken out of service for planned maintenance, switching is carried out so as to minimize disruption to customers.

The application of SCADA technology allied to Control Room oversight is a key component of CNPI operations, and also impacts upon reliability performance. CNPI's Niagara Region Control Room is currently staffed on a 5 day / 8 hour basis, and after-hours on-call personnel are equipped with the capability to remotely access the SCADA system from offsite locations using laptop computers. Alarms from the SCADA system are also routed to on-call personnel via smart-phones. These initiatives allow for efficient identification of system problems after-hours, which is an essential component of effective outage response.

CNPI's Gananoque territory is controlled by the Control Room located at CNPI's affiliate Cornwall Electric. SCADA upgrades have been implemented in Cornwall that provide the same level of after-hours capability as exists in CNPI's Niagara Region.

CNPI maintains MS Access databases of all outages that occur on its distribution systems. This allows for the tracking and analysis of reliability performance. SAIDI and SAIFI indices are computed from the data. These indices are defined as follows:

- *System Average Interruption Duration Index (SAIDI)* – reflects the total outage time to the average customer over a period of one year.
- *System Average Interruption Frequency Index (SAIFI)* – reflects the number of interruptions to the average customer over a period of one year.

Indices are computed on a monthly and annual basis. Data is submitted to the Ontario Energy Board in accordance with regulatory requirements. In addition, data is also analysed internally by CNPI to identify reliability trends and potential areas for reliability improvement.

Reliability indices for CNPI for the five-year time period 2011-2015 are shown in the table below. The data excludes outages due to Loss of Supply.

Year	2011	2012	2013	2014	2015	Average
SAIDI (hours)	2.41	1.89	3.23	1.95	2.36	**2.37**
SAIFI	**1.80**	**2.21**	**2.72**	**2.07**	**2.78**	**2.32**

Table 26: CNPI-Reliability Indices for years 2011-2015

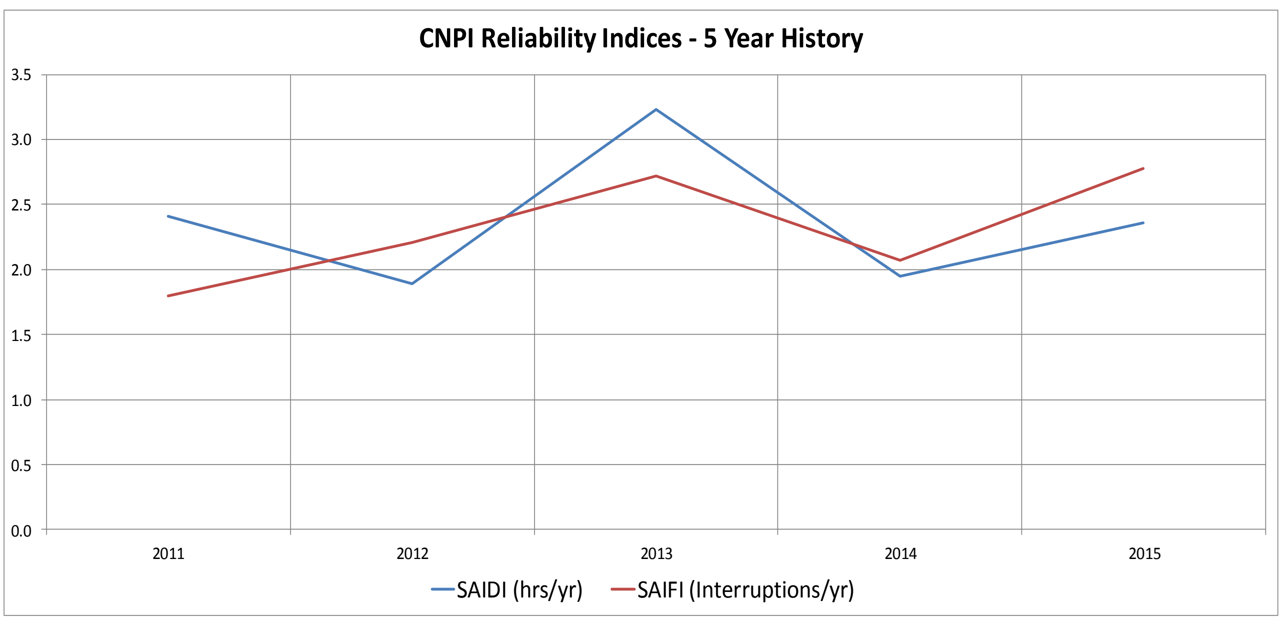


Figure 35: CNPI Reliability Indices – 5 Year History

As an example of the type of reliability analysis that CNPI performs, several inferences can be drawn from the data displayed above. In 2013, both SAIDI and SAIFI exceeded the five year historical average. In 2015, SAIFI again exceeded the historical average. The contributing factors to these period of declining performance are explained below.

2013 SAIDI and SAIFI

In 2013, CNPI experienced a higher than average SAIDI of 3.23 compared to the balance of the five year period ranging from 1.89 to 2.41. In the same year, SAIFI was also above the five year historical average. This was primarily due to a significant weather event on November 1st during which sustained wind speeds in excess of 80 km/h were experienced. There were 53 separate outage events that impacted thousands of customers over a 14 hour period in the areas of Fort Erie and Port Colborne.

2015 SAIFI

In 2015, CNPI experienced a higher than average SAIFI of 2.78 compared to the five year historical average of 2.32. There were three significant events that contributed to this decline in performance.

The first significant event occurred on September 9th. A fault occurred on CNPI's 34.5kV system due to failure of a surge arrester. At the time of the event, a large section of feeder was out of service due to construction activities and work protection requirements. The feeder section was transferred to an adjacent circuit, resulting in over 7,000 customers being temporarily supplied from a single 34.5kV feeder. This constraint limited back-feed possibilities resulting in a significant outage duration for most of the customers affected.

The second significant event occurred on October 29th which consisted of a wind storm with sustained wind speeds in excess of 80 km/h. Gusts in excess of 105 km/h where experienced throughout the event. There were 36 separate outage events that impacted thousands of customers in Fort Erie and Port Colborne over a 12 hour period.

The third significant even occurred on November 12th. Again, sustained wind speeds in excess of 80 km/h were experienced with gusts in excess of 105 km/h. There were 49 separate outage events that impacted customers in the Fort Erie and Port Colborne areas over a period of 12 hours.

Historical Summary

The following two figures illustrate the historical SAIDI and SAIFI values between 2011 and 2015. The indices shown exclude of loss of supply events. As indicated, the aforementioned significant events contributed negatively to CNPI's SAIDI and SAIFI performance over the historical period. Observation of the SAIDI and SAIFI trending with consideration given to these events indicate a relatively consistent performance overall in recent years.

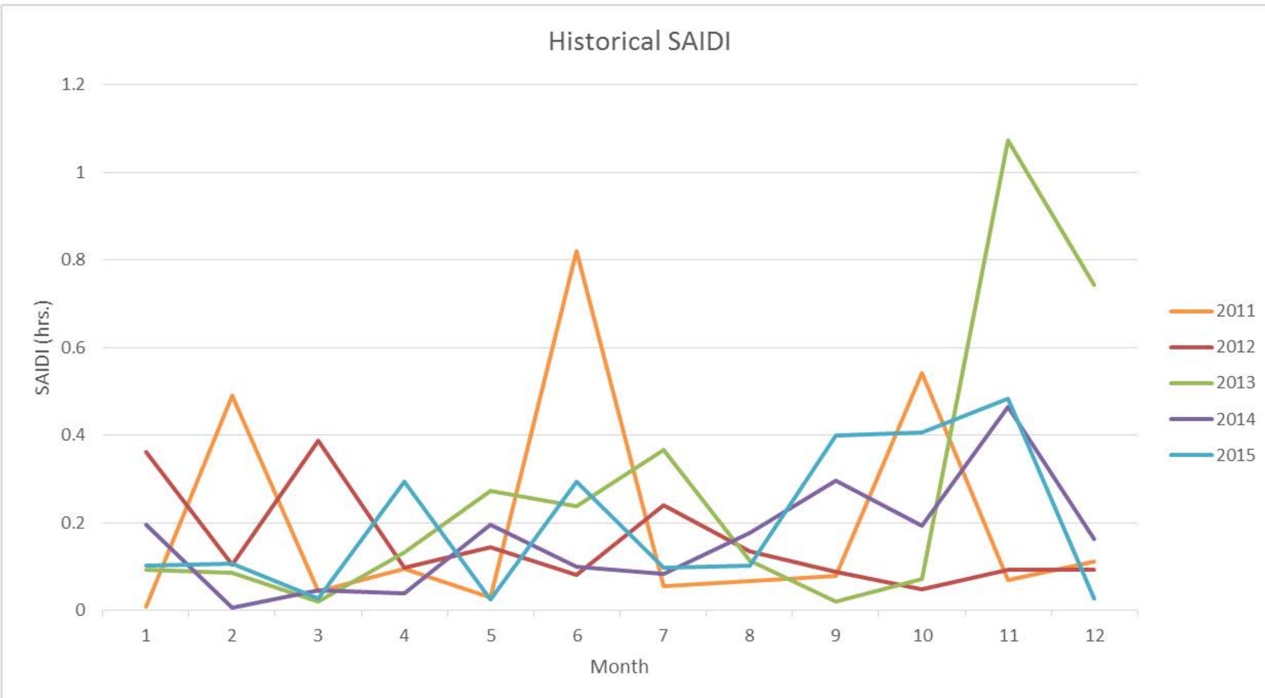


Figure 36: CNPI Historical SAIDI

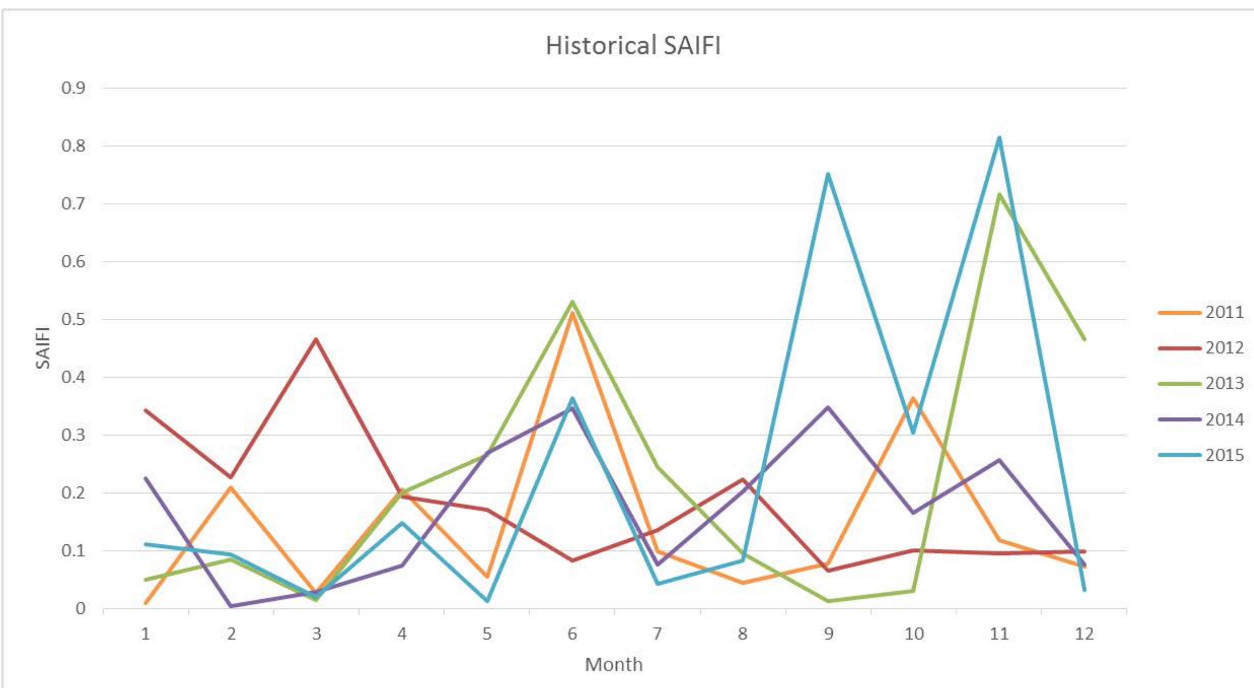


Figure 37: CNPI Historical SAIFI

Figure 37 shows the five year trend of SAIDI and SAIFI with these significant events removed. The chart indicates a general trend of improving reliability in CNPI's service territory, as evidenced by the declining SAIDI and SAIFI indices over the years. This illustrates why CNPI analyzes reliability trends over a period of several years rather than focusing on year-by-year comparisons.

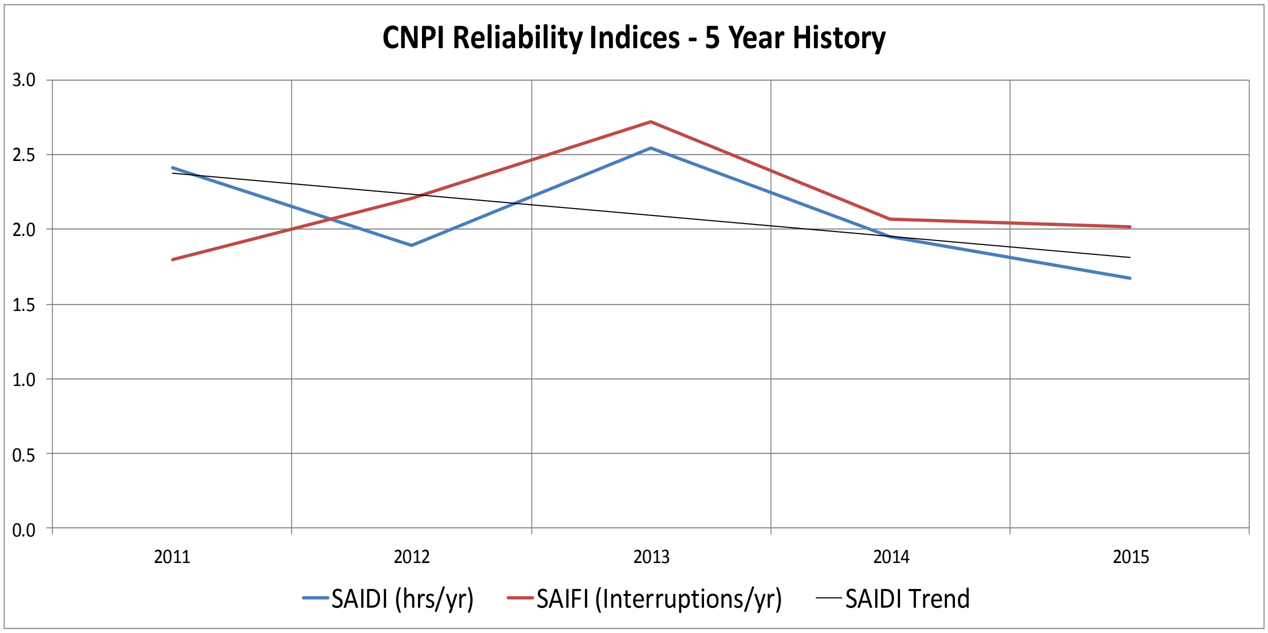


Figure 38: CNPI Reliability Indices – 5 Year History Excluding Significant Events

CNPI also performs more in-depth analysis of outage data to, for example, determine the major causes of outages (both sustained and momentary) and identify poorer-performing areas of its distribution systems. The results of these analyses are then used to support or develop Capital or Maintenance programs aimed at addressing specific weaknesses in the system. Examples of the results of these analyses are shown in the chart below.

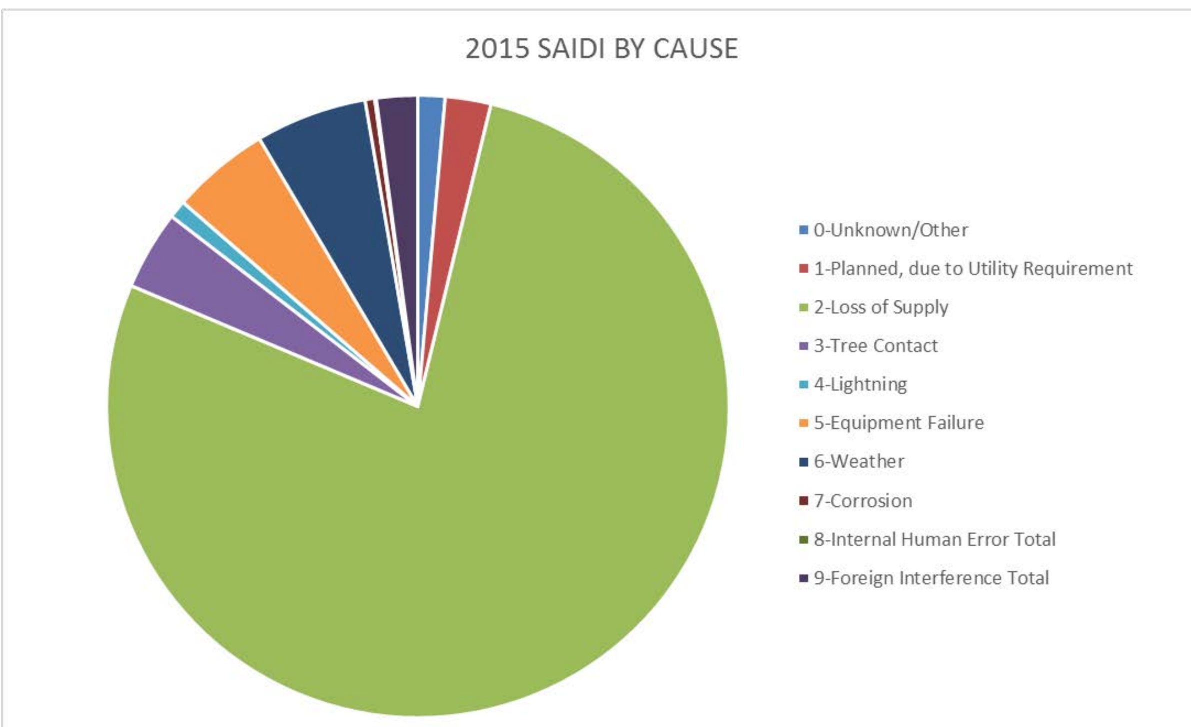


Figure 39: Fort Erie SAIDI for 2015 by Cause Code

Figure 38 above displays Fort Erie SAIDI data for 2015, broken down by Cause Code. Following Loss of Supply, Weather and Equipment Failure were the most significant contributors. This indicates the need for ongoing capital investment to upgrade or replace aging assets.

Aside from its current operational and data management practices pertaining to reliability performance, CNPI has implemented a computerized Outage Management System to improve the effectiveness of its outage response in terms of problem identification, internal communications, and dissemination of information to customers, crew dispatching, and automated collation of outage data. CNPI is also developing mechanisms to set reliability targets specific to individual service territories. CNPI is also monitoring developments in possible OEB initiatives to introduce reliability performance into the regulatory regime, in order to be prepared for the implementation of such requirements.

9.2.2 Feeder Level Analysis

The charts in the following sub-sections display feeder SAIDI and SAIFI data for Fort Erie, Port Colborne, and Gananoque in 2015. This data provides an overview of how well individual feeders performed during the year. Poorly performing feeders can be identified from this analysis, which then allows for further analysis to be undertaken to determine the precise causes for the poor performance of those feeders. Specific plans are then developed to address any issues identified from the analysis. CNPI has developed internal reliability indices called "Feeder SAIDI" (or F-SAIDI) and "Feeder SAIFI" (or F-SAIFI). In calculating these indices, the number of customers on the specific feeder is used as the denominator, rather than the total number of customers on the system. This method allows for normalization of feeder performance and eliminates the skewing of data that could result because feeders serve different numbers of customers. For example, a feeder that only served a few customers but experienced lengthy outages may show only a small contribution to overall system SAIDI. However, using the F-SAIDI computation allows for the derivation of feeder performance specific to the customers it serves.

CNPI's Distribution Automation Program is designed to target feeders with poorly trending performance. Feeders with high year over year values of F-SAIFI become candidates for the implementation of automated devices such as SCADA enabled line reclosers. The implementation of such devices reduces feeder exposure and mitigates the number of customers affected during an unplanned event.

The automated devices are remotely visible and controlled allowing CNPI to expedite switching for fault isolation. This capability puts downward pressure on F-SAIDI numbers based on the ability to restore line sections via CNPI's SCADA system.

The distribution automation program also focuses on the interoperability between automated devices to improve protection coordination. In 2015, CNPI conducted a protection study in order to improve coordination between downstream reclosers and feeder breakers. Protection modifications were implemented at the end of 2015 in an effort to reduce F-SAIDI and F-SAIFI on CNPI's 34.5kV system. The 34.5kV feeders were a major contributor to both of these indices in 2015.

9.2.2.1 Fort Erie

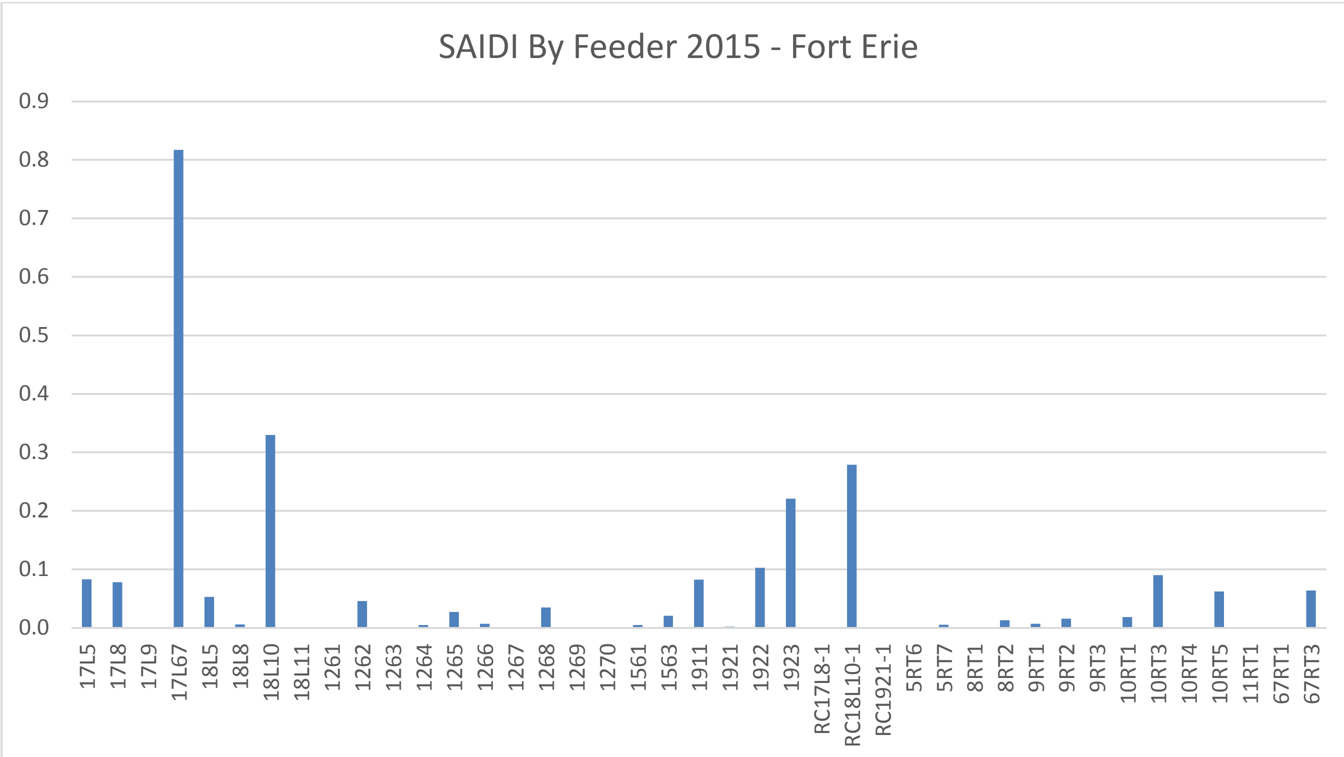


Figure 40: Fort Erie SAIDI for 2015 by Feeder (F-SAIDI)

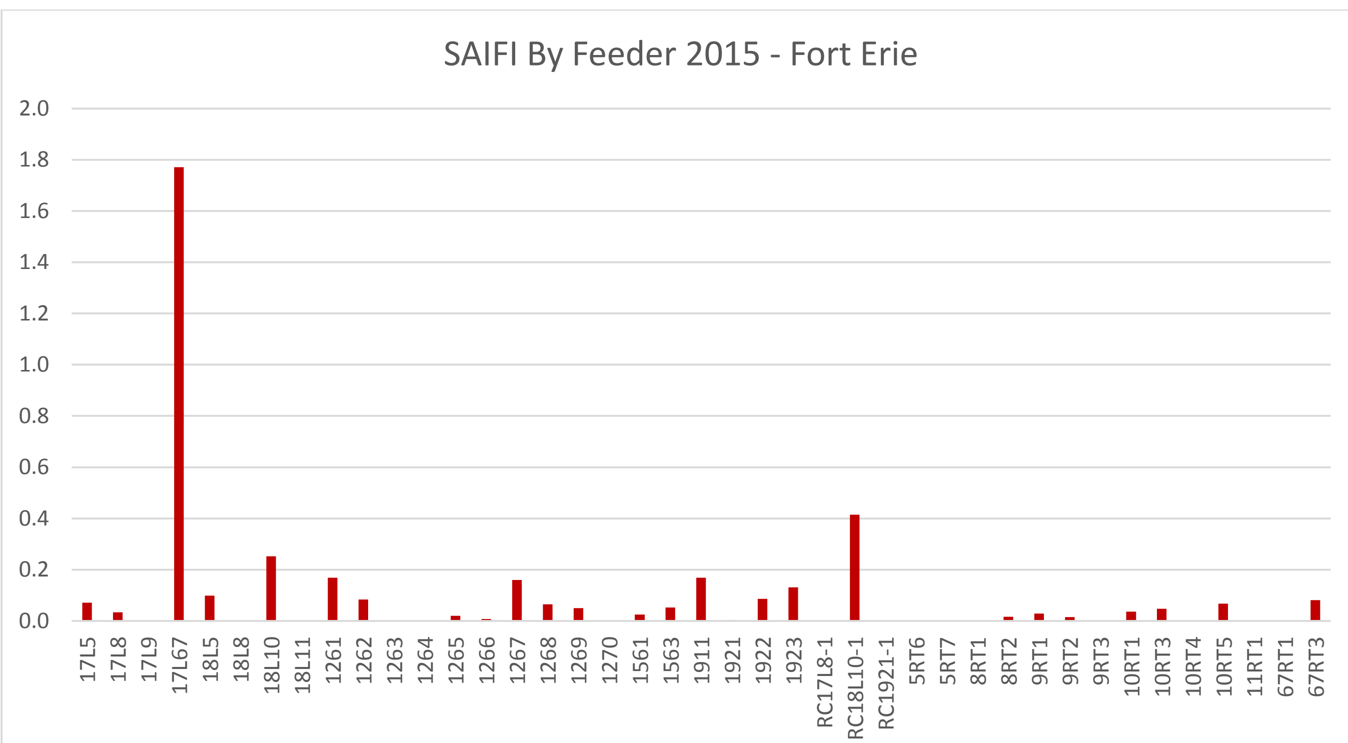


Figure 41: Fort Erie SAIFI for 2015 by Feeder (F-SAIFI)

9.2.2.2 Port Colborne

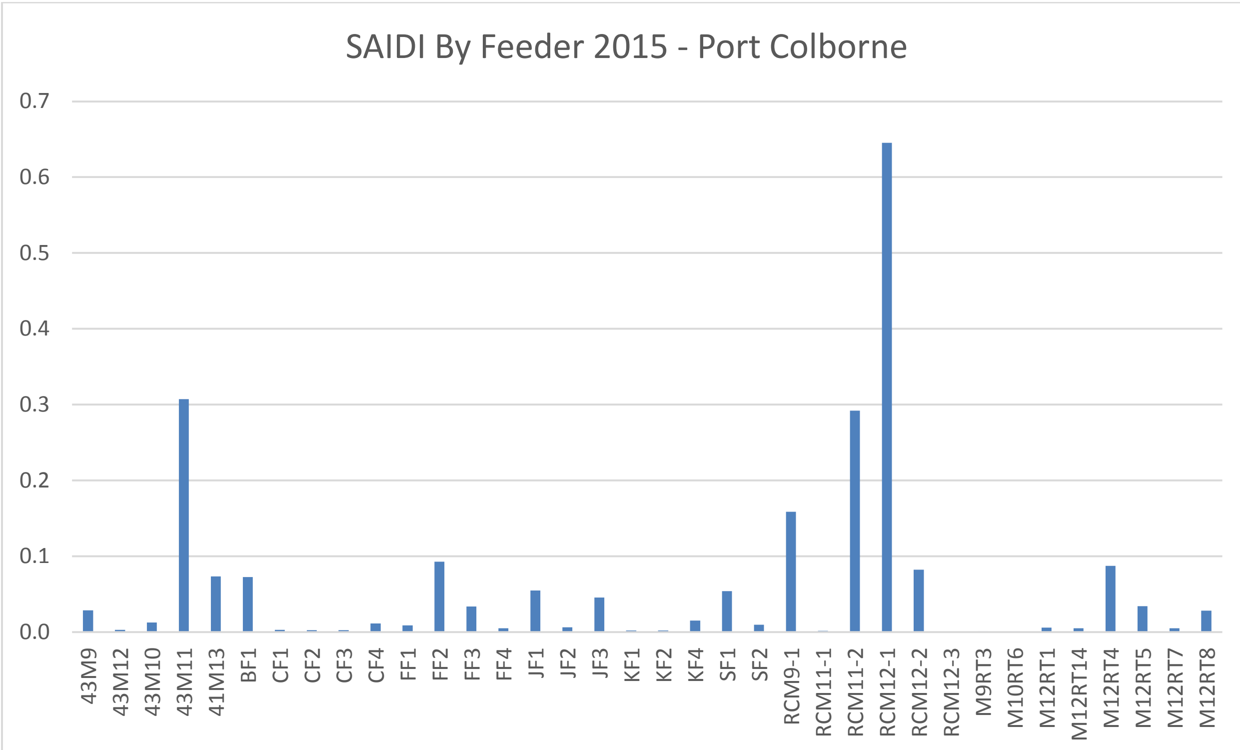


Figure 42: Port Colborne SAIDI for 2015 by Feeder (F-SAIDI)

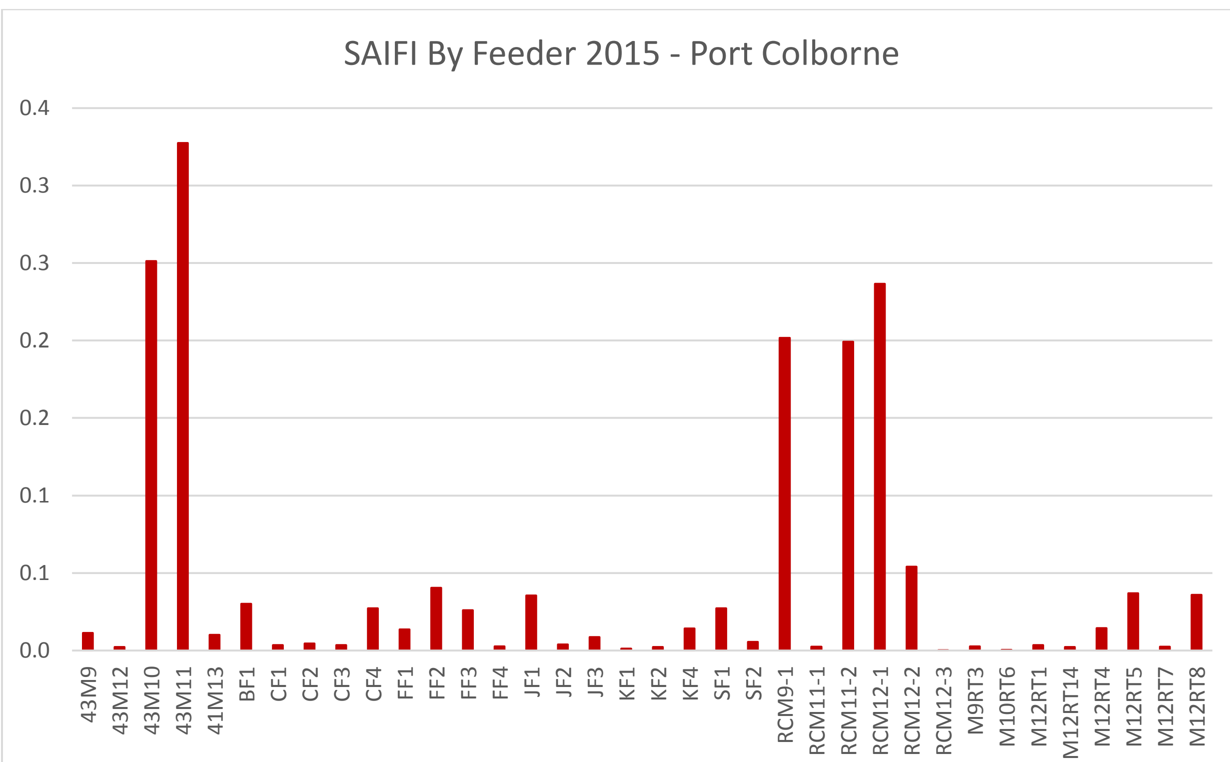


Figure 43: Port Colborne SAIFI for 2015 by Feeder (F-SAIFI)

9.2.2.3 Gananoque

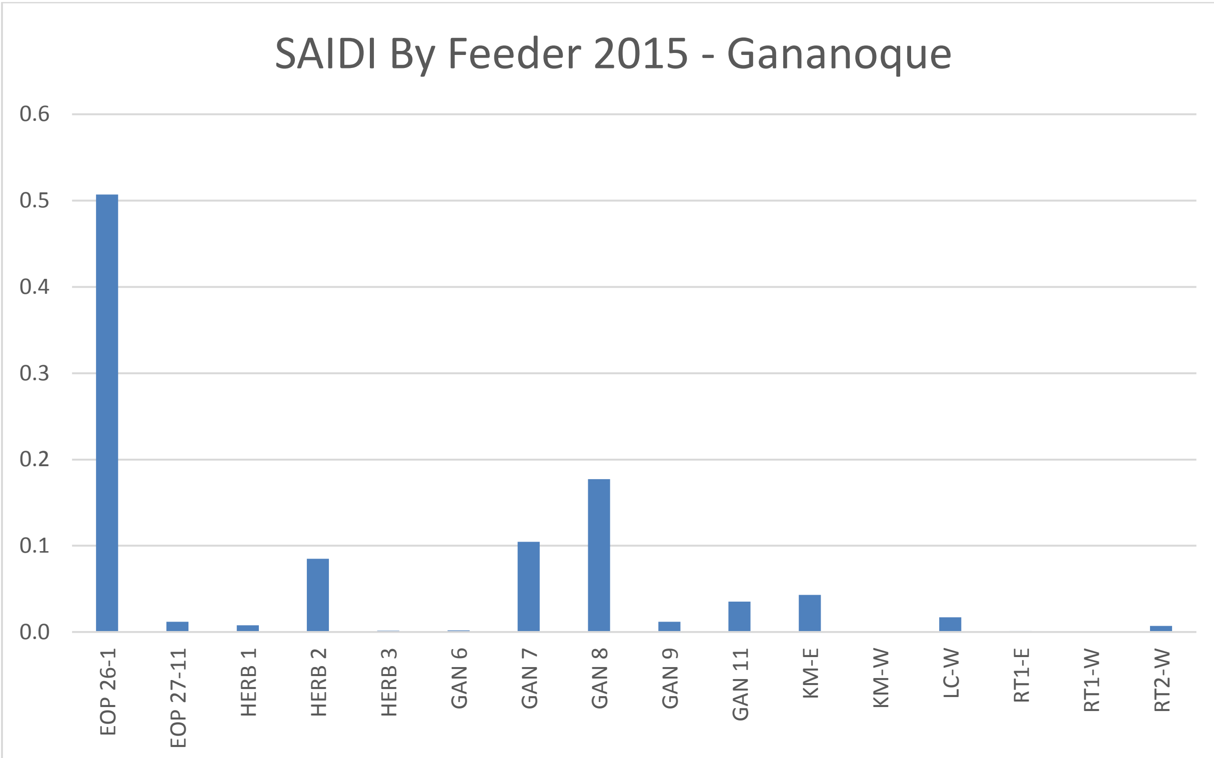


Figure 44: Gananoque SAIDI for 2015 by Feeder (F-SAIDI)

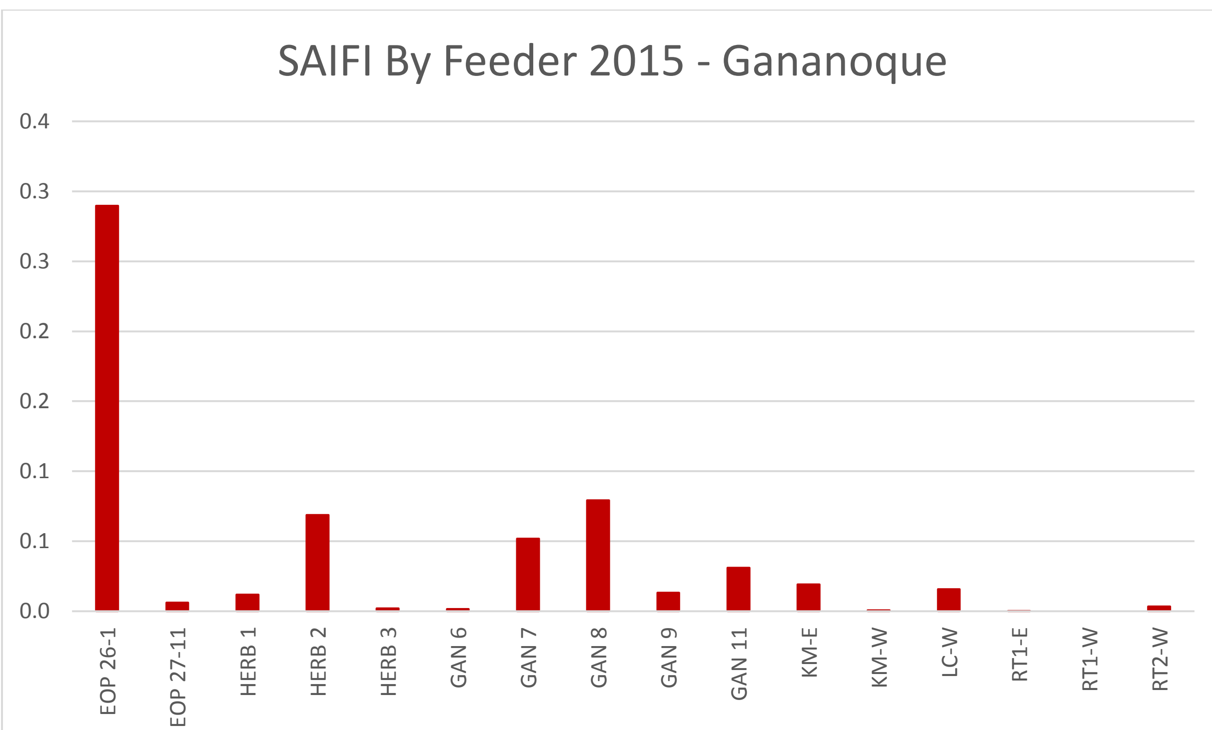


Figure 45: Gananoque SAIFI for 2015 by Feeder (F-SAIFI)

10 Appendices

Table of Contents:

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Appendix A.
Maps of CNPI Regions

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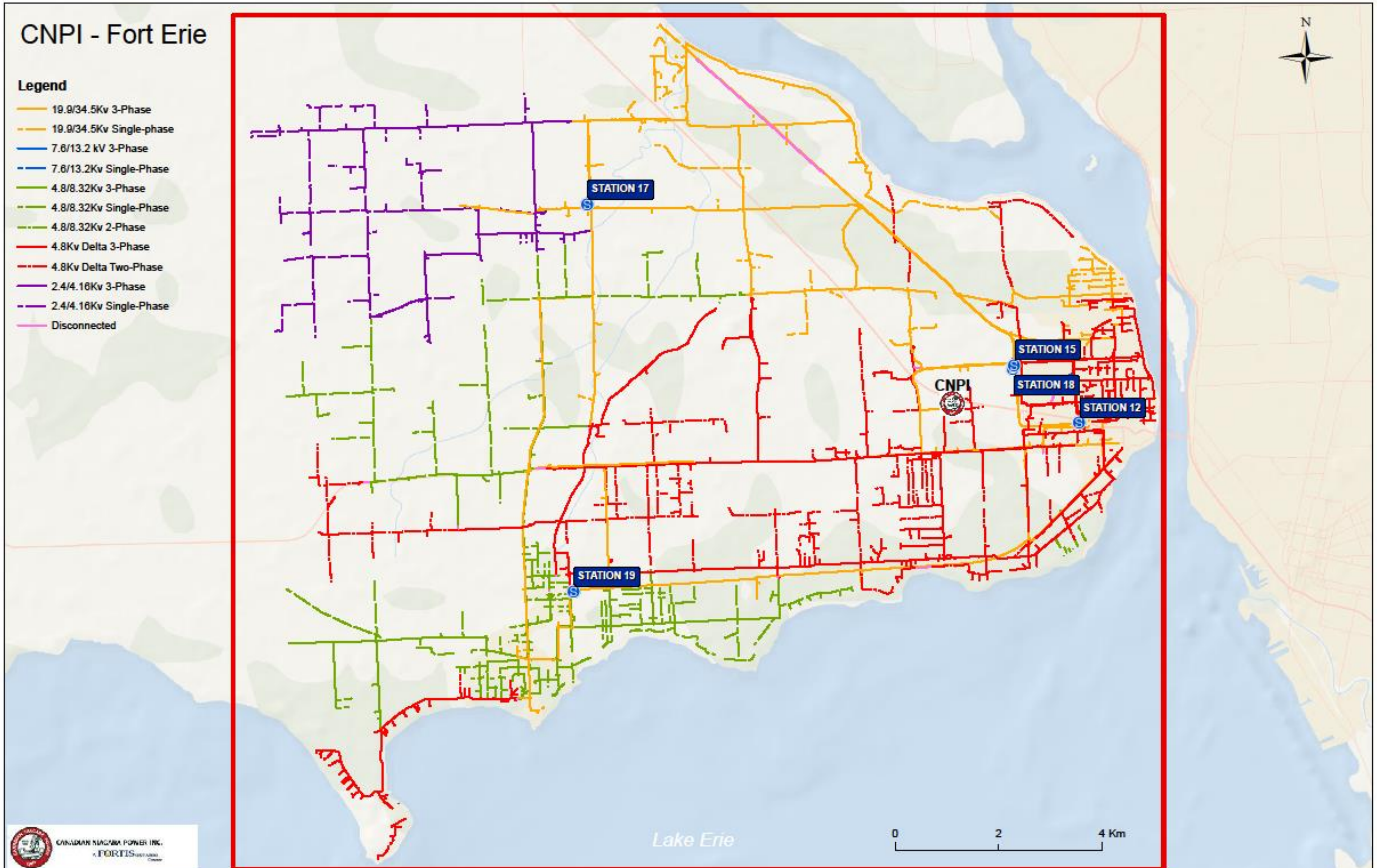
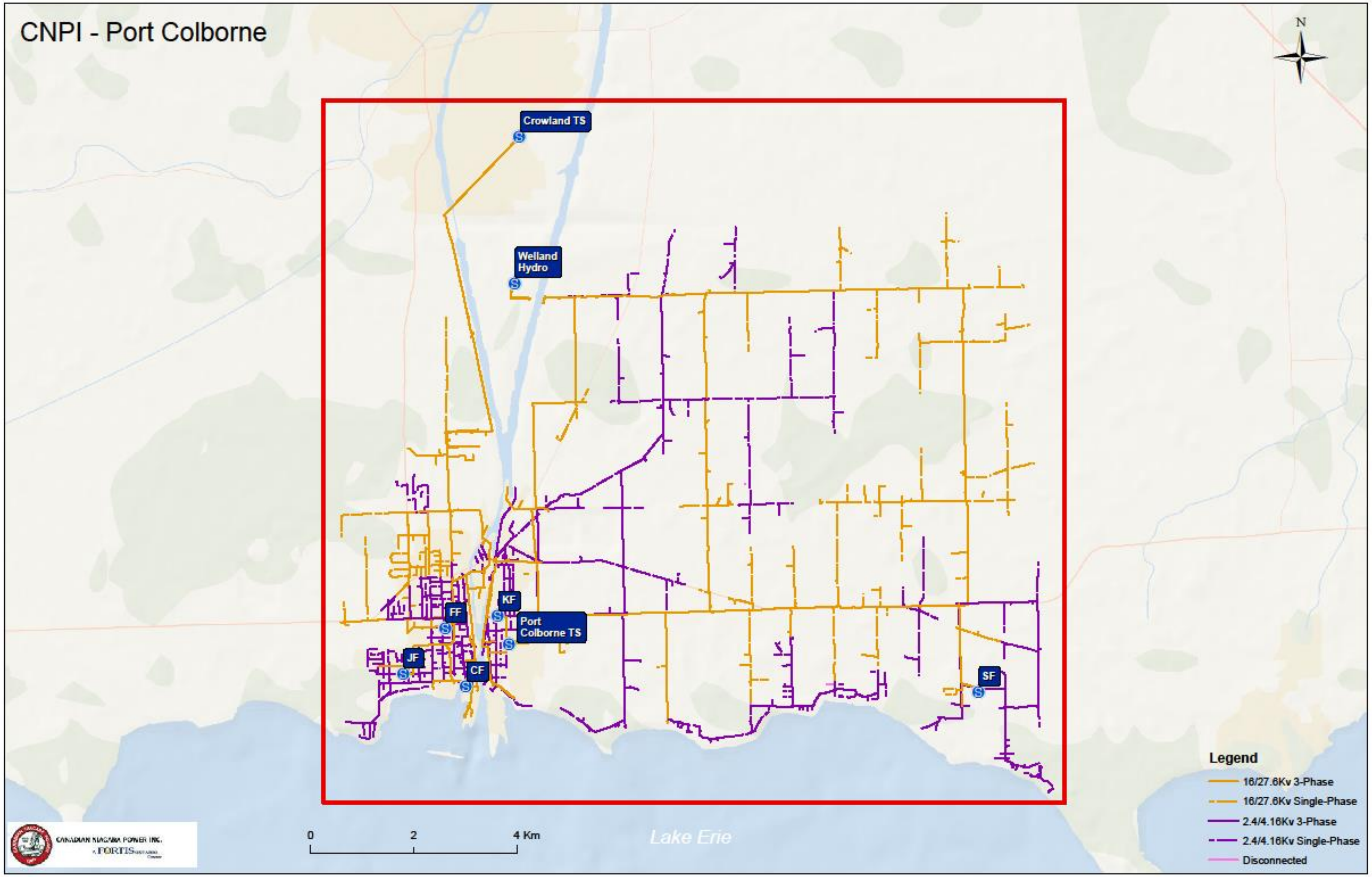
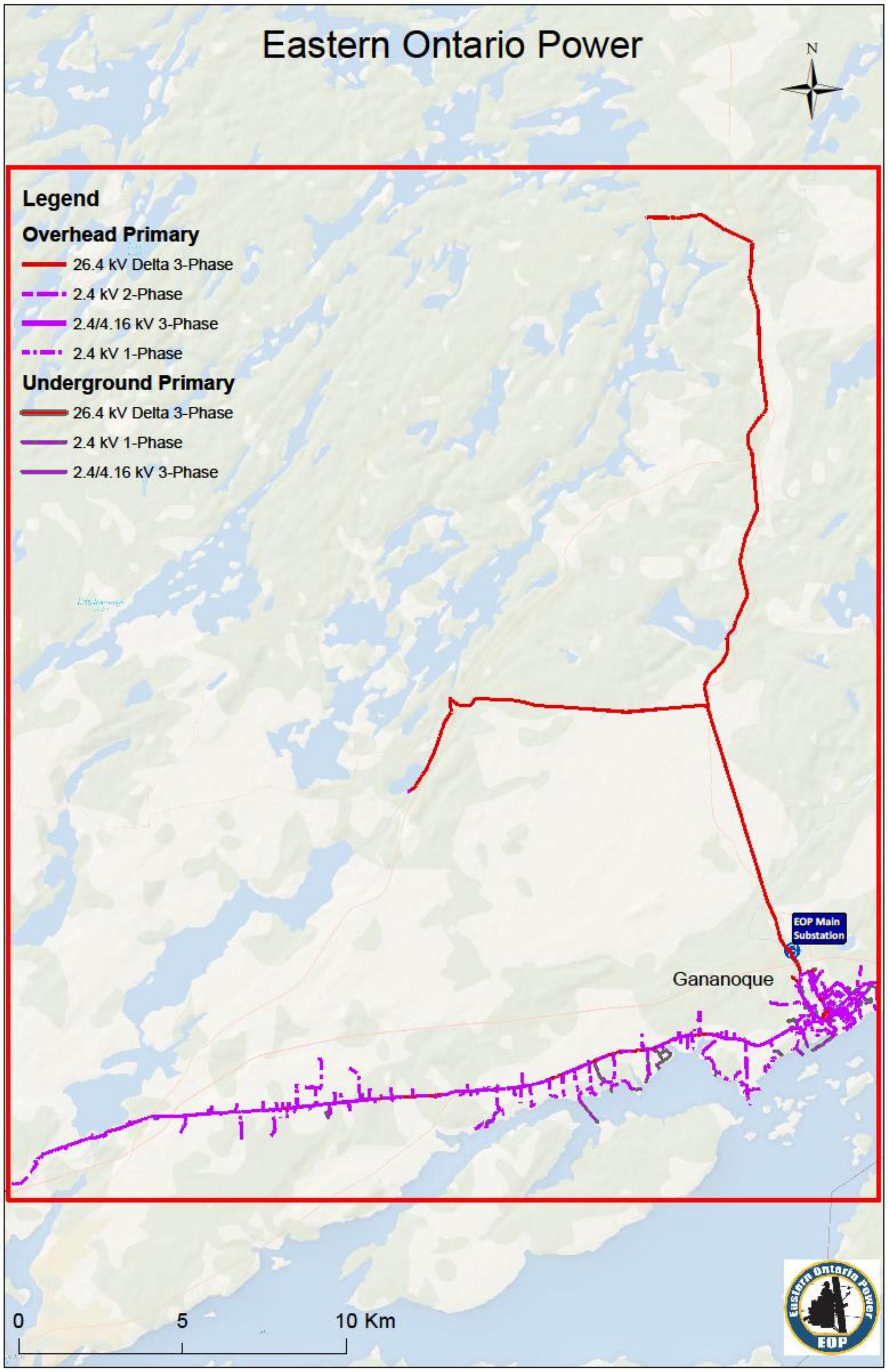
A1. Fort Erie


CNPI - Fort Erie
Legend
19.9/34.5Kv 3-Phase
19.9/34.5Kv Single-phase
7.6/13.2 kV 3-Phase
7.6/13.2Kv Single-Phase
4.8/8.32Kv 3-Phase
4.8/8.32Kv Single-Phase
4.8/8.32Kv 2-Phase
4.8Kv Delta 3-Phase
4.8Kv Delta Two-Phase
2.4/4.16Kv 3-Phase
2.4/4.16Kv Single-Phase
Disconnected
N
STATION 17
STATION 15
STATION 18
STATION 12
STATION 19
CNPI
Lake Erie
0
2
4 Km
CANADIAN NIAGARA POWER INC.
A FORTIS

A2. Port Colborne



A3. EOP (Gananoque)



Appendix B.
Samples of CNPI Substation Maintenance Documents

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B1. Distribution Substation Electrical Department Monthly Inspection

CANADIAN NIAGARA POWER INC.

Electrical Dept. Substation Inspections

PROCEDURES	SYSTEM Condition	FREQUENCY
V - VISUALLY INSPECT	X = Action Required	M = Monthly
C - CHECK	D = During Inspection	Q = Quarterly
C - CLEAN	√ = Good	S = Six Months
T - TEST		Y = Yearly

Distribution Substation Report of

		Station	
12	✓		
15		Barrick Sta.	
19		Catherine Sta.	
		Fielden Sta.	
		Jefferson Sta.	
		Killaly Sta.	
		Sherkston Sta.	

Performed By V.K - J.F

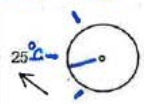
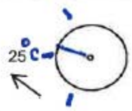
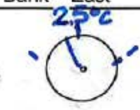
Date FEB. 25 - 2016

ITEM		Visual	Check	Service	Clean	Test	Frequency	Condition	Type of follow-up required during inspection
	BATTERY SYSTEM								
1	*Electrolyte Level*	V	C	S			M	✓	
2	Specific Gravity	V	C			T	M	✓	
3	Battery cell / block voltage	V	C			T	M	✓	
4	Charger / Battery voltage	V	C			T	M	✓	
5	Pos. / Neg. ground voltage	V	C			T	M	✓	
4	Remove corrosion clean & dry	V	C	S	C		S	X	CORROSION BUILD UP
5	Terminals Tighten	V	C	S			Y	X	REQUIRES CLEANING +
6	Reset charger codes	V		S			M	NA	TIGHTENING
	AC STATION SERVICE								
1	General Inspection	V					M	✓	DRAINS BACK-UP WHEN RAINING
2	Panel pilot lights control lamps	V		S			M	✓	1083 + 1053 REQ'S 48V L.E.D
3	Building Int. & Ext. lighting	V		S	C	T	M	X	WEST SIDE M/C H.P.S DUSK TO
4	Station structure lighting	V		S	C	T	M	✓	DAWN FAULTY
5	Panel emerg. lighting	V		S	C	T	Q	✗	REQ. BATTERY EXIT (
6	Circuit breakers tripped	V	C	S			M	✓	
7	Fuses test output voltage	V	C	S			Q	NO	
8	Ac & Dc spare fuse review	V	C				Q	✓	REQ. A LIST TO REVIEW.
9	Pilot light spare lamp review	V	C				Q	NO	
10	Station maps update	V		S			Q	X	31/08/2015
11	Air filter insp. / block / winter cycle	V	C	S			S	✓	
12	Exhaust fan lubrication	V	C	S			Y	X	(FIRST EXHAUST FAN M/C.
13	Building heaters fan & elements	V	C	S	C	T	S	X	REQ'S CHANGING)
14	Building cooling fan / filters	V	C	S	C	T	S		
									PORTABLE HTR. VERY NOISY TAKEN OUT.
	STATION INSPECTION								
1	General transformer inspection	V					M	✓	
2	Pot transformer / Current trans.	V					M	✓	
3	Gauges temp. / oil	V	C				M	✓	
4	Differential air pressure gauge	V	C				M	✓	
5	SF6 / Nitrogen gauges	V	C				M	NA	
6	Bushings / Arrestors	V					M	✓	
7	Radiators & Fan motors	V	C	S		T	M	✓	
8	Breakers / Enclosures	V	C				M	✓	
9	Gang sw.'s / Bld. Sw.'s / Fuse's	V					M	X	M/O 1055 NOT CLOSING FULLY
10	Insulators	V					M	X	(NOT CLOSING PAST
11	Inferred inspection	V				T	Q		INTERRUPT
	FIELD INSPECTION								(TRACKING ABOVE) SW.)
1	Fence grounding / Placards	V	C				M	✓	R1183
2	Sump pump	V	C	S		T	M	NA	
3	Drainage chambers grates	V	C	S	C		M	NA	
4	CSP soak away evidence	V	C	S	C		M	NA	
5	Water sample form chambers	V				T	S	NA	
6	Underground Stor.Tank. integrity	V	C				Y	NA	
7	Vegetation / weed growth	V					M	✓	

First Aid	Eye Wash	Spil Kit	Rubber Gloves	Sw. Sticks	Modiewark Tester	IHSA Tags	Gate & Fence	Fire Extinguishers
✓	✓	✓	MAR .2-2015	✓	✓	✓	✓	✓

Distribution 27.6 Kv. 34.5 Kv. Substation Report of

Station No. 12	Bank 1	Bank 2	Bank 3
Date: FEB. 25-16			
Ambient Temp. 0°C			
Trans. Upper Limit Oil Temp.	38°C	32°C	37°C
Trans. Operating Oil Temp.	17°C	19°C	15°C
Upper Limit Winding Temp		39°C	
Operating Winding Temp.		24°C	
Differential Air Pressure	-.5	0	+.5
Liquid Level (Temp.Tank) %			
Transformer Fans	✓	✓	✓
Liquid Level Main Tank %			

BANK3	Bank 2 West	Bank 1 East
		25°C 

Station 12	
Date:	
34.5 K.v. Breakers	
Operations	
Oil Brk.	Current
R1083	5
R1183	5
R1053	56
R1121	126
R1132	? 11
4.8 K.v. Breakers	
Operations	
Mag.	Current
R401	856
R402	827
R403	192
R404	740
R405	917
R406	549
R411	899
R412	14
R413	882
R414	849
R415	803
R416	705
R421	148
R422	999
R423	847
R424	846
R425	927

Station 15	
Date:	
34.5 K.v. Breaker	
Operations	
Oil Brk.	Current
R1553	
4.8 K.v. Breakers	
Operations	
R611	
R612	
R613	
R614	

Station 19	
Date:	
8.3 K.v. Breakers	
Operations	
Vacuum	Current
R1-B1	
R1911	
R1912	
R1913	
RB1-B2	
R1-B2	
R1921	
R1922	
R1923	

Fielden Station T1	
Date:	
4.16 K.v. Breakers	
Operations	
Mag.	Current
RWI	
FB-1	
FB-2	
FB-3	
FB-4	

Fielden Station T2	
Date:	
4.16 K.v. Breakers	
Operations	
Vacuum	Current
F-T2 M9	
FB-5	
FB-6	
FB-7	

Jefferson Station	
Date:	
4.16 K.v. Breakers	
Operations	
Mag.	Current
JB-1	
JB-2	
JB-3	

Sherkston Station	
Date:	
27.6 K.v. Breakers	
Operations	
Vacuum	Current
SB-110	
SB-210	
4.16 K.v. Breakers	
Operations	
Viper	Current
SB-1130	
SB-2230	
SB-3330	
SB-5530	

R1132 REQ'S NEW OPERATIONS COUNTER.

B2. Distribution Substation Battery Report

Canadian Niagara Power Co. Ltd.

Station F.E.	**12**

Date	25th FEB 2016
Tested by	J

Make of Batteries	**GOULD**	
Cell Type	**(3ETC7)**	
Batteries Number of cells 60		
Pos. electrode low antimony led alloy		
Electrolyte - Diluted sulfuric acid density = 1.24 kg/l		
Amp. Hr. Cap. Disc. 8 Hr. rate to 1.80V @ 20`C		130 A
Short Circuit Current Amp		
Typical Weight	Lbs	

Float Charge Voltage	2:23 V@ 20`C ( 68`F)
	2:21 V @ 25` C (77`)
Nominal Float Voltage	133.8 Volts
Nominal Equalize Voltage	141.1 Volts

Correction temp. sp.grv. 1.215 @ 77`F (25`C)
(each 3`F above or below 77`F + or - .001)

Battery Charger **STATICON**
Model No. CT34A120B6
Serial No. 7302 March 70
Input Voltage 120 vac
Input Curent 12 amp
Output DC 120v 6 amp
Output Voltage Float 133.8 VDC (2.23V/C)
Output Voltage Equalize 141.0 VDC (2.35V/C)
Max. Current Limit. Set @ low battery voltage 127.0V current 7A

Hydra. Reading	Cell Temp.	Correction	Read. Cor. to. 77`F
1.213sp.g	68`F 20`C	-0.003	1.210 sp.g
1.207sp.g	86`F 30`C	0.003	1.210 sp.g
1.204sp.g	95`F 35`C	0.006	1.210 sp.g
* Indicates Higher than norm value 6.81v max			
X Indicates Lower than norm value 6.69v max			

General Cell Bank Testing

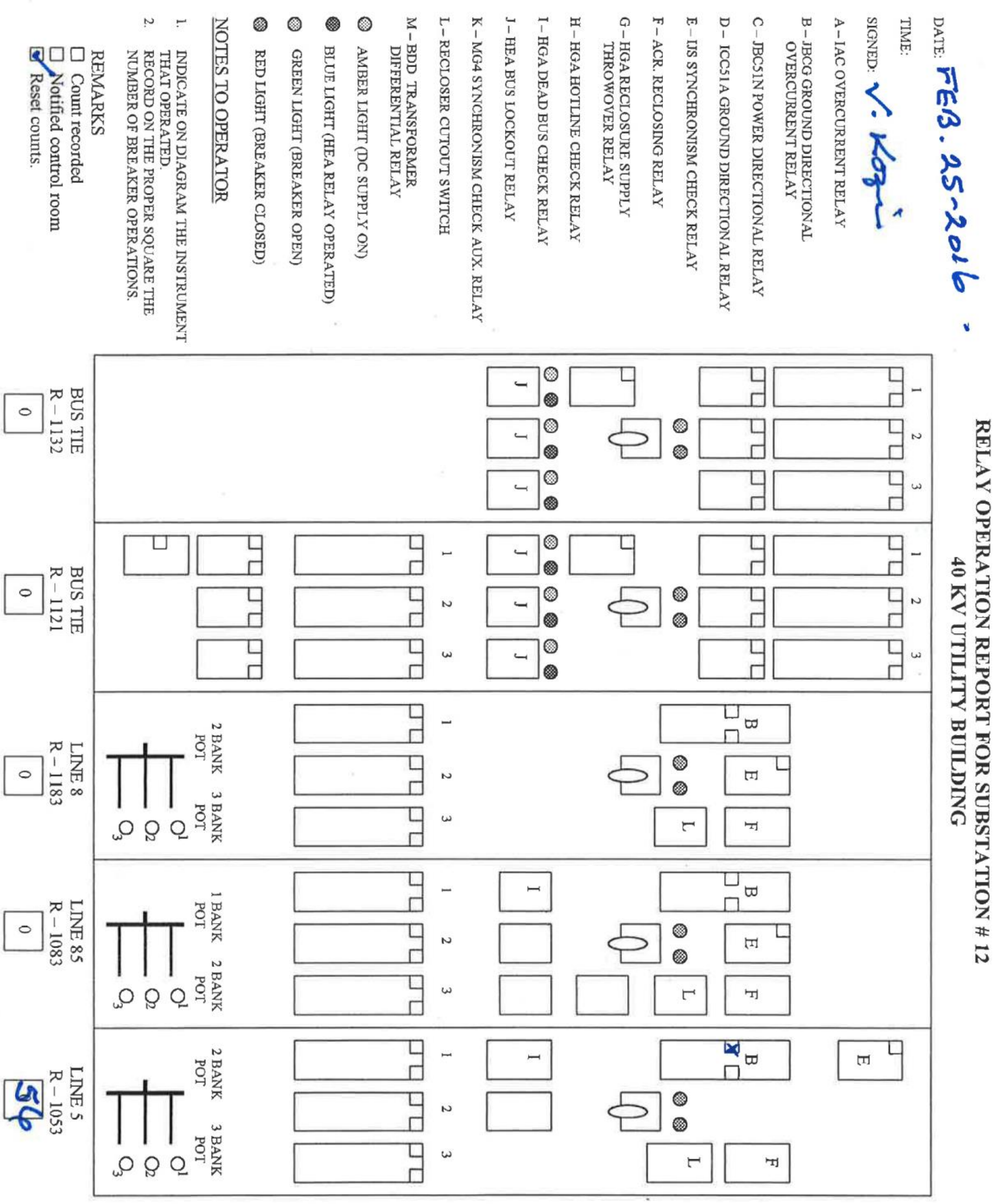
Cell	S.P.	Voltage	Level	Cell	S.P.	Voltage	Level
1				31			
2				32			
3				33			
4				34			
5				35			
6				36			
7				37			
8				38			
9				39			
10				40			
11				41			
12				42			
13				43			
14				44			
15				45			
16				46			
17				47			
18				48			
19				49			
20				50			
21				51			
22				52			
23				53			
24				54			
25				55			
26				56			
27				57			
28				58			
29				59			
30				60			
Avg. Cell Temperature							

Test Readings		
Float Output Voltage	136	Volts
Float Charging Rate	4.6	Amps
Battery Post Voltage + / -	134.3	Volts
Positive Post / Gnd.	66.5	Volts
Negative Post / Gnd.	67.6	Volts
Note Requirement for Equalizing:		
Equalize Voltage		Volts
Equalize Charging Rate		Amps
Room Air Temperature	51 F.	Temp.
Pilot Cell Temperature	11°C	Temp.
Hydra - Correction Temp.	+1	Temp.
Pilot Avg.Temp. (AntonPaar)	11.2°C	Temp.
Time of Testing	11:30 AM	

Sample Cell testing				
Cell	S.P.	Voltage	Level	P. to Gnd.
15	1222	2.243	✓	66.5
50	1218	2.238	✓	Pos to Neg. 134.3
2	1210	2.247	✓	
20	1224	2.257	✓	67.6
Avg. Cell Tempera... 11°C				N. to Gnd.

COMMENTS:	Battery TERMINALS REQUIRE CLEANING

B3. Distribution Substation Relay Operation Report



B4. Transformer Oil Sample Analysis Results (2 pg)

OIL SAMPLE ANALYSIS RESULTS
IN SERVICE - OIL

Cust PO : PORT COLBORNE

Lab No . . . : T 2015-1676
File No . . . : 10320
Cust No . . . : CAN44

CANADIAN NIAGARA POWER COMPANY LTD.
1130 BERTIE ROAD
P.O. BOX 1218
FORT ERIE ONT
L2A 5Y2

Date Received : OCT 06 2015
Analysis Date : OCT 08 2015
Analyzed By : MJ
Reviewed By : SwD

SAMPLE IDENTIFICATION

Description : PORT COLBORNE, SHERKSTON ST. BANK 1 TRANSFORMER

Rating :	5.0 MVA	Volume	: 1070 IMP. GALLONS
HV_Rating :	27.6 kV	Sample Port	: BOTTOM - MAIN TANK
Manuf. / Date:	RELIANCE 1959	Sampled By	: V.K
Serial No :	P51431	Sample Date	: OCT 02 2015

TEST	ASTM NO.	RECOMMENDED LIMITS	TEST VALUES
Dielectric Breakdown	D1816	mm Gap KV (Min) 1816 -	
	D877	30 KV (Min) 877 -	57
Neutralization Number	D974	0.2 Max (0.5 - Scrap) Milligrams KOH/gram	<0.01
Interfacial Tension	D971	25 Dynes/cm (Minimum)	44
Specific Gravity	D1298	(60/60°F)	0.864
API Gravity			32.2
Colour	D1500	0.5 – 8.0	1.0
Visual Condition		Clarity	CLEAR
	D1524	Sediment	NONE
		Free Water	NO
Water Content	D1533	35 p.p.m. max	15
Power Factor (25 C)	D924	0.5 % max	0.031
Power Factor (100°C)	D924	5.0 % max	

TEST EVALUATION

OIL IS IN SATISFACTORY CONDITION FOR CONTINUED USE

RECOMMENDATIONS: SAMPLE AS PER SCHEDULE

Notes :

RONDAR INC. 333 Centennial Parkway North Hamilton, Ontario L8E 2X6
Telephone : (905) 561-2808 Fax : (905) 561-8871

DISSOLVED GAS ANALYSIS - OIL
ASTM Method D3612 Part C

Cust PO : PORT COLBORNE		Lab No	: D 2015-1699
		File No	: 10320
		Cust No	: CAN44
CANADIAN NIAGARA POWER COMPANY LTD.			
1130 BERTIE ROAD		Date Received	: OCT 06 2015
P.O. BOX 1218		Analysis Date	: OCT 06 2015
FORT ERIE	ONT	Analyzed By	: MJ
L2A 5Y2		Reviewed By	: S.D

SAMPLE IDENTIFICATION

Description : PORT COLBORNE, SHERKSTON ST. BANK 1 TRANSFORMER

Rating	: 5.0 MVA	Fluid Temp.	: 23 (°C)
HV Rating	: 27.6 kV	Volume	: 1070 IMP. GALLONS
Manuf. / Date	: RELIANCE 1959	Preservation	: BREATHING
Serial No	: P51431	Syringe Serial	: 5444
Sample Port	: BOTTOM - MAIN TANK	Sampled By	: V.K
		Sample Date	: OCT 02 2015

COMPONENT	MEASURED PPM	% COMBUSTIBLES
Hydrogen (H2)	8	11.9
Oxygen + Argon (O2 + A)	31239	-----
Nitrogen (N2)	53546	-----
Methane (CH4)	<1	.0
Carbon Monoxide (CO)	54	80.6
Carbon Dioxide (CO2)	530	-----
Ethylene (C2H4)	<1	.0
Ethane (C2H6)	<1	.0
Acetylene (C2H2)	<1	.0
Propane (C3H8)	5	7.5
Total Gas Content	8.54 %	
Combustible Gas Content	67 ppm	.078 %

*PPM = Part Per Million by volume N.D. = Not Detectable

General Comments: FAULT GAS CONCENTRATIONS HAVE REMAINED WITHIN NORMAL RANGE SINCE SEP/14.

Recommendations : SAMPLE AS PER SCHEDULE FOR DISSOLVED GASES

Notes :

RONDAR INC. 333 Centennial Parkway North Hamilton, Ontario L8E 2X6
Telephone : (905) 561-2808 Fax : (905) 561-8871

Appendix C.
Samples of CNPI Line Maintenance Documents

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C1. Line Inspection Form

LINE INSPECTIONS FOR 2015

Charge time to: # 5003825

WHAT TO CHECK FOR IN ZONE #3:

GRIDS

- CHECK ACCURACY OF SWITCHES, GEOGRAPHICS,LINE STYLES, NOMENCLATURE, PRIMARY WIRE SIZE AND PHASE MARKINGS.
- ALL CHANGES TO BE INDENTIFIED IN RED INK.

DEFICIENCIES - GRADE 1 (PLANNING) & GRADE 2 (LINES MAINT)

- DOCUMENT PICTURE FOR ANY GRADE 1 DEFICIENCY
- CROSS ARMS
- SWITCHES AND ARRESTORS
- GROUND WIRES
- DOWN GUYS
- POLES
- TRANSFORMERS

DO NOT CREATE DEFICIENCIES FOR THE FOLLOWING MAKE THE REPAIR ON SITE.

- GUY GUARDS
- BROKEN PINS,INSULATORS AND FLOATERS
- REPAIR BROKEN OR STOLEN DOWN GROUNDS

C2. CNPI Field Deficiency Report (2 pg)

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

DEFICIENCY REPORT Nº 1404

Date: 2014/11/24

Location: 3469 SWITCH RD

Feeder: 17L5 Grid: 2724 Zone: 1

Deficiency Found:

- BROKEN POLE

Corrective / Temporary Action Taken: Date: 2014/11/24

- MOVED CROSS ARM DOWN
- PUT CENTER PHASE ON ARM

COMPLETE
S. Benner 901 2013
DATE 2015/07/24
CANADIAN NIAGARA POWER INC.

Is Corrective Action Permanent? ☐ Yes ☑ No

Recommendation for Further Action:

- NEW POLE

Emailed to: __________

Date: __________

Reported By: STEVE BUHL

White - Departmental Supervisor Yellow - Responsible Department Pink - Operations

C3. Job Plan Deficiency Correction Form

FORTIS ONTARIO **SMALL PROJECT WORK PLAN**

Brief Description of **Deficiency** or **Small Project**

☐ **Deficiency or Project No.:** ____________

Type of Project (select one only):
☐ Like-for-Like Replacement (Legacy)
☐ Upgrade of Existing Plant

Attachments forming part of this work instructions (in addition to Approved Standard Designs):
☐ Job drawing or Sketch
☐ Photograph(s) ___ (Quantity)
☐ Bill of approved materials
Other ____________

Description of Work to Perform
(Ensure that all Construction Standard Numbers to be used are shown):

☐ All planned work is using **Standard Designs** or Engineered Designs (allowing a **competent** person to inspect and certify)

Sketch of Work to Perform
(Ensure that all Construction Standard Numbers to be used are shown):

N ↑

JOB PLAN CHECKLIST
☐ Only approved material will be used
☐ All standard designs used in this project are clearly identified
☐ Construction personnel have copies of all standard designs to be used for this work
☐ Work instructions were prepared by competent personnel (where standard designs were not used)
☐ All 3rd Party (J.U.) attachments meet or exceed minimum acceptable safety standards

Certification of Design Approval:

☐ This is to certify that, for FortisOntario, the work designs covered by this document (and any related documents listed above) meet the safety standards of Section 4 of Ontario Regulation 22/04 by the use of Standard Designs and/or other engineered designs,

☐ This is to certify that the work designed covered by this document (and any related documents listed above) meets the definition of Like-for-Like replacement as defined in O.Reg. 22/04 and meets all necessary safety standards as described in Section 4 of O. Reg. 22/04

____________ Signature of Competent Person 20__/__/__ year month day

Record of Inspection

☐ Only approved equipment has been used
☐ Approved Plan (on this form) has been followed.

All construction is in accordance with standard designs and/or meets or exceeds all appropriate safety standards:
☐ YES ☐ NO (details on reverse side)
☐ No Non-Conformances, this is a Final Inspection. - or -
☐ There are NON-Conformances (details on reverse side)

____________ Signature of Competent Person 20__/__/__ year month day

Certification of Construction Approval

In accordance to *Ontario Regulation 22/04*:
This is to certify that:

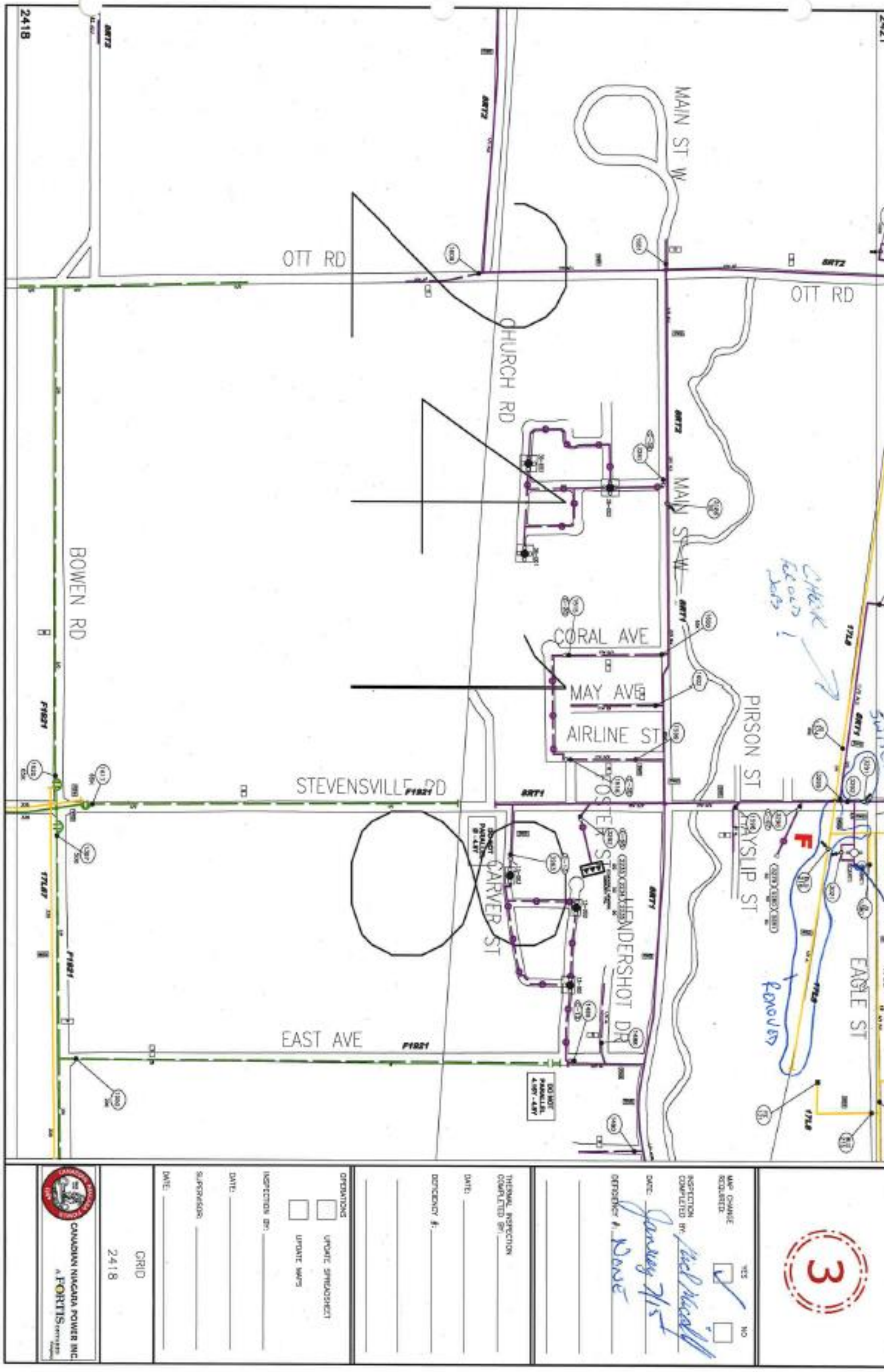
- The construction recorded on this document is consistent with FortisOntario Standard Designs and work instructions.
- All 'as-built' field changes have been approved by the Engineering / Planning department or Operations department and properly recorded on the work instructions.
- Only approved equipment was used.
- All worksites were left in a safe condition, and no undue hazards are present.

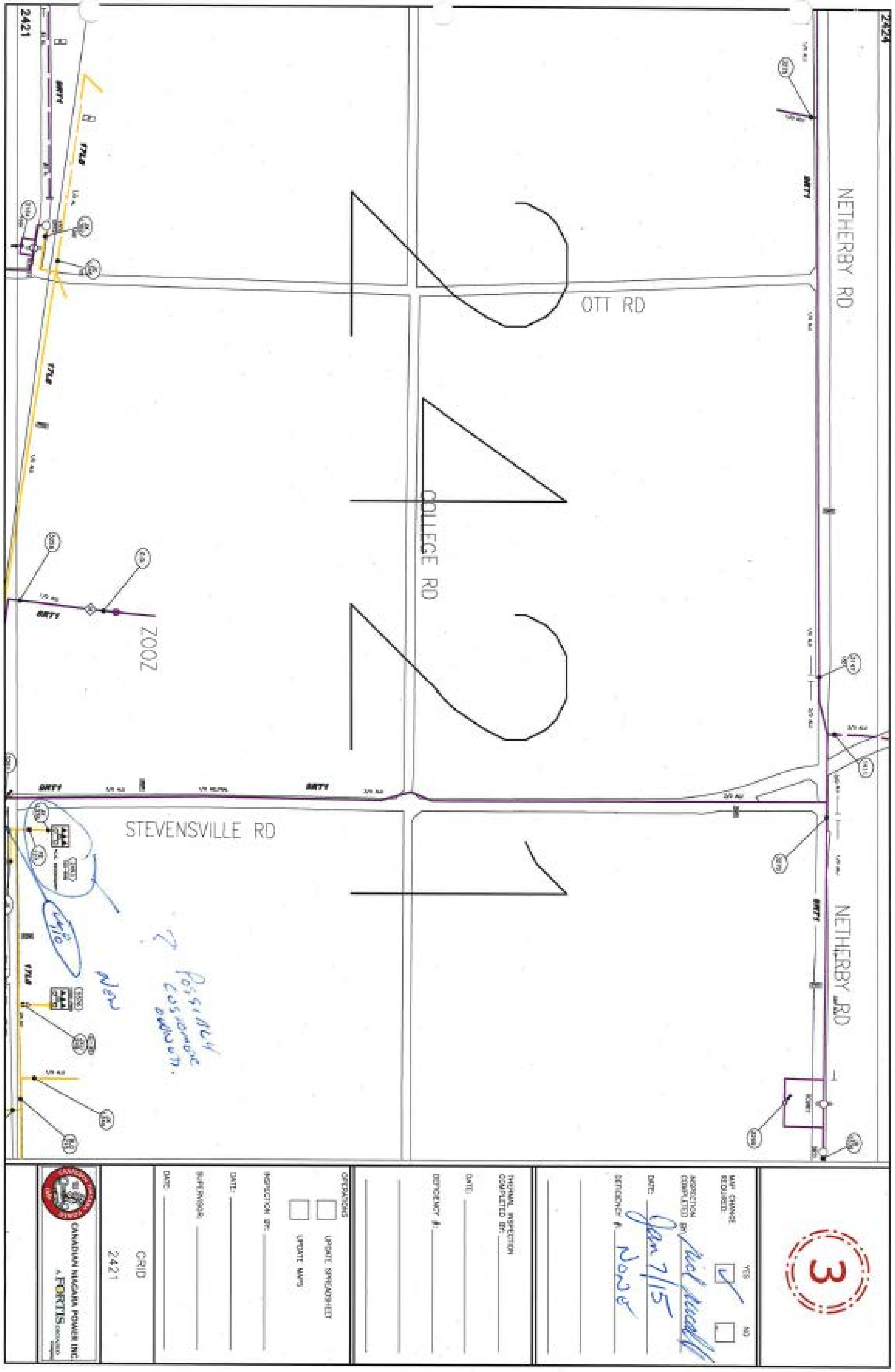
____________ Signature of Competent Person 20__/__/__ year month day

PLANNING USE ONLY: ☐ No Map, Model or Data Update Required ☐ Map, Model and/or data Updates Complete Initials:______ Date: 20___/___/___

O. Reg. 22/04 compliant document. Revised on 2016-02-04

C4. Distribution Line Inspection (3-Year Cycle) (2 sheets)




2421
2424
NETHERBY RD
OTT RD
COLLEGE RD
STEVENSVILLE RD
NETHERBY RD
Possibly customer owned.
New
MAP CHANGE REQUIRED:
YES
NO
INSPECTION COMPLETED BY:
DATE: Jan 7/15
DEFICIENCY #: None
THERMAL INSPECTION COMPLETED BY:
DATE:
DEFICIENCY #:
OPERATIONS
UPDATE SPREADSHEET
UPDATE MAPS
INSPECTION BY:
DATE:
SUPERVISOR:
DATE:
GRID
2421
CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company
3

C5. Line Operations Activity Log

FORTIS ONTARIO

Line Operations Activity Log

Employee Name ______________________________ Date _______________________ Sheet _____ of _____

Order # and/or Address: ____

Local Meter # Found: ______________ Meter Reading Found: ______________

Local Meter # Left: ______________ Meter Reading Left: ______________

❑ Disconnect ☐ Reconnect
❑ New service
❑ Repair to service
❑ Re-Fuse transformer
❑ Other ____________________

Non-Conforming Utility Equipment: ☐Yes ☐No
Non-Conforming Customer Equipment: ☐Yes ☐No

Notes: _________________________

Record of Inspection:
❑ Only approved material was used
❑ Non-Conformance present (provide details)
❑ All work was as per Standard Designs
❑ No undue hazards exist. Final Inspection

Signature ________________ Date ___________

Certificate of Construction Approval: In accordance with *Ontario Regulation 22/04,* this is to certify that the construction recorded on this document is consistent with FortisOntario Standard Designs and/or meets all minimum safety standards. All equipment used has been approved. All worksites were left in a safe condition. No UNDUE HAZARDS are present.

Signature________________ Date ___________

Order # and/or Address: ____

Local Meter # Found: ______________ Meter Reading Found: ______________

Local Meter # Left: ______________ Meter Reading Left: ______________

❑ Disconnect ☐ Reconnect
❑ New service
❑ Repair to service
❑ Re-Fuse transformer
❑ Other ____________________

Non-Conforming Utility Equipment: ☐Yes ☐No
Non-Conforming Customer Equipment: ☐Yes ☐No

Notes: _________________________

Record of Inspection:
❑ Only approved material was used
❑ Non-Conformance present (provide details)
❑ All work was as per Standard Designs
❑ No undue hazards exist. Final Inspection

Signature ________________ Date ___________

Certificate of Construction Approval: In accordance with *Ontario Regulation 22/04,* this is to certify that the construction recorded on this document is consistent with FortisOntario Standard Designs and/or meets all minimum safety standards. All equipment used has been approved. All worksites were left in a safe condition. No UNDUE HAZARDS are present.

Signature________________ Date ___________

Order # and/or Address: ____

Local Meter # Found: ______________ Meter Reading Found: ______________

Local Meter # Left: ______________ Meter Reading Left: ______________

❑ Disconnect ☐ Reconnect
❑ New service
❑ Repair to service
❑ Re-Fuse transformer
❑ Other ____________________

Non-Conforming Utility Equipment: ☐Yes ☐No
Non-Conforming Customer Equipment: ☐Yes ☐No

Notes: _________________________

Record of Inspection:
❑ Only approved material was used
❑ Non-Conformance present (provide details)
❑ All work was as per Standard Designs
❑ No undue hazards exist. Final Inspection

Signature ________________ Date ___________

Certificate of Construction Approval: In accordance with *Ontario Regulation 22/04,* this is to certify that the construction recorded on this document is consistent with FortisOntario Standard Designs and/or meets all minimum safety standards. All equipment used has been approved. All worksites were left in a safe condition. No UNDUE HAZARDS are present.

Signature________________ Date ___________

Order # and/or Address: ____

Local Meter # Found: ______________ Meter Reading Found: ______________

Local Meter # Left: ______________ Meter Reading Left: ______________

❑ Disconnect ☐ Reconnect
❑ New service
❑ Repair to service
❑ Re-Fuse transformer
❑ Other ____________________

Non-Conforming Utility Equipment: ☐Yes ☐No
Non-Conforming Customer Equipment: ☐Yes ☐No

Notes: _________________________

Record of Inspection:
❑ Only approved material was used
❑ Non-Conformance present (provide details)
❑ All work was as per Standard Designs
❑ No undue hazards exist. Final Inspection

Signature ________________ Date ___________

Certificate of Construction Approval: In accordance with *Ontario Regulation 22/04,* this is to certify that the construction recorded on this document is consistent with FortisOntario Standard Designs and/or meets all minimum safety standards. All equipment used has been approved. All worksites were left in a safe condition. No UNDUE HAZARDS are present.

Signature________________ Date ___________

Order # and/or Address: ____

Local Meter # Found: ______________ Meter Reading Found: ______________

Local Meter # Left: ______________ Meter Reading Left: ______________

❑ Disconnect ☐ Reconnect
❑ New service
❑ Repair to service
❑ Re-Fuse transformer
❑ Other ____________________

Non-Conforming Utility Equipment: ☐Yes ☐No
Non-Conforming Customer Equipment: ☐Yes ☐No

Notes: _________________________

Record of Inspection:
❑ Only approved material was used
❑ Non-Conformance present (provide details)
❑ All work was as per Standard Designs
❑ No undue hazards exist. Final Inspection

Signature ________________ Date ___________

Certificate of Construction Approval: In accordance with *Ontario Regulation 22/04,* this is to certify that the construction recorded on this document is consistent with FortisOntario Standard Designs and/or meets all minimum safety standards. All equipment used has been approved. All worksites were left in a safe condition. No UNDUE HAZARDS are present.

Signature________________ Date ___________

Rev. 2005-11-24

C6. Trouble Call / Outage Report – Operations

FORTIS ONTARIO **Trouble Call / Outage Report - Operations**

Rev. 2005-11-28

Completed by:______________________ Job #:____________________

Date 20____ / _____ / _____ (year, month, day) Customer Name:____________________

Address:________________________________ Phone Number: ____________

________________________________ Postal Code: ______________

Problem or Description of Activity: ______________________________________

____

____

Corrective Action Taken:____

____

Customer-Signed "Work Authorization" Number ____________ ☐ None required

Work Status: ☐ All Work Completed

☐ Needs Permanent Job (Site Left in SAFE Condition)

Police Incident Number:

____

Other Comments: ____

____

____

Time Called: __________________

Time On-Site: __________________

Time Completed: ________________

Outage Reporting:

☐ No Outage ☐ Outage (see below)

Voltage: ______________________

Device: ________________________

Transformer Size and #, Switch #, and/or Feeder

Weather Code (see back): ☐.☐.☐

Cause Code (see back): ☐.☐

Cause Desc:______________________

______________________ Age:_____

Outage Start Time: ______________

Outage Finish Time: _____________

Outage Duration: ______ hours ______ min

\# of Customers Affected: ______________

Load after restoration: _________Amps

☐ NO Construction occurred (DO NOT complete rest of sheet) ☐ Construction Occurred (Complete rest of sheet)

Record of Inspection (Standard Designs Only)

☐ Yes ☐ No Only Approved Equipment used

☐ Yes ☐ No All work used only *Standard Designs*

☐ Yes ☐ No Non-Conformance Present

☐ Yes ☐ No Final Inspection

________________________ ____________

Signature of Qualified Inspector Date

Certificate of Construction Approval (Standard Designs Only)

In accordance with Ontario Regulation 22/04 (EDSR):
This is to certify that the construction recorded on this document is fully consistent with FortisOntario Standard Designs and work instructions. Only approved equipment has been used. All worksites were left in a safe condition.

____________________ ________________ __________

Signature of QUALIFIED Person Position or Title Date

Record of Inspection (Non-Standard Designs)

☐ Yes ☐ No Only Approved Equipment used

☐ Yes ☐ No Work was "Like-for-Like Replacement"

☐ Yes ☐ No Deviation(s) from *Standard Designs* meets or exceeds all safety standards

☐ Yes ☐ No UNDUE HAZARD(S) present

☐ Yes ☐ No Final Inspection

________________________ ____________

Signature of Competent Inspector Date

Certificate of Construction Approval (Non-Standard Designs)

In accordance with Ontario Regulation 22/04 (EDSR):
This is to certify that the construction recorded on this document is meets or exceeds all appropriate safety standards. Only approved equipment has been used. All worksites were left in a safe condition, and NO UNDUE HAZARDS are present.

____________________ ________________ __________

Signature of COMPETENT Person Position or Title Date

Routing: ☑ Line Supervisor ☐ Control Center ☐ Engineering ☐ Manager ☐ Other:________________ ☑ File

Appendix D.
Samples of CNPI Metering Maintenance Documents

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D1. Distribution Substation Metering Dept. Substation Inspection

CANADIAN NIAGARA POWER SUBSTATION REPORTS

SUBSTATION: 12
REPORT FOR THE MONTH OF: June

(YYYY.MM.DD) DATE OF INSPECTION: 2011.07.06
INSPECTED BY: DF

SUBSTATION BANK READINGS

BANK NUMBER	ENERGY PRESENT KWH	ENERGY PREVIOUS KWH	CONSUMPTION KWH	DEMAND MAX KW	DEMAND MAX KVA	DEMAND MAX KVAR	VOLTAGE PHASE AB MAX	VOLTAGE PHASE AB MIN	VOLTAGE PHASE BC MAX	VOLTAGE PHASE BC MIN	VOLTAGE PHASE CA MAX	VOLTAGE PHASE CA MIN	CURRENT DEMAND A(Blue) MAX	CURRENT DEMAND B(White) MAX	CURRENT DEMAND C(Red) MAX	3 PH. AVG S.D. MAX	3 PH. AVG S.D. MIN
1	164808915	163145500	1,663,415	3,183	3218	1352	5,102	4,870	5,056	4,776	5,087	4,838	381	355	404	380	165
2	267633429	265163638	2,469,791	5,182	5293	1147	5,012	4,803	4,997	4,755	5,008	4,592	596	683	613	631	218
3	176461710	174670713	1,790,997	3,056	3152	844	5,052	0	5,028	0	5,064	-1	346	383	396	375	0

STATION SERVICE READINGS

BANK NUMBER	ENERGY PRESENT KWH	ENERGY PREVIOUS KWH	CONSUMPTION KWH			BILLING MULTIPLIER	CALCULATED CONSUMPTION KWH		
1	82,030	77,841	4,189			10	41890		
2	105,651	98,165	7,486			1	7486		
3	72,367	67,039	5,328			10	53280		

SUBSTATION FEEDER READINGS

BANK NUMBER	FEEDER NUMBER	MAX DEMAND CURRENT READINGS PH-A(Blue)	PH-B(White)	PH-C(Red)	COUNTER PRESENT	COUNTER PREVIOUS	COUNTER DIFFERENCE	TARGETS	SF6 PRESS KPA	COMMENTS
1	1265	78	84	97	814	814	0		N.A.	
	1268	159	128	173	905	905	0		N.A.	
	1270	44	41	46	983	983	0		N.A.	
	1271	137	129	131	990	990	0		N.A.	
	R401(BANK)				124	124	0		N.A.	
	R406 TIE				538	538	0		N.A.	
2	1262	205	222	183	847	847	0		N.A.	
	1263	60	64	63	734	734	0		N.A.	
	1264	175	220	179	830	830	0		N.A.	
	1266	176	193	193	837	837	0		N.A.	
	R411(BANK)				895	895	0		N.A.	
	R416 TIE				865	865	0		N.A.	
3	1261	205	207	210	802	802	0		N.A.	
	1267	101	105	140	779	779	0		N.A.	
	1269	57	62	44	886	886	0		N.A.	
	1272	31	31	31	690	690	0		N.A.	
	R421 (BANK)				721	721	0		N.A.	
1	R1083				711	711	0		N.A.	
2	R1183				618	618	0		N.A.	
3	R1053				445	445	0		N.A.	
1-2	R1121				115	115	0		N.A.	
2-3	R1132				304	304	0		N.A.	

	OIL TEMPERATURE MAX C	OIL TEMPERATURE PRES C	WINDING TEMP MAX C	WINDING TEMP PRES C
BANK 1	53	48	n/a	n/a
BANK 2	52	42	62	49
BANK 3	55	42	n/a	n/a

COMMENTS

Eye-wash to be changed Jan 2012

AMBIENT TEMP	28	MODIE WOK	X	FANS	OK	INSULATORS	OK	EUSA TAGS	OK	FIRE EXT	OK
BLK RELAY SHEETS	OK	C BATTERIES	OK	Spill kit	OK						
GATES & FENCE	OK	RUBBER GLOVES	OK	EYE WASH	OK	PANEL BULBS	OK	LIGHTS	OK	FIRST AID	OK

D2. Revenue Meter Activity Log:

FORTIS ONTARIO **Revenue Meter Activity Log** 00001

Employee Name ____________ Date ____________ Sheet _____ of _____

Order # and/or Address: ____________

Local # Found: ________ Reading Found: ________ Seal # Found: ________

Local # Left: ________ Reading Left: ________ Seal # Left: ________

❑ Disconnect ☐ Reconnect
❑ Metering Installation
❑ Metering Change-Out
❑ Metering Removal
❑ Other ____________

Non-Conforming Utility Equipment: ☐Yes ☐No
Non-Conforming Customer Equipment: ☐Yes ☐No

Notes: ____________

Record of Inspection:
❑ Only approved material was used
❑ Non-Conformance present (provide details)
❑ All work was as per Standard Designs
❑ No undue hazards exist: Final Inspection

Signature ________ Date ________

Certificate of Construction Approval: In accordance with *Ontario Regulation 22/04*, this is to certify that the construction recorded on this document is consistent with FortisOntario Standard Designs and/or meets all minimum safety standards. All equipment used has been approved. All worksites were left in a safe condition. No UNDUE HAZARDS are present.

Signature ________ Date ________

Order # and/or Address: ____________

Local # Found: ________ Reading Found: ________ Seal # Found: ________

Local # Left: ________ Reading Left: ________ Seal # Left: ________

❑ Disconnect ☐ Reconnect
❑ Metering Installation
❑ Metering Change-Out
❑ Metering Removal
❑ Other ____________

Non-Conforming Utility Equipment: ☐Yes ☐No
Non-Conforming Customer Equipment: ☐Yes ☐No

Notes: ____________

Record of Inspection:
❑ Only approved material was used
❑ Non-Conformance present (provide details)
❑ All work was as per Standard Designs
❑ No undue hazards exist: Final Inspection

Signature ________ Date ________

Certificate of Construction Approval: In accordance with *Ontario Regulation 22/04*, this is to certify that the construction recorded on this document is consistent with FortisOntario Standard Designs and/or meets all minimum safety standards. All equipment used has been approved. All worksites were left in a safe condition. No UNDUE HAZARDS are present.

Signature ________ Date ________

Order # and/or Address: ____________

Local # Found: ________ Reading Found: ________ Seal # Found: ________

Local # Left: ________ Reading Left: ________ Seal # Left: ________

❑ Disconnect ☐ Reconnect
❑ Metering Installation
❑ Metering Change-Out
❑ Metering Removal
❑ Other ____________

Non-Conforming Utility Equipment: ☐Yes ☐No
Non-Conforming Customer Equipment: ☐Yes ☐No

Notes: ____________

Record of Inspection:
❑ Only approved material was used
❑ Non-Conformance present (provide details)
❑ All work was as per Standard Designs
❑ No undue hazards exist: Final Inspection

Signature ________ Date ________

Certificate of Construction Approval: In accordance with *Ontario Regulation 22/04*, this is to certify that the construction recorded on this document is consistent with FortisOntario Standard Designs and/or meets all minimum safety standards. All equipment used has been approved. All worksites were left in a safe condition. No UNDUE HAZARDS are present.

Signature ________ Date ________

Order # and/or Address: ____________

Local # Found: ________ Reading Found: ________ Seal # Found: ________

Local # Left: ________ Reading Left: ________ Seal # Left: ________

❑ Disconnect ☐ Reconnect
❑ Metering Installation
❑ Metering Change-Out
❑ Metering Removal
❑ Other ____________

Non-Conforming Utility Equipment: ☐Yes ☐No
Non-Conforming Customer Equipment: ☐Yes ☐No

Notes: ____________

Record of Inspection:
❑ Only approved material was used
❑ Non-Conformance present (provide details)
❑ All work was as per Standard Designs
❑ No undue hazards exist: Final Inspection

Signature ________ Date ________

Certificate of Construction Approval: In accordance with *Ontario Regulation 22/04*, this is to certify that the construction recorded on this document is consistent with FortisOntario Standard Designs and/or meets all minimum safety standards. All equipment used has been approved. All worksites were left in a safe condition. No UNDUE HAZARDS are present.

Signature ________ Date ________

Order # and/or Address: ____________

Local # Found: ________ Reading Found: ________ Seal # Found: ________

Local # Left: ________ Reading Left: ________ Seal # Left: ________

❑ Disconnect ☐ Reconnect
❑ Metering Installation
❑ Metering Change-Out
❑ Metering Removal
❑ Other ____________

Non-Conforming Utility Equipment: ☐Yes ☐No
Non-Conforming Customer Equipment: ☐Yes ☐No

Notes: ____________

Record of Inspection:
❑ Only approved material was used
❑ Non-Conformance present (provide details)
❑ All work was as per Standard Designs
❑ No undue hazards exist: Final Inspection

Signature ________ Date ________

Certificate of Construction Approval: In accordance with *Ontario Regulation 22/04*, this is to certify that the construction recorded on this document is consistent with FortisOntario Standard Designs and/or meets all minimum safety standards. All equipment used has been approved. All worksites were left in a safe condition. No UNDUE HAZARDS are present.

Signature ________ Date ________

Appendix E.
Samples of other documents that support Asset Management

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E1. Certificate of Design Approval

FORTIS ONTARIO

Certificate of Design Approval

Project Number: ______________________________

Description: ____

____

Type of Project: ☐ New Construction ☐ Like-for-Like Replacement (Legacy)
☐ Retirement ☐ Upgrade of Existing Plant

☐ All designs follow **Standard Designs** and/or designs approved by a Professional Engineer

- or-

☐ All work is NOT per Standard Designs (requiring a Professional Engineer to approve the designs for this project)

Drawings and Specifications forming part of this plan (in addition to approved Standard Designs):

☐ Job drawing

☐ Bill of approved materials

____

____

____

____

____

____

Enclosures checklist:

☐Yes ☐No ☐N/A	Appropriate Underground Locates are included.
☐Yes ☐No ☐N/A	Construction personnel have copies of all standard designs to be used for this work.
☐Yes ☐No ☐N/A	Project documentation includes any special designs certified by a Professional Engineer.
☐Yes ☐No ☐N/A	Correct "**Record of Inspection**" form has been included in work instructions.
☐Yes ☐No ☐N/A	"**Certificate of Construction Approval**" form has been included.

Review checklist:

☐Yes ☐No ☐N/A	Only approved material will be used
☐Yes ☐No ☐N/A	All standard designs used in this project are clearly identified
☐Yes ☐No ☐N/A	All work instructions are clear and appropriate
☐Yes ☐No ☐N/A	Work instructions were prepared by competent personnel, where standard designs were not used
☐Yes ☐No ☐N/A	All 3rd Party (J.U.) attachments meet or exceed minimum acceptable safety standards

Statement of Compliance (for Plans using only Standard Designs):

This is to certify that, for FortisOntario, the work designs covered by the documents listed above meet the safety standards of Section 4 of Ontario Regulation 22/04 by the use of Standard Designs and/or other engineered designs.

Print Name ______________ Signature and Professional Designation ______________ Date ______________

Statement of Compliance (for Plans **NOT** using Standard Designs):

This is to certify that, for FortisOntario, the work designs covered by the documents listed above meet **all** appropriate safety standards of Section 4 of Ontario Regulation 22/04.

Print Name ______________ Signature and Professional Designation of P.Eng ______________ Date ______________

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Appendix F.
Asset Condition Reports

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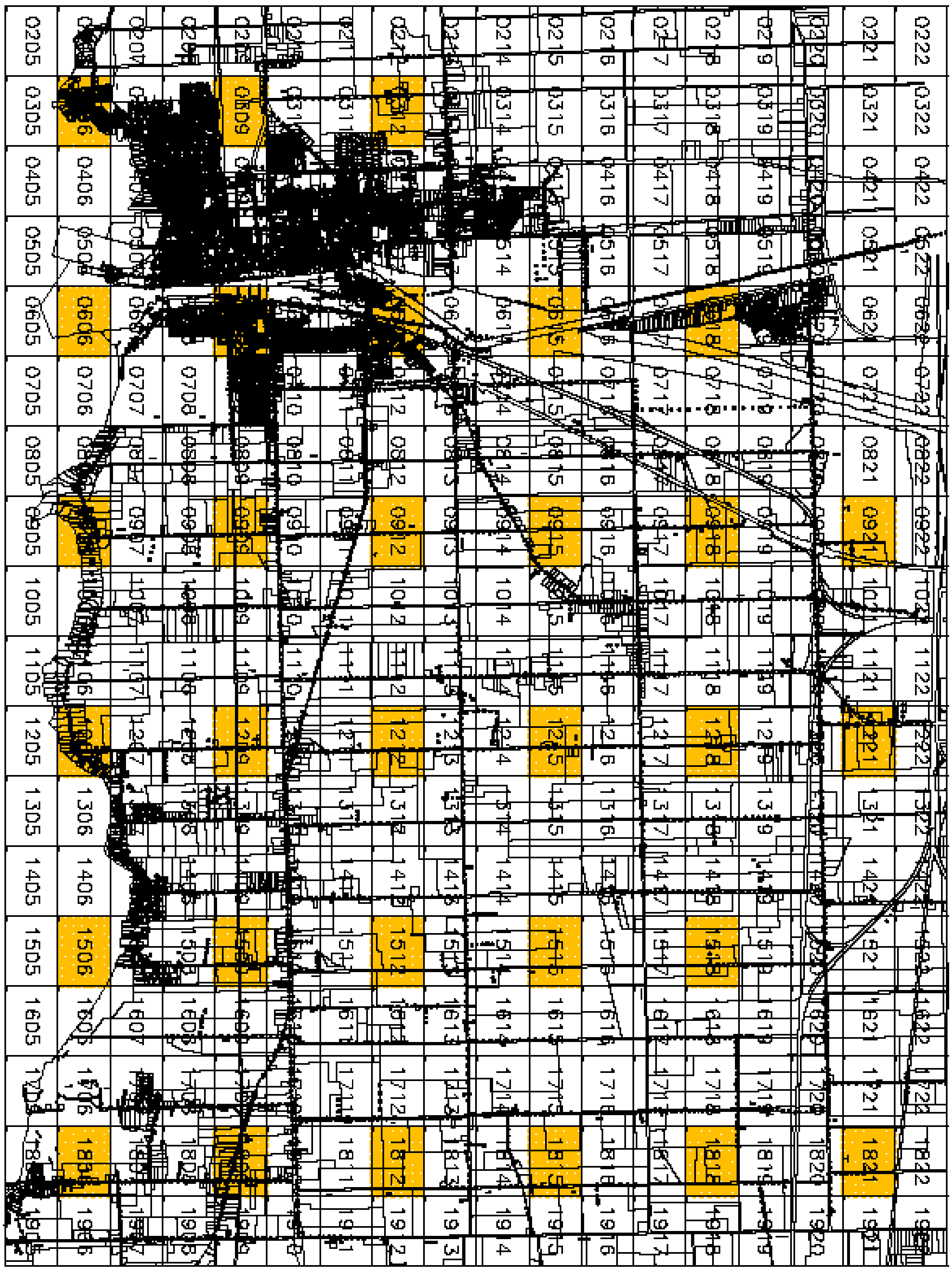
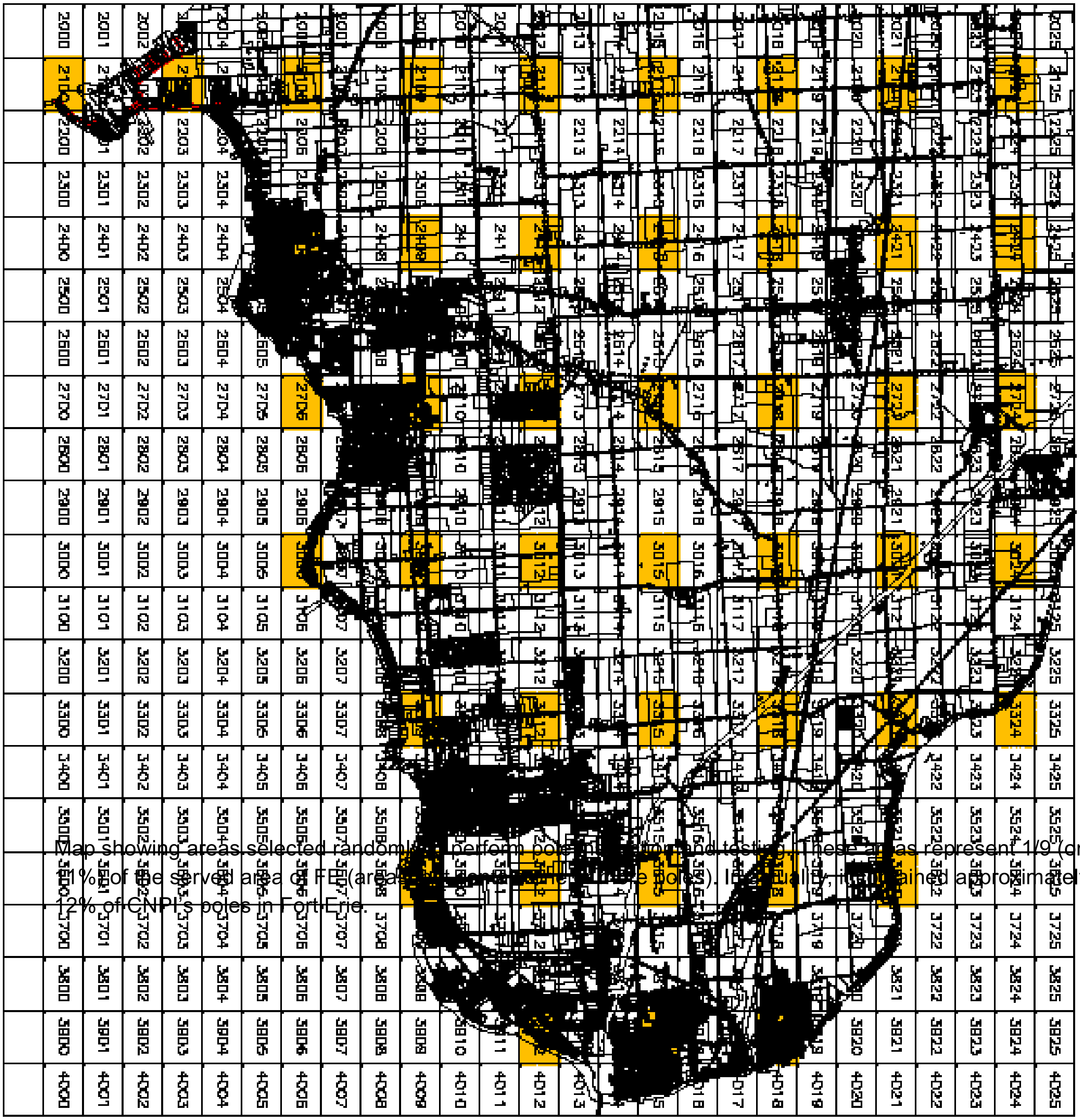
F1.Map Showing Poles Tested - Port Colborne



Map showing areas selected randomly to perform pole inspection and testing. These areas represent 1/9 (or 11%) of the served area of PC (areas that contains one or more poles). In actuality, it contained approximately 10% of CNPI's poles in Port Colborne.

F2.Map Showing Poles Tested - Fort Erie



Map showing areas selected randomly to perform pole inspection and testing. These areas represent 1/9 (or 11%) of the served area of FE (areas that contain poles). In actuality, it contained approximately 12% of CNPI's poles in Fort Erie.

F3. Sample of a Pole Inspection Sheet

Tested by:	**PoleCare International Inc.** 2011 WOOD POLE INSPECTION: Canadian Niagara Power	Map #:	Recorded by:

City/Town:	Date:	Record No:	House No:	Street: Ridgewood

St Index: St Blvd Line Pl Ave Rd Dr Lane Crt Cres Cir

St. Direction: East West North South

Pole Class: 2 3 4 5 6

Pole Height (ft): 30 35 40 45 50 55

Species: WRC SP JP Cedar Pine Other

Treat Length: Butt Full

Treat Type: C P CCA

Installation Date: Yr: 75 Not Known

Pole ID:

Other ID: T224

Private Property? Yes No

Does the pole sound hollow at GL? Yes No

RG Done Yes No

			Slight	Moderate	Extensive
Carpenter ants Damage	Yes	No			
Completely rotten at GL	Yes	No	----------	----------	
Cracks	Yes	No			
Crack to GL	Yes	No	----------	----------	
Cross Arm Rot	Yes	No			
Decay pockets at GL	Yes	No			
Fire Damage	Yes	No			
Internal Decay	Yes	No			
Mechanical Damage	Yes	No			
Pole Top Feathering/Split/Rot	Yes	No			
Surface rot above GL	Yes	No			
Surface rot below GL	Yes	No			
Wood Loss	Yes	No			
WP Hole	Yes	No			

Overall Condition: Good Fair Fair - Poor Poor

POLE STRENGTH MEASUREMENTS

Test #	Location above GL (ft)		Dia(in)	Strength (psi)	Comments
1	______	______	11.8	4500	______

COMMENTS

(____ Bend in pole) (______ Broken ground wire) (____ Climbing inspection reqd) (_____ Dip) (____Ground guard reqd)

(____ Guy pole) (____ Guy guard reqd) (____Joint use) (____ Lights on pole) (____ Obstruction at GL) (____ Pole in pavement)

(_____Pole ID missing) (____ Pole leaning) (_____ Pole in water) (____Pole not accessible) (____ Pole not on list)

(____ Slack ground wire) (____ Slack guy wire) (____Transformer) (_____ Visual inspection only) (_____ Wire touching tree)

(_______BELL POLE)

RECOMMENDATIONS:

(____ Replace in ___________) (____ RG Tested, Replace in __________) (_____RG Tested OK) (____RG Tested, retest in___ _______)

(DANGER POLE______)

OTHER COMMENTS

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Appendix G.
Distribution System Inspection Program (DSIP)

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FORTIS ONTARIO

Distribution System Inspection Program (DSIP)

Prepared by: Don Gilbert, Manager T&D Operations

Initial Release Date: April 1, 2007

1.0 INTRODUCTION

The FortisOntario Distribution System Inspection Programme (DSIP) establishes requirements for regular inspections of FortisOntario Distribution systems. Regular inspections of FortisOntario distribution facilities to proactively identify potential deficiencies are an integral aspect of the company's goal to maintain safe and reliable distribution systems. The requirements laid out in the DSIP are based upon the *Minimum Inspection Requirements* presented in Appendix C of the Ontario Energy Board (OEB) *Distribution System Code.*

The DSIP applies to all distribution systems in the FortisOntario territories of Fort Erie, Port Colborne, Cornwall, and Gananoque. Distribution systems are defined as including the following overhead and underground power system components:

- Lines, cables, conductors, and all associated structures (e.g., poles, towers) and hardware (e.g., insulators, connectors).
- Substations and all components contained therein.
- Distribution transformers.
- Switching and protective devices.
- Reclosers.
- Regulators.
- Capacitors.
- Civil infrastructure.
- Vegetation

The DSIP details inspection requirements for the above components, and also lays out requirements for thermal infra-red scanning.

2.0 DISTRIBUTION SYSTEMS IN THE FORTISONTARIO TERRITORIES

For the purposes of the DSIP, distribution facilities are defined as those operating at a voltage below 50 kV. Table I below details the various line-to-line operating voltages of distribution systems found in the FortisOntario service territories. Secondary distribution systems (that is, systems operating at 750 Volts are less) are common to all territories and are not included in the table.

Territory	Fort Erie	Port Colborne	Cornwall	Gananoque
Distribution	34.5 kV 8.3 kV 7.2 kV 4.8 kV 4.16 kV	27.6 kV 4.16 kV	12.5 kV	44 kV 26 kV 4.16 kV

Table I: Distribution Systems in FortisOntario territories

3.0 SCOPE OF INSPECTIONS

Inspections of FortisOntario Distribution facilities shall be conducted by:
a) visual patrol inspections, and
b) thermal infra-red scanning.

The DSIP details separate cycles for inspections and for infra-red scanning. Where the cycles coincide, the patrol and infra-red scan could be conducted simultaneously.

Patrol inspections may consist of walking or driving by lines or equipment to identify obvious deficiencies and potential hazards such as leaning poles, broken crossarms, broken or missing ground/bonding conductors, damaged padmounted enclosures, and vandalism. In cases where a patrol identifies a problem or notices a condition that warrants a more thorough inspection, the problem or condition shall be recorded and followed up with a closer inspection (such as the inspection of the top of a pole from a bucket).

Infra-red scanning shall be conducted either in-house or by a contractor.

Inspection cycles differ between Urban and Rural facilities, generally defined as follows:
- Rural: less populated areas located outside standard metropolitan regions. In general, rural areas would have a line density of less than 60 customers per kilometre of line.
- Urban: areas with higher population density, where consequently safety and reliability issues affect larger numbers of customers.

For the purposes of the DSIP, all Distribution facilities serving Fort Erie, Port Colborne, and Cornwall are defined as “urban”. In Gananoque, all Distribution facilities are defined as “urban”, with the exception of the North Line which is defined as “rural”.

Table II below outlines “check lists” of obvious defects to look for when inspecting various components. Note that these are generic minimum expectations and specific equipment or field conditions may involve defects over and above these lists.

Component	**Inspection Requirement**
Padmounted Transformers and Switchgear	Paint condition and corrosion/rust
	Placement on pad or vault
	Condition of lock and penta-bolt
	Grading changes
	Access changes (shrubs, trees, etc.)
	Phase indicators and unit numbers match operating map (where used)
	Oil leaks or evidence of gas leaks (for gas-filled equipment)
	Condition of gauges (oil, gas pressure, temperature)
	Flashed or cracked insulators, bushings, and elbows
	Enclosure damage, missing bolts/hinges
	Warning signs in place

Component	Inspection Requirement
Switching/Protective Devices	Overhead - Bent, broken bushings and cutouts, damaged lightning arrestors, control boxes, current and potential transformers, grounding of non-current-carrying metal components.
	Underground - Security and structural condition of enclosure
	Pad mounted - Security and structural condition of enclosure
Regulators	Condition of bushings
	Tank corrosion / leaks
	Damaged disconnect switches, lightning arrestors, control boxes
	Tank grounding
Capacitors	Condition of bushings
	Tank corrosion / leaks
	Damaged cutouts, disconnects, or control cabinets
	Tank grounding
Conductors and Cables	Low conductor clearance
	Broken/frayed conductors or tie wires
	Tree conditions, exposed broken ground conductors
	Broken strands, bird caging and excessive or inadequate sag
	Insulation fraying/cuts
Poles/Supports/Towers	Bent, cracked or broken poles
	Indications of rotting
	Excessive surface water or scaling
	Loose, cracked or broken cross arms and brackets
	Woodpecker or inspect damage, bird nests
	Loose or unattached guy wires or stubs
	Guy strain insulators pulled apart or broken
	Guy guards out of position or missing
	Grading changes or washouts
	Indications of burning
Hardware and Attachments	Loose or missing hardware
	Insulators unattached from pins
	Conductor unattached from insulators
	Insulators flashed over or obviously contaminated (difficult to see)
	Tie wires unravelled
	Ground wire broken or removed
	Ground wire guards removed or broken
Overhead and underground transformers and switchgear	Contamination / discolouration of bushings
	Oil leaks or gas leaks
	Paint condition and corrosion/rust
	Ground lead attachments
	Ground wires on arrestors unattached
	Bird or animal nests
	Vines or brush growth interference
	Condition of bushings, insulators, and elbows
	Accessibility compromised

Vegetation and Rights-of-Way	Leaning or broken "danger" trees
	Growth into line of "climbing" trees
	Unapproved/unsafe occupation or secondary use

Component	Inspection Requirement
Civil Infrastructure (Cable vaults, Equipment vaults/rooms)	Condition of concrete – breaks, cracking, spalling – exposed rebar
	Condition of access doors, hatches, ventilation grids, ladderways
	Changes in grade – settling/rising
Underground Systems (riser poles, conduit systems, u/g cables)	Condition of Cable terminations, arrestors, switches
	Condition of visible cables and splices
	Grounding/bonding of non-current-carrying metal parts
	Changes in grade – evidence of collapsed ducts, exposed cables

Table II: Minimum inspection requirements for various distribution components

4.0 INSPECTION CYCLES

This section defines inspection cycles for FortisOntario Distribution Systems. Table III below illustrates the maximum inspection cycles for FortisOntario Distribution Systems, both urban and rural.

	Maximum interval in years (except where noted)	
Distribution Component	**Inspection Cycle - Urban facilities**	**Inspection Cycle - Rural facilities**
Distribution Transformers		
Overhead	3	6
Submersible	3	6
Vault	3	6
Pad Mounted	3	6
Stations		
Switching or Transformer Station	1 month	2 months
Lines and Associated Equipment		
Regulators	1 month	2 months
Switches and Fusing Devices	3	6
Reclosers	3	6
Capacitors (automatically switched)	1 month	2 months
Capacitors (manually switched)	1	2
Conductors and Cables		
Overhead	3	6
Underground	3	6
Submarine	3	6
Structures		
Poles	3	6

Civil Infrastructure	3	6
Other		
Vegetation	3	3
Infra-red scanning	3	6

Table III: Distribution System Inspection Cycles

5.0 INSPECTION PLANS

For the FortisOntario territories, Distribution System line inspection plans will be based on a 3-year cycle, to match the 3-year Urban inspection cycle and the 6-year Rural inspection cycle. FortisOntario intends to inspect all its Urban distribution systems in each 3-year cycle. Because the ESA regulation 2204 came into effect in May 2005, Cycle 1 will cover the time period from May 2005 to May 2008. Consequently, Cycle 2 will commence in May 2008 and will run until May 2011. Each FortisOntario territory will be subdivided into three sectors, and each year all distribution facilities within a given sector will be inspected. Each year, an Inspection Plan will be prepared for each FortisOntario territory, detailing exactly what lines or sections of lines will be inspected or infra-red scanned the following year. FortisOntario will commence preparing these detailed plans in 2007, in preparation for Cycle 2.

Maps of each FortisOntario territory showing the subdivision into sectors can be found in Appendix I.

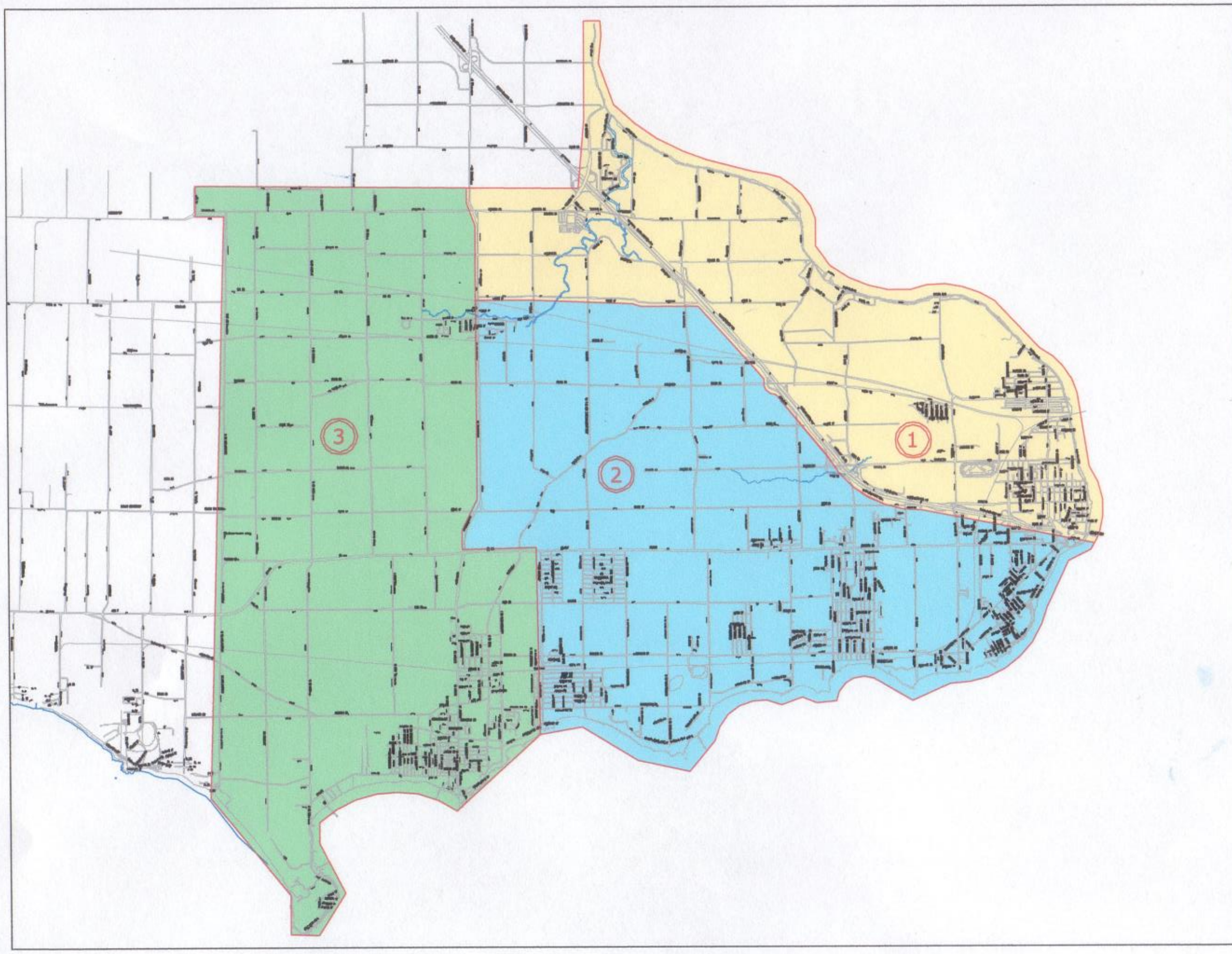
6.0 DOCUMENTATION

The results of all inspections, including any deficiencies noted, will be documented and maintained in electronic databases. Samples of the relevant documents can be found in Appendix II, and are described below:

- The *Substation Inspection Form* records the results of Substation Inspections.
- The *Regulator Inspection Sheet* documents the results of regulator inspections, and shall note any physical deficiencies as well as information on instantaneous taps and maximum/minimum taps.
- The *Capacitor Inspection Sheet* documents the results of capacitor regulator inspections, and shall note physical deficiencies as well as information on automatic switched operations, if applicable.
- The *Inspection Patrol Status Report* shall be used to document the results of feeder inspections. The scope of a feeder inspection shall include all distribution components along a feeder except for substations, regulators, and capacitors. The form shall indicate the section of feeder inspected and shall note any deficiencies observed.
- The *Inspection Patrol Deficiency Report* shall be used to provide details of each deficiency found during an inspection. This Report shall also record the status of any required corrective action.
- The *Sector Inspection Certification Form* shall be used to certify that an entire sector has been inspected in accordance with the requirements of the FortisOntario DSIP. The Sector

Certification Form describes the sections of lines that were inspected and also certifies the completion of all required substation, regulator, and capacitor inspections.

Appendix I



Revision				
NO.	DATE	DESCRIPTION	BY	CHK
1	13 MAR 07	4 ZONES TO 3 ZONES	B.D.	B.D.

Notes:

1.
2007 – ZONE 1
2008 – ZONE 2
2009 – ZONE 3

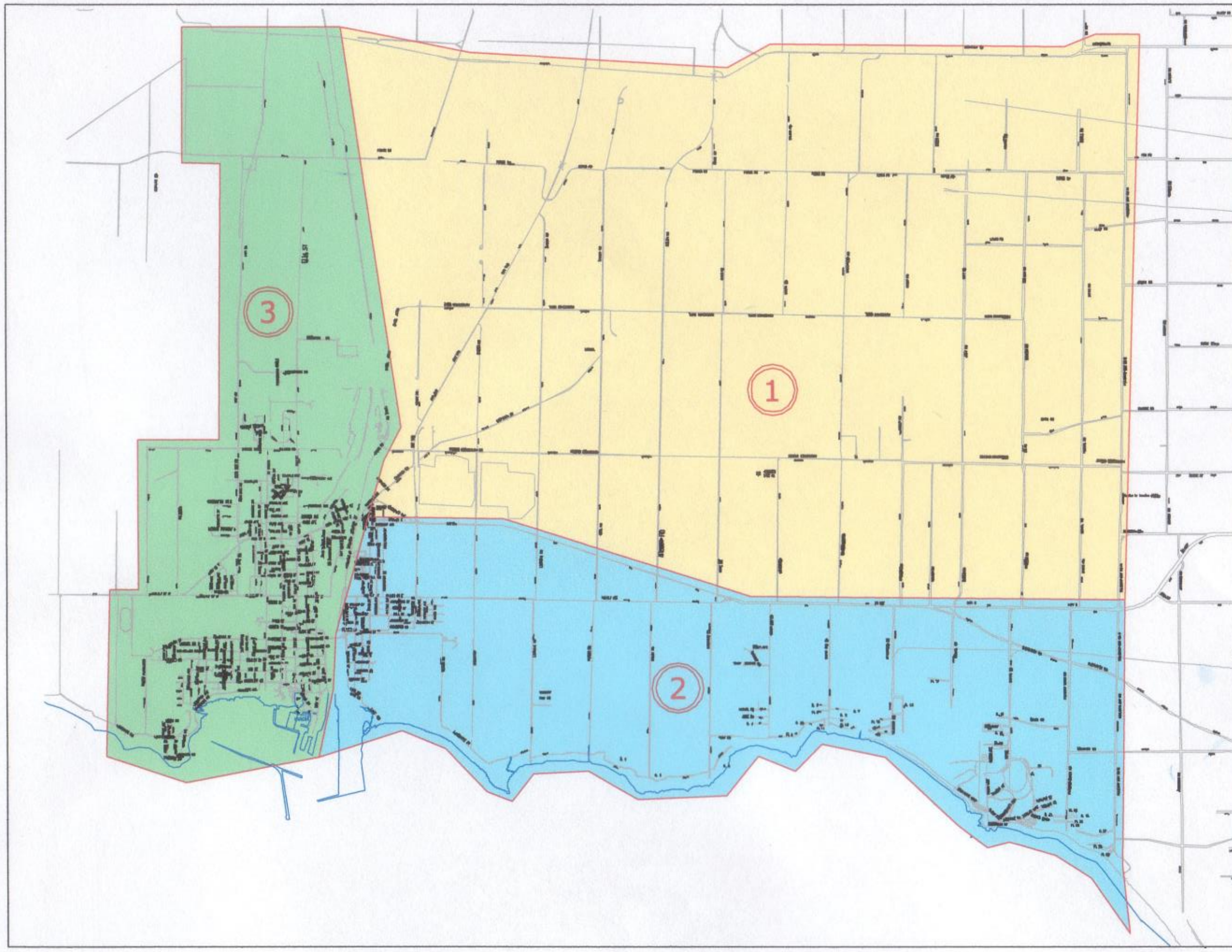
2010 – ZONE 1
2011 – ZONE 2
2012 – ZONE 3

DWG NO.	DESCRIPTION	BY
	REFERENCE	

CANADIAN NIAGARA POWER INC
A FORTIS

MANAGEMENT
PLAN
TOWN OF FORT ERIE

DR. C.W.	CH. B.D.	APP'D	SCALE
DATE 13 MAR 07	ENG.		Sheet 1 of 1
FE-50208 – FE TREE CUTTING		REV.	SIZE
E-FILE		1	B



Revision				
NO.	DATE	DESCRIPTION	BY	CHK
1				

Notes:

1\.
2007 – ZONE 1
2008 – ZONE 2
2009 – ZONE 3

2010 – ZONE 1
2011 – ZONE 2
2012 – ZONE 3

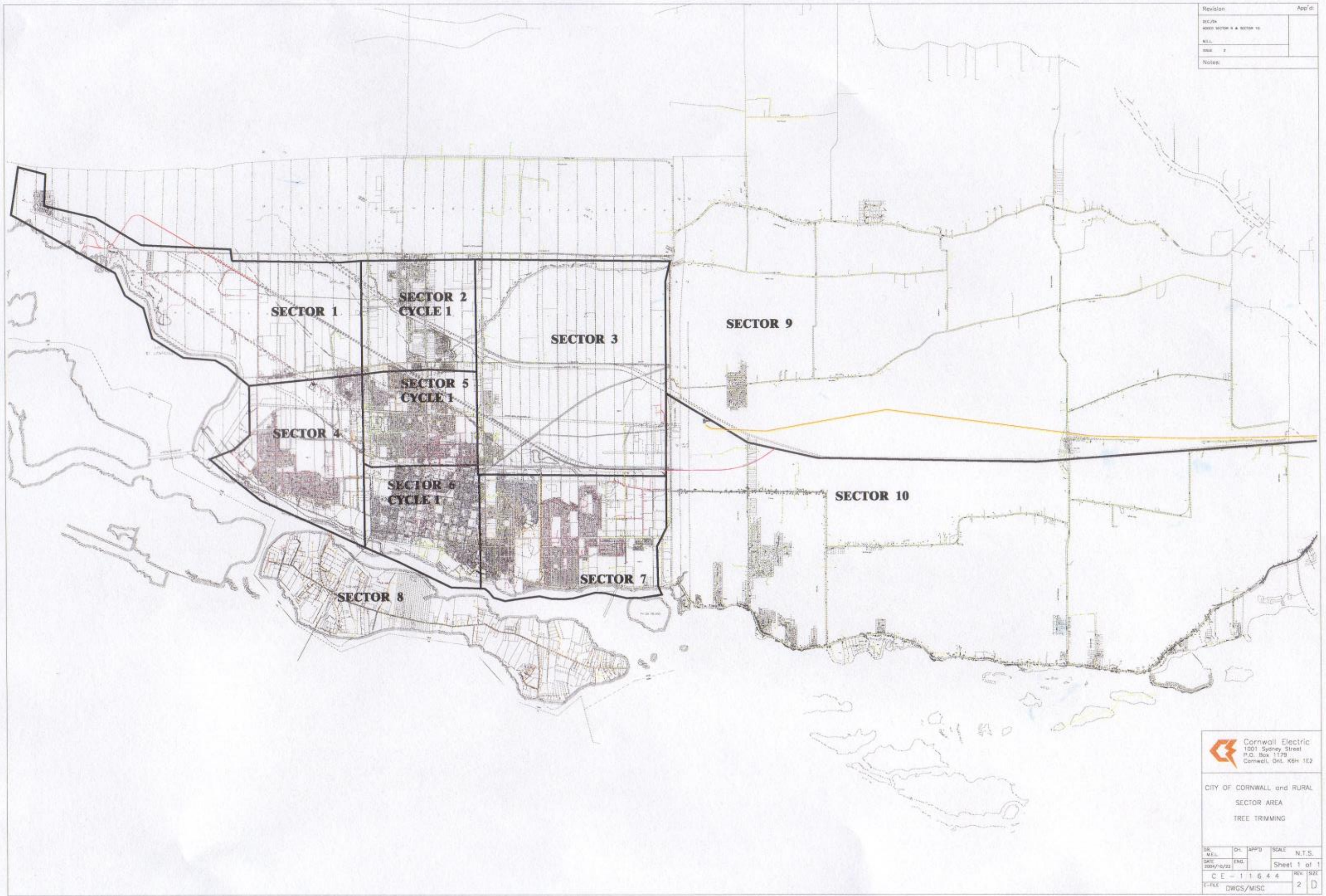
DWG NO.	DESCRIPTION	BY
	REFERENCE	

CANADIAN NIAGARA POWER INC
A FORTIS

MANAGEMENT
PLAN
CITY OF PORT COLBORNE

DR. C.W.	CH. B.D.	APP'D	SCALE
DATE 13 MAR 07	ENG.		Sheet 1 of 1

FE-50205 – PC TREE CUTTING	REV.	SIZE
E-FILE	1	B


Revision
App'd:
Notes:
SECTOR 1
SECTOR 2
CYCLE 1
SECTOR 3
SECTOR 4
SECTOR 5
CYCLE 1
SECTOR 6
CYCLE 1
SECTOR 7
SECTOR 8
SECTOR 9
SECTOR 10
Cornwall Electric
1001 Sydney Street
P.O. Box 1179
Cornwall, Ont. K6H 1E2
CITY OF CORNWALL and RURAL
SECTOR AREA
TREE TRIMMING
DR. M.E.L.
CH.
APP'D
SCALE N.T.S.
DATE 2004/10/22
ENG.
Sheet 1 of 1
C E - 1 1 6 4 4
REV. 2
SIZE D
E-FILE DWGS/MISC

Appendix II

SUBSTATION BARRICK
REPORT FOR THE MONTH OF February

DATE OF INSPECTION 2007.03.05
INSPECTED BY: DF/BL

SUBSTATION BANK READINGS

BANK	ENERGY	ENERGY	ONSUMPTIO	DEMAND			VOLTAGE						CURRENT DEMAND				
NUMBER	PRESENT	PREVIOUS		MAX	MAX	MAX	PHASE	AN	PHASE	BN	PHASE	CN	A(Red)	B(White)	C(Blue)	3 PH. AVG	
	KWH	KWH	KWH	KW SD	KVA SD	KVAR SD	MAX	MIN	MAX	MIN	MAX	MIN	MAX SD	MAX SD	MAX SD	MAX	MIN
RW1	5,624,243	N/A	#VALUE!	1,693	1790	597	2,602		2,610		2,594		231.652	253.568	243.74		

SUBSTATION FEEDER READINGS

BANK	FEEDER	MAX DEMAND CURRENT READINGS			COUNTER			TARGETS	COMMENTS
NUMBER	NUMBER	PH-A	PH-B	PH-C	PRESENT	PREVIOUS	DIFFERENCE		
	BF1	125.287	160.914	156.218	268	252	16		
	BF2	75.78	47.648	49.391	443	443	0		
							0		
							0		
							0		

	Winding				OIL	
	MAX	PRES	LEVEL	MAX	PRES	LEVEL
	C	C	OK / LOW	C	C	OK / LOW
BF1				21	19	OK

STATION SERVICE READINGS

BANK	ENERGY	ENERGY	CONSUMPTI	DEMAND		BILLING	CALCULATED	CAL DEMAND	
NUMBER	PRESENT	PREVIOUS	ON	MAX	PRES	MULTIPLIER	CONSUMPTION	MAX	PRES
METER	KWH	KWH	KWH	W	W		KWH	KW	KW
28236	74,235	70669	3,566	n/a	n/a	1	3566	n/a	n/a

AMBIENT TEMP	-4	FIRST AID	OK	LIGHTS	OK	FANS		H2O	OK
GATES & FENCE	OK	RUBBER GLOVES	n/a	EYE WASH	OK	PANEL BULBS	OK		
BLK RELAY SHEETS	OK	EUSA TAGS	OK	FIRE EXT	OK	SPILL KIT	OK		

COMMENTS

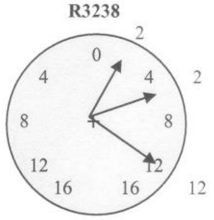
BATTERY REPORT							AT FUSE	AT METER	TEMP	COMP
CELL #	7	8	9	10	11	12	VDC	DC AMPS	n/a	n/a
VOLTAGE	1.51	1.52	1.52	1.51	1.52	1.51	27.4	0.9		
SPECIFIC GRAVITY	1210	1210	1210	1220	1210	1210				

REGULATORS

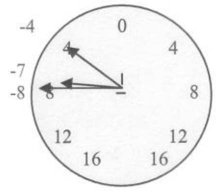
Date: 2007.03.01
Inspected By: DF/BL

LOCATION: DOMINION RD.

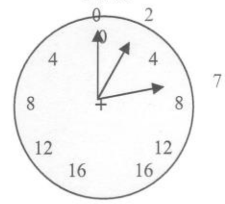
R3238



R3240



R3239



Present Count (as found)	68060
Previous Count	67642
Total Counts (Present - Previous)	418
Output Voltage	117.4
Count (as left)	68062

Present Count (as found)	144062
Previous Count	143934
Total Counts (Present - Previous)	128
Output Voltage	117.0
Count (as left)	144064

Present Count (as found)	86347
Previous Count	86038
Total Counts (Present - Previous)	309
Output Voltage	118.4
Count (as left)	86349

Comments: Cabinet for 3240 needs a new hasp.

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Fort Erie Inspection Patrol
Deficiency Status Report

Municipality Fort Erie **Utility** Canadian Niagara Power Inc

Zone FE1 Cycle 1

Feeder 1261 **Zone** FE1 **Cycle** 1

No.	Reported	By	Location	Problem	Grade	Action	Perm/Temp	Recommendation	Completed
12	11/27/2006	T. Burrell	West of Switch 1308 (1 span)	Tree Removal Required	Grade 2			Remove Tree	
15	11/27/2006	T. Burrell	Corner of Englewood and Crescent Rd	Requires Switch Numbering	Grade 2	Installed Switch Numbering	Permanent		11/27/2006

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Fort Erie Inspection Patrol Deficiency Report (Open Action Status)

Report Number	Reported By	Date Reported	Cycle
28	N. Micallef	1/9/2007	1

Location

Municipality	Zone	Grid	Feeder
Fort Erie	FE1	3912	1266

Location

Bertie St and Stanton St

Obvious Structural Problem or Hazard

Component	Grade
Conductors and Cables	Grade 2

Problem

Temporary connections made mid span on road side phase of primary during Oct 06 Storm

Corrective Action Taken

ActionType	Action
Temporary	Temporary mid span primary connection on road side phase

Recommendations for Further Actions

Recommendation

Road side phase requires to be sleeved out

All Actions Completed

Date	By	Order

Appendix H.
2015 Thermographic Scan Inspection Report

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Fortis Ontario

Canadian Niagara Power Inc.

1130 Bertie Street,
Fort Erie, Ontario
L2A 5Y2

Scan Locations:
Zone 3 Fort Erie, Port Colborne,
Stevensville, Ridgeway & Crystal Beach

Electrical Infrared Thermographic Inspection

IR Reference # **151288**
Inspection Dates: **March 16 - 18, 2015**

Item #1

Location

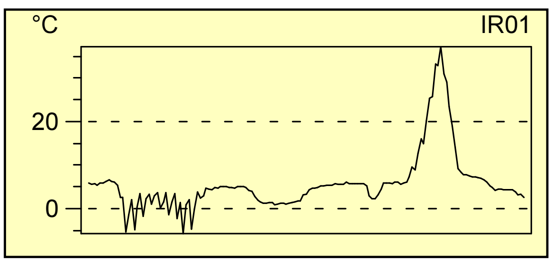
Reclosure Location # **RC8RT1**
Pole # **CNP-245-A**, Feeder **FDR 8RT 1**
Grid 2418,
Eagle Street.
STEVENSVILLE.

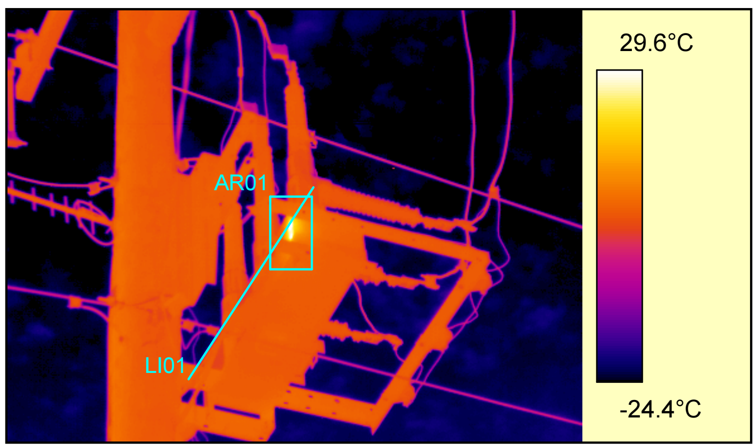
Description

Rear lower road side (internal) portion of auto-reclosure.
Further investigation recommended.

** Possible normal operation, as other units similar thermal pattern **

Object parameter	Value
Emissivity	0.95
Object distance	20.0 m
Ambient temperature	5.0°C





Observation at 3/16/2015 9:58:24 AM

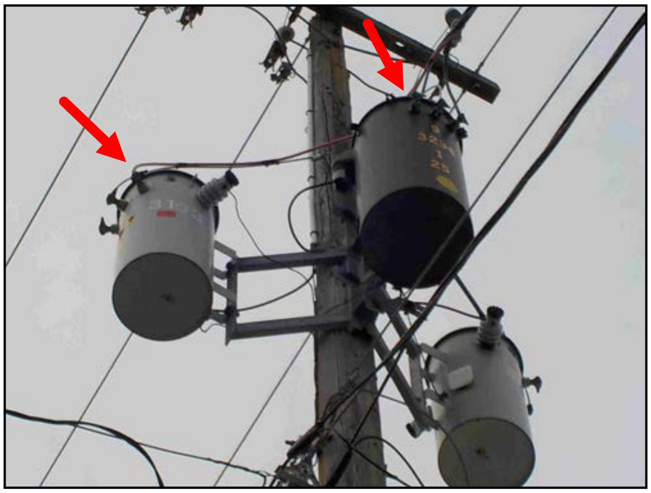
AR01... **37.4°C** **OK AR02...** **-** **T.Rise...** **32.4°C** **PRIORITY:**

Notes & Recommendations

Deficiency Report Reference **#2517**

Repaired ____________________ by ______________________________

Item #2



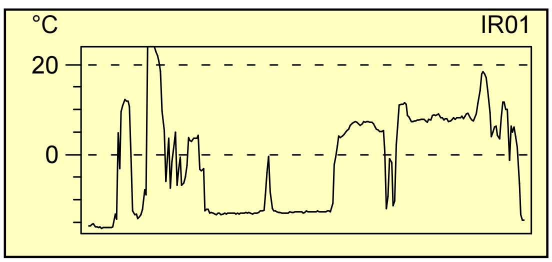
Location

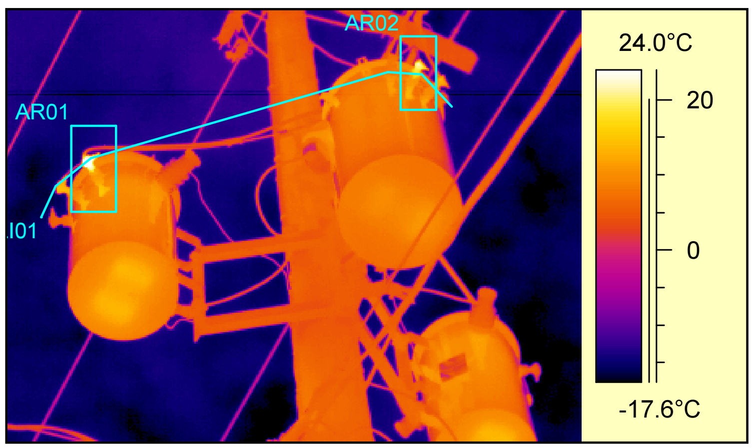
Pole # **CNP-217**,
Transformer # **T-3583, T-3163, T-3234**
Grid 2418,
Stevensville Road at Paul Alley.
STEVENSVILLE.

Description

Secondary bushing connections to leads on Road & Centre phase transformers.

Object parameter	Value
Emissivity	0.95
Object distance	18.0 m
Ambient temperature	5.0°C





Observation at 3/16/2015 10:09:55 AM

Fault AR01... **31.0°C** **Fault AR02...** **22.3°C** **T.Rise...** **26.0°C** **PRIORITY:**

Notes & Recommendations

Deficiency Report Reference **#2518**

Repaired ____________________ by ______________________________

Item #3

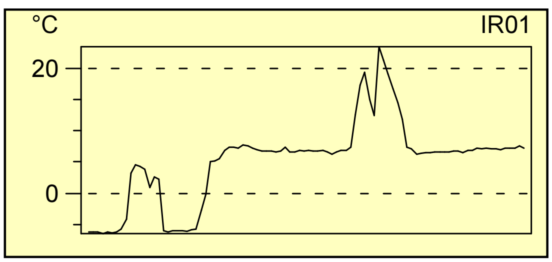
Location

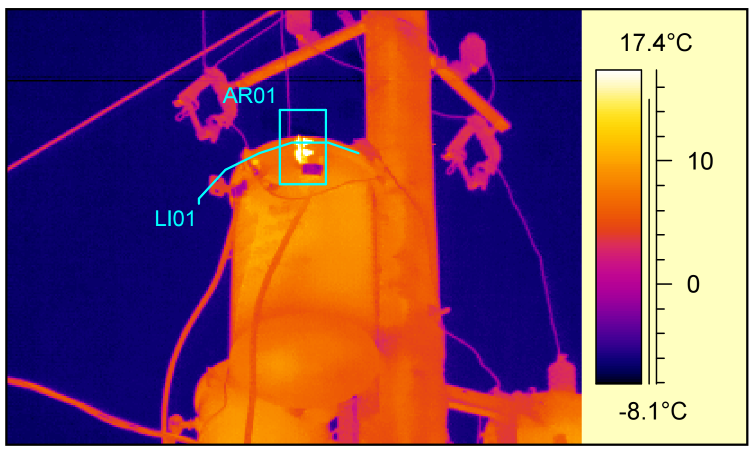
Pole # *unknown*,
Transformer # **5981**
Grid 2409,
Dominion Road near Ridge Road.
RIDGEWAY.

Description

Secondary bolted bushing connection
to lead on Field phase transformer.

Object parameter	Value
Emissivity	0.95
Object distance	15.0 m
Ambient temperature	4.0°C





Observation

at 3/16/2015 2:35:36 PM

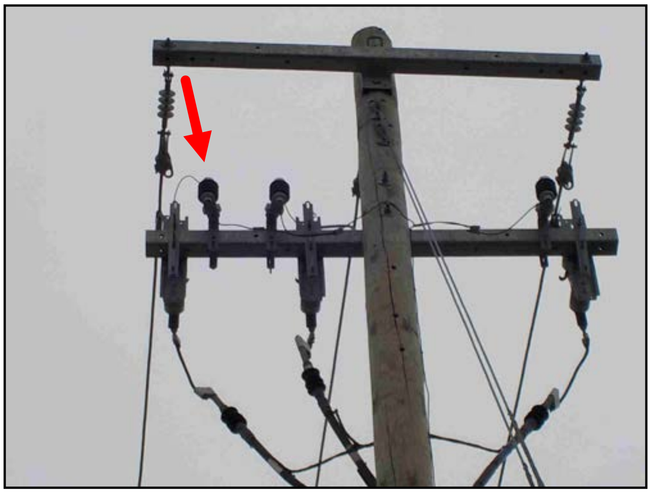
Fault AR01... **23.5°C** **OK AR02...** **-** **T.Rise...** **19.5°C** **PRIORITY:**

Notes & Recommendations

Deficiency Report Reference **#2518**

Repaired ____________________ by ______________________________

Item #4



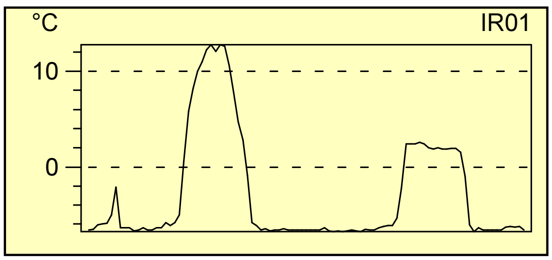
Location

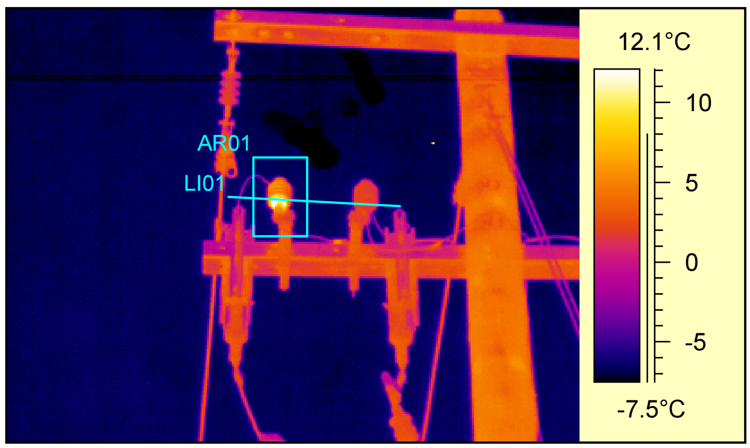
Pole # *unknown*,
Switch # **3236**
Grid 2406,
Elm Street at Ridge Road South.
RIDGEWAY.

Description

Road phase lightning arrestor assembly above cross arm and switch.

Object parameter	Value
Emissivity	0.95
Object distance	20.0 m
Ambient temperature	4.0°C





Observation at 3/16/2015 3:34:18 PM

Fault AR01... **14.7°C** **OK AR02...** **-** **T.Rise...** **10.7°C** **PRIORITY:**

Notes & Recommendations

Deficiency Report Reference **#2519**

Repeated ______________ by ______________

Item #5

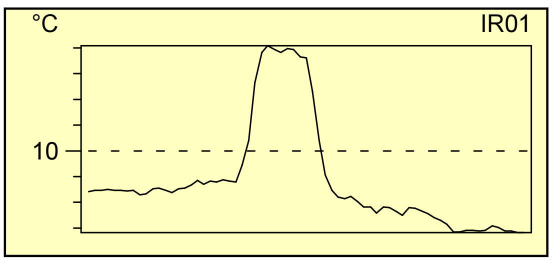
Location

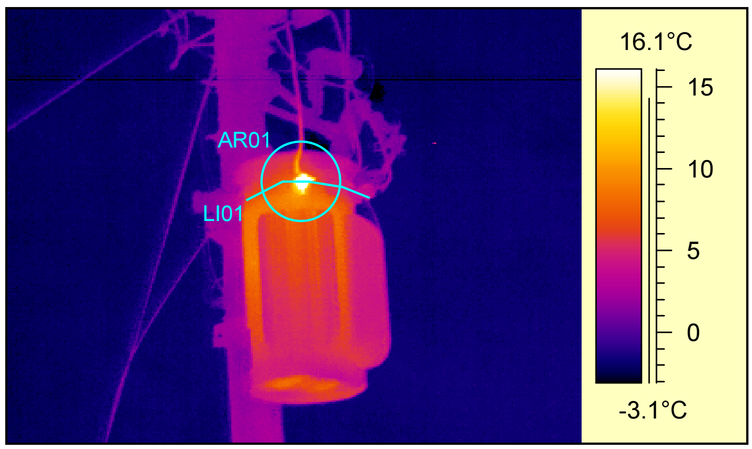
Pole # *unknown*,
Transformer Location # **57**
Grid 0018,
Near #3397 Townline Road.
PORT COLBORNE.

Description

Secondary bushing on
single phase transformer.
Hydro-One feed circuit.

Object parameter	Value
Emissivity	0.95
Object distance	22.0 m
Ambient temperature	3.0°C





Observation at 3/16/2015 4:53:59 PM

Fault AR01... **18.6°C** **OK AR02...** **-** **T.Rise...** **15.6°C** **PRIORITY:**

Notes & Recommendations

Deficiency Report Reference **#2520**

Repeared ______________ by ______________

Item #6

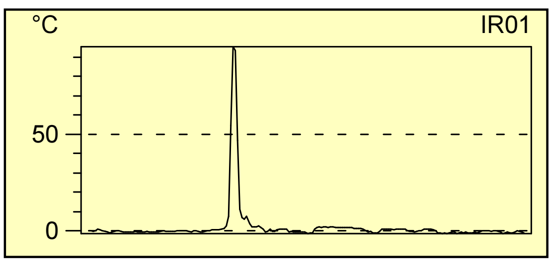
Location

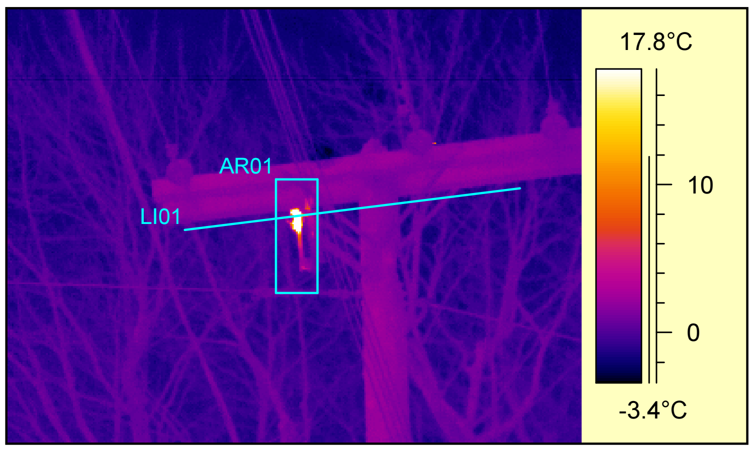
Pole # *unknown*,
Switch Location # **113-80**
Grid 0306,
Near #179 Tennessee Avenue
at Rosemount Avenue.
PORT COLBORNE.

Description

Upper clamp assembly
on Single phase primary switch.

Object parameter	Value
Emissivity	0.95
Object distance	20.0 m
Ambient temperature	3.0°C





Observation at 3/16/2015 5:37:57 PM

Fault AR01... **100.4°C** **OK AR02...** **-** **T.Rise...** **97.4°C** **PRIORITY:**

Notes & Recommendations

Deficiency Report Reference **#2521**

Repaired ________________ by ____________________

Item #7

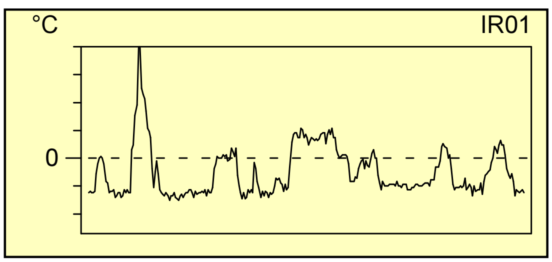
Location

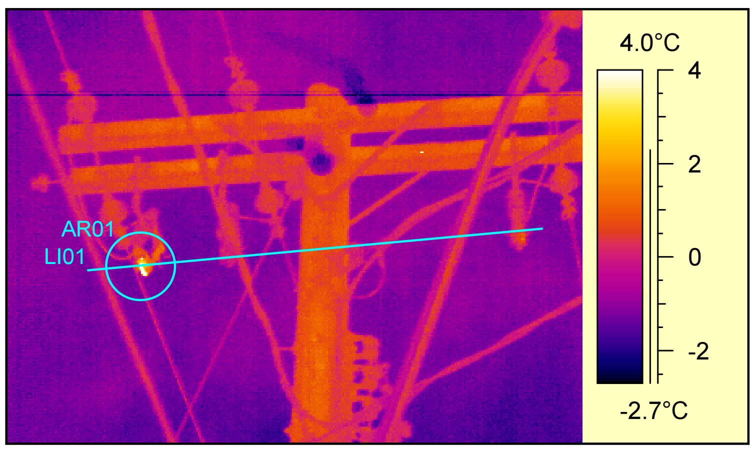
Pole # *unknown*,
Switch Location # **329-140**
Grid 0306,
Near #99 Bayview Lane.
PORT COLBORNE.

Description

Lower pivot assembly and lead termination on Field phase primary switch.

Object parameter	Value
Emissivity	0.95
Object distance	20.0 m
Ambient temperature	3.0°C





Observation

at 3/16/2015 5:48:54 PM

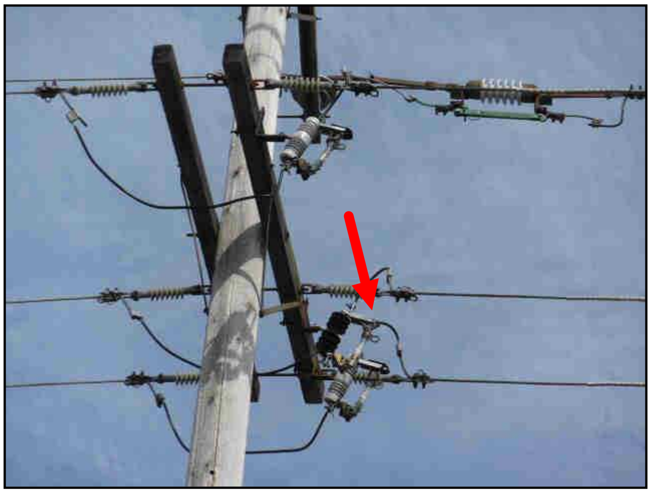
Fault AR01...	**11.6°C**	**OK AR02...**	**-**	**T.Rise...**	**8.6°C**	**PRIORITY:**	

Notes & Recommendations

Deficiency Report Reference **#2522**

Repaired ____________________ by ______________________________

Item #8



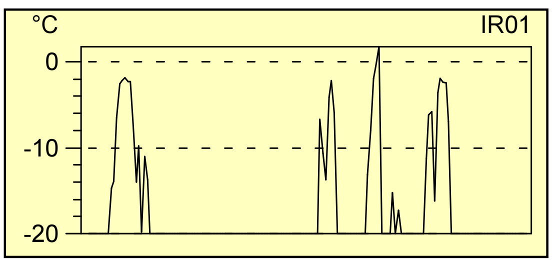
Location

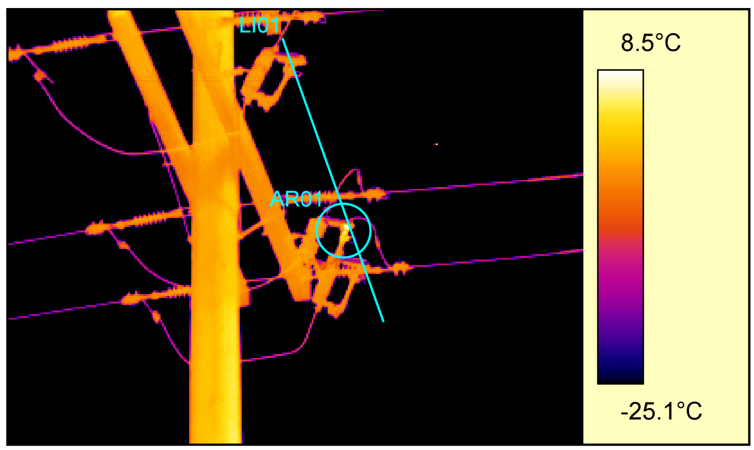
Pole # *unknown*,
Switch Location # **344-200, BLD-52**
Grid 0309,
Killaly Street West at Westdale Road.
PORT COLBORNE.

Description

Upper clamp assembly on
Centre phase switch, lowest circuit.

Object parameter	Value
Emissivity	0.95
Object distance	20.0 m
Ambient temperature	1.0°C





Observation at 3/17/2015 11:48:39 AM

Fault AR01... **10.5°C** **OK AR02...** **-** **T.Rise...** **9.5°C** **PRIORITY:**

Notes & Recommendations

Deficiency Report Reference **#2523**

Repeired ____________ by ____________

Item #9

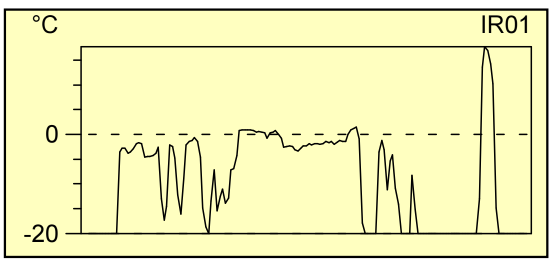
Location

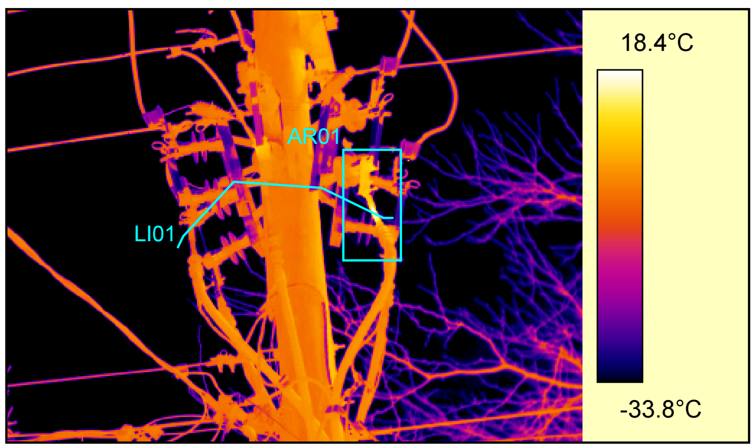
Pole # *unknown*,
Switch Location # **309**, Feeder # **309-F4**
Grid 0306,
Near #5 Catherine Street.
PORT COLBORNE.

Description

Upper portion of primary conductor above stresscone and below Road phase switch.

Object parameter	Value
Emissivity	0.95
Object distance	20.0 m
Ambient temperature	2.0°C





Observation

at 3/17/2015 12:11:10 PM

Fault AR01... **26.5°C** **OK AR02...** **-** **T.Rise...** **24.5°C** **PRIORITY:**

Notes & Recommendations

Deficiency Report Reference **#2524**

Repaired ____________________ by ____________________

Item #10

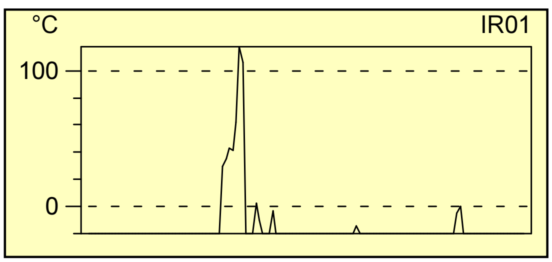
Location

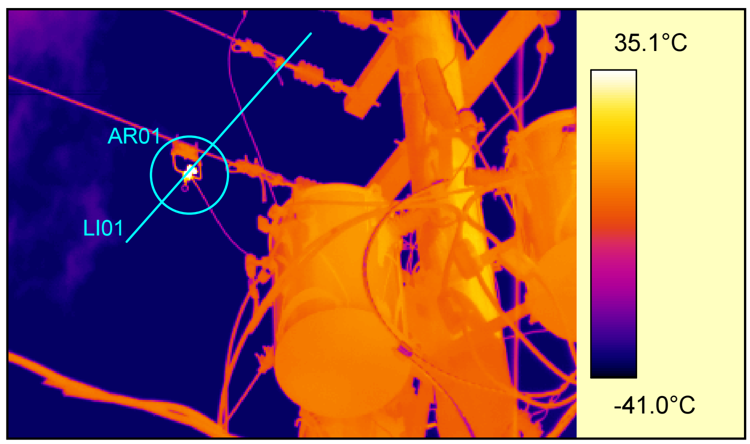
Pole # *unknown*,
Transformer Location # **96**
Grid 0309,
Near #21 Adelaide Street.
PORT COLBORNE.

Description

Hot line clamp at duck bill connection to lead on Field phase conductor, lower circuit.

Object parameter	Value
Emissivity	0.95
Object distance	20.0 m
Ambient temperature	2.0°C





Observation at 3/17/2015 1:12:30 PM

Fault AR01... **266.1°C** **OK AR02...** **-** **T.Rise...** **264.1°C** **PRIORITY:**

Notes & Recommendations

Deficiency Report Reference **#2525**

****** CONTROL ROOM NOTIFIED -- March 17, 2015 @ 1:20pm ******

Repeired ________________ by ____________________________

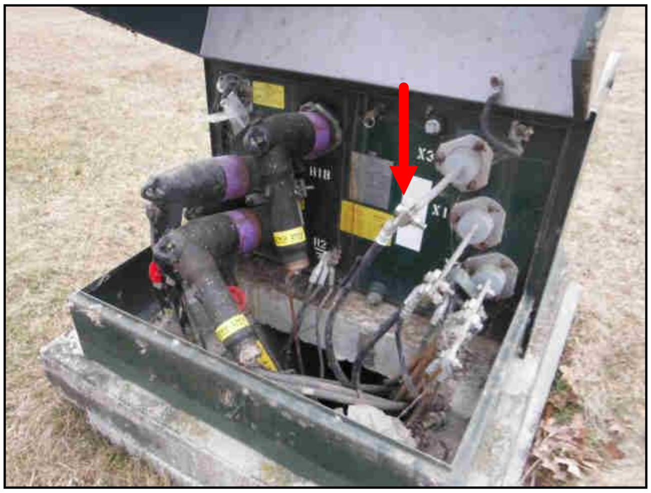
Underground Inspection

Scan Locations:

Zone 3

IR Reference # **141257**
Inspection Dates: **April 7 - 8, 2015**

Item #11



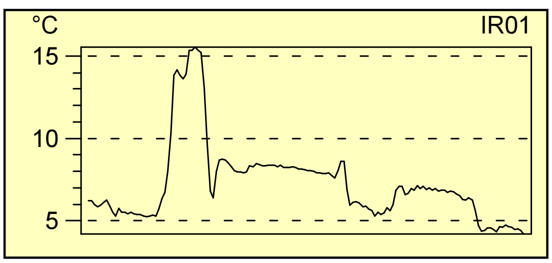
Location

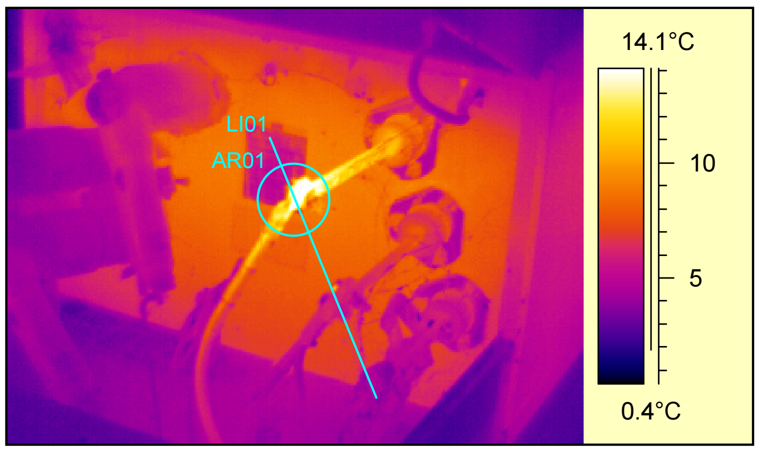
Transformer Location **#2827**
Grid #2100
Across from #4855 Abino Dune Road,
POINT ABINO.

Description

Secondary Service connection on X3
bushing.

Object parameter	Value
Emissivity	0.94
Object distance	2.0 m
Ambient temperature	2.5°C





Observation at 4/7/2015 7:52:57 AM

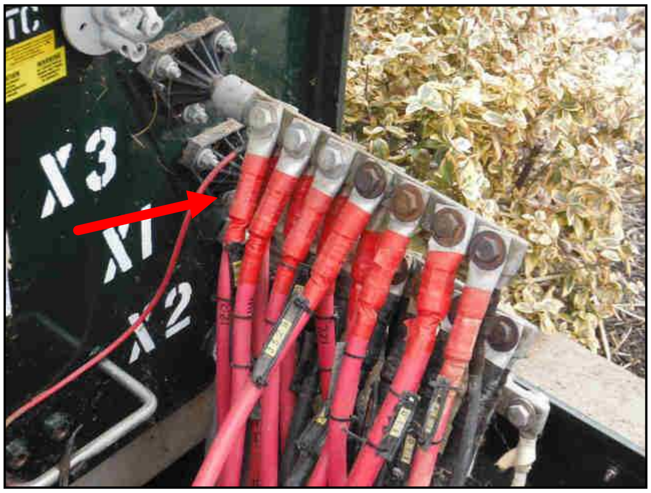
Fault AR01... **15.7°C** **OK AR02...** - **T.Rise...** **13.2°C** **PRIORITY:**

Notes & Recommendations

Deficiency Report Reference **#2526**

Repaired ____________ by ____________

Item #12



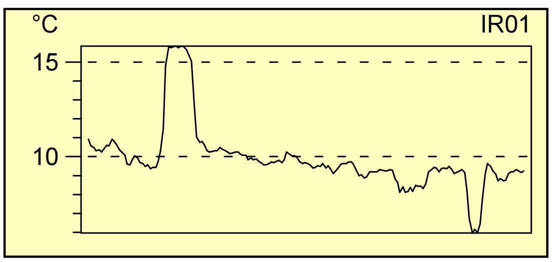
Location

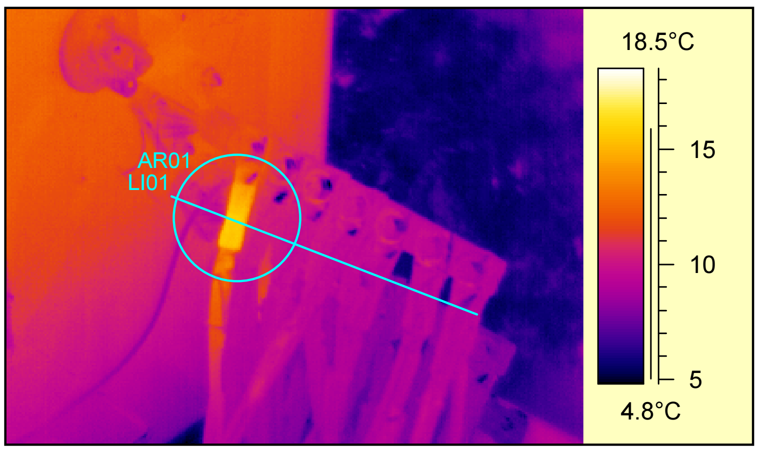
Transformer Location **#5264**
Grid #2406
Near #121 Sunrise Court,
RIDGEWAY.

Description

Secondary crimped connection on X3 bushing.
Wire **#128**

Object parameter	Value
Emissivity	0.94
Object distance	2.0 m
Ambient temperature	4.9°C





Observation at 4/7/2015 10:23:42 AM

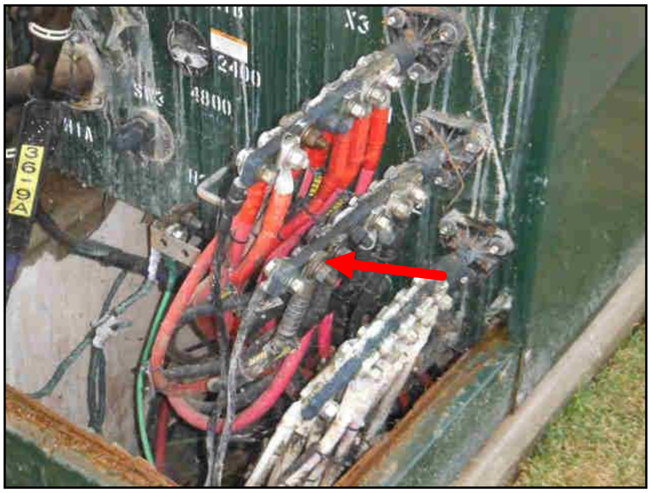
Fault AR01... **16.0°C** **OK AR02...** **-** **T.Rise...** **11.1°C** **PRIORITY:**

Notes & Recommendations

Deficiency Report Reference **#2527**

Repaired ____________ by ____________

Item #13



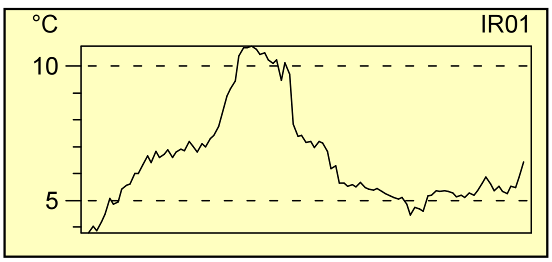
Location

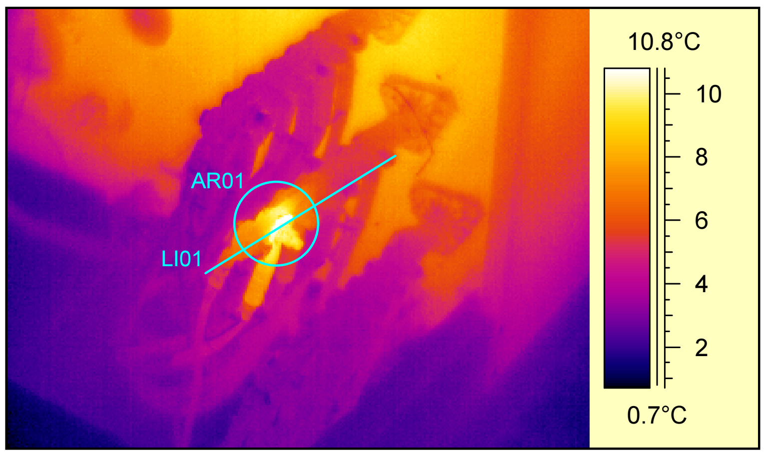
Transformer Location **#5798**
Grid #2418
Near #3889 Settler's Cove Drive,
STEVENSVILLE.

Description

Secondary lug connection on X1 Bushing.
Wire **#3890**

Object parameter	Value
Emissivity	0.94
Object distance	2.0 m
Ambient temperature	2.8°C





Observation at 4/8/2015 8:07:28 AM

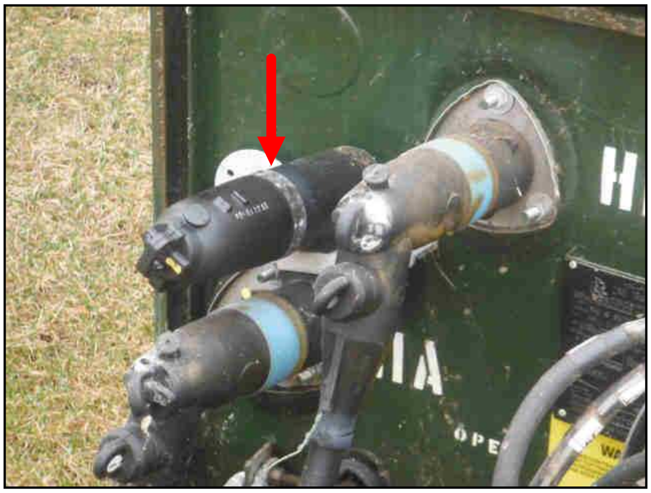
Fault AR01... **11.4°C** **OK AR02...** - **T.Rise...** **8.6°C** **PRIORITY:**

Notes & Recommendations

Deficiency Report Reference **#2528**

Repaired ______________ by ______________________

Item #14



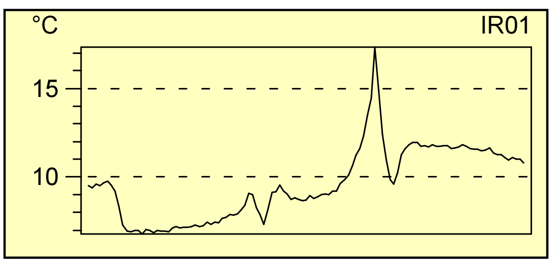
Location

Transformer Location **#1512**
Primary Cable **#24**,
Grid #0312
70 Hillcrest Road,
PORT COLBORNE.

Description

Blue phase parking stand feed through.

Object parameter	Value
Emissivity	0.94
Object distance	2.0 m
Ambient temperature	4.2°C



Observation at 4/8/2015 9:30:17 AM

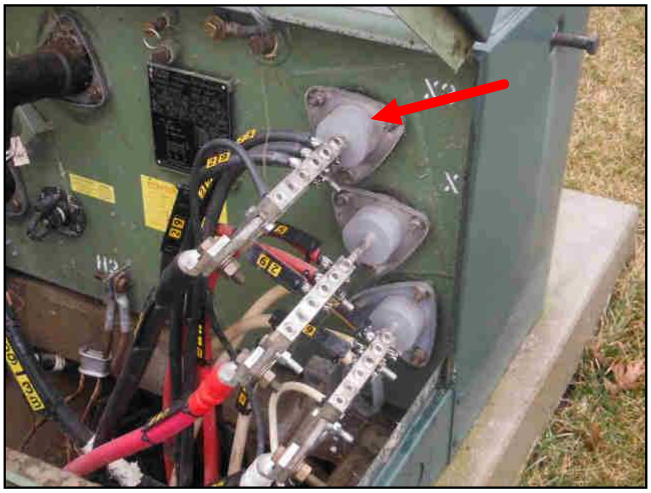
Fault AR01... **18.6°C** **OK AR02...** - **T.Rise...** **14.4°C** **PRIORITY:**

Notes & Recommendations

Deficiency Report Reference **#2529**

Repaired ____________________ by ______________________________

Item #15



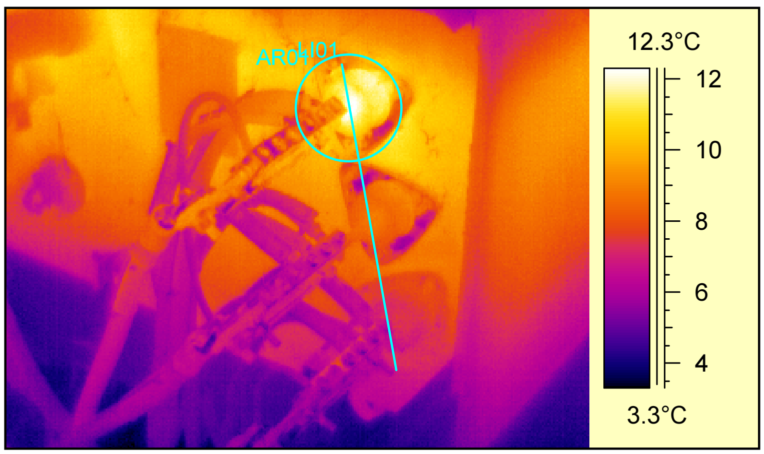
Location

Transformer Location **#7966**,
Grid #0312
29 Donlea Drive,
PORT COLBORNE.

Description

Secondary internal fault on X3 bushing.

Object parameter	Value
Emissivity	0.94
Object distance	2.0 m
Ambient temperature	4.2°C



Observation

at 4/8/2015 9:58:01 AM

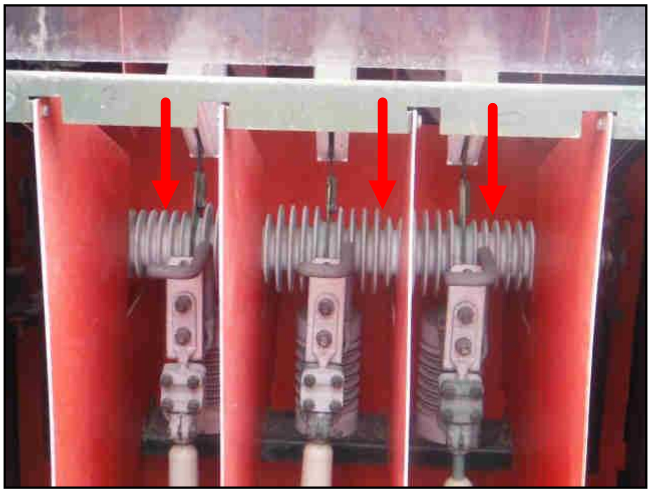
Fault AR01... **12.5°C** **OK AR02...** **-** **T.Rise...** **8.3°C** **PRIORITY:**

Notes & Recommendations

Deficiency Report Reference **#2530**

Repaired ____________________ by ________________________________

Item #16



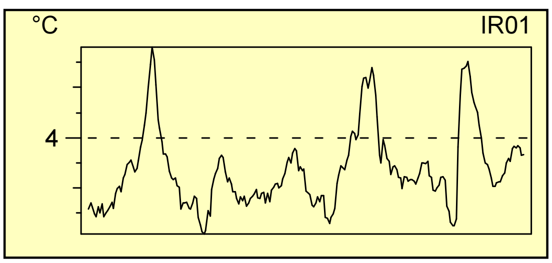
Location

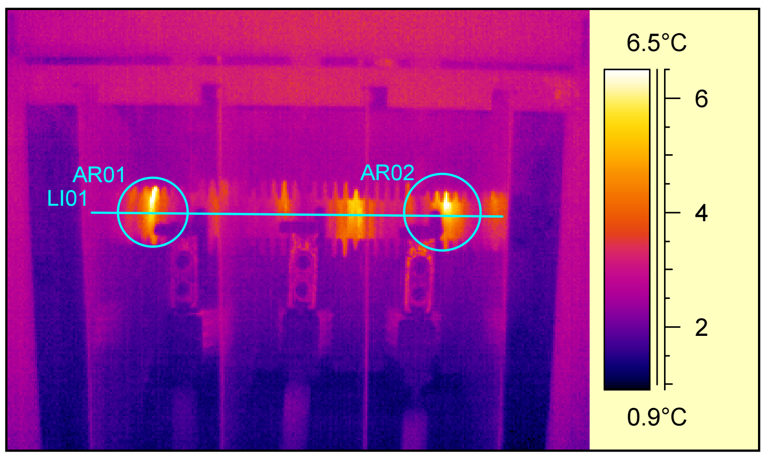
Switch Location **#79M14-35**
Grid #0309
Near #300 Elgin Street West,
PORT COLBORNE.

Description

Insulator assemblies behind all three phase switches.

Object parameter	Value
Emissivity	0.94
Object distance	2.0 m
Ambient temperature	4.8°C





Observation at 4/8/2015 10:32:50 AM

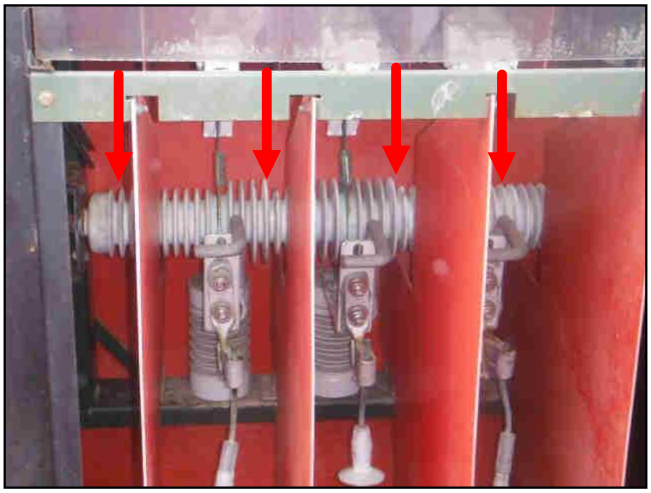
Fault AR01... **7.0°C** **Fault AR02...** **6.8°C** **T.Rise...** **2.2°C** **PRIORITY:**

Notes & Recommendations

Deficiency Report Reference **#2531**

Repaired ____________ by ____________

Item #17



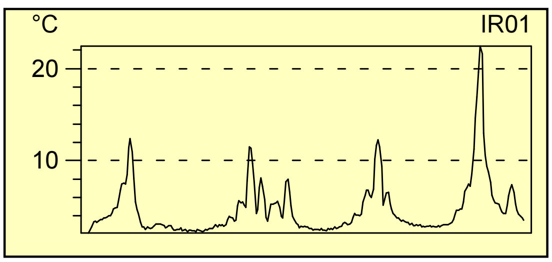
Location

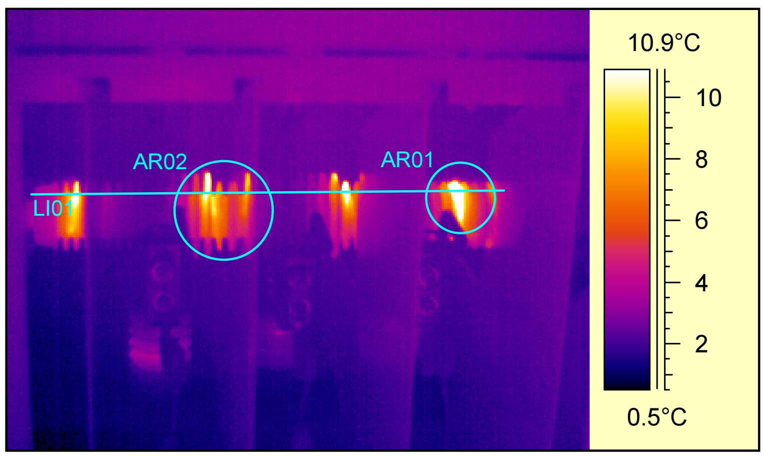
Switch Location **#79M14-40**
Grid #0309
Near #300 Elgin Street West,
PORT COLBORNE.

Description

Insulator assemblies behind all three phase switches.

Object parameter	Value
Emissivity	0.94
Object distance	2.0 m
Ambient temperature	4.8°C





Observation at 4/8/2015 10:33:11 AM

Fault AR01... **23.9°C** **Fault AR02...** **16.1°C** **T.Rise...** **19.1°C** **PRIORITY:**

Notes & Recommendations

Deficiency Report Reference **#2532**

Repeared ____________________ by ______________________________

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Appendix I.
2014 Station 12 Structural Review

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Canadian Niagara Power Inc.

Fort Erie Transformer Station Structural Review Draft Report

Prepared by:

AECOM
50 Sportsworld Crossing Road, Suite 290 519.650.5313 tel
Kitchener, ON, Canada N2P 0A4 519.650.3424 fax
www.aecom.com

Project Number:

60316819

Date:

March 2014

Statement of Qualifications and Limitations

The attached Report (the "Report") has been prepared by AECOM Canada Ltd. ("Consultant") for the benefit of the client ("Client") in accordance with the agreement between Consultant and Client, including the scope of work detailed therein (the "Agreement").

The information, data, recommendations and conclusions contained in the Report (collectively, the "Information"):

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- represents Consultant's professional judgement in light of the Limitations and industry standards for the preparation of similar reports;
- may be based on information provided to Consultant which has not been independently verified;
- has not been updated since the date of issuance of the Report and its accuracy is limited to the time period and circumstances in which it was collected, processed, made or issued;
- must be read as a whole and sections thereof should not be read out of such context;
- was prepared for the specific purposes described in the Report and the Agreement; and
- in the case of subsurface, environmental or geotechnical conditions, may be based on limited testing and on the assumption that such conditions are uniform and not variable either geographically or over time.

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AECOM: 2012-01-06

AECOM
50 Sportsworld Crossing Road, Suite 290 519.650.5313 tel
Kitchener, ON, Canada N2P 0A4 519.650.3424 fax
www.aecom.com

March 17, 2014

Mr. Sean Burger, EIT
Distribution Engineer
Canadian Niagara Power Inc.
PO Box 1218
1130 Bertie Street
Fort Erie, Ontario L2A 5Y2

Dear Mr. Burger:

Project No: 60316819

Regarding: Fort Erie Transformer Station Structural Review

Please find enclosed the draft report for the structural elements of the Control Building and transformer yard of the transformer station located at 241 Oakes St. in Fort Erie. This report summarizes the main findings of the structural review that we performed on February 26, 2014. This report also presents our recommendations and estimates of the remaining lifespan of the structural elements.

We would like to thank the Canadian Niagara Power Inc. staff who provided us with their assistance during our on-site review. We trust that this report meets your requirements. Please contact the undersigned if you have any questions.

Sincerely,
AECOM Canada Ltd.

Jim Flanigan, P.Eng., MBA
District Manager
Buildings + Places - Ontario
Manager, Kitchener Office
jim.flanigan@aecom.com

Distribution List

# of Hard Copies	PDF Required	Association / Company Name
	1	Canadian Niagara Power Inc.

Revision Log

Revision #	Revised By	Date	Issue / Revision Description
1	JF	March 17, 2014	Draft Report

AECOM Signatures

Report Prepared By:

Jim Flanigan

Executive Summary

AECOM was retained by Canadian Power Niagara Inc. (CPNI) to prepare a structural condition assessment report for the existing transformer station at 241 Oakes Drive, Fort Erie.

The transformer station was originally constructed circa 1920 with a major upgrade completed circa 1970. Various repairs and modifications have been completed since the 1970's upgrade. The original steel lattice termination structures were removed circa 2000 and were replaced with a combination of steel pole and wood pole termination structures.

The interior walls of the Control Building are in fair to poor condition with substantial diagonal and horizontal cracking noted. The remainder of the interior structural elements of the Control Building are in generally good condition. The exterior brick walls are in fair condition with some failure of the mortar joints noted. We recommend that the building be removed and replaced with a smaller prefabricated building as the existing building is nearing the end of its service life.

The exterior galvanized steel support structure is in generally good condition except for several localized areas where heavier corrosion on steel members, corrosion on connection bolts and a missing connection bolt was noted. The overall design approach affects the question of remaining service life since the required design loads for ice build-up and wind have increased substantially since the structure was designed. We recommend further analysis of the existing steel structure to verify if reinforcement or replacement is required to ensure an additional 20 years of service life.

The concrete piers at selected column locations are in poor condition and should be replaced. One concrete pier appears to have heaved due to insufficient frost protection and should be replaced.

The concrete foundation of Bank #1 transformer appears to be in good condition; however, further investigation is required to determine if it is adequate to support the proposed increased weight of the replacement transformer.

The assistance of CPNI staff in gaining access to the site, providing information and answering questions is noted and appreciated.

Table of Contents

1. Introduction

1.1 Scope of the Report

The scope of this assignment included a visual assessment of the structural elements of the Control Building and transformer yard of the transformer station located at 241 Oakes St. in Fort Erie. The assessment visit was conducted on February 26, 2014. The visual assessment was performed to evaluate the general structural condition of the control building, transformer foundations, yard structure foundations and visible above grade structural elements. The assessment included only those elements that were directly visible at the time of the assessment. The roof area was not included in the scope as the roof was anticipated to be snow covered. Assessment of architectural, civil, mechanical and electrical systems is outside the scope of this report.

1.2 Assessment Methodology

The primary assessment methodology for this condition assessment has been to visit the building and provide a visual review of the existing sight-exposed surfaces which are associated with the structural elements. Copies of selected drawings of the facility were provided for our use. The drawings were not complete sets; however, they provided a general layout of the facility and some indication of structural details.

We understand that Canadian Niagara Power Inc. (CPNI) requests our opinion as to the remaining expected service life of the structures and in particular if they are considered adequate to provide another 20 years of service life. We also understand that the Bank #1 transformer is scheduled for replacement.

The assistance of CPNI staff in gaining access to the site, providing information and answering questions is noted and appreciated.

2. Review of the Control Building and Yard Structures

The transformer station was originally constructed circa 1920 with a major upgrade completed circa 1970. Various repairs and modifications have been completed since the 1970's upgrade. The original steel lattice termination structures were removed circa 2000 and were replaced with a combination of steel pole and wood pole termination structures.

2.1 Summary of Observations

2.1.1 Control Building Structural Condition

The Control Building is a single storey building with no basement. The building is constructed of clay tile load-bearing walls (perimeter walls plus a central wall) supporting the roof framing. The roof framing is a cast-in-place concrete slab supported on structural steel beams. The steel beams bear directly on built-in areas of clay brick set into the clay tile walls. The clay tile walls are supported on concrete foundation walls. The exterior of the building is brick with a concrete parapet cap. We understand that there is no insulation in the exterior walls.

The interior of the building is in fair to poor condition. Numerous areas of cracking were noted in the perimeter clay tile walls. On the east and west walls (the end walls of the building) the cracking was predominantly diagonal. Diagonal cracks are an indication of excessive lateral movement of the wall. On the south wall (facing the transformer yard) a substantial horizontal crack was observed extending most of the length of the wall. This crack indicates that excessive settlement of the foundations along this wall has occurred. The possible settlement of the south wall could have caused the diagonal cracks in the east and west walls. The central load bearing wall in the Control building was in fair condition with only a few smaller cracks observed.

The concrete roof slab and supporting structural steel beams appear to be in good condition with minor surface corrosion noted on the beams.

The floor is a concrete slab-on-grade in generally good condition.

The exterior of the building is in fair condition. Some areas of brick mortar joints are failed most likely due to water entering the walls and enduring repeated freeze-thaw cycles over the years. The concrete parapet cap has open joints and appears to have shifted in one corner.

The Control Building houses very little equipment compared to the original design intent.

2.1.2 Transformer Station Yard Elements Structural Condition

The exterior yard structures support the overhead electrical conductors from the termination structures to the transformers. The overhead structure is comprised of galvanized structural steel supported on concrete foundations. Many of the beam-column connections are riveted. More recent additions use bolts for the connections. In general the structural steel members appeared to be in good condition with only light corrosion noted. In some areas, particularly on the higher level members and between connection plates, heavier corrosion was observed. The bolts also were observed to have considerable corrosion in some areas.

The general design of the steel framing is that of a braced frame. Bracing is provided through diagonal knee braces in most cases and full angle cross-bracing in several locations. The position of the knee braces requires that the columns act to provide stability through bending in both directions as well as supporting the vertical loads from the conductors. The base of the columns is connected to the concrete foundation via a baseplate with 2 anchor bolts in most cases. We noted that one bolt was missing from one of the higher level knee braces on the north side of the transformers.

The newer concrete foundations are square concrete piers while the older piers have a tapered section. A number of the older tapered concrete piers exhibit substantial spalling of the concrete face. We understand that various repairs to this concrete have been attempted over the years but none have been effective in the long term.

The concrete pier at one of the newer sections of steel framing appears to have heaved – most likely due to insufficient frost protection. The framing and connection at this column did not exhibit any particular distress; however, the noticeable change in elevation would have created additional forces in the connections that were not allowed for in the original design.

The transformer foundations appear to be a solid concrete slab. The thickness of the slab is not known and no drawings were available for this part of the structure.

2.1.3 Switchgear Building Structural Condition

The Switchgear Building is a prefabricated steel enclosure supported on a series of concrete piers. The building was installed approximately 1975. CPNI advised that, around 1996, settlement of several piers was observed. Additional sections of structural steel shims were fabricated to the heights required to be set on each concrete pier to level the building. At the time of our review the building appeared to be generally level and no further noticeable settlement had occurred.

2.2 Summary of Conclusions

2.2.1 Control Building

The cracking observed in the perimeter clay tile walls indicates excessive movement due to either settlement or sway of the building. The deterioration of the exterior brick mortar joints and of the joints in the concrete parapet cap indicates excessive water entering the wall and causing damage due to the effect of freezing and thawing. It is our opinion that the service life of the building is less than 20 years and that it is not worth spending additional money to repair the noted problems. We recommend that CPNI consider demolishing this building and installing a new prefabricated building sized appropriately for the required equipment. There are many options available for this type of building in terms of exterior finishes needed to suit a particular urban location.

2.2.2 Transformer Station Yard Elements

While the overall condition of the exterior galvanized steel structure is in generally good condition, there are a few areas where heavier corrosion was observed particularly where two plates of a connection were nearly back to back. The only way to properly repair this deterioration is to remove the element in question, remove the corrosion, repair the galvanized finish and reinstall the element. Where the knee brace connection bolt is missing it could simply be replaced. Where the connection bolts are corroded they could be replaced with appropriately designed connection bolts.

The larger issue that affects the remaining service life is the overall design approach used for the structure. The original design approach using light knee braces and depending on the columns to resist bending loads in both directions was probably adequate for the required design loads at the time of construction. Current design codes require allowance for substantially thicker ice build-up on conductors in combination with substantially higher wind loads. Based on a visual assessment only, it is our opinion that the existing structure would not be able to safely resist the current design loads. We recommend a more detailed investigation be completed into the structural capacity of the steel structure in order to verify if the steel structure is in fact adequate or if not then to assess the estimated cost of reinforcing or replacing the structure.

The concrete piers which exhibit substantial spalling should be removed and rebuilt. The final decision on the steel structure as noted above will dictate the most reasonable approach to repairing the piers. If the steel structure is to remain then the piers could be demolished and recast below the existing columns. If the steel structure is to be replaced it is likely that the new concrete piers and foundations would be required.

The one concrete pier which appears to have heaved due to insufficient frost protection should be removed and replaced with a new pier and foundation set to the correct elevation below grade.

The existing concrete foundation of the Bank #1 transformer is in good condition with no visible evidence of structural distress noted. We understand that the existing transformer weight is 30,400 pounds and the proposal is to replace it with a new transformer weighing 40,278 pounds. This is an increased weight of 32.5%. While the existing foundation shows no signs of distress, with no information available regarding the size of the existing foundation or the type and capacity of the supporting soil we cannot confirm if the existing foundation will be adequate to support the proposed transformer. It was reported that there is a very high water table on the site. We note that a high water table generally reduces the bearing capacity of the soil affected. A small excavation next to the foundation would be needed to verify the size of the foundation and the bearing capacity of the soil below.

2.2.3 Switchgear Building

It appears that the settlement previously observed at the Switchgear Building has stopped. This building should be monitored at least annually for signs of further settlement.

2.3 Summary of Recommendations

2.3.1 Control Building

- Remove the existing Control Building and replace it with an appropriately sized prefabricated building.

2.3.2 Transformer Station Yard Elements

- Conduct further analysis of the steel structures to verify capacity to resist design loads according to current codes.
- Replace concrete piers which exhibit substantial spalling.
- Replace concrete pier and foundation which has heaved.
- Conduct further investigation and analysis on the foundation of the Bank #1 transformer to verify if it is adequate to support the proposed transformer.

2.3.3 Switchgear Building

- Monitor building annually for signs of additional settlement.

Photograph 1 – Control Building

Photograph 2 – Yard Structure Arrangement

Photograph 3 – Control Building Wall Cracks

Photograph 4 – Control Building Parapet Joint Failure

Photograph 5 – Knee Braces on Columns

Photograph 6 – Missing Connection Bolt

Photograph 7 – Repaired Concrete Pier

Photograph 8 – Heaved Concrete Pier

Photograph 9 – Bank #1 Transformer Foundation

Photograph 10 – Switchgear Building Foundation

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Appendix J.
2014 Station 12 Outdoor Structure Assessment

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AECOM
50 Sportsworld Crossing Road, Suite 290
Kitchener, ON, Canada N2P 0A4
www.aecom.com
519.650.5313 tel
519.650.3424 fax

October 7, 2014

Mr. Sean Burger, EIT
Distribution Engineer
Canadian Niagara Power Inc.
PO Box 1218
1130 Bertie Street
Fort Erie, Ontario L2A 5Y2

Dear Mr. Burger:

Project No: 60316819

Regarding: Fort Erie Transformer Station – Structural Assessment

As requested, we have completed our structural assessment of the existing exterior steel structure and we report as follows.

Canadian Niagara Power retained AECOM to structurally assess the existing exterior steel structure at this facility. There were no original drawings available of this structure. The limited drawings available to AECOM were of various modifications to the original structure, giving limited information. AECOM structural engineering staff Adrian Wright, P.Eng., and Stephen Beck visited the site on September 9, 2014, to measure the existing structure with the assistance of Canadian Niagara Power staff Denis Levesque, Vic Kozina, and John Fenwick.

AECOM summarized and modelled the structural members and subsequently performed an analysis on 2 typical frames to determine levels of stress and associated lateral deflections. The dead loads of the steel members, insulators, conductors, and other components were included in the model. The weight of 19mm (3/4") of ice was applied to each member and component. The wind load in accordance with the current Ontario Building Code was applied to the individual components. The following represents our results. Please refer to the attached structural layout drawings for grid line indications.

North-South Frame on Grid 3 (see attached reference drawing):

Lateral deflection of the top of the structure due to wind: 126mm (5.0") in the north-south direction.
Main Columns: Factored bending moment is 2.57 times the capacity of the column.
Horizontal Beams: Factored bending moment is 1.05 times the capacity of the beam.
Knee-braces: Factored axial load in the knee-brace is less than the capacity of the knee-brace.

West-East Frame on Grid B (see attached reference drawing):

Lateral deflection of the top of the structure due to wind: 612mm (24.1") in the west-east direction.
Main Columns: Factored bending moment is 5.45 times the capacity of the column.
Horizontal Beams: Factored bending moment is less than the capacity of the beam.
Knee-braces: Factored axial load is 1.27 times the capacity of the knee brace.

The above results indicate substantial overstresses and excessive deflections. For comparison of the lateral deflection item, the typical allowable deflection of a building of similar height to the structure would be 0.75". The allowable deflection of a building is generally determined based on the flexibility of associated building elements and the requirement to prevent them from cracking. In this case, the conductors and other elements supported on the steel structure seem quite flexible so a prescribed deflection limit is unclear.

We recommend that the structure be reinforced by the addition of bracing in both directions between the columns to reduce the lateral deflection and also to reduce the column bending moments. The final geometry of new bracing would be subject to discussion with Canadian Niagara Power to ensure that required clearances for normal operations are maintained. We would be pleased to work with you on the implementation of the structural bracing.

We trust that this information meets your requirements. Should you have any questions regarding this information, please call me.

Sincerely,
AECOM Canada Ltd.

LICENSED PROFESSIONAL ENGINEER
J. P. FLANIGAN
PROVINCE OF ONTARIO

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Appendix K.
2015 Station 12 – 15kV XLPE Assessment

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Canadian Niagara Power Inc.

CONDITION ASSESSMENT OF SIX SAMPLES OF 350 KCMIL, XLPE INSULATED, 15 KV CABLE

Performed March 16, 2015 to June 4, 2015 as per
Kinectrics Quote Q422036BOE (MV cable test, CNP)-R1

Kinectrics Inc. Report: K-423253-RC-0000-R00
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DISCLAIMER

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CONDITION ASSESSMENT OF SIX SAMPLES OF 350 KCMIL, XLPE INSULATED, 15 KV CABLE

Kinectrics Inc. Report No.: K-423253-RC-0000-R00
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1.0 INTRODUCTION

At the request of Canadian Niagara Power Inc., Kinectrics Inc. performed condition assessment of three samples of 350 kcmil, compressed aluminum conductor, XLPE insulated, 15 kV cable design cables as per a mutually agreed upon test program seen in Kinectrics Quote Q422036BOE (MV cable test, CNP)-R1.

The initially received three samples (Figure 1) were split into six test samples, each approximately 37 feet long. The samples were identified as segments from three conductor bundled cable hung overhead on poles (Figure 2). The cable was originally installed approximately 30 years ago and removed from service November 2014).

The goal of the assessment and electrical testing was to evaluate the condition of the cable samples and determine if the remaining identical cable still installed in the field is suitable to use for 8.4kV L-L (4-wire WYE) rated voltage and its ongoing use in a 4.8 kV L-L (3-wire Delta) rated voltage.

2.0 TEST PROGRAM

The actual test program that was followed is given below:

1) Received 3x73 foot cable sections (one of each phase – identified by CNP as 350 kcmil, compressed aluminum conductor, XLPE insulated, 15 kV cable design) and conducted visual inspection to identify gross deficiencies, damage, and copper tape screen corrosion;

2) *"EXTRA – CONDITIONING FOR FURTHER TESTING"* – We took the 3x73 foot cable sections, and immersed them in water tanks for a period of 1 week to re-wet any water trees that may have dried out in

storage since removal. Water was forced into the conductor to guarantee that the all water treeing was reconstituted. During the soak period, the cable samples were energized at phase-to-ground voltage of 4 kV.

3) Checked the construction of the cable to verify its voltage class and technical data; wafered a cable section to measure the average insulation thickness and determine if it was suitable to use for 8.4kV L-L (4-wire WYE) rated voltage and its ongoing use at a 4.8 kV L-L (3-wire Delta) rated voltage. Also, performed a microscopic examination for direct evidence of water trees, electrical trees, and/or insulation defects on 40 wafers to determine the quality of insulation;

4) Prepared 6 x approximately 37' complete test cable sections from received cables and installed laboratory terminations on each section for electrical diagnostic tests;

5) Conducted low frequency dielectric spectroscopy (DS) measurements on 6 cable sections using IDAX 300, which is a dedicated tool for this test. The IDAX 300 measures the capacitance and dielectric losses (Tan δ) of a specimen at a variable voltage and frequency (typically 0.1 Hz to close to power frequency). Dielectric spectroscopy is a well-recognized test method for gaining an indication of water treeing or water induced degradation in insulation; The test to be performed at 0.5Un, Un, and 1.5 Un to calculate the Delta - Tan δ; Note that according to the criteria found in IEEE 400.2-2013 there are three actions recommended based on the condition assessment of service aged XLPE based insulations using 0.1 Hz test voltage and these are namely: “1. No action required; 2. Further study required; 3. Action required”. In case the tested samples fall into the “No action required” category, normally that implies that they may remain “good” for up to 5 years;

6) Conducted timed breakdown tests on 6 x cable sections as per ICEA S-94-649 to determine breakdown voltage V_{bd};

7) Provided testing report and analysis including Kinectrics view on cable condition relative based on comparison with new cable specifications, industry guidance, and internal knowledge.

3.0 TEST SET UP AND TEST RESULTS

3.1 Receiving and visual inspection

The cable samples sent by Canadian Niagara Power Inc. were received on March 16, 2015. Figure 1 shows the cable specimens as received. During the receiving inspection, it was noted that there were more samples available for testing than necessary. After discussions with Canadian Niagara Power Inc., it was decided to use the samples cut from the end of the cable circuit as the phase colours of these were easily identifiable. The three samples, one from each phase, chosen for testing were marked as sample “Cable Blue”, “Cable Red”, and “Cable White” by Kinectrics.

A thorough visual inspection was made of the cable. Manufacturer identification markings (Figure 3) were found on the insulation semicon shield under the tape neutral. It identified the manufacturer as “Industrial Wire and Cable”, the voltage class as 15 kV, and the construction as shielded. This manufacturer was bought out over 25 years ago by Canada Wire and Cable which was subsequently acquired by Alcatel (now Nexans). This indicated that the cable was made on old-design extrusion lines with less clean materials. It also indicated that it had been in service for at least 25 years consistent with the 30 years in service stated by CNP.

In spite of the age of the cable, there was still a “new cable” smell to the insulation. This smell comes from the by-products of the chemical crosslinking process.

It was noted that the cable metallic tape neutral was damaged in many places (Figure 4). It could not be determined if this damage was the result of handling when it was removed or it was damaged in service. There was substantial amount of copper oxide on the tape.

The copper neutral tape was examined more closely (Figure 5). There were clear indications of where the copper tape was overlapped. This allowed for an appraisal of the lay of the tape.

Approximately 17 m of cable was laid out in the laboratory so that the outside of the cable could be inspected. This was done to be sure that the outside of the cable was not damaged especially in the cable shield to shield contact points. An inspection of the cable’s insulation semicon shield surface did not reveal any major damage. Several small damage spots were identified on the semicon surface (Figures 6 To 10). None of the damages appeared to penetrate the semicon and enter the insulation.

The tape neutral was also examined. Although it was found shifted and damaged in many spots only a few places showed possible electrical damage (Figure 11) or that the tape was tearing (Figure 12).

Because the cables were triplexed so that three cables were bundled together, there were metal tape ties holding the cables together (Figure 13). A look under this tie point revealed no major activity but only minor corrosion (Figure 14).

3.2 Water immersion under voltage

The ends of the three cable sections had to be prepared and terminated accordingly since the cable samples needed to be energized at the required conditioning voltage while being immersed in tap water. This was done in order to re-wet any water trees that may have formed during service life.

The conductors of each of the cable samples prepared for the soaking was filled with tap water prior to applying the high voltage. The samples were also fitted with plastic funnels (used to top up water that evaporates) arranged at the ends around the conductors and then immersed in a tank full of tap water. At this time the three samples were energized at 4 kV. The samples were then soaked for 7 days. Figure 15 shows the setup used.

The conditioning described above successfully took place from May 8 to 15, 2015.

3.3 Dimensional Measurements of the Cable

A full examination of the cable dimensions was undertaken. These measurements were compared to standard requirements. A full listing of the cable requirements from current standards is given in Appendix A.

Initial measurements were made of the cable size and are listed in Table 1. The diameter over conductor shield and diameter over the insulation were required for area calculations. The diameter over the insulation and the conductor size are important for determining cable shield and insulation thickness requirements. As can be seen from Figure16, this is a XLPE insulated cable with extruded conductor and insulation semicon shields and a compact stranded conductor. From the diameter and the fact it is compact stranding, it was determined that the conductor was 350 MCM.

Table 1 - Initial Dimensional Measurements

<table>
<tr><td>Diameter over Conductor Shield</td><td>0.667” (16.9 mm)</td><td rowspan="2">Gives 194 mil
Average Insulation Thickness</td></tr>
<tr><td>Diameter over Insulation</td><td>1.055” (26.8 mm)</td></tr>
<tr><td>Conductor (Compact Al)
Diameter Measurements</td><td>0.612”
0.6092”
0.6090”
0.6110”</td><td>0.610” (15.5 mm) average
350 MCM compact</td></tr>
</table>

The dimensions of the insulation and the semicon shields were taken from wafers cut from the cable insulation. These wafers are described in the section on Microscopic Examination of the Insulation. The results of those measurements are presented in Table 2. They were compared to the standard requirements in Table 2. All the measurements fell within acceptable ranges.

Table 2 - Dimensional Measurements from Wafers

Sample #	Insulation Shield (mm, (mils))		Insulation Thickness (mm,(mils))		Conductor Shield Min (mm, (mils))
	min	max	min	max	
1	1.1 (43)	1.6 (63)	4.9 (193)	5.2 (205)	0.6 (24)
2	1.05 (41)	1.55 (61)	4.45 (175)	5.1 (200)	0.7 (28)
3	1.2 (47)	1.6 (63)	4.45 (175)	5.2 (205)	0.8 (31)
Requirement 15 kV. 350 MCM, 1.0-1.5" over insulation	1.02 (40)	1.91 (75)	4.19 (165)	5.21 (205)	0.41 (16)

3.4 *Microscopic Examination of the Insulation*

Two sections, each approximately 6 inch long, were cut from the two samples of supplied cable. These sections were then sliced in small wafers (approx. 39 mils (1 mm) thickness) and boiled in de-ionized water in order to expose the water trees under microscopic examination as per ICEA S-94-649 and ASTM standards. The slices were kept in water so that the trees would not dry out.

The samples were examined under a microscope to determine the dimensions of the insulation and the extruded conductor and insulation shield. The results of that examination were presented in Table 2 of Section 3.3. The examination also looked for any inclusions in the insulation, such as voids, contaminants or ambers. The samples were also examined for water treeing. Water trees have been associated with the degradation of polymeric (rubber and plastic) insulated power cables insulation.

The detailed observations are given in Appendix B.

3.4.1 Manufacturing defects found in the cable

There were 40 wafers examined under the microscope. This represented a volume of insulation of almost 1 in^3. Several large contaminants and voids were found in the insulation (Table 3). This was consistent with the period of manufacture of the cable. Note that the largest void was 2.6 times larger, and the largest contaminant was 1.6 times larger than would be allowed in today's cable.

Table 3 - Summary of Manufacturing Defects Found in the Cable

Defect noted	Length Examined	Volume	Number	Largest	Significance
Halo	4.40 cm (1.73")	-	-	90% of insulation	Halos have been associated with reduced cable capability
Voids >3 mils	4.40 cm (1.73")	14.9 cm^3 (0.91 in^3)	9	8 mils	This cable fails both the void and contaminant count expected from modern cables. These defects will reduce the breakdown strength of the cable.
Contaminants >5 mils	4.40 cm (1.73")	14.9 cm^3 (0.91 in^3)	5	8 mils	

3.4.2 Water treeing

Water treeing has been associated with a decrease in the breakdown strength of polymeric insulation. It was found that a large number of very small water trees did not affect the insulation strength. Usually trees greater than 25% of the insulation thickness were considered significant to the breakdown strength of the insulation.

Table 4 presents a summary of the findings of the microscopic examination for water trees. The results of the examination showed that some degradation of the insulation due to water treeing should be expected.

Table 4 - Summary of Microscopic Water Treeing Examination Results

Water Tress Found	Length Examined	Volume	Number	Density	Significance
10-25% of insulation	2.90 cm (1.14")	9.8 cm^3 (0.60 in^3)	72 (69 bowtie, 2 conductor and 1 insulation streamer)	7.1/cm^3 (116/in^3)	Indicative of a cable that has been in a moist environment. Not particularly significant to the long-term life of the cable
25-50% of insulation	4.40 cm (1.73")	14.9 cm^3 (0.91 in^3)	13 (all bowtie)	0.87/cm^3 (14.3/in^3)	Some significant degradation due to water treeing. Would expect a reduction in breakdown strength of the cable.
Largest Water	70 mils (bowtie ~35% of insulation thickness)				

3.5 Semicon Shield Resistivity

The condition of the cable's insulation and conductor semicon shields was investigated. Tests were done to see if the materials' resistance was sufficiently low to meet today's standards. Tests were performed on 3 samples (2 of the conductor shield and one of the insulation shield). The tests were performed using the 4 electrode method as described in Section 9.8.4.2 of the cable standard (ICEA S-94-649).

The information necessary to calculate the volume resistivity is given in Tables 5 and 6. In accordance with the requirements of the standard, the tests were done at 90°C (maximum operating temperature), 110°C, and at 130°C (the emergency overload temperature). In addition the test was also performed at room temperature for comparison purposes.

Table 5 - Distance Between Electrodes

Sample	A to B*	B to C *	C to D*
Insulation Shield #1	1.07" (27.21 mm)	2.30" (58.36 mm)	1.09" (27.70 mm)
Conductor Shield #1	1.12" (28.40 mm)	2.07" (52.74 mm)	1.09" (27.73 mm)
Conductor Shield #2	1.32" (33.54 mm)	2.08" (52.88 mm)	1.12" (28.46 mm)

*where A and D were the current injection electrodes, and B and C were the potential electrodes

Table 6 - Parameters Used to Calculate Volume Resistivity

Parameter	Insulation Semicon	Conductor Semicon
Diameter over Conductor Shield	-	0.667" (16.9 mm)
Diameter over Insulation	1.055" (26.8 mm)	-
Thickness	0.053" (1.35 mm)	0.028" (0.7 mm)
D	1.108" (28.15 mm)	0.667" (16.9 mm)
d	1.055" (26.8 mm)	0.639" (16.2 mm)

The results of the test are given in Table 7. The conductor shield easily meets the requirement of the standard. The insulation shield, however, has a 6 times higher resistivity (~3000 Ω-m) than required by the standard (500 Ω-m), although the resistivity at room temperature was very low.

Table 7 - Resistance and Resistivity Measurements

Sample	Temperature	Current	Voltage (ac)	Resistance	Resistivity
Insulation Shield #1	23.9°C	0.93 mA	5.556 V	5.97 kΩ	6.0 Ω-m
	90°C	1.4 µA	4.209 V	3.01 MΩ	3000 Ω-m
	110°C	1.4 µA	4.312 V	3.08 MΩ	3070 Ω-m
	130°C	1.3 µA	4.073 V	3.13 MΩ	3120 Ω-m
Conductor Shield #1	23.9°C	5.62 mA	2.299 V	0.409 kΩ	0.07 Ω-m
	90°C	0.0533 mA	0.927 V	17.4 kΩ	0.31 Ω-m
	110°C	2.24 mA	4.726 V	2.11 kΩ	0.37 Ω-m
	130°C	2.60 mA	4.417 V	1.70 kΩ	0.30 Ω-m
Conductor Shield #2	23.9°C	10.48 mA	4.152 V	0.394 kΩ	0.07 Ω-m
	90°C	0.625 mA	1.139 V	1.82 kΩ	0.32 Ω-m
	110°C	2.92 mA	5.016 V	1.71 kΩ	0.30 Ω-m
	130°C	2.92 mA	4.752 V	1.62 kΩ	0.28 Ω-m

3.6 Low frequency dielectric spectroscopy

The low frequency dielectric spectroscopy (DS) measurements on the six samples were conducted on May 19, 2015.

The DS tests were performed using an IDAX 300 system and a 30kV amplifier, which is a dedicated tool for this diagnostics test. The IDAX 300 measures the impedance of a specimen at a variable voltage and frequency. A Digital Signal Processing (DSP) unit generates a test signal with the desired frequency. This signal is amplified with an internal amplifier and then applied to the specimen. The voltage across, and the current through, the specimen are measured with high accuracy using a voltage divider and an electrometer (ampere meter). The IDAX 300 system measures the capacitance and dielectric losses at discrete frequencies both above and below the main frequency of 60 Hz.

IEEE 400.2 provides guidance, based on data obtained industry-wide, with respect to Low Frequency DS testing and was used for acceptance criteria for these measurements. The criteria are based primarily on the 0.1Hz tanδ value obtained at $0.5U_0$, $1.0\ U_0$ and $1.5U_0$. The guideline for XLPE cables is provided in Table 8 below. Three categories are considered - no action required, further study required and further action required (in general, the action required in the latter designation refers to performing a further test at the next maintenance cycle, not necessarily cable replacement).

Table 8 – Condition assessment of service-aged XLPE-based insulations, using 0.1Hz test voltage (IEEE 400.2)

Condition Assessment	tan δ @ U_0 $[10^{-3}]$		Δtan δ (tan δ @1.5 U_0 - tan δ @$0.5U_0$) [10-3]
No Action Required	<4	and	<5
Further Study Advised	4 to 50	or	5 to 80
Action Required	>50	or	>80

In this particular case, 5 test voltages were applied assuming the cable rating was 13.8 kV: 4 kVrms (corresponding to $0.5U_0$), 8 kVrms, 12 kVrms (corresponding to $1.5U_0$), 16 kVrms, and again half the cable rated voltage 4 kVrms (the measurement at $0.5U_0$ was repeated in order to check the stability of the dielectric loss current). Each test voltage was applied at frequency in the range of 0.01 Hz up to 100 Hz (or up to at least 46.4 Hz). The measurements performed at $0.5U_0$ and $1.5U_0$ were used to derive the dissipation factor tip-up or Δtan δ. The complete set of data is provided in Appendix B. The summarized results are shown in Table 9 and an interpretation of these results is discussed below.

Table 9 – Summary of tan delta data recorded at 0.1 Hz, 15 kV class cables

Sample ID	Test Date	Tan δ @ $0.5U_0$ (4kV)	Tan δ @ U_0 (8kV)	Tan δ @ $1.5U_0$ (16kV)	Δtan δ	Pass/Fail
Cable Blue 1A	May 19, 2015	0.23E-3	0.23E-3	0.27E-3	0.03E-3	Pass
Cable Blue 1B	May 19, 2015	0.26E-3	0.28E-3	0.32E-3	0.06E-3	Pass
Cable Red 1A	May 19, 2015	0.25E-3	0.24E-3	0.24E-3	-0.01E-3	Pass
Cable Red 1B	May 19, 2015	0.23E-3	0.25E-3	0.28E-3	0.05E-3	Pass
Cable White 1A	May 19, 2015	0.24E-3	0.25E-3	0.35E-3	0.10E-3	Pass
Cable White 1B	May 19, 2015	0.25E-3	0.25E-3	0.30E-3	0.06E-3	Pass

Evaluation of the data presented in Table 9 reveals that the tan δ values at different voltages and at 0.1Hz are in the range of 0.23×10^{-3} to 0.51×10^{-3}. Furthermore, the tip-up (Δtan δ) is in the range of -0.01×10^{-3} to 0.10×10^{-3}. All values fall within the requirements by the standard, hence the tested cables are considered not to exhibit adverse effects due to moisture ingress at this stage of their service life.

3.7 High voltage timed breakdown tests

The high voltage timed test (HVTT) was performed following the procedure of ICEA S-94-649-2013, Section 10.1.3. The six cable samples' ends were prepared in such a way to provide an active cable length of approximately 37 feet long for each individual sample. The results are summarized in Table 10.

Table 10 – Summary of results for HVTT

Applied Voltage* [kV]	Voltage Stress**		Sample No.					
	[V/mil]	[kV/mm]	Blue Cable 1A	Blue Cable 1B	Red Cable 1A	Red Cable 1B	White Cable 1A	White Cable 1B
17.5	100	3.9	Pass	Pass	Pass	Pass	Pass	Pass
24.5	140	5.5	Pass	Pass	Pass	Pass	Pass	Pass
32	180	7.2	Pass	Pass	Pass	Pass	Pass	Pass
39	220	8.8	2m 25s	4m 57s	Pass	2m 32s	2m 18s	Pass
46	260	10.3			0.27 min			0m 52s
Withstand Voltage			32 kV	32 kV	39 kV	32 kV	32 kV	39 kV
Withstand Stress**			180 V/mil (7.2 kV/mm)	180 V/mil (7.2 kV/mm)	220 V/mil (8.8 kV/mm)	180 V/mil (7.2 kV/mm)	180 V/mil (7.2 kV/mm)	220 V/mil (8.8 kV/mm)

* 5 minute voltage steps

** based on nominal insulation thickness of 175 mils (4.45 mm)

From the data presented in Table 10 it is observed that samples "Red Cable 1A" and "White Cable 1B" failed at the higher breakdown level of 46 kV and withstood 39 kV for 5 min. Samples "Blue Cable 1A", "Blue Cable 1B", "Red Cable 1B", and "White Cable 1A" withstood 32 kV for 5 minutes and failed at the same voltage level of 39 kV. The lowest breakdown voltage level (V_{bd}) is corresponding to an electrical stress of 220 V/mil (8.8 kV/mm). It is worth noting that in normal operation these cables would be subjected to a line-to-ground voltage of 8.4 kV, which is about 3.8 times lower compared to V_{bd}.

4.0 TEST EQUIPMENT USED

Manufacturer	Model Number	Serial Number	Calibration Due Date
Fluke	52 II	KIN-03125	2016-02
Fluke	87V	KIN-01885	2016-04
Fluke	87V	KIN-02515	2016-03
Fluke	87V	KIN-03939	2016-03
Slaughter	02975	KIN-01766	2016-03
Megger	S1-1052/2	KIN-00844	2015-08
Kinectrics	Type T	KIN-01745	2016-02
FTC	CR2032	KIN-03612	2015-09
Omega	TMQSS125U-6	KIN-01027	2016-05
Omega	TMQSS125U-6	KIN-01020	2016-05
Agilent	34972A	KIN-03664	2016-28
Fischer Scientific	Digital Barometer	KIN-00794	2015-06
Cole Parmer - Digital Psychrometer	3312-21	KIN-02056	2015-08
MWB	300 kV Cap Voltage Divider	015722-0	2016-05
Nexxtech	Stop Watch	KIN-00866	2015-08

5.0 CONCLUSIONS

A series of examinations and tests was performed on the cable sample supplied by CNP. The results of those examinations are summarized in Table 11. For the most part, the cable performed well especially considering that it was made during a time when cable quality was not near today's standards. Three areas were identified as possibly problematic: (1) mechanical damage to the metallic tape neutral, (2) large voids and contaminants in the insulation and (3) a high resistivity in the insulation shield at the higher temperatures.

Table 11 - Summary of test results

Examination or Test	Results
Visual Examination	- mechanical damage to the metallic tape shield but little sign of electrical damage - minor damage to the surface of the insulation semicon shield
Cable Dimensions	- all within acceptable limits for 15 kV cable
Microscopic Examination	- voids 2.6 times larger than acceptable - contaminants 1.6 times larger than acceptable
	- some significant water trees - amount of water treeing was very good for a cable of this age
Semicon Shield Resistivity	- resistivity of the conductor shield was good - resistivity of the insulation shield was 6 times higher than expected at the higher temperatures
Dielectric Spectroscopy	- considered not to exhibit adverse effects due to moisture ingress at this stage of their service life - no action was required on this cable
Timed Breakdown Test	- breakdown voltage was > 32 kV - at 4.8 kV (2.77 kV to ground) - >11 U_0 - at 8.4 kV (4.8 kV to ground) - >6.7 U_0 - at 15 kV (8 kV to ground) - >4 U_0

5.1 Evaluation for use at 4.8 kV delta connected

5.1.1 The mechanical damage to the metallic tape shield needs to be evaluated. There was no sign of electrical damage to the tape and little indication that the underlying cable was damaged significantly. It is suspected that the damage may have occurred during the installation or handling of the cable.

5.1.2 The cable dimensions gave a wide extra margin when used at this voltage. The voltage stress in the cable would continue to be much lower than most cable in service.

5.1.3 The microscopic examination revealed larger than expected inclusions (i.e. voids and contaminants) in the insulation. The much lower stress levels in the cable at this voltage should mitigate most of the effects of the large inclusions. Water treeing had started in the insulation but was progressing very slowly and had not significantly affected the breakdown voltage.

5.1.4 The higher than expected resistivity of the insulation shield might cause some problems especially if the metallic tape neutral was not intact. Its effects would be expected to be only long term since little damage was seen on the insulation semicon during the visual inspection.

5.1.5 Dielectric spectroscopy indicated that as whole the cable was not exhibiting any adverse effects from moisture ingress.

5.1.6 The breakdown voltage of the cable was well above 4 U_0 at this voltage. This suggested that there was sufficient residual breakdown strength to continue using this cable.

5.1.7 **Overall performance is expected to be good at this voltage level and continued use is recommended. Expected life of the cable should be more than 10 years, provided ground faults are cleared in a timely fashion.**

5.2 *Evaluation for use at 8.4 kV wye connected*

5.2.1 The mechanical damage to the metallic tape shield needs to be evaluated. A separate ground wire would be required for wye connected use. There was no sign of electrical damage to the tape and little indication that the underlying cable was damaged significantly. It is suspected that the damage may have occurred during the installation or handling of the cable.

5.2.2 The cable dimensions gave an extra margin when used at this voltage. The voltage stress in the cable would be lower than most cable in service.

5.2.3 The microscopic examination revealed larger than expected inclusions (i.e. voids and contaminants) in the insulation. The lower stress levels in the cable at this voltage should mitigate the effects of the large inclusions. Water treeing had started in the insulation. This would be accelerated somewhat with the higher voltage. To this point, water treeing had not significantly affected the breakdown voltage.

5.2.4 The higher than expected resistivity of the insulation shield might cause some problems especially if the metallic tape neutral was not intact. Its effects would be expected to be only long term since little damage was seen on the insulation semicon during the visual inspection. The higher voltage would not be expected to affect the longevity of the cable with respect to the effect of the shield resistivity.

5.2.5 Dielectric spectroscopy indicated that as whole the cable was not exhibiting any adverse effects from moisture ingress.

5.2.6 The breakdown voltage of the cable was well above 4 U_0 at this voltage. This suggested that there was sufficient residual breakdown strength to consider using this cable at the higher voltage.

5.2.7 **Overall performance is expected to be good at this voltage level, although its expected life would be reduced compared to operation at the lower voltage level. Expected life of the cable would be 5 to 10 years based on Kinectrics experience dealing with underground service aged cables.**

NOTE: It should be noted that all testing was performed under wet conditions (the conductors were filled with tap water and the insulation semicon layer was immersed in tap water throughout all the electrical testing documented in this report).

Figure 1 – Cable specimens as received

Figure 2: Cable as it was installed

Figure 3: Manufacturer Identification Found under the Tape Neutral

Figure 4: Condition of the Metallic Tape Neutral

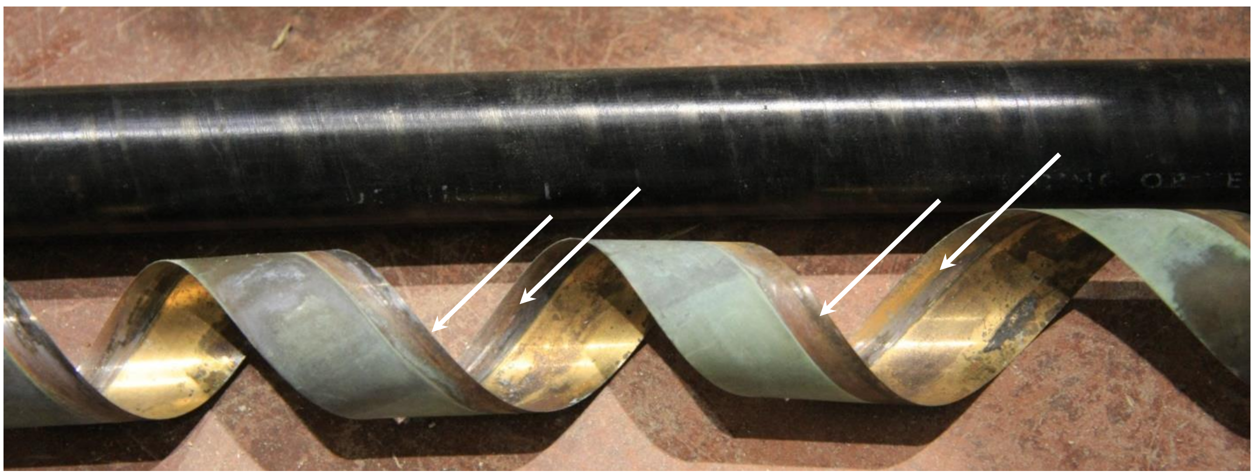

Figure 5: Cable Surface and the Metallic Neutral clearly Showing the Tape Overlap Region (arrow)

Figure 6: Minor Surface Damage to the Insulation Semicon

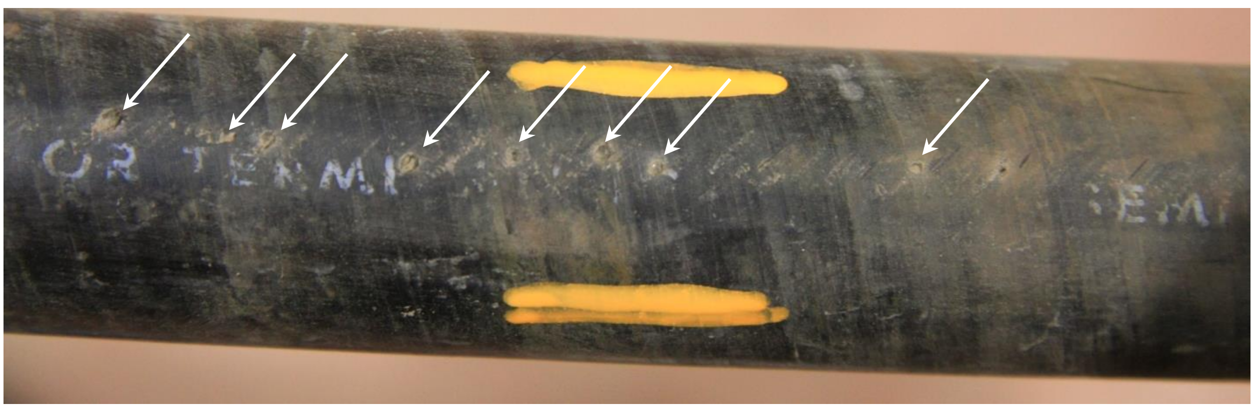

Figure 7: Pitting on the Surface but No Penetration to Insulation

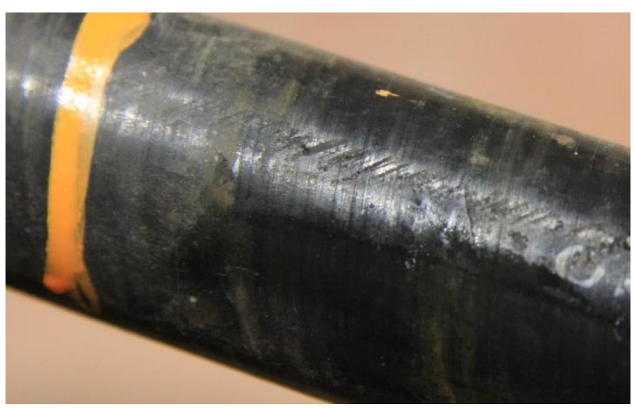

Figure 8: Some Surface Scratches

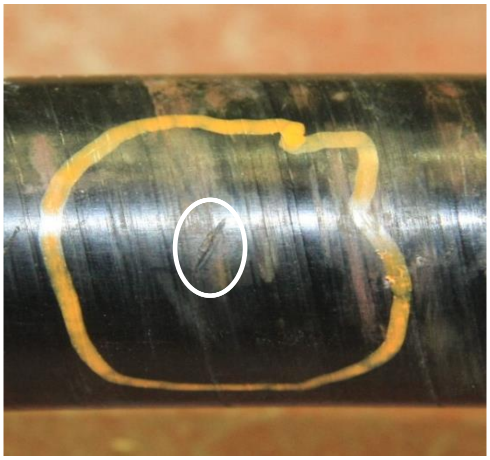

Figure 9: Small Surface Cut

Figure 10: Small Crack in the Semicon

Figure 11: Possible Electrical Damage to the Metallic Tape Neutral

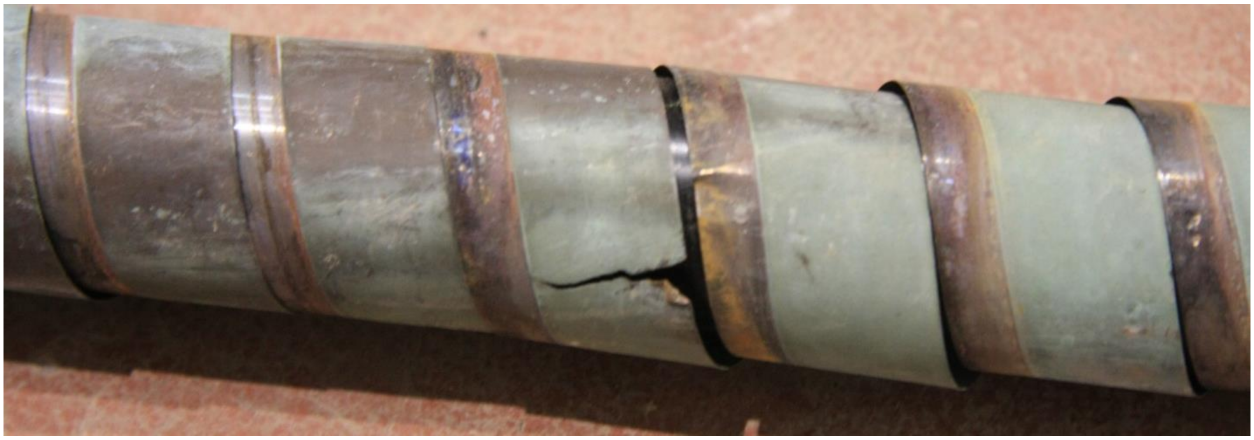

Figure 12: Tear in the Metallic Neutral

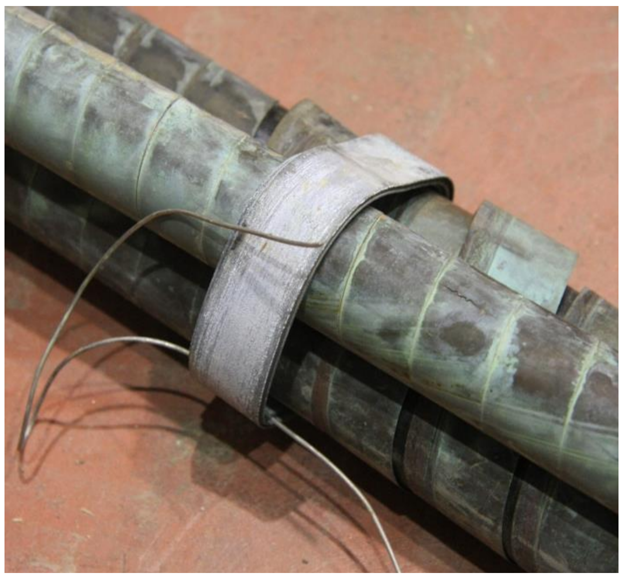

Figure 13: Metal Tie Holding the Three Conductor Bundle Together

Figure 14: Only Minor Damage Found under the Tie

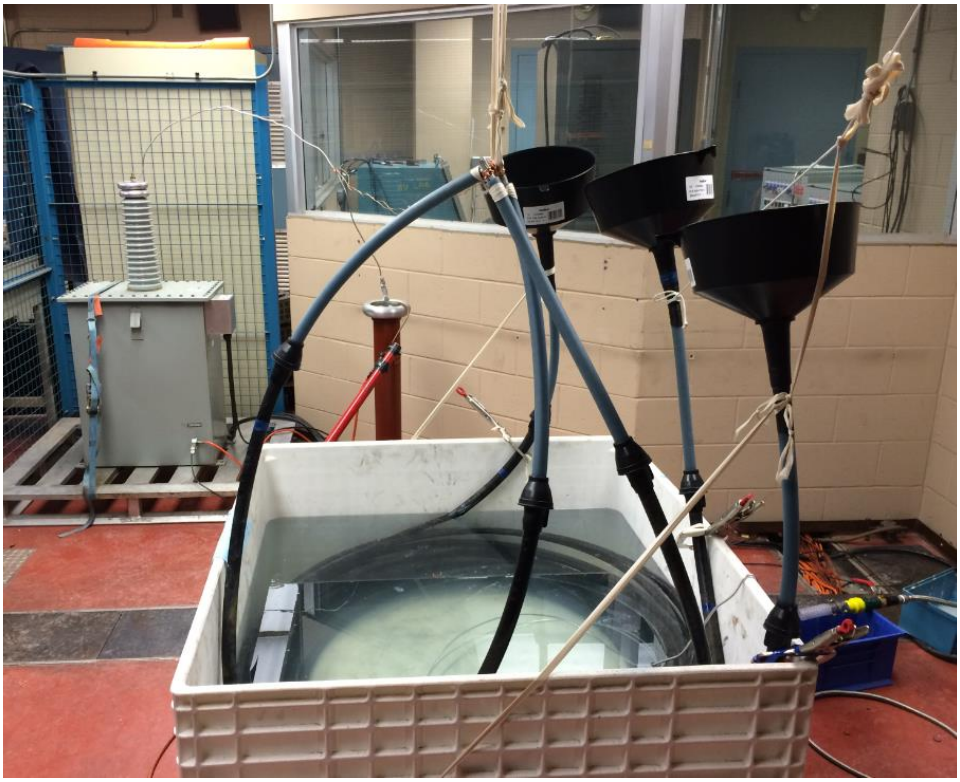

Figure 15 – Setup for soaking under voltage of cable specimens

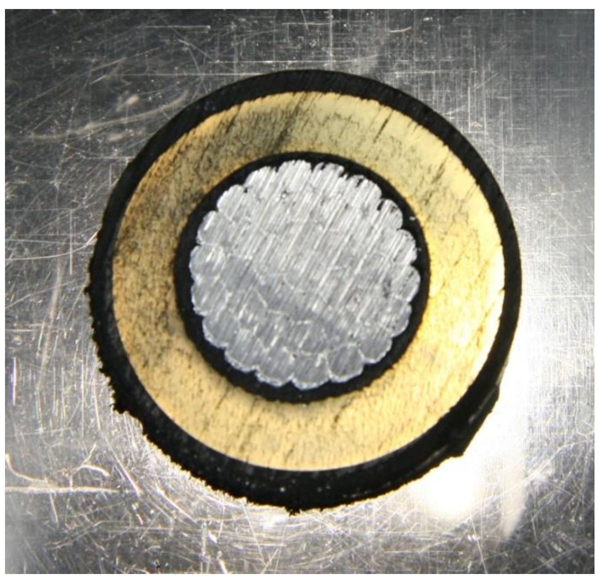

Figure 16: Cross-section of the Cable

APPENDIX A – CABLE STANDARD REQUIREMENTS

Table A-1 Part 1
Based on ANCI/ICEA S-94-649-2004 for XLPE insulation

Type of Examination	Cable Part	Section Reference	Specific Examination	Requirement				
Dimensions	Insulation Semicon Shield	5.2, Table 5-1	Min/Max Point Thicknesses	Min Diameter over Insulation		Min Point	Max Point	
				0 -1.000” (0-25.40 mm)		30 mils, 0.76 mm	60 mils, 1.52 mm	
				1.001-1.500” (25.43-38.10 mm)		40 mils, 1.02 mm	75 mils, 1.91 mm	
				1.501-2.000” (38.13-50.80 mm)		55 mils, 1.40 mm	90 mils, 2.29 mm	
				≥2.001” (≥50.83 mm)		55 mils, 1.40 mm	105 mils,2.67mm	
			Max Neutral Indent	0 -1.500” (0-38.10 mm)		-	15 mils, 0.38 mm	
				≥1.501” (≥38.13 mm)		-	20 mils, 0.51 mm	
	Insulation	4.2, Tables 4-7 and 4-8	Min/Max Point Thickness	Volt. (ϕ - ϕ)	Cond. Size	Min Point	Max Point	AC Test V
				2 – 5kV	#8 – 1000	85mils, 2.16mm	120mils, 3.05mm	18 kV
					1001 - 3000	135, 3.43	170, 4.32	28 kV
				>5 – 8 kV	#6 – 1000	110, 2.79	145, 3.68	23 kV
					1001 - 3000	165, 4.19	205, 5.21	35 kV
				>8 – 15 kV	#2 – 1000	165, 4.19	205, 5.21	35 kV
					1001 - 3000	210, 5.33	250, 6.35	44 kV
				>15 – 25 kV	#1 – 3000	245, 6.22	290, 7.37	52 kV
				>25 – 28 kV	#1 - 3000	265, 6.73	310, 7.87	56 kV
				>28 – 35 kV	1/0 - 3000	330, 8.38	375, 9.53	69 kV
				>35 – 46 kV	4/0 - 3000	425, 10.8	485, 12.3	89 kV
	Conductor Semicon Shield	3.2, Table 3-1 (see Note 1)	Min Point Thickness	-	#8 to 4/0	12 mils, 0.03 mm	-	-
				-	212 - 550	16 mils, 0.41 mm	-	-
				-	551 - 1000	20 mils, 0.51 mm	-	-
				-	≥1001	24 mils, 0.61 mm	-	-

Table A-1 Part 2

Type of Examination	Cable Part	Section Reference	Specific Examination	Requirement				
Dimensions	Conductor	2.5, Table 2-4	Diameter ±2% (selection from Table)	Size	Solid	Compact	Compressed	Class B
				#2	0.2294”	0.268”	0.283”	0.292”
				#1	0.2893”	0.299”	0.322”	0.332”
				1/0	0.3249”	0.336”	0.362”	0.373”
				2/0	0.3648”	0.376”	0.406”	0.419”
				4/0	0.4600”	0.475”	0.512”	0.528”
				250	0.5000”	0.520”	0.558”	0.575”
				300	0.5477”	0.570”	0.611”	0.630”
				350	0.5916”	0.616”	0.661”	0.681”
				400	0.6325”	0.659”	0.706”	0.728”
				450	0.6708”	0.700”	0.749”	0.772”
				500	0.7071”	0.736”	0.789”	0.813”
				550	-	0.775”	0.829”	0.728”
				600	-	0.813”	0.866”	0.772”
				650	-	0.845”	0.901”	0.813”
				700	-	0.877”	0.935”	0.855”
				750	-	0.908”	0.968”	0.893”
				800	-	0.938”	1.000”	0.929”
				900	-	0.999”	1.061”	1.094”
				1000	-	1.060”	1.117”	1.152”
				1250	-	-	1.251”	1.289”
				2000	-	-	1.583”	1.632

Table A-1 Part3

Type of Examination	Cable Part	Section Reference	Specific Examination	Requirement
Microscopic Investigation	Insulation Semicon	5.3, 5.4.1, 5.4.1.2 (see Figs 9-1, 9-2 for measurement procedure after Table) [XLPE]	Protrusions	Into insulation – Max 5 mils (0.127 mm) Into semicon shield – Max 7 mils (0.18 mm)
			Voids	Max 5 mils (0.127 mm)
			Neutral indent	See Dimensions section above Diam. over insul. – 0 -1.500" (0-38.10 mm) - max. 15 mils (0.38mm) Diam. over insul. – ≥1.501" (≥38.13 mm) - max. 20 mils (0.51 mm)
		5.4.1.1	Strippability	Stripping tension at room temp. – ≥3 pds (13.4 N) and ≤24 pds (107 N)
	Insulation	4.3.3.1 (see Note 2)	Voids	Max 3 mils (0.076) Max 30/in^3 (1.8/cm^3) >2 mils (0.051 mm)
			Contaminants	Max 5 mils (0.076) in greatest dimension Max 15/in^3 (0.9/cm^3) >2 mils (0.051 mm)
			Ambers	Max 10 mils (0.254 mm) in greatest dimension
		Not in Standard (see Note 2)	Water trees	Measure number and density of trees in the following ranges of insulation thickness 95 - 100% 75 - 94% 50 - 74% 25 - 50% 10 - 24% Trees ≥25% of insulation thickness are considered significant
	Conductor Semicon	3.3, 3.4 (see Figs 9-1, 9-2 for measurement procedure after Table) [XLPE]	Protrusions	Discrete or continuous Into insulation – Max 3 mils (0.076 mm) Into semicon shield – Max 7 mils (0.18 mm) (see Note 1)
			Convolutions	Max 7 mils (0.18 mm) (see Note 1)
			Voids	Max 3 mils (0.076 mm)

Table A-1 Part4

Type of Examination	Cable Part	Section Reference	Specific Examination	Requirement
Electrical Tests	Insulation Semicon	5.4.1.4 (see 9.8.2, 9.8.3, 9.8.4 for measurement procedure after Table)	Volume Resistivity	≤ 500 Ω-m at 90°C and 110°C for 90°C rated cable ≤ 500 Ω-m at 105°C and 125°C for 105°C rated cable
	Extruded Conductor Semicon	3.6.1 (see 9.8.1, 9.8.3, 9.8.4 for measurement procedure after Table)	Volume Resistivity	≤ 1000 Ω-m at normal and emergency operating temperatures
Tape Shield	Metal Tape	6.2 in ICEA S-97-682-2000 "Utility Shielded Power Cables Rated 5-46 kV"	Thickness	Tinned or untinned copper – 0.0025" (0.06 mm) thick
			Overlap	If overlapped must be at least 10% of tape width If gapped, gap must be 5% ≤ gap ≤ 20% of the tape width
			Other conditions	Right or left lay Tape free from burrs Joints must be welded soldered or brazed (not butted)

Note 1: *Reduced Extruded Conductor Shield* – For compact round and solid conductors (with eccentricity (max-min diameter) > 2 mils), the conductor shield may be 50% of the values above by prior agreement of manufacturer and purchaser. Protrusions into the semicon and convolutions cannot exceed 50% of required minimum point thickness.

Note 2: *Amount of Cable to Examine* and *Calculation of Volume* – 10 wafers approximately 40 mils (1 mm) thick should have detailed examination. Another 10-20 wafers should be looked at for any very large anomalies. Calculation of volume examined is given by:

$$V = \sum t \times \left\{ \pi \left(\frac{D}{2}\right)^2 - \pi \left(\frac{d}{2}\right)^2 \right\}$$

where t is the thickness of each sample, D is the diameter over the insulation and d is the diameter over the conductor shield.

APPENDIX B – MICROSCOPIC EXAMINATION RAW DATA

Sample #	Wafer Thickness (mm)	Halo	Insulation Shield		Insulation			Conductor Shield			Water Trees					
			Protru-sion	Void	Void	Contam-nant.	Amber	Protru-sion	Convol-ution	Void	++	10-24	25-50	50-74	75-94	95+
1	1.03	*	0	0	0	0	0	0	0	0	B SI SC	5 0 0	0	0	0	0
2	1.3	*	0	0	0	0	0	0	0	0	B SI SC	4 0 0	0	0	0	0
3	1.0	*	0	0	0	6 mils(1)	0	0	0	0	B SI SC	3 0 0	0	0	0	0
4	0.9	*	0	0	4 mils(1) 6mils(1)	0	0	0	0	0	B SI SC	0	0	0	0	0
5	1.1	*	0	0	0	0	0	0	0	0	B SI SC	3 0 0	0	0	0	0
6	1.25	*	0	0	0	5 mils(1)	0	0	0	0	B SI SC	0	1 0 0	0	0	0
7	1.45	*	0	5 mils(1)	0	0	0	0	0	0	B SI SC	6 0 0	1 0 0	0	0	0
8	0.81	*	0	0	0	0	0	0	0	0	B SI SC	3 0 0	1 0 0	0	0	0
9	0.85	*	Semicon Missing		0	0	0	0	0	0	B SI SC	0 0 1	0	0	0	0
10	1.15	*	0	0	0	0	0	0	0	0	B SI SC	6 0 0	0	0	0	0
11	0.9	*	0	0	0	0	0	0	0	0	B SI SC	1 0 0	0	0	0	0
12	0.34	*	0	0	3 mils(1)	0	0	0	0	0	B SI SC	4 1 0	1 0 0	0	0	0

* The first 10% of the insulation adjacent to the conductor semicon was clear, but the remaining part (all the way to the insulation semicon) was hazy.

** Largest water tree - 70 mils

++ Type of water tree: B = bowtie, SI = streamer from insulation shield, and SC = streamer from conductor shield

Sample #	Wafer Thickness (mm)	Halo	Insulation Shield		Insulation			Conductor Shield			Water Trees					
			Protru-sion	Void	Void	Contam-nant.	Amber	Protru-sion	Convol-ution	Void	++	10-24	25-50	50-74	75-94	95+
13	1.14	*	0	0	0	0	0	0	0	0	B SI SC	0	0	0	0	0
14	1.1	*	0	0	6 mils(1)	0	0	0	0	0	B SI SC	0	1 0 0	0	0	0
15	1.2	*	0	0	0	0	0	0	0	0	B SI SC	3 0 0	0	0	0	0
16	1.0	*	0	0	0	4 mils(1)	0	0	0	0	B SI SC	4 0 0	0	0	0	0
17	1.45	*	0	0	0	0	0	0	0	0	B SI SC	5 0 0	0	0	0	0
18	1.1	*	0	0	0	0	0	0	0	0	B SI SC	2 0 0	0	0	0	0
19	1.2	*	0	0	0	0	0	0	0	0	B SI SC	3 0 0	0	0	0	0
20	1.2	*	0	0	0	0	0	0	0	0	B SI SC	3 0 0	0	0	0	0
21	1.1	*	0	0	1 mils(2)	0	0	0	0	0	B SI SC	0 0 1	0	0	0	0
22	1.15	*	0	0	0	0	0	0	0	0	B SI SC	3 0 0	0	0	0	0
23	1.45	*	0	0	0	0	0	0	0	0	B SI SC	5 0 0	1** 0 0	0	0	0
24	1.1	*	0	0	0	0	0	0	0	0	B SI SC	0	0	0	0	0
25	1.35	*	0	0	0)	0	0	0	0	0	B SI SC	0	0	0	0	0

* The first 10% of the insulation adjacent to the conductor semicon was clear, but the remaining part (all the way to the insulation semicon) was hazy.
** Largest water tree - 70 mils
++ Type of water tree: B = bowtie, SI = streamer from insulation shield, and SC = streamer from conductor shield

Sample #	Wafer Thickness (mm)	Halo	Insulation Shield		Insulation			Conductor Shield			Water Trees					
			Protru-sion	Void	Void	Contam-nant.	Amber	Protru-sion	Convol-ution	Void	++	10-24	25-50	50-74	75-94	95+
26	1.35	*	0	0	4 mils(1) 3 mils(2)	0	0	0	0	0	B SI SC	6 0 0	0	0	0	0
27	1.25	*	0	0	0	0	0	0	0	0	B SI SC	-	0	0	0	0
28	1.68	*	0	0	3 mils(1)	8 mils(1)	0	0	0	0	B SI SC	-	2 0 0	0	0	0
29	1.03	*	0	0	4 mils(1)	0	0	0	0	0	B SI SC	-	0	0	0	0
30	0.25	*	0	0	0	0	0	0	0	0	B SI SC	-	1 0 0	0	0	0
31	0.27	*	0	0	3 mils(1)	6 mils(1)	0	0	0	0	B SI SC	-	1 0 0	0	0	0
32	1.25	*	0	0	4 mils(1)	0	0	0	0	0	B SI SC	-	1 0 0	0	0	0
33	1.2	*	0	0	8 mils(1)	0	0	0	0	0	B SI SC	-	0	0	0	0
34	1.1	*	0	0	6 mils(1)	0	0	0	0	0	B SI SC	-	0	0	0	0
35	1.0	*	0	0	4 mils(1)	0	0	0	0	0	B SI SC	-	0	0	0	0
36	1.4	*	0	0	0	0	0	0	0	0	B SI SC	-	1 0 0	0	0	0
37	1.3	*	0	0	0	8 mils(1)	0	0	0	0	B SI SC	-	0	0	0	0
38	1.2	*	0	0	0	0	0	0	0	0	B SI SC	-	1 0 0	0	0	0

* The first 10% of the insulation adjacent to the conductor semicon was clear, but the remaining part (all the way to the insulation semicon) was hazy.
** Largest water tree - 70 mils
++ Type of water tree: B = bowtie, SI = streamer from insulation shield, and SC = streamer from conductor shield

Sample #	Wafer Thickness (mm)	Halo	Insulation Shield		Insulation			Conductor Shield			Water Trees					
			Protru-sion	Void	Void	Contam-nant.	Amber	Protru-sion	Convol-ution	Void	++	10-24	25-50	50-74	75-94	95+
39	1.0	*	0	0	0	0	0	0	0	0	B SI SC	-	0	0	0	0
40	1.07	*	0	0	0	0	0	0	0	0	B SI SC	-	0	0	0	0

* The first 10% of the insulation adjacent to the conductor semicon was clear, but the remaining part (all the way to the insulation semicon) was hazy.
** Largest water tree - 70 mils
++ Type of water tree: B = bowtie, SI = streamer from insulation shield, and SC = streamer from conductor shield

APPENDIX C – DETAILED DATA FROM DIELECRIC SPECTROSCOPY TESTING

Table C1 – Dielectric spectroscopy data from "Cable Blue 1A" sample

K-423253 CNP XLPE Cables" - "2015-05-19, Circuit 1a" - "XLPE Cable, Blue.idf							
Configuration	Hum (60Hz)	Offset	Capacitance (1Hz, 500V (RMS)				
GST-Ground	0.9 uA	-0.3 nA	3004.4 pF				
4kVrms (0.5Uo)		8kVrms (Uo)		12kVrms (1.5Uo)		4kVrms (0.5Uo)	
Frequency	Tan Delta	Frequency	Tan Delta	Frequency	Tan Delta	Frequency	Tan Delta
100.0000	0.00059					100.0000	0.00062
46.4160	0.00043	46.4160	0.00043	46.4160	0.00044	46.4160	0.00044
21.5440	0.00036	21.5440	0.00035	21.5440	0.00036	21.5440	0.00037
10.0000	0.00032	10.0000	0.00032	10.0000	0.00034	10.0000	0.00033
4.6416	0.00030	4.6416	0.00031	4.6416	0.00033	4.6416	0.00031
2.1544	0.00030	2.1544	0.00029	2.1544	0.00031	2.1544	0.00031
1.0000	0.00030	1.0000	0.00030	1.0000	0.00033	1.0000	0.00031
0.4642	0.00024	0.4642	0.00025	0.4642	0.00027	0.4642	0.00025
0.2154	0.00022	0.2154	0.00022	0.2154	0.00026	0.2154	0.00023
0.1000	**0.00023**	**0.1000**	**0.00023**	**0.1000**	**0.00027**	**0.1000**	**0.00025**
0.0464	0.00023	0.0464	0.00024	0.0464	0.00026	0.0464	0.00024
0.0215	0.00029	0.0215	0.00026	0.0215	0.00030	0.0215	0.00029
0.0100	0.00034	0.0100	0.00033	0.0100	0.00036	0.0100	0.00036

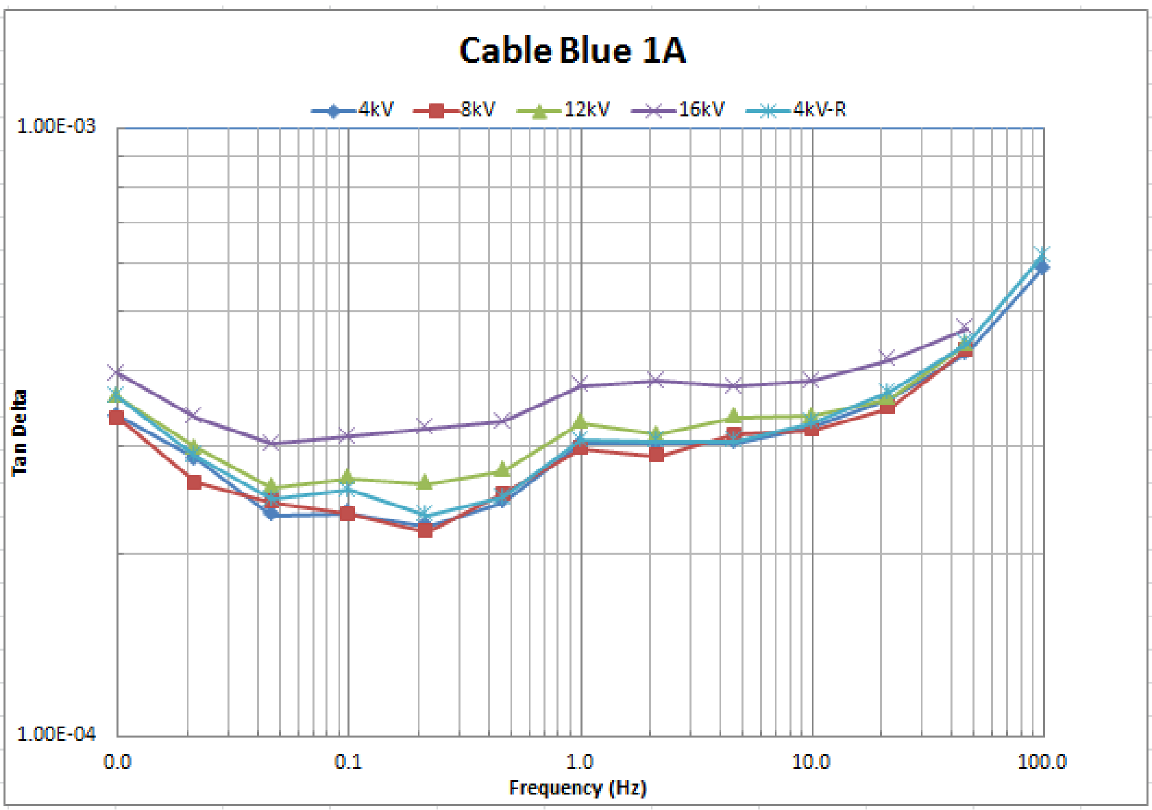

Figure B1 – Graph of dielectric spectroscopy data from "Cable Blue 1A" sample - R' suffix denotes repeat test at $0.5U_0$ to check stability of loss current.

Table C2 – Dielectric spectroscopy data from “Cable Blue 1B” sample

K-423253 CNP XLPE Cables" - "2015-05-19, Circuit 1b" - "XLPE Cable, Blue.idf							
Configuration	**Hum (60Hz)**	**Offset**	**Capacitance (1Hz, 500V (RMS)**				
GST-Ground	0.98 uA	-0.33 nA	3017.3 pF				
4kVrms (0.5Uo)		**8kVrms (Uo)**		**12kVrms (1.5Uo)**		**4kVrms (0.5Uo)**	
Frequency	**Tan Delta**	**Frequency**	**Tan Delta**	**Frequency**	**Tan Delta**	**Frequency**	**Tan Delta**
100.0000	0.00064					100.0000	0.00065
46.4160	0.00046	46.4160	0.00047	46.4160	0.00051	46.4160	0.00047
21.5440	0.00039	21.5440	0.00038	21.5440	0.00043	21.5440	0.00040
10.0000	0.00035	10.0000	0.00036	10.0000	0.00041	10.0000	0.00036
4.6416	0.00032	4.6416	0.00035	4.6416	0.00039	4.6416	0.00034
2.1544	0.00033	2.1544	0.00033	2.1544	0.00037	2.1544	0.00034
1.0000	0.00033	1.0000	0.00034	1.0000	0.00039	1.0000	0.00034
0.4642	0.00027	0.4642	0.00030	0.4642	0.00034	0.4642	0.00029
0.2154	0.00026	0.2154	0.00025	0.2154	0.00032	0.2154	0.00027
0.1000	**0.00026**	**0.1000**	**0.00028**	**0.1000**	**0.00032**	**0.1000**	**0.00029**
0.0464	0.00027	0.0464	0.00028	0.0464	0.00031	0.0464	0.00028
0.0215	0.00031	0.0215	0.00031	0.0215	0.00036	0.0215	0.00033
0.0100	0.00040	0.0100	0.00041	0.0100	0.00044	0.0100	0.00043

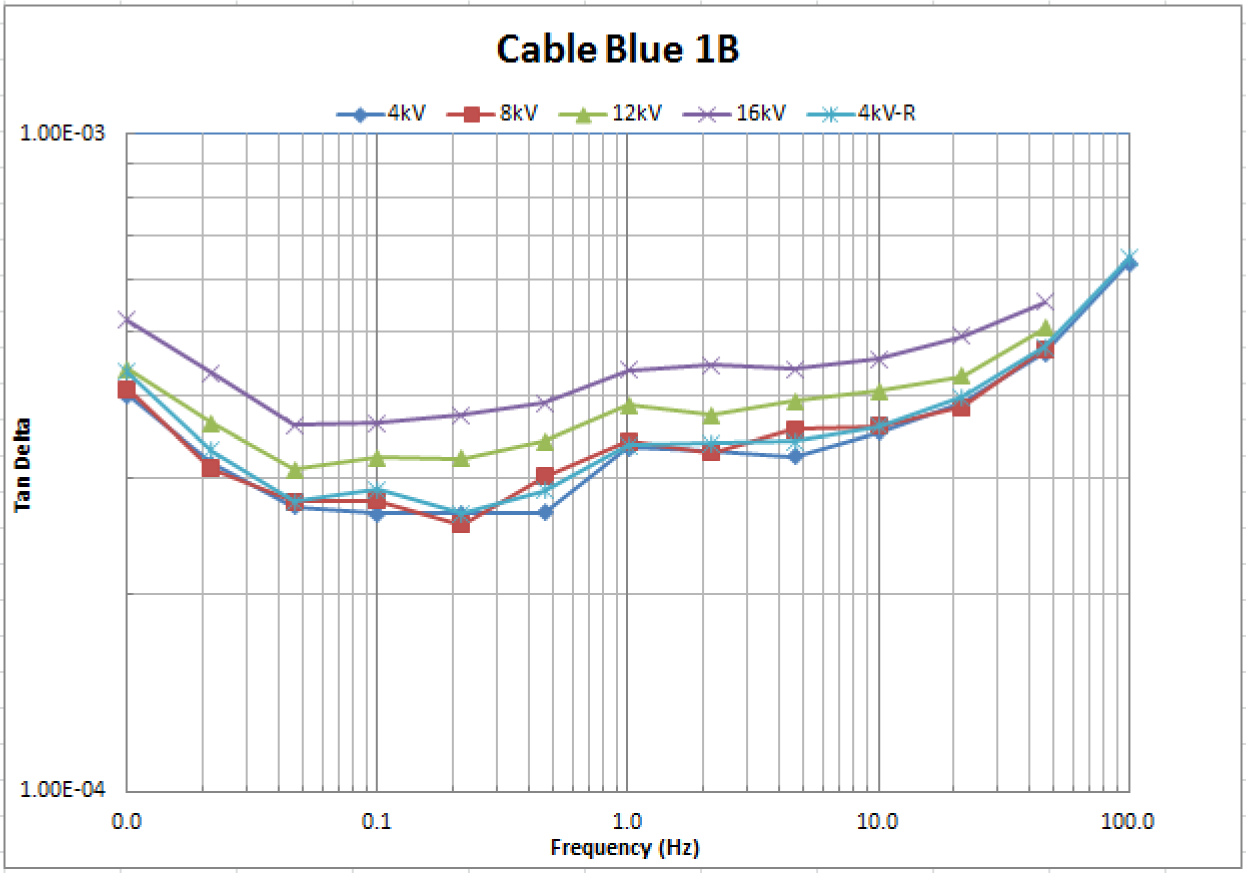

Figure B2 – Graph of dielectric spectroscopy data from “Cable Blue 1B” sample - R’ suffix denotes repeat test at $0.5U_0$ to check stability of loss current.

Table C3 – Dielectric spectroscopy data from "Cable Red 1A" sample

K-423253 CNP XLPE Cables" - "2015-05-19, Circuit 1a" - "XLPE Cable, Red.idf							
Configuration	**Hum (60Hz)**	**Offset**	**Capacitance (1Hz, 500V (RMS)**				
GST-Ground	0.94 uA	-0.39 nA	2920 pF				
4kVrms (0.5Uo)		**8kVrms (Uo)**		**12kVrms (1.5Uo)**		**4kVrms (0.5Uo)**	
Frequency	**Tan Delta**	**Frequency**	**Tan Delta**	**Frequency**	**Tan Delta**	**Frequency**	**Tan Delta**
100.0000	0.00089					100.0000	0.00089
46.4160	0.00057	46.4160	0.00056	46.4160	0.00056	46.4160	0.00057
21.5440	0.00042	21.5440	0.00040	21.5440	0.00040	21.5440	0.00043
10.0000	0.00035	10.0000	0.00034	10.0000	0.00034	10.0000	0.00036
4.6416	0.00032	4.6416	0.00032	4.6416	0.00032	4.6416	0.00032
2.1544	0.00031	2.1544	0.00029	2.1544	0.00029	2.1544	0.00031
1.0000	0.00031	1.0000	0.00030	1.0000	0.00031	1.0000	0.00030
0.4642	0.00024	0.4642	0.00026	0.4642	0.00026	0.4642	0.00026
0.2154	0.00024	0.2154	0.00022	0.2154	0.00022	0.2154	0.00025
0.1000	**0.00025**	**0.1000**	**0.00024**	**0.1000**	**0.00024**	**0.1000**	**0.00026**
0.0464	0.00026	0.0464	0.00025	0.0464	0.00026	0.0464	0.00026
0.0215	0.00031	0.0215	0.00028	0.0215	0.00030	0.0215	0.00032
0.0100	0.00039	0.0100	0.00038	0.0100	0.00039	0.0100	0.00041

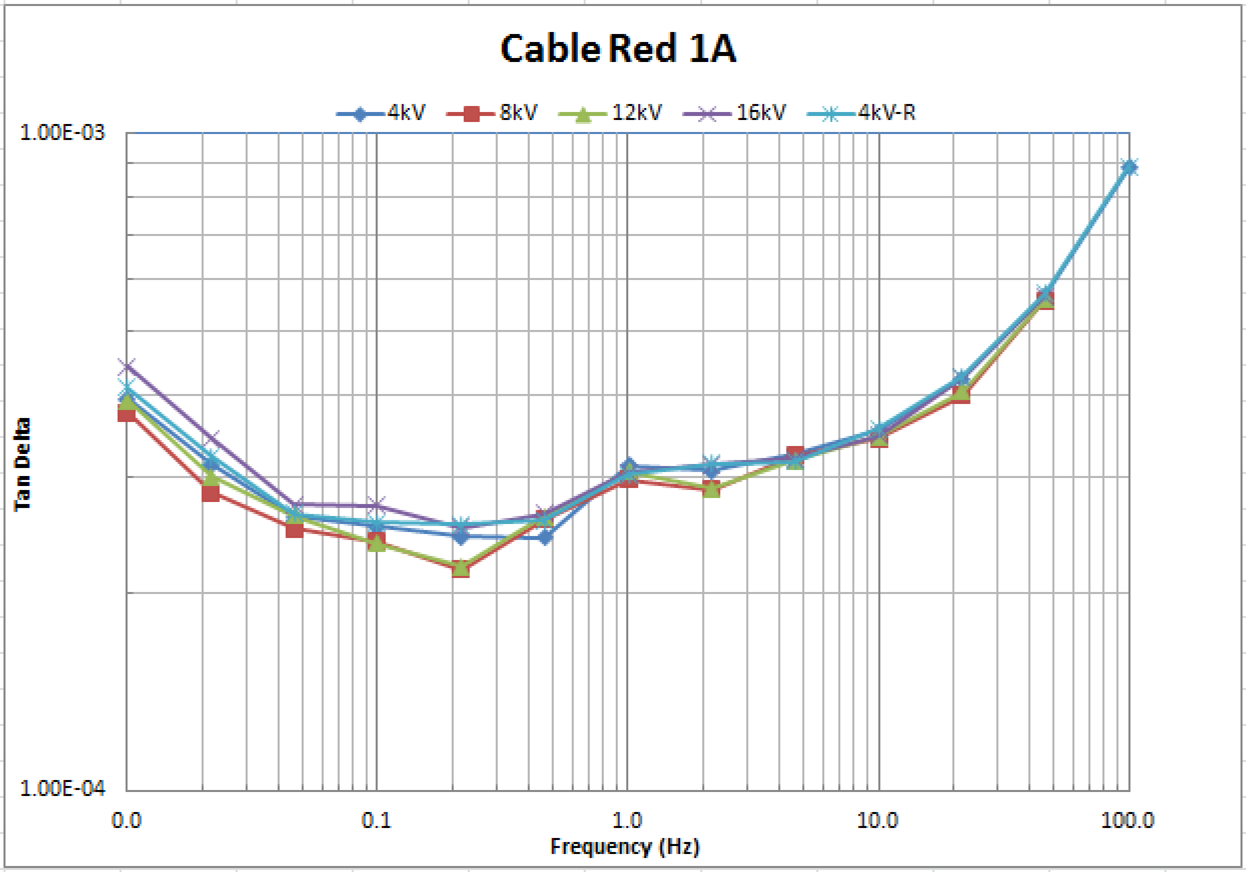

Figure B3 – Graph of dielectric spectroscopy data from "Cable Red 1A" sample - R' suffix denotes repeat test at $0.5U_0$ to check stability of loss current.

Table C4 – Dielectric spectroscopy data from "Cable Red 1B" sample

K-423253 CNP XLPE Cables" - "2015-05-19, Circuit 1b" - "XLPE Cable, Red.idf							
Configuration	**Hum (60Hz)**	**Offset**	**Capacitance (1Hz, 500V (RMS)**				
GST-Ground	0.96 uA	-0.62 nA	2903.4 pF				
4kVrms (0.5Uo)		**8kVrms (Uo)**		**12kVrms (1.5Uo)**		**4kVrms (0.5Uo)**	
Frequency	**Tan Delta**	**Frequency**	**Tan Delta**	**Frequency**	**Tan Delta**	**Frequency**	**Tan Delta**
100.0000	0.00142					100.0000	0.00137
46.4160	0.00081	46.4160	0.00080	46.4160	0.00080	46.4160	0.00079
21.5440	0.00053	21.5440	0.00051	21.5440	0.00051	21.5440	0.00052
10.0000	0.00039	10.0000	0.00039	10.0000	0.00039	10.0000	0.00040
4.6416	0.00033	4.6416	0.00033	4.6416	0.00034	4.6416	0.00033
2.1544	0.00030	2.1544	0.00029	2.1544	0.00031	2.1544	0.00031
1.0000	0.00030	1.0000	0.00029	1.0000	0.00031	1.0000	0.00030
0.4642	0.00023	0.4642	0.00025	0.4642	0.00028	0.4642	0.00024
0.2154	0.00021	0.2154	0.00021	0.2154	0.00027	0.2154	0.00024
0.1000	**0.00023**	**0.1000**	**0.00025**	**0.1000**	**0.00028**	**0.1000**	**0.00024**
0.0464	0.00024	0.0464	0.00024	0.0464	0.00032	0.0464	0.00024
0.0215	0.00028	0.0215	0.00029	0.0215	0.00045	0.0215	0.00030
0.0100	0.00037	0.0100	0.00039	0.0100	0.00068	0.0100	0.00039

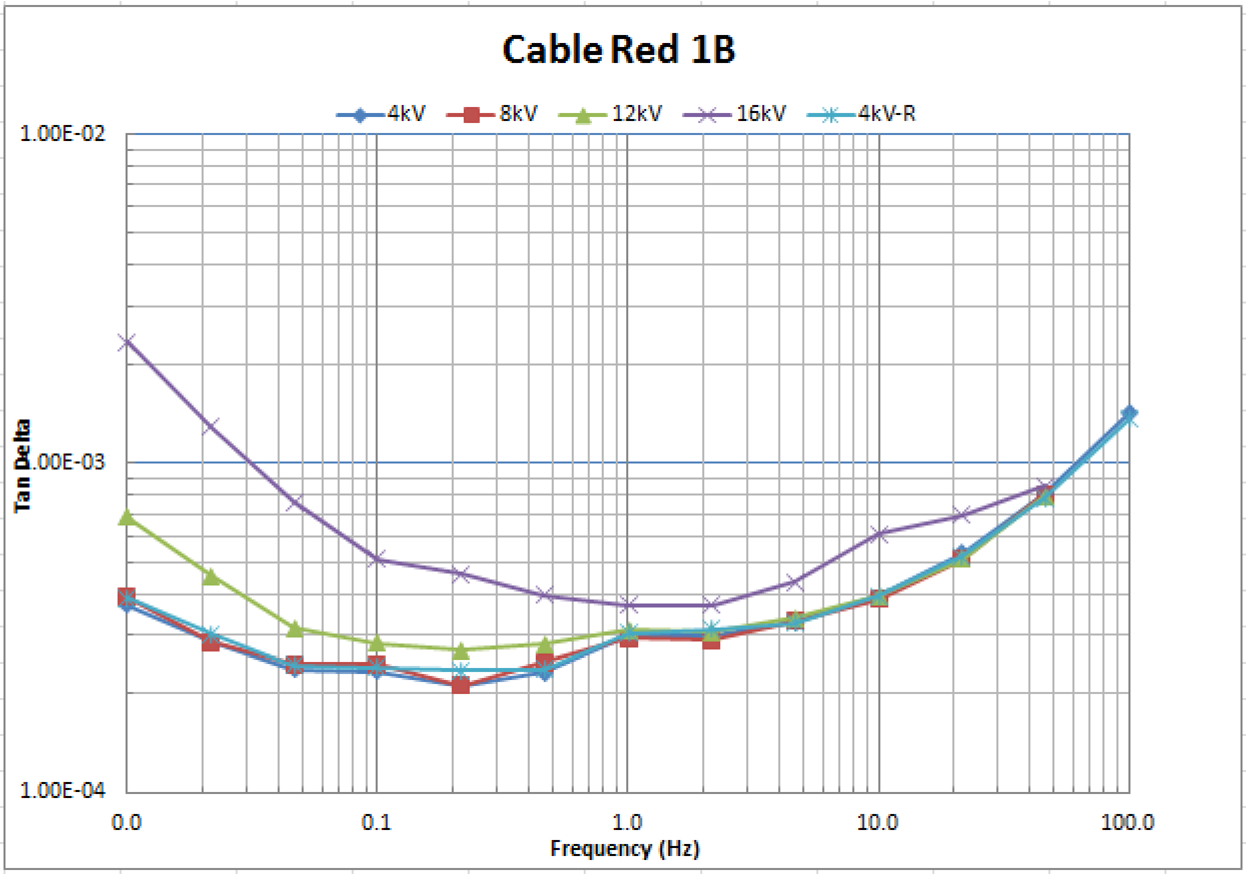

Figure B4 – Graph of dielectric spectroscopy data from "Cable Red 1B" sample - R' suffix denotes repeat test at $0.5U_0$ to check stability of loss current.

Table C5 – Dielectric spectroscopy data from “Cable White 1A” sample

K-423253 CNP XLPE Cables" - "2015-05-19, Circuit 1a" - "XLPE Cable, White.idf							
Configuration	**Hum (60Hz)**	**Offset**	**Capacitance (1Hz, 500V (RMS)**				
GST-Ground	0.94 uA	-0.62 nA	2887.8 pF				
4kVrms (0.5Uo)		**8kVrms (Uo)**		**12kVrms (1.5Uo)**		**4kVrms (0.5Uo)**	
Frequency	**Tan Delta**	**Frequency**	**Tan Delta**	**Frequency**	**Tan Delta**	**Frequency**	**Tan Delta**
100.0000	0.00092					100.0000	0.00092
46.4160	0.00058	46.4160	0.00061	46.4160	0.00066	46.4160	0.00058
21.5440	0.00043	21.5440	0.00045	21.5440	0.00052	21.5440	0.00044
10.0000	0.00035	10.0000	0.00035	10.0000	0.00041	10.0000	0.00036
4.6416	0.00031	4.6416	0.00033	4.6416	0.00041	4.6416	0.00031
2.1544	0.00030	2.1544	0.00030	2.1544	0.00039	2.1544	0.00031
1.0000	0.00029	1.0000	0.00031	1.0000	0.00040	1.0000	0.00032
0.4642	0.00024	0.4642	0.00027	0.4642	0.00035	0.4642	0.00026
0.2154	0.00024	0.2154	0.00024	0.2154	0.00032	0.2154	0.00024
0.1000	**0.00024**	**0.1000**	**0.00025**	**0.1000**	**0.00035**	**0.1000**	**0.00024**
0.0464	0.00025	0.0464	0.00027	0.0464	0.00033	0.0464	0.00025
0.0215	0.00032	0.0215	0.00030	0.0215	0.00036	0.0215	0.00030
0.0100	0.00042	0.0100	0.00041	0.0100	0.00046	0.0100	0.00039

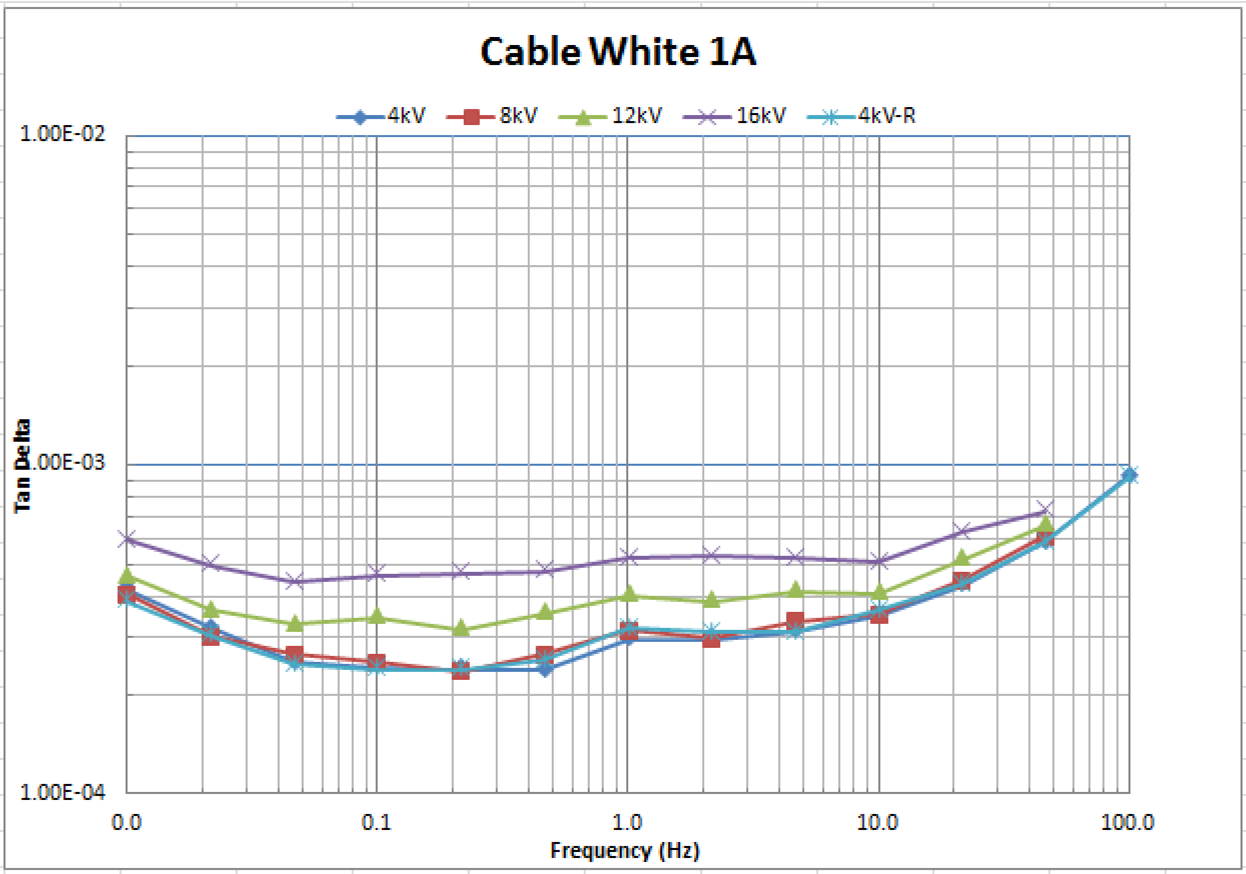

Figure B5 – Graph of dielectric spectroscopy data from “Cable White 1A” sample - R’ suffix denotes repeat test at $0.5U_0$ to check stability of loss current.

Table C6 – Dielectric spectroscopy data from "Cable White 1B" sample

K-423253 CNP XLPE Cables" - "2015-05-19, Circuit 1b" - "XLPE Cable, White.idf							
Configuration	**Hum (60Hz)**	**Offset**	**Capacitance (1Hz, 500V (RMS)**				
GST-Ground	0.98 uA	-0.33 nA	2925.4 pF				
4kVrms (0.5Uo)		**8kVrms (Uo)**		**12kVrms (1.5Uo)**		**4kVrms (0.5Uo)**	
Frequency	**Tan Delta**	**Frequency**	**Tan Delta**	**Frequency**	**Tan Delta**	**Frequency**	**Tan Delta**
100.0000	0.00080					100.0000	0.00079
46.4160	0.00052	46.4160	0.00052	46.4160	0.00053	46.4160	0.00052
21.5440	0.00040	21.5440	0.00039	21.5440	0.00040	21.5440	0.00040
10.0000	0.00034	10.0000	0.00034	10.0000	0.00036	10.0000	0.00034
4.6416	0.00030	4.6416	0.00032	4.6416	0.00033	4.6416	0.00031
2.1544	0.00030	2.1544	0.00029	2.1544	0.00031	2.1544	0.00031
1.0000	0.00030	1.0000	0.00031	1.0000	0.00032	1.0000	0.00030
0.4642	0.00024	0.4642	0.00025	0.4642	0.00028	0.4642	0.00025
0.2154	0.00022	0.2154	0.00022	0.2154	0.00025	0.2154	0.00024
0.1000	**0.00025**	**0.1000**	**0.00025**	**0.1000**	**0.00030**	**0.1000**	**0.00025**
0.0464	0.00025	0.0464	0.00026	0.0464	0.00031	0.0464	0.00024
0.0215	0.00031	0.0215	0.00031	0.0215	0.00039	0.0215	0.00031
0.0100	0.00041	0.0100	0.00043	0.0100	0.00053	0.0100	0.00042

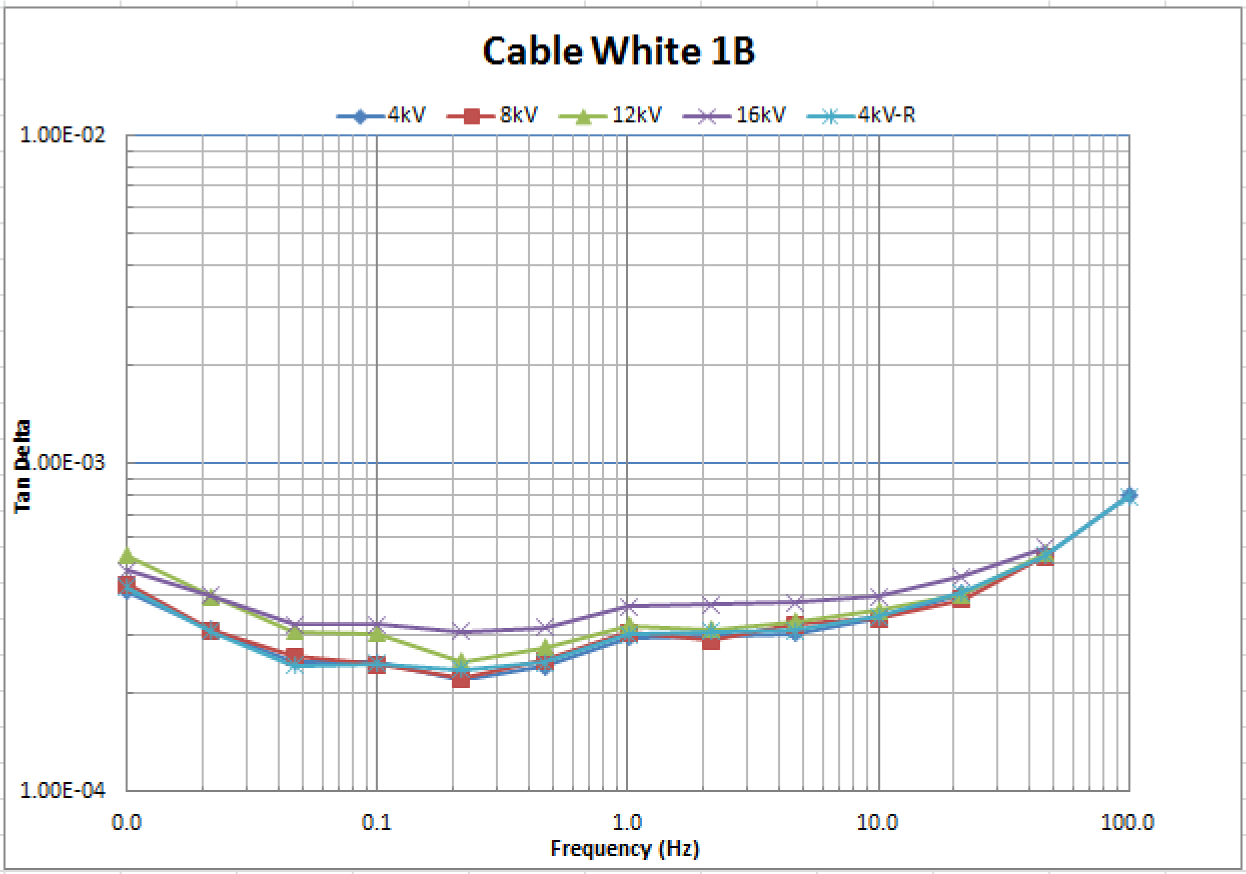

Figure B6 – Graph of dielectric spectroscopy data from "Cable White 1B" sample - R' suffix denotes repeat test at $0.5U_0$ to check stability of loss current.

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Appendix L.
2016 Grubbing Area - Zone 1

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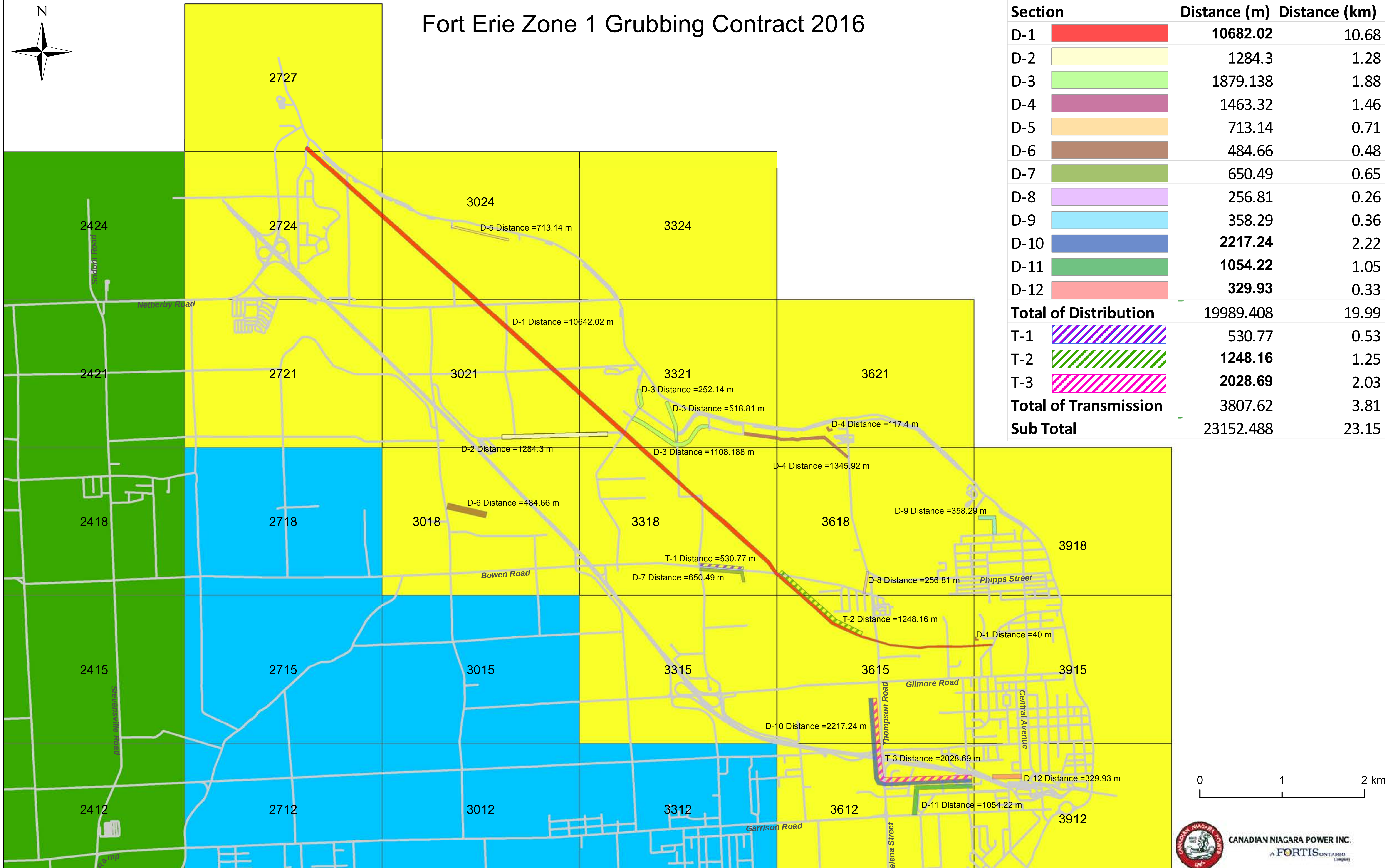
Fort Erie Zone 1 Grubbing Contract 2016



Section	Distance (m)	Distance (km)
D-1	**10682.02**	10.68
D-2	1284.3	1.28
D-3	1879.138	1.88
D-4	1463.32	1.46
D-5	713.14	0.71
D-6	484.66	0.48
D-7	650.49	0.65
D-8	256.81	0.26
D-9	358.29	0.36
D-10	**2217.24**	2.22
D-11	**1054.22**	1.05
D-12	**329.93**	0.33
Total of Distribution	19989.408	19.99
T-1	530.77	0.53
T-2	**1248.16**	1.25
T-3	**2028.69**	2.03
Total of Transmission	3807.62	3.81
Sub Total	23152.488	23.15

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Appendix M.
2016 EAB Impact Assessment

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Emerald Ash Borer Impact Assessment

Performed for Canadian Niagara Power Inc. January 2015

Purpose

The purpose of this assessment is to identify the Ash tree population that will or may impact Canadian Niagara Power Inc. (CNPI) transmission and distribution systems within its service territories and the defined areas of this assessment.

Scope

This assessment of the sampled areas included CNPI owned lands and rights-of-ways, Municipal and Regional allowances which CNPI assets occupy and/or abut, and any other Ash trees which may pose risk to CNPI assets. CNPI"s Port Colborne distribution system was the primary focus of the assessment. In late 2013, a fatality occurred resulting from a failure of a decayed Maple tree. Subsequent bylaw amendments require homeowners and landowners to remove identified hazard trees within 30 days of discovery.

Background

Emerald Ash borer (EAB), is an invasive beetle that was discovered in southeastern Michigan near Detroit in the summer of 2002. The adult beetle nibbles on Ash foliage but cause little damage. The larvae (the immature stage) feed on the inner bark of Ash trees, disrupting the tree's ability to transport water and nutrients. Emerald Ash borer probably arrived in the United States on solid wood packing material carried in cargo ships or airplanes originating in its native Asia.

Since its discovery, EAB has: Killed tens of millions of Ash trees in southeastern Michigan alone, with tens of millions more lost in Arkansas, Colorado, Connecticut, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Massachusetts, Maryland, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Ontario, Pennsylvania, Tennessee, Quebec, Virginia, West Virginia, and Wisconsin. Needless to say, this Beetle is spreading fast, and is very destructive as an invasive species.

What to know about the Emerald Ash Borer:

- It attacks only Ash trees (Fraxinus spp.).
- Adult Beetles are metallic green and about 1/2-inch long.
- Adults leave a D-shaped exit hole in the bark when they emerge in spring.

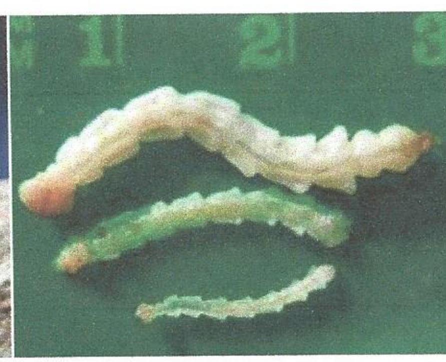
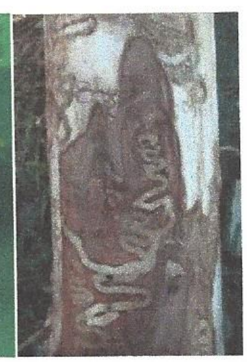
- Woodpeckers like EAB larvae; heavy woodpecker damage on Ash trees may be a sign of infestation
- Trees die within 2-3 years of infestation, leaving them brittle and prone to failure.
- Tree stumps are still a viable food source

Trees left behind after EAB have fed and moved on, have quickly dried out and no longer have the ability to bend and move in the wind which allows them to stand tall. This lack of movement makes the trees very prone to cracking, or breaking either one branch at a time, or often right at the base of the tree. Many trees have been reported recently of uprooting, as the roots die and break away from themselves.

Identification

Adult beetles are metallic blue-green, narrow, hairless, elongate, 8.5 to 14.0 mm long and 3.1 to 3.4 mm wide. The head is flat and the vertex is shield-shaped. The eyes are bronze or black and kidney shaped. The prothorax is slightly wider than the head and is transversely rectangular, but is the same width as the anterior margin of the elytra. The posterior margins of the elytra are round and obtuse with small tooth-like projections on the edge.

Mature larvae are 26 to 32 mm long and creamy white. The body is flat and broad shaped. The posterior ends of some segments are bell-shaped. The abdomen is 10-segmented. The 1st 8 segments each have one pair of spiracles and the last segment has one pair of brownish, pincer-like appendages.

- Adult A. planipennis (8.5-14 mm long). Metallic, green-blue body.
- Various larval instars of A. planipennis.
- S-shaped larval galleries of A. planipennis.

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Host Trees

Fraxinus, Juglans, Pterocarya and *Ulmus*.In North America, only *Fraxinus* has been found infested to date.

Location of Infestation within the Tree

Larvae feed on the inner bark and sapwood along the entire bole and larger branches (greater than 2.5 cm diameter) in the crown. In addition to mature trees, galleries can occur in young saplings. Immature beetles' maturation feed on leaves.

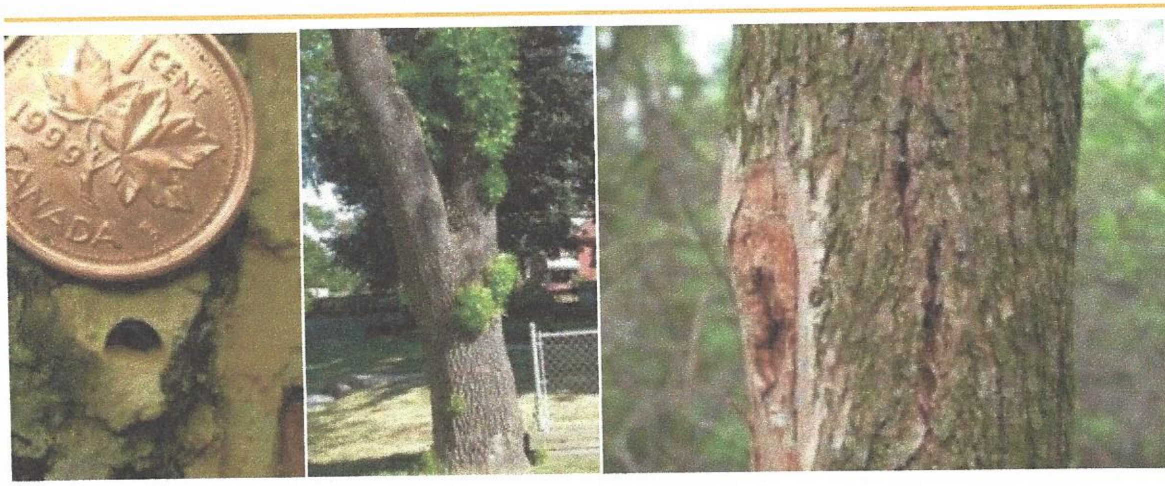
Host Condition

Healthy or weakened trees.

Signs and Symptoms

Immature beetles maturation feed on host tree foliage, creating irregular notches in the leaves. Eggs are laid singly on the bole or branches. First instar larvae bore through the bark and feed on the inner bark and the outer sapwood, eventually forming flat and wide (6 mm), "S-shaped" galleries that are filled with a fine brownish frass. Galleries are 9 to 16 cm long (up to 20 to 30 cm) and increase in width from the beginning to the end. Galleries can occur along the entire bole and in branches that are at least 2.5 cm in diameter. Callus tissue may be produced by the tree in response to larval feeding and may cause vertical bark cracks to occur over a gallery.

Pupation takes place at the end of a gallery just beneath the bark, or near the surface of the sapwood (5 to 10 mm) and even in the corky tissue of thick-barked trees. Beetles emerge through "D-shaped" exit holes, 3.5 by 4.1 mm in size. These holes are very difficult to find so careful inspection is required. Woodpecker activity may also indicate the presence of this beetle. Dying or dead trees, particularly with bark sloughing off and crown die-back can also be used as indicators of attack. Other signs of attack include a thinning crown, epicormic shoots, and vertical cracks on the trunk.



- D-shaped exit hole (3.5 by 4.1 mm) of A. planipennis.
- Epicormic shoots caused by A. planipennis.
- Vertical bark cracks over larval galleries caused by callus tissue production.

How To Identify Infested Trees

EAB only attacks Ash trees of the genus Fraxinus. This does not include Mountain Ash. The most tree damage is caused by the EAB larvae, which destroy the layer under the bark (the cambium) that is responsible for transporting nutrients and water throughout the tree. See Figure 1.

With this transport system blocked, an otherwise healthy tree may die in 2 to 5 years, depending on its age and the extent of infestation. Damage to the tree from the larvae will be apparent under the bark. The feeding larvae create distinctive serpentine (or S-shaped) galleries in the wood as they feed. See Figure 2.

Signs of EAB infestation usually only become apparent once a tree has been heavily infested. These signs include the loss of green colour in the uppermost leaves (chlorosis) and thinning and dieback of the crown. See Figure 3.

As the infestation continues, the tree may develop sprouts (epicormic shoots) from the roots, trunk or branches, in an effort to find new ways to transport nutrients. Eventually however, with more and more of the crown dying, the tree will starve to death. See Figure 4.

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Adult EAB beetles typically begin to emerge from the tree in May, creating small D-shaped exit holes. These adults will then fly to the next available Ash tree and feed on leaves until they lay eggs on the bark, which eventually become larvae and then the cycle begins again. See Figure 5.

Figure 1

Figure 2

Figure 3

Figure 4

Figure 5

Figure 1: Size comparison of EAB larva to a penny - Jerry Dowding, CFIA staff

Figure 2: 'S'-shaped galleries between the bark and the wood caused by larvae feeding - CFIA

Figure 3: Declining crown resulting from EAB infestation - Ches Caister, CFIA staff

Figure 4: 'S'-shaped galleries between the bark and the wood caused by larvae feeding and sprouts or epicormic shoots - CFIA

Figure 5: 'S'-shaped galleries between the bark and the wood caused by larvae feeding and 'D'-shaped exit holes - Troy Kimoto, CFIA staff

Transporting regulated articles

EAB regulated articles moving out of a regulated area must be accompanied by a Movement Certificate issued by the CFIA.

All vehicles used to transport regulated articles must be cleaned of debris prior to loading at origin and prior to departure from the receiving facility. The required treatment will depend upon the regulated article transported, but may include sweeping or power wAshing.

For more information about transporting regulated articles, contact your local CFIA office.

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Tree trimmings and yard waste

Movement of yard waste outside of regulated areas is also prohibited, as it may contain Ash tree bark, branches or trimmings.

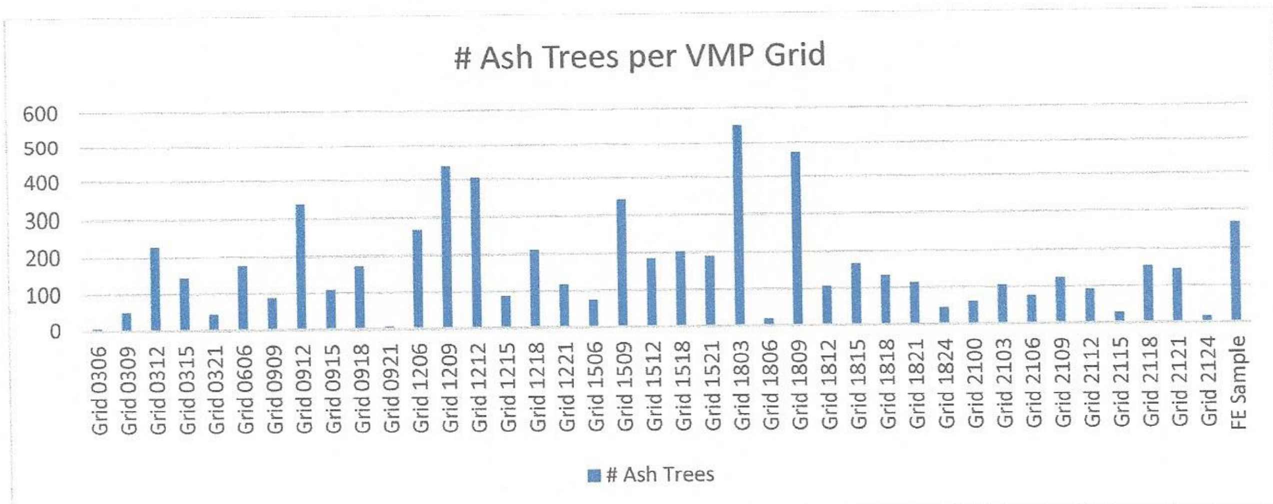
Municipalities with EAB infestations may have established special procedures for handling yard waste from regulated areas. Contact your municipality for the latest information on disposal of regulated yard waste. If you live in a regulated area or have been issued a Notice of Prohibition of Movement, please contact your local government for more information on what to do with any yard waste.

Findings

1. A total of 6590 Ash trees were identified during the assessment of sampled areas. An excerpt of the assessed area and data collected is shown below.

# of Ash trees	Address/Location	City tree/Privately owned/CNPI Owned Land	Accessible by truck(Y/N)	DBH over 1'
Grid 0306				
1	383 Sugarloaf(tree is accross the street from lines)	City	Y	N
1	19 Bayview	Private	Y	N
2	Across from city yard on King Stl	City	Y	N
2	South end of Catharines St	City	Y	Y

2. Summary of assessment below represents the total findings of the sample areas on a per grid basis, in accordance with CNPI's Vegetation Management Program.



Conclusion

All Ash trees in the Niagara Region are considered infested and a potential hazard. Even though their appearance may look healthy, they should be treated with caution. Aside from the fact that so many Ash trees are now dead, these trees are obviously, very dangerous. Not only do they present hazards simply from falling on people, but also from falling onto objects such as utility equipment, vehicles, dwellings, etc. It is because of these reasons reason we recommend immediate removal of all infested Ash on Properties owned and operated by CNPI. Consideration should be given to the removal of trees that still have some life in them allowing for improved worker safety. Or additional safety protocols and potential costs may be incurred. Trees near CNPI equipment that are located on road allowance, easement rights, of way, private property etc. should also be considered infested and a potential hazard.

It should be noted that a portion which could be as high as 40% of the 6590 Ash trees identified throughout this assessment may or may not have any negative impact on CNPI owned plant and may be excluded from budgeting with respect to mitigation and removal.

References

Dobesberger, E. J. 2002. Agrilus planipennis. Emerald Ash Borer. Pest Facts Sheet. Plant Health Risk Assessment Unit. Science Division. Canadian Food Inspection Agency. 10 p.

Signature

Rachel Bowery, BAppSc
President, Certified ISA Arborist and Utility Arborist #ON-1409AU, Ontario Arborist #400155620 and Ontario Utility Arborist #400184823, TRAQ Qualified

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Appendix B
Capital Projects (Appendix 2-AA)

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Appendix 2-AA

Projects	2012	2013	2014	2015	2016 Bridge Year	2017 Test Year
Reporting Basis	CGAAP	ASPE	ASPE	ASPE	ASPE	ASPE
System Access						
Overhead Services SA	156,473	241,748	298,464	300,145	389,183	212,731
Underground Services SA	194,342	137,752	154,130	211,346	153,037	159,301
Dist. Upgrades & Expansions SA	881,754	501,091	1,056,320	958,459	1,211,377	950,202
New Dist Transformers & Reg SA				138,084		
New Smart Centre Garrison Rd SA		114,004				
Killaly St. Relocate from Knoll to King SA		512,119				
Sugarloaf & Lynwood Upgrade - 3rd Party Access SA			105,986			
Central Avenue Bridge Replacement SA			140,774	164,959		
Ridgeway by The Lake Subdivision SA				111,398		
Spears Rd Expansion and Subdivision SA				181,291		
Miscellaneous SA	25,418	220,636	235,695	183,161	69,508	136,663
Capital Contributions SA	-558,487	-1,062,493	-1,658,435	-1,264,311	-1,470,207	-550,000
Sub-Total	699,501	664,857	332,934	984,532	352,898	908,897

System Renewal						
Station 19 Projects SR	121,109					347,849
M11 Line Rebuild SR	161,691	218,904				
18L10 Line Rebuild Albany and Helena SR		213,553	194,171			
Dodd's Court Rebuild SR	293,384					
Royal Road Phase 2 SR	131,826					
Rose, Gaspare Rebuild SR		100,368	183,919			
Barrick Conversion to 27.6kV and Rebuild SR			644,011	754,132		
Fielden Station Projects SR		235,172	573,401	645,004		
Gilmore Station Projects SR				135,530	1,604,002	
Gilmore Egress Project SR					519,944	
FE North Rebuilds Supporting Conversion SR					751,054	884,802
Port Colborne South New DS SR						409,245
5/8 Line Rebuild SR			218,193	275,833		
Forks Road Canal Riser Rebuild SR				184,826		
Dist. Upgrades & Expansions SR	1,544,666	1,641,998	1,297,651	1,758,291	1,567,692	2,073,958
FE Ridgeway Rebuilds Supporting Conversion SR					620,000	294,938
New Dist. Transformers & Reg SR	205,999	261,400	261,842	278,843	306,000	315,000
New MIST Meters SR				234,065		
New Meters SR	131,194	164,326	132,694	127,324	180,072	189,419
New Smart Meters SR	355,960	4,879,044				
Ontario Street Rebuild SR		122,901				
Oak Alley Rebuild SR		186,384	133,333			
Elizabeth Street Pole Replacement SR				138,805		
Pine Street Pole Replacement SR				235,266		
Construct Herbert DS to Gananoque DS Intertie SR					380,000	
North Line Rebuild SR						257,110
Substation TX Replacement (#1, #2, Leaky Creek) SR		328,232				
Miscellaneous SR	51,283	494,960	393,979	152,846	107,944	218,496
Sub-Total	2,997,112	8,847,242	4,033,193	4,920,766	6,036,707	4,990,817

System Service						
Distribution Automation SS	144,333	180,676			308,283	311,432
Delta to Wye Conversion Niagara SS	155,910	156,934		127,675		
Ridgeway Delta to Wye Conversion Niagara SS					330,000	450,313
Stevensville Upgrades - Stepdown Load Relief SS	152,381					
Station 18 New Feeder Configuration SS		102,623				
18L10 Extension Hwy 3 SS			507,744	147,429		
Houck Cres. Conversion SS				268,338		
FE North Conversion SS						156,031
SCADA and Communication Projects SS			118,501	152,677		
Herbert Street Feeder Reinforcement Ph. 5 SS	178,390					
EOP Main Substation - Delta to Wye Conversion SS						750,768
Miscellaneous SS	4,912	114,034	236,902	188,156	84,206	173,133
Sub-Total	635,926	554,267	863,147	884,275	722,488	1,841,678
General Plant						
Transportation GP	723,447	392,686	365,132	116,593	327,000	175,000
S/C Leasehold Improvements GP		362,239				
PC Assets GP	2,881,511	188,965				
General Expense Capital GP	1,140,053					
Miscellaneous IT GP	168,283	275,702	251,804	177,759	346,428	228,071
Server Storage Replacements GP	417,992				386,339	246,081
SAP Improvements GP	252,000	352,945	364,081	248,787	715,195	540,027
GIS/OMS GP	186,000	288,181	161,052	287,637	340,000	300,000
Environment Health & Safety GP		110,386	120,749			100,000
Software Licensing GP		345,544	177,115	173,000	214,000	214,000
Firewall Upgrades GP			121,457			
Smart Meter Technology GP		798,570				
Miscellaneous GP	10,422	133,307	93,767	236,098	189,170	212,587
Sub-Total	5,779,708	3,248,525	1,655,157	1,239,874	2,518,132	2,015,766
Total	**10,112,247**	**13,314,890**	**6,884,432**	**8,029,447**	**9,630,225**	**9,757,158**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***						
Total	**10,112,247**	**13,314,890**	**6,884,432**	**8,029,447**	**9,630,225**	**9,757,158**

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Appendix C
Capital Expenditures (Appendix 2-AB)

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Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated

First year of Forecast Period: *2017*

CATEGORY	Historical Period (previous plan(1) & actual)								Bridge Year	Test Year	Forecast Period (planned)			
	2012		2013		2014		2015		2016	2017	2018	2019	2020	2021
	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual						
	$ '000		$ '000		$ '000		$ '000		$ '000					
System Access	(1)	699,501	(1)	664,857	(1)	332,934	(1)	984,532	352,898	908,897	536,611	547,343	559,940	571,139
System Renewal	(1)	2,997,112	(1)	8,847,242	(1)	4,033,193	(1)	4,920,766	6,036,707	4,990,817	5,939,120	5,496,072	5,460,618	7,043,601
System Service	(1)	635,926	(1)	554,267	(1)	863,147	(1)	884,275	722,488	1,841,678	1,064,435	1,504,806	1,179,108	835,558
General Plant	(1)	5,779,708	(1)	3,248,525	(1)	1,655,157	(1)	1,239,874	2,518,132	2,015,766	1,825,260	1,621,293	2,477,611	2,073,684
TOTAL EXPENDITURE		**10,112,247**		**13,314,890**		**6,884,432**	-	**8,029,447**	**9,630,225**	**9,757,158**	**9,365,426**	**9,169,514**	**9,677,278**	**10,523,982**
System O&M		$ 3,341,251		$ 3,472,966		$ 3,620,493		$ 3,615,556	$ 3,861,773	$ 4,106,946	$ 4,189,085	$ 4,272,867	$ 4,358,324	$ 4,445,490

Notes to the Table:

(1) This is Canadian Niagara Power's first Distribution System Plan and as such planned expenditures were not allocated to Chapter 5 Investment Categories.

Explanatory Notes on Variances (complete only if applicable)
Notes on shifts in forecast vs. historical budgets by category
Notes on year over year Plan vs. Actual variances for Total Expenditures
Notes on Plan vs. Actual variance trends for individual expenditure categories

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CAPITAL EXPENDITURE ANALYSIS

Summary of Capital Expenditures

Appendix 2-AB, Table 2- Capital Expenditure Summary from Chapter 5 Consolidated below provides a summary of historical capital expenditures during the past four historical years, 2012 through 2015, budgets for the 2016 Bridge Year and 2017 Test year, as well as projections for the period 2018 through 2021. CNPI has made best efforts to categorize historical capital expenditures into the investment categories.

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated

First year of Forecast Period: *2017*

CATEGORY	Historical Period (previous plan(1) & actual)								Bridge Year	Test Year	Forecast Period (planned)			
	2012		2013		2014		2015		2016	2017	2018	2019	2020	2021
	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual						
	$ '000		$ '000		$ '000		$ '000		$ '000					
System Access	(1)	699,501	(1)	664,857	(1)	332,934	(1)	984,532	352,898	908,897	536,611	547,343	559,940	571,139
System Renewal	(1)	2,997,112	(1)	8,847,242	(1)	4,033,193	(1)	4,920,766	6,036,707	4,990,817	5,939,120	5,496,072	5,460,618	7,043,601
System Service	(1)	635,926	(1)	554,267	(1)	863,147	(1)	884,275	722,488	1,841,678	1,064,435	1,504,806	1,179,108	835,558
General Plant	(1)	5,779,708	(1)	3,248,525	(1)	1,655,157	(1)	1,239,874	2,518,132	2,015,766	1,825,260	1,621,293	2,477,611	2,073,684
TOTAL EXPENDITURE		10,112,247		13,314,890		6,884,432	-	8,029,447	9,630,225	9,757,158	9,365,426	9,169,514	9,677,278	10,523,982
System O&M		$ 3,341,251		$ 3,472,966		$ 3,620,493		$ 3,615,556	$ 3,861,773	$ 4,106,946	$ 4,189,085	$ 4,272,867	$ 4,358,324	$ 4,445,490

Notes to the Table:
(1) This is Canadian Niagara Power's first Distribution System Plan and as such planned expenditures were not allocated to Chapter 5 Investment Categories.

Variance of Year over Year Category Spending

An analysis of year over year trending for historical capital expenditures within the DSP categories is as follows:

2012 Actual vs. 2013 Actual

Category	*2012 Actual*	*2013 Actual*	*Variance from 2012 Actual*
System Access	699,501	664,857	-34,644
System Renewal	2,997,112	8,847,242	5,850,130
System Service	635,926	554,267	-81,659
General Plant	5,779,708	3,248,525	-2,531,183
Total Capital Expenditures	**$10,112,247**	**$13,314,890**	**$3,202,643**

System Access (SA) - Variance – 2013 Actual $34,644 less than 2012 Actual

This variance is within the normal variability of expenditures in this category and below the materiality threshold level.

System Renewal (SR) – Variance – 2013 Actual $5,850,130 more than 2012 Actual

Approximately $4,900,000 of Smart Meter assets were capitalized during 2013, resulting in a $4,500,000 increase over 2012 Smart Meter investments.

2013 storm rebuilds stemming from major weather events in July and November contributed a $175,000 increase to the variance.

Replacement of end of life assets within the Gananoque service territory during 2013 resulted in approximately $640,000 increase to System Renewal expenditures.

System Service (SS) – Variance – 2013 Actual $81,659 less than 2012 Actual

This variance is within the normal variability of expenditures in this category and below the materiality threshold level.

General Plant (GP) – Variance – 2013 Actual $2,531,183 less than 2012 Actual

2013 General Plant expenditures do not include any costs pertaining to the acquisition of Port Colborne Hydro assets, or General Expense Capital charges. The absence of these costs results in decreases to 2013 expenditures of $2,700,000 and $1,100,000 respectively when compared to previous year expenditures.

Additionally, there were no large vehicle purchases in 2013. As part of CNPI's Fleet Asset Management Replacement Schedule, a large vehicle was purchased the previous year. The absence of a large vehicle purchase in 2013 provides approximately $330,000 in decreased costs.

During 2013 approximately $800,000 of technology costs associated with the completion of the Smart Meter project were realized. These costs included SAP specific development such as programmatic updates, net new interfacing with external systems and minor external consulting. These charges resulted in an $800,000 increase to General Plant expenditures when compared to the prior year.

Leasehold improvement projects totalling approximately $360,000 occurred during 2013 at the Fort Erie Service Centre. These improvements were largely a result of the consolidation of the Port Colborne and Fort Erie service centres and accommodation of current staffing levels through the construction of additional office space.

In 2013, internal and external efforts pertaining to a newly developed Environment Health and Safety applications resulted in approximately $110,000 of increased General Plant expenditures.

-$2,700,000	Port Colborne Hydro Assets
-$1,100,000	General Expense Capital
-$330,000	Fleet Purchase
+$800,000	Smart Meter Technology
+$360,000	Leasehold Improvements
+$345,000	Software Development
+$110,000	Health, Safety & Environment Software
-$2,515,000	**Net Variance Explanation**

2013 Actual vs. 2014 Actual

Category	***2013 Actual***	***2014 Actual***	***Variance from 2013 Actual***
System Access	664,857	332,934	-331,923
System Renewal	8,847,242	4,033,193	-4,814,049
System Service	554,267	863,147	308,880
General Plant	3,248,525	1,655,157	-1,593,368
Total Capital Expenditures	**$13,314,890**	**$6,884,432**	**-$6,430,458**

System Access (SA) – Variance - 2014 Actual $331,923 less than 2013 Actual

System Access investments and third party contributions are entirely based on the needs of external stakeholders such as customers, and joint use partners. These needs fluctuate from year to year. There is no reason to expect that the total amounts would be consistent from year to year.

System Renewal (SR) – Variance – 2014 Actual $4,814,049 less than 2013 Actual

2014 System Renewal expenditures do not include any costs related to the capitalization of Smart Meter assets or the M11 Line Rebuild, resulting in a decrease of approximately $4,900,000 and $218,000 respectively.

Replacement of end of life assets within the Gananoque service territory during 2014 decreased significantly, resulting in a $500,000 decrease within the System Renewal expenditure category.

During 2014 the Barrick Conversion and Rebuild was initiated, contributing a $645,000 increase towards the variance.

Additionally, Rebuilding of the 5/8 Line commenced during 2014, providing a $220,000 increase towards 2014 System Renewal expenditures.

-$4,900,000	Smart Meter assets
-$ 218,000	M11 Line Rebuild
-$500,000	End of life asset replacements – Gananoque
+$645,000	Barrick Conversion & Rebuild
+$220,000	5/8 Line Rebuild
-$4,753,000	**Net Variance Explanation**

System Service (SS) – Variance – 2014 Actual $308,880 more than 2013 Actual

2014 Delta to Wye Conversion efforts were captured under the 18L10 Line Extension project. Construction efforts for 18L10 Line Extension project resulted in approximately a $350,000 increase to 2014 System Service expenditures.

2014 System Service expenditures do not include any costs related to the Station 18 New Feeder Configuration Project, resulting in a decrease of approximately $100,000.

General Plant (GP) – Variance – 2014 Actual $1,593,368 less than 2013 Actual

During 2014, no costs associated with the completion of the Smart Meter project, leasehold improvements or acquisition of Port Colborne Hydro assets were realized. The absence of these costs resulted in decreases of approximately $800,000, $360,000 and $190,000 respectively, within the General Plant expenditure category when compared to the prior year. Additionally, 2014 software development costs decreased approximately $170,000 when compared to the prior year. This decrease is offset partially through the firewall hardware replacement during 2014. The replacement resulted in a $120,000 increase within the General Plant expenditure category over the previous year as shown below.

-$800,000	Smart Meter assets
-$360,000	Leasehold Improvements
-$190,000	Port Colborne Hydro Assets
-$170,000	IT Software Development
+$120,000	IT Firewall Replacement
-$1,400,000	**Net Variance Explanation**

2014 Actual vs. 2015 Actual

Category	*2014 Actual*	*2015 Actual*	*Variance from 2014 Actual*
System Access	332,934	984,532	651,598
System Renewal	4,033,193	4,920,766	887,573
System Service	863,147	884,275	21,128
General Plant	1,655,157	1,239,874	- 415,283
Total Capital Expenditures	**$6,884,432**	**$8,029,447**	**$1,145,015**

System Access (SA) – Variance – 2015 Actual $651,598 more than 2014 Actual

System Access investments and third party contributions are entirely based on the needs of external stakeholders such as customers, and joint use partners. These needs fluctuate from year to year. There is no reason to expect that the total amounts would be consistent from year to year.

System Renewal (SR) – Variance – 2015 Actual $887,573 more than 2014 Actual

Construction of a new distribution substation, Gilmore DS, was initiated in 2015. This resulted in a $135,000 increase to 2015 System Renewal expenditures.

$234,000 in MIST Meter assets were capitalized during 2015, completing regulatory requirements in this area.

During 2015, a $185,000 increase to System Renewal expenditures occurred stemming for a rebuild of the Canal Risers on Forks Road.

Targeted replacement of end-of-life assets during 2015 in the Gananoque service territory resulted in a $240,000 expenditure increase from previous year. This investment was directed at achieving sustainable end of life pole replacement levels.

$100,000 of increased efforts pertaining to the Barrick Conversion and Rebuild project were also realized during 2015.

+$135,000	Gilmore DS
+$234,000	MIST Meter assets
+$185,000	Canal Riser Rebuild
+$240,000	End of life asset replacements – Gananoque
+$100,000	Barrick Conversion & Rebuild
+$894,000	**Net Variance Explanation**

System Service (SS) – Variance – 2015 Actual $21,128 more than 2014 Actual

This variance is within the normal variability of expenditures in this category and below the materiality threshold level.

General Plant (GP) – Variance – 2015 Actual $415,283 less than 2014 Actual

2015 General Plant expenditures do not include the purchase of a bucket truck. As part of CNPI's Fleet Asset Management Replacement Schedule, a large vehicle was purchased the previous year. The absence of a large vehicle purchase in 2015 provides approximately $250,000 in decreased costs.

Additionally, during 2015, there were no replacements to firewall hardware within the General Plant expenditure category. A replacement had occurred the previous year, resulting in a $120,000 decrease in 2015 expenditures.

2015 Actual vs. 2016 Forecast

Category	*2015 Actual*	*2016 Forecast*	*Variance from 2015 Actual*
System Access	984,532	352,898	-631,634
System Renewal	4,920,766	6,036,707	1,115,941
System Service	884,275	722,488	-161,787
General Plant	1,239,874	2,518,132	1,278,258
Total Capital Expenditures	**$8,029,447**	**$9,630,225**	**$1,600,778**

System Access (SA) – Variance – 2016 Forecast $631,634 less than 2015 Actual

System Access investments and third party contributions are entirely based on the needs of external stakeholders such as customers, and joint use partners. These needs fluctuate from year to year. There is no reason to expect that the total amounts would be consistent from year to year.

System Renewal (SR) – Variance – 2016 Forecast $1,115,941 more than 2015 Actual

As a result of the need to construct the new Gilmore distribution substation in 2016, net increases totaling $1.35 million relating to substation projects over the prior year have been forecasted.

There are no forecasted costs associated with MIST Meter assets or the Forks Road Canal Riser Rebuild in 2016. Absence of these costs results in decreases to 2016 System Renewal expenditures of approximately $234,000 and $185,000 respectively.

System Service (SS) – Variance – 2016 Forecast $161,787 less than 2015 Actual

There are no forecasted costs associated with the 18L10 Line Extension Project in 2016, resulting in a $150,000 decrease of System Service expenditures.

General Plant (GP) – Variance - 2016 Forecast $1,278,258 more than 2015 Actual

As part of CNPI's Fleet Asset Management Replacement Schedule, a large bucket truck vehicle is forecasted for purchase during 2016, resulting in a net $210,000 increase to the General Plant expenditure category.

Approximately $470,000 of SAP software improvements are scheduled to occur in 2016, resulting in an increase over the prior year. These improvements include SAP Work Manager mobile application, asset management integration, bill print enhancements and business process improvements.

During 2016, CNPI's SAP server and associated storage system are scheduled for replacement at a cost of approximately $385,000 which contributes to the General Plant expenditure category.

Additionally, within Information Technology there are several costs captured under miscellaneous including Adobe software upgrades, a complete upgrade to the existing SharePoint intranet and the introduction of PowerAssist call management. These costs result in a $170,000 increase within the 2016 General Plant expenditure category.

+$210,000	Fleet purchase
+$470,000	SAP Software Improvements
+$385,000	SAP Server & Storage System Replacement
+$170,000	Misc. IT General Plant
+$1,235,000	**Net Variance Explanation**

2016 Forecast vs. 2017 Forecast

Category	*2016 Forecast*	*2017 Forecast*	*Variance from 2016 Forecast*
System Access	352,898	908,897	555,999
System Renewal	6,036,707	4,990,817	-1,045,890
System Service	722,488	1,841,678	1,119,190
General Plant	2,518,132	2,015,766	-502,366
Total Capital Expenditures	**$9,630,225**	**$9,757,158**	**$126,933**

System Access (SA) – Variance – 2017 Forecast $555,999 more than 2016 Forecast

System Access investments and third party contributions are entirely based on the needs of external stakeholders such as customers, and joint use partners. These needs fluctuate from year to year. There is no reason to expect that the total amounts would be consistent from year to year.

System Renewal (SR) – Variance – 2017 Forecast $1,045,890 less than 2016 Forecast

A net decreases totaling $1.7 million relating to substation projects over the prior year have been forecasted in 2017. This decrease results from the completion of the new Gilmore substation project during 2016.

Increased system rebuilds are forecasted for 2017 within the CNPI service territories, resulting in a $315,000 increase within the System Renewal expenditure category. These forecasted increases are detailed within section 5.4.6.1 of the Distribution System Plan (DSP).

During 2017, improvements at Station 19 are scheduled to occur. These improvements total $350,000 and result in an increase within the System Renewal expenditure category. This is detailed within section 5.4.6.13 of the DSP.

System Service (SS) - Variance - 2017 Forecast $1,119,190 more than 2016 Forecast

An increase of Delta to Wye system conversion efforts is forecasted to occur during 2017 across all CNPI service territories. The conversions projects totaling approximately $1 million result in an increase to the System Service expenditure category when compared to the previous year. This is detailed within sections 5.4.6.2, 5.4.6.4 and 5.4.6.9 of the DSP.

General Plant (GP) – Variance – 2017 Forecast $502,366 less than 2016 Forecast

In 2017, there are less significant lifecycle related IT hardware replacements scheduled as well as reduced IT based software costs, resulting in a $473,000 decrease in General Plant expenditures.

2017 Test Year vs. 2018 Forecast

Category	*2017 Forecast*	*2018 Forecast*	*Variance from 2017 Forecast*
System Access	908,897	536,611	-372,286
System Renewal	4,990,817	5,939,120	948,302
System Service	1,841,678	1,064,435	-777,243
General Plant	2,015,766	1,825,260	-190,506
Total Capital Expenditures	**$9,757,158**	**$9,365,426**	**-$391,733**

System Access (SA) – Variance – 2018 Forecast $372,286 less than 2017 Forecast

System Access investments and third party contributions are entirely based on the needs of external stakeholders such as customers, and joint use partners. These needs fluctuate from year to year. There is no reason to expect that the total amounts would be consistent from year to year.

System Renewal (SR) – Variance – 2018 Forecast $948,302 more than 2017 Forecast

CNPI plans to construct a new Distribution Substation (DS) in Port Colborne to allow for the retirement of two other DS's that are at or near the end of their useful lives. This DS construction has a net increase of approximately $900,000 within the System Renewal expenditure category in 2018.

System Service (SS) – Variance – 2018 Forecast $777,243 less than 2017 Forecast

There are no forecasted costs associated with Delta to Wye conversion efforts in the Gananoque service territory in 2018. System Service expenditures in 2018 have decreased approximately $750,000 as a result.

General Plant (GP) – Variance – 2018 Forecast $190,506 less than 2017 Forecast

There are no 2018 forecasted costs associated with the replacement of the non-SAP host servers as part of the lifecycle management process. Absence of these replacements during 2018 results in a decrease of approximately $200,000 within the General Plant expenditure category.

2018 Forecast vs. 2021 Forecast

Category	***2018 Forecast***	***2019 Forecast***	***2020 Forecast***	***2021 Forecast***	***2021 Variance from 2018 Forecast***
System Access	536,611	547,343	559,940	571,139	34,528
System Renewal	5,939,120	5,496,072	5,460,618	7,043,601	1,104,482
System Service	1,064,435	1,504,806	1,179,108	918,380	-228,877
General Plant	1,825,260	1,621,293	2,477,611	2,073,684	248,424
Total Capital Expenditures	**9,365,426**	**9,169,514**	**9,677,278**	**10,523,982**	**1,158,556**

2018 to 2021 System Access (SA) – Variance – 2021 Forecast $34,528 more than 2018 Forecast

System Access investments and third party contributions are entirely based on the needs of external stakeholders such as customers, and joint use partners. These needs fluctuate from year to year. There is no reason to expect that the total amounts would be consistent from year to year. At the time of this filing, CNPI is forecasting an 'average' volume of such work with an 'average' volume of offsetting CIAC's. Since overall SA investments are impossible to forecast with any certainty, CNPI has assumed an average year-over-year growth of 2% from 2018 to 2021.

2018 to 2021 System Renewal (SR) – Variance – 2021 Forecast $1,104,482 more than 2018 Forecast

In 2021, CNPI Intends to build a new Distribution Station (DS) in the south eastern area of Fort Erie. This station is anticipated to require $550,000 more investments in substations than in 2018.

CNPI will be engaged in significant efforts to eliminate its legacy Delta systems throughout the forecast period. Some of this work is straight voltage conversion, attributed to System Service (SS), and some of this work required accompanying refurbishment or replacement of legacy line, attributed to System Renewal (SR). In 2021, CNPI expects a change in the relative mix of these two types of work, contributing to a net increase in SR of $470,000.

2018 to 2021 System Service (SS) – Variance – 2021 Forecast $228,877 less than 2018 Forecast

CNPI will be engaged in significant efforts to eliminate its legacy Delta systems throughout the forecast period. Some of this work is straight voltage conversion, attributed to System Service (SS), and some of this work requires accompanying refurbishment or replacement of legacy line, attributed to System Renewal (SR). In 2021, CNPI expects a change in the relative mix of these two types of work, contributing to a net decrease in SS of $229,000.

2018 to 2021 General Plant (GP) – Variance – 2021 Forecast $248,424 more than 2018 Forecast

The summary below represents the two primary areas of focus in respect of technology related capital improvements. In general, the year over year allocation to these areas remain consistent with the exception of hardware. The hardware variances are attributed to significant replacement of systems that are at the end of their lifecycle. Such systems include but are not limited to host servers, storage systems and associated network gear.

Please note, all values in the table below are in '000s of $.

	2016	2017	2018	2019	2020	2021
Hardware	600	354	250	200	200	400
Software	1,491	1,274	1,004	1,000	1,000	1,000
	$2,091	$1,628	$1,254	$1,200	$1,200	$1,400

INFORMATION TECHNOLOGY STRATEGY

Background

CNPI's information technology strategy ("IT Strategy") has focused on enhancing IT systems to facilitate improvements in customer service and operational efficiency throughout the organization. Starting in 1998, the decision to implement SAP as the primary enterprise resource planning ("ERP") system solidified this commitment. SAP is a fully integrated billing and back office system, which represents a cost beneficial solution that meets the business needs of CNPI and its consumers. SAP is a world renowned software provider with a proven track record. The SAP ECC 6.0 core modules or back office ERP (financial system, plant maintenance/work order management, and materials management) were implemented and went live in February 1999. The utility billing and front office customer care and service ("IS-U/CCS") module went live in April 1999. A minor upgrade of the IS-U/CCS module was performed in May of 2000. New operational components created by industry restructuring in Ontario included the introduction of electricity retailers, which required a change to a two-contract data model. Also, these requirements included the unbundling of historically bundled electricity rates. The SAP system provided CNPI with a technology that was capable of delivering new invoices which split out individual line item charges, a new bill format and presentations, new configuration for collection activity to ensure compliance with market rules, and new interfaces to the financial system module to facilitate new billing rates. The requirement of billing standard supply and distributor billing options were significant components of the operational requirements for retailers. The end result is that CNPI has developed an Ontario template that is efficient and stable, and meets the requirements of Ontario's unique regulatory environment.

CNPI uses a centralized IT system to deliver IT to its service territories. Having a single centralized system rather than multiple IT systems reduces overall IT costs which results in savings to customers. In recognizing the complex technical requirements of Time of Use ("TOU") and related Smart Meter efforts, a technical upgrade of the existing SAP system was carried out beginning in May, 2010 and completed by April, 2011. Subsequent to this major update, the SAP base software has remained relatively unchanged to date; however, coding changes have been performed in respect of business improvements and ongoing regulatory requirements.

IT Strategy

The key components of CNPI's IT Strategy are as follows:

- Maintain business continuity including system reliability and integrity;
- Provide capabilities for regulatory initiatives and future business growth; and
- Manage capital and support costs associated with the system.

The goal of CNPI's IT Strategy is to invest in technology to improve customer service and operating efficiency. This is achieved through a variety of initiatives ranging from the development of automations, building in-house technical competence and consolidation of technology. In addition, CNPI's IT systems must remain flexible to respond to new requirements driven by regulatory changes and market demands.

Some examples of the specific IT projects that have assisted in implementing CNPI's IT Strategy include the following:

Customer Service

- Improving communication during customer interactions
  - Electronic Bill Management: Provides a web portal for customers to view and pay their bills thereby eliminating their traditional paper bill
  - Outage Management Information: Provides customer service representatives with direct information to current outage related events in an effort to improve customer experience
- Implementing required regulatory changes to the billing functions
  - TOU rate model delivery
  - OESP (Ontario Electricity Support Program): Providing all SAP and business process related changes necessary in delivering this government initiative to consumers

- Automation improvements
  - Electronic Bill Management: Consolidation of all internal bill printing processes to a single external vendor via periodic electronic transfers
  - microFIT Payment Management: Elimination of manual cheque signing through internally developed payment process within SAP incorporating necessary financial controls that provides a complete solution for payments sent to microFIT customers.

Safety

- Maintain software critical to the successful function of the Health, Safety & Environment Department
  - Compliance Science: Application that facilitates the effective recording, monitoring and measuring of CNPI's health safety and environment management system, including statistics, audit results, work observations, inspections, training and safety meeting planning
  - Critical information maintained on company intranet including key contacts, procedures and external links
- SCADA (Supervisory Control & Data Acquisition) software
  - Key function in monitoring/controlling substations

Financial Performance

- Reporting improvements
  - OEB information presentment
  - Monthly/quarterly management reports
  - Monthly/quarterly/annual board reports

IT Reliability

- Achieving performance targets with respect to system downtime and number of incidents.
- Annual assessments through audits
  - Disaster recovery

- Firewall vulnerability
- Service Desk application responsible for tracking and managing technology based requests and change management associated with related system improvements

Human Resource Management

- Maintain department specific software
  - Human Resource Partner
  - Intranet policies and procedures

Asset Management

CNPI IT assets include hardware and software. The main components of the IT hardware include servers, switches, network equipment, and workstations (desktops and laptops). The software that is used in conjunction with this hardware includes: email applications, file/print services, and the SAP ERP. There are other specific software applications that are used within CNPI that are unique to departmental needs. All of CNPI's IT assets are managed in-house utilizing a department comprised of the following eleven (11) employees:

- Department Manager
- Supervisor – IT Infrastructure
- Supervisor – SAP Services
- Supervisor – IT Business Support
- Programmer
- Business Application Analyst
- Applications Analyst
- IT Systems Administrator (two positions)
- IT Technician III
- Service Desk Analyst

The lifecycle for replacement of hardware is five years. Generally, CNPI's software is replaced in conjunction with the vendor's maintenance and lifecycle schedules. Updates and upgrades of software are normally implemented upon the vendor's recommended specifications. An exception is the SAP software, which undergoes a more in-depth review to ensure continued alignment with business requirements. CNPI will also continue to utilize lower cost in-house SAP trained IT staff in conjunction with external backup from SAP consultants as required.

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CAPITAL PROJECTS - INFORMATION TECHNOLOGY

Asset Management

CNPI IT assets include hardware and software. The main components of the IT hardware include servers, switches, network equipment, and workstations (desktops and laptops). The software that is used in conjunction with this hardware includes: email applications, file/print services, and the SAP ERP. There are other specific software applications that are used within CNPI that are unique to departmental needs. The strategy for delivering the hardware and software is discussed within Exhibit 2, Tab 2, Schedule 3.

For the purpose of this document, CNPI utilizes a shared services model referenced within Exhibit 4, Tab 5, Schedule 1. Through this method, appropriate costs are allocated to each business unit within FortisOntario.

Hardware

Workstations

CNPI maintains approximately 135 workstations (both desktops and laptops) within the Fort Erie, Port Colborne and Gananoque locations. The lifecycle of these assets has been set at five years, which generally coincides with the warranty coverage and useful life of the assets.

The annual cost to replace the workstations has remained relatively consistent using the five-year lifecycle.

Servers

The server assets are also managed using a five-year lifecycle. CNPI maintains approximately 73 servers. The annual schedule of replacing CNPI servers is in line with the five-year warranties of the systems. The capital projects table provides a summary of hardware and software costs for purchases above the materiality threshold of $100,000.

Capital Projects - Information Technology						
Projects	2012	2013	2014	2015	2016 Bridge Year	2017 Test Year
Miscellaneous IT GP	168,283	275,702	251,804	177,759	346,428	228,071
Server Storage Replacements GP	417,992				386,339	246,081
SAP Improvements GP	252,000	352,945	364,081	248,787	715,195	540,027
GIS/OMS GP	186,000	288,181	161,052	287,637	340,000	300,000
Environment Health & Safety GP		110,386	120,749			100,000
Software Licensing GP		345,544	177,115	173,000	214,000	214,000
Firewall Upgrades GP			121,457			
Smart Meter Technology GP		798,570				
Total IT	**1,024,275**	**2,171,328**	**1,196,258**	**887,183**	**2,001,962**	**1,628,179**

The following is a discussion of the major IT hardware projects for the years 2012 Actual – 2017 Test Years. Material, labour and contracted services are included in these costs.

<u>2012 Actual Hardware</u>

In 2012 Actual, the following IT equipment was purchased:

- Replacement of workstations that were at end of lifecycle – $46,681
- Replacement of non-SAP corporate servers and storage system which was at end of lifecycle - $417,992
- Miscellaneous improvements - $99,952
  - Network printer replacements per lifecycle requirements
  - Phone system upgrades
  - Minor firewall upgrades

<u>2013 Actual Hardware</u>

In 2013 Actual, the following IT equipment was purchased:

- Replacement of workstations that were at end of lifecycle – $57,372
- Miscellaneous hardware improvements - $140,639
  - Network switches
  - Data centre upgrades
  - Wireless technology updates

<u>2014 Actual Hardware</u>

In 2014, the following IT equipment was purchased:

- Replacement of workstations that were at end of lifecycle – $71,612
- Firewall upgrade - $121,457
- Miscellaneous hardware improvements - $79,645
    - Network printers
    - Phone system upgrades
    - Cellular technology upgrades

<u>2015 Actual Hardware</u>

In 2015, the following IT equipment was purchased:

- Replacement of workstations that were at end of lifecycle – $79,875

<u>2016 Bridge Year</u>

In 2016 Bridge, the following IT equipment will be purchased:

- Replacement of workstations that were at end of lifecycle – $75,000
- Replacement of SAP server/storage system that is at end of lifecycle - $386,339
- Miscellaneous - $61,428
    - Network printer replacements
    - Wireless technology improvements
    - Phone system call recording updates

<u>2017 Test Year</u>

In 2017, the following IT equipment will be purchased:

- Replacement of workstations that were at end of lifecycle – $73,071
- Replacement of the non-SAP server/storage system that is at end of lifecycle - $246,081
- Miscellaneous - $35,000
    - Wireless access points
    - Network switches

Software

Computer software encompasses all applications that are installed and run on workstations and/or servers. This includes the following:

- Operating system
  - Microsoft Windows (workstation)
  - Microsoft Windows Server (server)
- Client specific office productivity
  - Microsoft Office
  - Adobe Acrobat – pdf creation and viewing application
  - WinZip – file compression application
  - SnagIt – screen capture application
- Server specific application
  - Microsoft SQL Server
  - Microsoft SharePoint Server
  - VMware vSphere Virtualization Application
  - Commvault Data Protection
  - Citrix Remote VPN Access
  - Checkpoint Firewall
- Function specific
  - ADP HR Resource Partner Application
  - ADP Payroll Application
  - SAP specific
    - Epost/Electronic Bill Presentment
      - Transition bill from traditional on premise printers which are end of life to third party dedicated printing service
      - Develop necessary interfacing and programmatic changes to facilitate paperless E-presetment solution to customers
    - EBT (Electronic Billing Transactions) related
      - Automation and integration of remaining manual processes related to the retailer related transactions
    - Archiving Solution

    - In order to keep data set sizes manageable, which in turn ensure appropriate system response time, it is necessary to archive data that is no longer required for day to day operations.
    - Data meeting the business requirements are moved from active service into long term storage residing on more cost effective technology
- Enhancement Packs
    - SAP introduced method to simplify the way new updates and related functionality are applied
    - Isolates the impact of software updates and brings new functionality into production through shortened testing cycles
- Bill print enhancements
    - Improvements for installment plan and security deposit visibility (i.e. how much is still owed on plans, etc.)
    - Improvements to microFIT and net meter generation print display
- Business process improvements
    - Improvements to collection processes to incorporate creditworthiness checks into collection evaluation & activities
    - Interaction centre improvements to reduce call times and improve customer service representative call experience (i.e. Single-screen balance overview for business partner)
    - Support for automation of bank reconciliation via changes to inbound Electronic Bill Payment file processing (one payment lot per day, per financial institution)
    - SAP-enabled Operations trouble call/outage report & deficiency processes – ongoing initiative with Niagara Operations, with mobilization using SAP Work Manager
- SAP mobile platform development

  - Mobile-enabled, field automated meter install/exchange/remove process.
  - Service and maintenance notification processing in SAP Work Manager in support of improved trouble call/outage report processes
- SAP Process Orchestration Migration
  - Enhanced messaging/logging of interfaces
  - Streamlined and improved development tools
  - New, SAP-delivered adapters that can be used to streamline banking interfaces
- OESP Implementation (Ontario Electricity Support Program)
  - Full technical and business integration of government-legislated Ontario Electricity Support Program initiatives
  - All interactions with OESP are seamless to CSRs, 100% automated, no user intervention required
- Unicode Conversion
  - Conversion process necessary to ensure SAP code complies with universal standard to that of other applications.
  - Performing this conversion also allows the continued ability to integrate with related external systems.
- Smart Meter Related Technology
  - Internal labor assigned to SAP specific development of functionality associated with Smart Meter related requirements such as programmatic updates and net new interfacing with external systems
  - External consulting hired to support internal development team
  - Costs associated with an upgrade to the SAP system in support of Smart Meter requirements
- XpressPost Integration

            - Automatic creation/printing of mailing labels thereby reducing manual effort required by Customer Service staff
        - Security Redesign
            - Develop an updated security model within SAP that more accurately represents employee positions and their respective roles. Aspects such as segregation of duties and associated controls would be applied
    - GIS/OMS specific
        - Interface development between Sensus AMI meters and the OMS systems to capture AMI outage & restoration MultiSpeak messages and use them to log valid outage/restorations
        - Interface development to allow DisSPatch to ping meters and confirm that they do or do not have power
        - Run outage messages through SAP first to ensure the outages are valid (i.e. no open service orders or valid disconnections)
        - Build similar interface between Elster GS>50 meters to capture outage/restoration messages sent by meters over various data channels
        - Mobile enabled mapping solution eliminating paper based system
    - Health, Safety & Environment
        - Collection, tracking and reporting of all HSE data from multiple departments or locations.
        - Leading indicators: observation, inspection, HSE meetings, safety equipment maintenance, and all associated action items including responsibility assignment at each level of the organizational structure.
        - Lagging indicators: Incident reporting company, public and contractor with all associated action items including responsibility assignment at each level of the organizational structure.
        - Compliance and legal requirement management
        - Audit and inspection management
        - Document control and training management

- Vegetation Management
    - Facilitate workload forecasting throughout the year, creating schedules in advance.
    - Provide better data and historical information to assist with the budgetary planning process.
    - Establish a consistent and repeatable process to be used by multiple users.
    - Facilitate compliance with regulatory requirements
    - Provide consistent, more accurate record keeping method
    - Create/maintain metrics for various work activities, cost types, and other criteria currently not being captured
- Service Desk Application
    - Incident response/management
    - Change management
    - Patch management
    - Reporting tools
- Information Security Project
    - Review current environment
    - Agree to new control model
    - Define gap analysis
    - Execute new plan
    - Report on outcomes
- Computer-based engineering analysis, outage management, planning/staking, and mapping/geographical information system applications
- Z-Option (Excel/SAP interface application)
- Commvault (Data Protection Software)

Generally, CNPI's software is replaced in conjunction with the vendor's maintenance schedule and lifecycle schedule. Updates and upgrades of software are normally implemented in support of business improvements and consistent with industry standards. Costs associated with software encompasses license specific purchases and/or the development of business process through the use of software.

The following is a review of the major IT software projects for the years 2012 Actual – 2017 Test Years. Details for each initiative/improvement have been described above. Material, labour and contracted services are included in these costs.

<u>2012 Actual Software</u>

In 2012 Actual, the following costs were allocated to software:

- SAP improvements - $252,000
    - Epost – electronic customer bill presentment development within SAP
- GIS/OMS specific development - $186,000
- Miscellaneous Software - $21,650
    - Adobe Pro (PDF creation/management software)
    - Citrix vpn (allows for employee remote access to company systems)
    - Z-Option (SAP/Excel interface product)

<u>2013 Actual Software</u>

In 2013 Actual, the following costs were allocated to software:

- SAP improvements - $525,489
    - Unicode conversion
    - Archiving solution
    - EBT (Retailer Related) automations
    - GIS/OMS related interfacing
- Software Licensing - $173,000
    - SAP specific
    - Microsoft specific
- Health, Safety & Environment Application Improvements - $110,386
- GIS/OMS specific development - $288,181
- Smart Meter specific technology development – $798,570
- Miscellaneous Software - $77,691

  - AutoCAD
  - DUO mobile (Two-factor authentication software)
  - Footprints Service Desk

<u>2014 Actual Software</u>

In 2014 Actual, the following costs were allocated to software:

- SAP improvements - $364,081
  - SAP enhancement pack (mini upgrade)
  - EBT (Retailer Related) automations
  - EFT (Electronic File Transfer) automation
  - Canada Post Xpresspost integration/automation
  - Mobile workforce integration
- Software Licensing - $177,115
  - SAP specific
  - Microsoft specific
- Health, Safety & Environment Application Improvements - $120,749
- GIS/OMS specific development - $161,052
- Miscellaneous application improvements - $100,547
  - Intranet improvements
  - Security certificate software
  - Mobile device management software
  - External file share software
  - Phone system improvements

<u>2015 Actual Software</u>

- SAP Improvements - $248,787
  - Mobile workforce integration
  - Process Integration upgrade
  - OESP (Ontario Energy Support Program) implementation
  - microFIT payment automation
- Software Licensing - $173,000

    - SAP specific
    - Microsoft specific
- GIS/OMS specific development - $287,637
- Miscellaneous Software - $97,884
    - Adobe Pro
    - Health, Safety & Environment Application Improvements

<u>2016 Bridge Software</u>

In 2016 Bridge Year, the following costs will be allocated to software:

- SAP improvements - $715,195
    - SAP Work Manager mobile application
    - Asset management integration
    - Bill print enhancements
    - Business process improvements
    - SAP related system improvements
    - Mobile Workforce development
    - OESP (Ontario Energy Savings Plan) implementation
- Licensing agreement - $214,000
    - SAP specific
    - Microsoft specific
- GIS/OMS specific development - $340,000
- Miscellaneous application improvements - $346,428
    - Health, Safety & Environment application improvements
    - Adobe Professional software upgrades
    - SharePoint intranet upgrade
    - PowerAssist Call Management

<u>2017 Test Year Software</u>

In 2017 Test Year, the following costs will be allocated to software:

- SAP improvements - $540,027
    - SAP Workforce Manager

    - SAP Security Redesign
    - Process Improvements
    - GIS/OMS Integration
    - Annual configuration updates related to rate changes
- Software Licensing - $214,000
    - SAP Specific
    - Microsoft Specific
- Health, Safety & Environment application improvements - $100,000
- GIS/OMS specific development - $300,000
- Miscellaneous application improvements - $120,000
    - Vegetation Management application improvements
    - Software True-ups

CAPITALIZATION POLICY

CNPI follows Canadian generally accepted accounting principles, in particular Part II of the CPA Canada Handbook Section 3061, Property, Plant and Equipment as well as the guidelines set out in the Board's Accounting Procedures Handbook. Pursuant to the Board letter of July 17, 2012, CNPI has applied changes to the capitalization policies effective January 1, 2013, consistent with the Board's regulatory accounting policy direction contained in that letter. These changes are reflected in CNPI's 2013 Board Approved, 2013 Actuals, 2014 Actuals, 2015 Actuals, 2016 Bridge Year and 2017 Test Year results.

Allocation of Costs to Capital

The capital cost of construction includes the cost of labour, materials and directly attributable overhead expenses associated with such work as defined in Exhibit 2, Tab 4, Schedule 2.

Labour Costs

Labour is charged to capital at a fully loaded labour rate. The fully loaded labour rate is comprised of direct labour, payroll burden, vehicle charges and directly attributable costs as defined in Exhibit 2, Tab 4, Schedule 2. Supervisors and managers charge direct time to capital projects.

Material Supplies

Materials and supplies are charged to capital on the basis of actual costs for non-stock materials and the weighted average price for materials in inventory.

Materiality

As a practical matter, items of a capital nature that are less than $500 in value are charged to operating expenses as incurred.

Appendix 2-D
Overhead Expense

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another format best suited to focus on capitalized vs. uncapitalized OM&A.

OM&A Before Capitalization	2013 Historical Year	2014 Historical Year	2015 Historical Year	2016 Bridge Year	2017 Test Year
Operations and Maintenance	$ 4,487,625	$ 4,645,140	$ 4,798,379	$ 4,979,115	$ 5,273,059
Billing and Collecting	$ 1,888,566	$ 1,777,437	$ 1,771,188	$ 1,888,325	$ 1,974,575
Community Relations	$ 22,685	$ 14,503	$ 22,126	$ 25,300	$ 40,150
Administrative and General	$ 3,623,361	$ 4,126,783	$ 4,215,170	$ 4,465,819	$ 4,545,562
Total OM&A Before Capitalization (B)	$ 10,022,237	$ 10,563,864	$ 10,806,863	$ 11,358,559	$ 11,833,346

Applicants are to provide a breakdown of capitalized OM&A in the below table. Capitalized OM&A may be broken down using the categories listed in the table below if possible. Otherwise, applicants are to provide its own break down of capitalized OM&A.

Capitalized OM&A	2013	2014	2015	2016	2017	Directly Attributable? (Y/N)	Explanation for Change in Overhead Capitalized
employee benefits							
costs of site preparation							
initial delivery and handling costs							
costs of testing whether the asset is functioning properly							
professional fees							
costs of opening a new facility							
costs of introducing a new product or service (including costs of advertising and promotional activities)							
costs of conducting business in a new location or with a new class of customer (including costs of staff training)							
administration and other general overhead costs							
Operational Departments	$ 1,014,660	$ 1,024,647	$ 1,182,824	$ 1,117,342	$ 1,166,113	Y	No change since last CoS, costs are directly attributable to labour costs charged to capital and are included in burden rate
Customer Service Department	$ 13,787	$ 9,074	$ 16,582	$ 14,066	$ 14,549	Y	No change since last CoS, costs are directly attributable to labour costs charged to capital and are included in burden rate
Administrative and General Departments	$ 129,727	$ 95,329	$ 88,524	$ 96,335	$ 107,961	Y	No change since last CoS, costs are directly attributable to labour costs charged to capital and are included in burden rate
Total Capitalized OM&A (A)	$ 1,158,174	$ 1,129,050	$ 1,287,930	$ 1,227,743	$ 1,288,623		
% of Capitalized OM&A (=A/B)	12%	11%	12%	11%	11%		

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BURDEN RATES

CNPI's capitalization policy for the 2013, 2014 and 2015 Actuals, the 2016 Bridge Year and the 2017 Test Year complies with the OEB's letter issued July 17, 2012 that requires all distributors to change their accounting policies and to adopt capitalization policies consistent with the requirements of International Financial Reporting Standards effective on January 1, 2013. This change in accounting policy was implemented in CNPI as of January 1, 2013, and approved as part of CNPIs previous cost of service EB 2012-0112. CNPI has maintained this accounting policy in the 2017 Test Year.

CNPI uses fully loaded labour rates to capitalize costs into PP&E. On a departmental basis, CNPI uses direct wages, employee benefits and directly attributable overhead costs, including vehicle costs if applicable, in order to calculate the fully loaded labour rates. These rates are then used in the allocation of labour to both OM&A and PP&E.

The following schedule shows the average percentages applied to base wages for employee benefits and directly attributable overhead costs.

Schedule of Burden Rates Related to Capitalization of Costs to PP&E

	Actual 2013	Actual 2014	Actual 2015	Bridge Year 2016	Test Year 2017
Operational Departments	35%	37%	36%	34%	35%
Customer Service Departments	28%	26%	26%	25%	26%
General and Administrative Departments	29%	26%	27%	25%	26%

The following document is a CNPI internal policy standard related to the capitalization of burdens.

Standard: Property, Plant and Equipment

Topic: Capitalization - Burdens

Objective:

To document the accounting policy for the capitalization of burdens in compliance with International Financial Reporting Standards ("IFRS") IAS 16 for the CNPI business unit.

Background:

Core Principle

The cost of an item of property, plant and equipment (PP&E) is recognized as an asset if and only if:

a) It is probable that future economic benefits will flow to the company; and
b) The cost of the item can be measured reliably.

The cost of an item of PP&E includes any costs that are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

Examples of ***directly attributable costs*** are:

a) Costs of employee benefits (as defined in IAS 19 Employee Benefits) arising directly from the construction or acquisition of the item of property, plant and equipment;
b) Costs of site preparation;
c) Initial delivery and handling costs;
d) Installation and assembly costs;
e) Costs of testing whether the asset is functioning properly, after deducting the net proceeds from selling any items produced while bringing the asset to that location and condition (such as samples produced when testing equipment); and
f) Professional fees.

Directly attributable

The term "directly attributable" is not defined in IAS 16. The specific facts and circumstances surrounding the cost and the ability to demonstrate that the cost is directly attributable to an item of PP&E is critical to establishing whether the cost should be capitalized. The cost must be attributed to a specific item of PP&E at the time it is incurred. The incurrence of that cost should aid directly in the construction effort making the asset more capable of being used than if the cost had not been incurred.

Certain costs are ***explicitly prohibited*** from inclusion as ***costs*** of an item of PP&E:

a) Costs of opening a new facility;

b) Costs of introducing a new product or service (including advertising and promotion);

c) Costs of conducting business in a new location or with a new class of customer (including costs of staff training)

d) Administration and other general overhead costs; and,

e) Day-to-day servicing costs.

IAS 16 does not indicate what constitutes an item of PP&E. Judgment is required when applying the core principle.

<u>General and administrative overhead</u>

IFRS does not provide a definition of general and administrative overhead (G&A). The facts and circumstances surrounding the nature of the costs and the activity associated with it must be considered to determine if it is directly attributable to an item of PP&E.

G&A costs typically benefit the organization as a whole or areas of the organization more broadly rather than contributing directly to bringing a physical asset to the location and condition necessary for it to be capable of operating in the manner intended by management. The more the nature of a particular cost strays from being directly attributable to an item of PP&E, then the more likely it is that the cost will be determined to be in the nature of G&A.

<u>Day-to-day servicing costs</u>

Day-to-day servicing costs are defined as costs of labour and consumables and may include the cost of small parts. The purpose of these expenditures is often described as for the "repairs and maintenance" of the item of PP&E.

<u>Feasibility studies and pre-construction activities</u>

Normally, feasibility studies are not capitalized under IFRS as these costs do not always result in asset construction, and therefore may not meet the criteria of providing a future economic benefit. Additionally, the associated costs must be directly attributable to an item of PP&E. Pre-construction activities (such as design work) prior to a decision to go ahead with a capital project do not qualify for capitalization.

<u>Considerations</u>

Canadian GAAP/ASPE allowed for capitalization of general and administrative overhead, training costs, etc. while IFRS does not.

The Ontario Energy Board (OEB) requires electricity distributors to be in full compliance with IFRS requirements as applicable to non-regulated enterprises and only where Board authorizes specific alternative treatment for regulatory purposes is alternative treatment acceptable.

Under IFRS, training costs and repairs and maintenance cannot be capitalized. Training on how to install a piece of equipment can be capitalized, but actual training on a piece of equipment cannot be capitalized. Repairs and maintenance costs of an item of PP&E cannot be capitalized to the cost of that item of PP&E. Vehicle repair and maintenance should be capitalized into the cost of the constructed asset as part of the operating costs of the vehicle used in the construction activity. Under IFRS, short term employee benefits are allowed to be capitalized.

The company includes the wages for a number of management positions in its burdens for capitalization to capital. Some of these positions are more in the nature of G&A and should be excluded from capitalization under IAS 16. The salary costs for the manager of engineering and operations, manager of engineering are considered to be general and administrative overhead and not directly attributable unless time is charged specially to a capital job via timesheets. Operations managers and supervisors, linesmen and foremen are considered to be directly attributable to the cost of an item of PP&E since they spend time directly on the capital job.

IAS 16 specifically allows for the cost of employee benefits as defined in IAS 19 to be capitalized as a directly attributable cost. The company has included employee benefits in its burden rates in the past and under IAS 16 these would be considered to be costs eligible for capitalization.

Benefits which have not been included in burdens in the past but which would be allowable costs for capitalization under IAS 16 include professional dues, aid to education, clothing, counseling and employee share purchase plan. In addition, depreciation expense on vehicles involved in capital projects can be capitalized as part of the operating costs of the vehicle used in the construction of a capital asset.

A number of costs are currently included in the burdens which would not be allowed to be capitalized under IAS 16 as they are not considered to be directly attributable to an item of PP&E. The tables in Appendix A list the costs that are considered to be directly attributable to an item of PP&E and those costs that are not considered to be directly attributable to an item of PP&E.

Conclusion:

CNPI will capitalize all costs, when the cost is directly attributable to bringing the item of PP&E to the location and condition necessary for it to be capable of operating in the manner intended by management. These are itemized in Table 1 in Appendix A.

Any general and administrative costs currently included in the various burden rates, such as training, maintenance, miscellaneous and other administrative expenses will not be capitalized. These costs are itemized in Table 2 in Appendix A.

Appendix A

Table 1: Overhead Costs Directly Attributable To Capital – To be included in burden for capitalization
Cellular and telephone communication costs
Aid to Education: i.e. tuition, considered employee benefit
Employee welfare – short term benefit
Professional dues – short term benefit
Safety materials
Personal protection - benefit
Health & safety costs
Training for installation of the asset*
Travel: if for particular capital project, charge to particular code**
Small Tools including battery & flashlight
Cloth & Other: i.e. protective clothing
Glove Testing
Public & Reference materials
Work and gloves
Coveralls
Vehicle Order: maintenance, gas, oil, tires, etc.

Table 2: Costs included in burdens which are not to be capitalized under IAS 16
Advertising and Sponsorship
Bank charges
Telephone – land line
Couriers
Office Supplies
Freight
Postage
Print matter
Subscriptions
Inventory Scrap
Conferences
Material handling
Communications
Environment, Health & Safety Monitoring Analysis
Waste Management Hazardous
Print matters
Distribution Poles
Distribution C&D Primary
Distribution C&D Secondary
Transmission Co
Distribution Instr
Distribution Miscellaneous Metering
Miscellaneous Mat/Serv
Miscellaneous Equipment
Cost/Labour Rec
Environmental Supplies
Maintenance Agreement
Software - maintenance
Tree Trimming
Janitorial
General Repairs
C/S Distribution Poles
C/S Services
Employee Recognition – 5 year/10 year recognition, company party
Training to operate equipment*
Registration fees –
Project investigation
System Consultation
Legal Fees
Other Consultation - maintenance

Table 2 (continued): Costs included in burdens which are not to be capitalized under IAS 16
Travel not charged capital job**
Mileage
Meals
Other Travel
Cash over and short
Contracted Services
Courtiers
Credit Bureau
Customer Damage
Environmental supplies
Easement expense
Miscellaneous costs
Automotive Supplies
Yard and Garden
Kitchen Supplies
Electrical Supplies
Mechanical Supplies
Reel Deposits

* Training
- Training to install – attributable
- Training to operate – not attributable
- With new/large projects: address this issue in more detail when costs are incurred.

**Travel – generally not directly attributable or not allowed as it is not for a particular job. Travel for a particular job (capital) is charged to that particular project code.

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COSTS OF ELIGIBLE INVESTMENTS FOR THE CONNECTION OF QUALIFYING GENERATION FACILITIES

Section 2.2.2.5 of the Filing Requirements contemplates that a distributor will file for provincial rate protection associated with any costs incurred to make eligible investments, as described in section 79.1 of the Ontario Energy Board Act, 1998 (the "Act") and Regulation 330/09 (O. Reg. 330/09) made under the Act.

Costs incurred by a distributor, in accordance with cost responsibility rules in the OEB's Distribution System Code for the purpose of connecting or enabling the connection of a Renewable Energy Generation ("REG") facility to its distribution system, are considered to be eligible investments for the purpose of provincial rate recovery under s. 79.1 of the Act.

CNPI does not expect to make any capital expenditures related to renewable energy generation in its Distribution System Plan. There are no additional OM&A costs related to renewable generation as CNPI is able to process both microFIT and FIT applications utilizing existing employees. Therefore, CNPI does not require recovery of any costs incurred to make eligible investments as described in section 79.1 of the Act and O.Reg. 330/09 under the Act.

CNPI submits the following appendices related to REG, but they contain no non-zero values of significance:

- 2-FA: Renewable Generation Connection Investment Summary (past investments or over the future rate setting period)

- 2-FB: Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments

- 2-FC: Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Expansion Investments

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NEW POLICY OPTIONS FOR THE FUNDING OF CAPITAL

On September 18, 2014, the Board released *Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module.* In this report the Board has established the following mechanism to assist distributors in aligning capital expenditure timing and prioritization with rate predictability and smoothing:

> The review and approval of business cases for incremental capital requests that are subject to the criteria of materiality, need and prudence are advanced to coincide with the distributor's cost of service application. To distinguish this from the Incremental Capital Module ("ICM"), this new mechanism will be named the Advanced Capital Module (or "ACM").
>
> Advancing the reviews of eligible discrete capital projects, included as part of a distributor's Distribution System Plan and scheduled to go into service during the IR term, is expected to facilitate enhanced pacing and smoothing of rate impacts, as the distributor, the Board and other stakeholders will be examining the capital projects over the five-year horizon of the DSP.

CNPI does not currently have any discrete committed capital projects within the five-year horizon that it believes would require this new policy option. However, as noted in Section 5.4.1.7(a) of CNPI's Distribution System Plan, there is a well-known proposal in Fort Erie; the Canadian Motor Speedway, which could proceed in 2017 or 2018. The amount of capital investment required by CNPI would depend on the outcome of the economic evaluation performed in accordance with the DSC. Should this or a similar proposal proceed, CNPI may choose to file a related ICM application.

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ADDITION OF ICM ASSETS TO RATE BASE

CNPI has not received approval of an Incremental Capital Module ("ICM") asset during the incentive rate setting period following its last cost of service review, EB-2012-0112. Therefore, CNPI has no ICM assets included in its proposed 2017 Test Year rate base.

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SERVICE QUALITY AND RELIABILITY PERFORMANCE

CNPI has consistently exceeded the ESQR minimum standards in accordance with Section 7.0 of the Distribution System Code over the past five years. The table below summarizes the Service Quality Indicator standards met by CNPI for the period 2011 to 2015.

Table 2.8.1.1 – ESQR Summary

Indicator	OEB Minimum Standard	2011	2012	2013	2014	2015
Low Voltage Connections	90.0%	95.9%	95.7%	93.1%	96.0%	93.6%
High Voltage Connections	90.0%	---	0.0%	0.0%	0.0%	0.0%
Telephone Accessibility	65.0%	84.6%	84.6%	82.6%	78.0%	76.1%
Appointments Met	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Written Response to Enquires	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Emergency Urban Response	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Emergency Rural Response	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Telephone Call Abandon Rate	10.0%	2.3%	2.8%	2.5%	4.0%	4.6%
Appointment Scheduling	90.0%	99.2%	99.5%	99.2%	98.0%	97.0%
Rescheduling a Missed Appointment	100.0%	---	0.0%	0.0%	0.0%	0.0%
Reconnection Performance Standard	85.0%	---	100.0%	100.0%	100.0%	100.0%

CNPI measures its service reliability using the System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") which are calculated both on the basis of including loss of supply and excluding loss of supply. The table below summarizes SAIDI and SAIFI performance for the period 2011 through 2015.

Table 2.8.1.2 – SAIDI, SAIFI Performance

Index	Including outages caused by loss of supply					Excluding outages caused by loss of supply				
	2011	2012	2013	2014	2015	2011	2012	2013	2014	2015
SAIDI	2.523	7.756	3.461	1.952	5.870	2.412	1.891	3.225	1.951	2.361
SAIFI	2.070	3.825	2.970	2.067	3.550	1.797	2.209	2.719	2.067	2.783

5 Year Historical Average

Index	Including outages caused by loss of supply	Excluding outages caused by loss of supply
SAIDI	4.313	2.368
SAIFI	2.897	2.315

For the indices where CNPI is significantly above the calculated five year historical average (exclusive of outages caused by loss of supply), further details are provided below.

<u>2013 SAIDI and SAIFI</u>

In 2013, CNPI experienced a higher than average SAIDI of 3.23 compared to the balance of the five year period ranging from 1.89 to 2.41. In the same year, SAIFI was also above the five year historical average. This was primarily due to a significant weather event on November 1st during which sustained wind speeds in excess of 80 km/h were experienced. There were 53 separate outage events that impacted thousands of customers over a 14 hour period in the areas of Fort Erie and Port Colborne.

<u>2015 SAIFI</u>

In 2015, CNPI experienced a higher than average SAIFI of 2.78 compared to the five year historical average of 2.32. There were three significant events that contributed to this decline in performance.

The first significant event occurred on September 9th. A fault occurred on CNPI's 34.5kV system due to failure of a surge arrester. At the time of the event, a large section of feeder was out of service due to construction activities and work protection requirements. The feeder section was transferred to an adjacent circuit, resulting in over 7,000 customers being temporarily supplied from a single 34.5kV feeder. This constraint limited back-feed possibilities resulting in a significant outage duration for most of the customers affected.

The second significant event occurred on October 29th which consisted of a wind storm with sustained wind speeds in excess of 80 km/h. Gusts in excess of 105 km/h where experienced throughout the event. There were 36 separate outage events that impacted thousands of customers in Fort Erie and Port Colborne over a 12 hour period.

The third significant even occurred on November 12th. Again, sustained wind speeds in excess of 80 km/h were experienced with gusts in excess of 105 km/h. There were 49 separate outage events that impacted customers in the Fort Erie and Port Colborne areas over a period of 12 hours.

Historical Summary

The following two figures illustrate the historical SAIDI and SAIFI values between 2011 and 2015. The indices shown exclude outages due to loss of supply events. As indicated, the aforementioned significant events contributed negatively to CNPI's SAIDI and SAIFI performance over the historical period. Observation of the SAIDI and SAIFI trending with consideration given to these events indicate a relatively consistent performance overall in recent years.

Figure 2.8.1.1 – Historical SAIDI

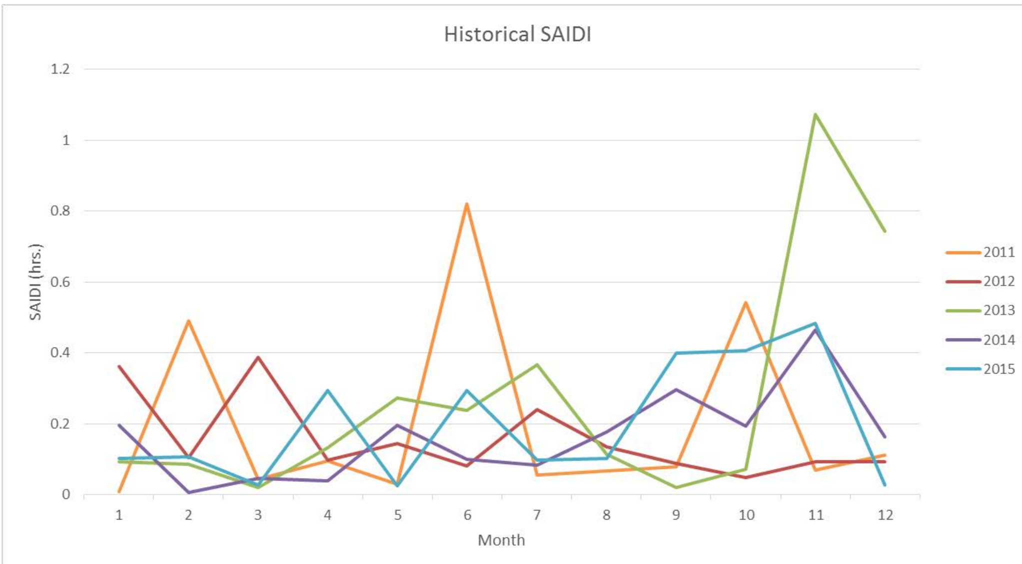
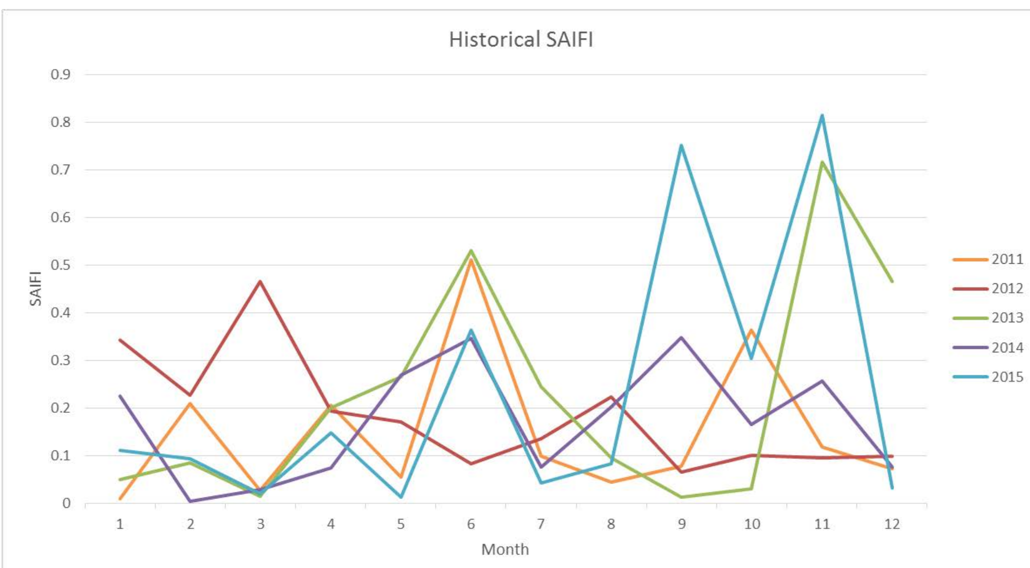


Figure 2.8.1.2 – Historical SAIFI



The following figure depicts CNPI's SAIDI and SAIFI performance for the period 2011-2015 using data excluding outages due to loss of supply:

Figure 2.8.1.3 – CNPI Reliability Indices - 5 Year History

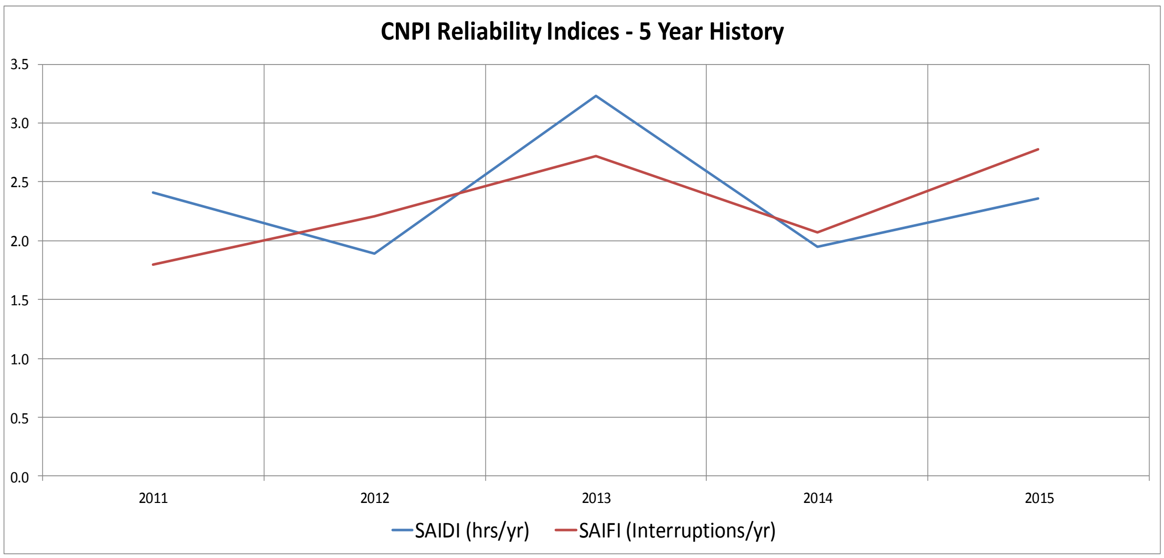
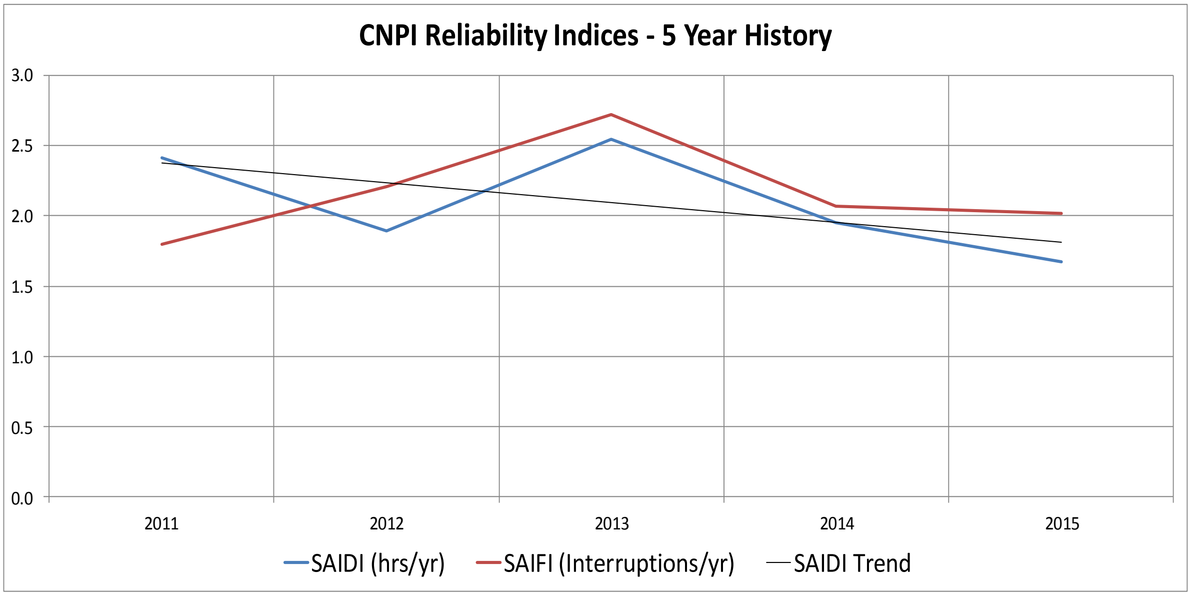


Figure 2.8.1.4 below, shows the five year trend of SAIDI and SAIFI with the aforementioned significant events removed. The chart indicates a general trend of improving reliability in CNPI's service territory.

Figure 2.8.1.4 – CNPI Reliability Indices - 5 Year History Excluding Significant Events



A summary of CNPI's service reliability performance is provided in Section 9 of CNPI's Distribution Asset Management Plan ("DAMP").

Appendix 2-G
Service Reliability Indicators
2011 - 2015

Index	Including outages caused by loss of supply					Excluding outages caused by loss of supply				
	2011	2012	2013	2014	2015	2011	2012	2013	2014	2015
SAIDI	2.523	7.756	3.461	1.952	5.870	2.412	1.891	3.225	1.951	2.361
SAIFI	2.070	3.825	2.970	2.067	3.550	1.797	2.209	2.719	2.067	2.783

5 Year Historical Average

	Including outages caused by loss of supply		Excluding outages caused by loss of supply	
SAIDI		4.313		2.368
SAIFI		2.897		2.315

SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index

Indicator	OEB Minimum Standard	2011	2012	2013	2014	2015
Low Voltage Connections	90.0%	95.9%	95.7%	93.1%	96.0%	93.6%
High Voltage Connections	90.0%	---	0.0%	0.0%	0.0%	0.0%
Telephone Accessibility	65.0%	84.6%	84.6%	82.6%	78.0%	76.1%
Appointments Met	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Written Response to Enquires	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Emergency Urban Response	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Emergency Rural Response	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Telephone Call Abandon Rate	10.0%	2.3%	2.8%	2.5%	4.0%	4.6%
Appointment Scheduling	90.0%	99.2%	99.5%	99.2%	98.0%	97.0%
Rescheduling a Missed Appointment	100.0%	---	0.0%	0.0%	0.0%	0.0%
Reconnection Performance Standard	85.0%	---	100.0%	100.0%	100.0%	100.0%

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