Chapter 5

Consolidated

Distribution System Plan

Delivered: February 24, 2015

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5.0 INTRODUCTION

On March 28, 2013, the Ontario Energy Board ("OEB" or the "Board") issued Chapter 5 of the Board's Filing Requirements for Electricity Transmission and Distribution Applications, entitled *Consolidated Distribution System Plan Filing Requirements (the "Chapter 5 Requirements").* The Chapter 5 Requirements provide a standard approach to a distributor's filing of asset management and capital expenditure plan information in support of a rate application and its Distribution System Plan.

PowerStream has compiled its consolidated Distribution System Plan (DS Plan) in accordance with the filing requirements for Chapter 5 for Electricity Transmission and Distribution applications.

Structure of this DS Plan

In accordance with Section 5.2 of the Chapter 5 Filing Requirements, this DS Plan has been organized to provide the required information using the section headings indicated. For clarity, the relevant section of Chapter 5 will commence each section, and is provided in 10 point italics font.

Section 5.0 and 5.2 of the Chapter 5 Filing Requirements states the format and expectations for structuring the DS Plan.

5.0

These filing requirements set out the information required by the Board under the renewed regulatory framework for electricity to assess distributor applications involving planned expenditures on distribution system and other infrastructure.[1] For the purposes of these filing requirements, a Distribution System Plan ("DS Plan") consolidates documentation of a distributor's asset management process and capital expenditure plan, where:

- *an Asset Management Process is the systematic approach a distributor uses to collect, tabulate and assess information on physical assets, current and future system operating conditions and the distributor's business and customer service goals and objectives to plan, prioritize and* *optimize expenditures on system-related modifications, renewal and operations and maintenance, and on general plant facilities, systems and apparatus; and*

- *a Capital Expenditure Plan sets out and robustly justifies according to the Board's standard requirements for evaluation a distributor's proposed expenditures on its distribution system and (non-system) general plant over a five-year planning period, including investment and asset-related maintenance expenditures.*

5.2

Distributors are encouraged to organize the required information using the section headings indicated. If a distributor's application uses alternative section headings and/or arranges the information in a different order, the distributor shall demonstrate that these requirements are met by providing a table that clearly cross-references the headings/subheadings used in the application as filed to the section headings/subheadings indicated below.

This DS plan has been formatted and organized to provide the information using the section headings indicated in the filing requirements.

Overview

The DS Plan reflects PowerStream's integrated approach to planning, prioritizing, managing assets and includes regional planning, local stakeholder consultations, renewable generation connections and smart grid considerations.

PowerStream has completed this DS Plan with a focus on customer preferences and operational effectiveness while achieving optimal value for capital spending.

Section 5.1.1 of the Chapter 5 Filing Requirements directs distributors to group each investment project and activity for filing purposes into one of four investment categories:

- System Access;
- System Renewal;
- System Service; and
- General Plant.

PowerStream has followed these four categories, specifically:

- **System Access:** Investments that are modifications to PowerStream's system in which there exists an obligation to perform customer connections and comply with mandated service obligations.

- **System Renewal:** Investments that involve replacing or refurbishing system assets which extend the service life of the assets.

- **System Service:** Investments that are modifications to PowerStream's distribution system to ensure that operational objectives are met and future customer requirements can be addressed.

- **General Plant:** Investments that are modifications, replacements or additions to PowerStream's assets where these assets are not part of the electrical distribution system (land, trucks, computers etc.).

The summary totals of investments within these four categories for the bridge year (2015) and subsequent years (2016-2020) proposed in this DS Plan are provided below in Table 1.

	2015 Proposed	2016 Proposed	2017 Proposed	2018 Proposed	2019 Proposed	2020 Proposed	Total
General Plant	$24,544,709	$17,631,419	$19,557,978	$13,966,910	$16,840,554	$18,205,522	$110,747,091
System Access	$24,145,118	$28,232,154	$28,469,723	$29,560,667	$28,726,052	$31,866,709	$171,000,423
System Renewal	$42,388,194	$48,714,625	$51,500,169	$52,051,933	$52,970,854	$52,405,780	$300,031,555
System Service	$27,321,977	$38,321,819	$32,071,882	$29,920,325	$26,963,080	$23,022,061	$177,621,144
Grand Total	$118,399,998	$132,900,017	$131,599,752	$125,499,835	$125,500,540	$125,500,071	$759,400,213

	2015 Proposed	2016 Proposed	2017 Proposed	2018 Proposed	2019 Proposed	2020 Proposed	Overall Total
General Plant	21%	13%	15%	11%	13%	15%	15%
System Access	20%	21%	22%	24%	23%	25%	23%
System Renewal	36%	37%	39%	41%	42%	42%	40%
System Service	23%	29%	24%	24%	21%	18%	23%
Grand Total	100%	100%	100%	100%	100%	100%	100%

Table 1: Annual Dollar Spending and Annual Percentage Spending by OEB Category

For compliance with Section 5.0, this DS Plan has been arranged in two parts:

1. The Asset Management Plan; and
2. The Capital Expenditure Plan.

Within the *Asset Management Plan*, the sections are:

- 5.0 Introduction (this section)

- 5.1.4 Planning in Consultation with Third Parties
    - Regional planning and consultations, renewable energy generation investments.

- 5.2.1 Distribution System Plan Overview
    - Key elements of the plan, source of costs savings due to the plan, changes since the last DS Plan, contingent events included in the plan.

- 5.2.2 Coordinated Planning with Third Parties
    - Consultation process with 3rd parties, external stakeholders, agencies and customers.

- 5.2.3 Performance Measurement for Continuous Improvement:
    - Corporate continuous improvement, asset investment planning improvements, results from the 2013 Ice storm and 2014 Wind storm, performance metrics and measures utilized to monitor the planning and implementation effectiveness of the DS Plan in efforts towards continuous improvement, effects of performance on the DS Plan.

- 5.3.1 Asset Management Process Overview
    - Asset management planning process, asset capacity/utilization/constraint assessment, worst performing feeder assessment.

- 5.3.2 <u>Overview of Assets Managed</u>
  - PowerStream's service territory, system configuration, asset utilization, assets managed.

- 5.3.3 <u>Asset Lifecycle Optimization Policies and Procedures</u>
  - Asset replacement and refurbishment policies, optimized, prioritized spending, impact of system renewal on routine OM&A and emergency/reactive repairs.

- 5.4.3 <u>System Capability Assessment for Renewable Energy Generation</u>
  - Applications from renewable generators over 10kW, number and capacity of renewable connections anticipated, PowerStream capacity for connection per station, system constraints,

Within the *Capital Expenditure Plan*, the sections are:

- 5.4.1 <u>Capital Expenditure Plan Summary</u>
  - Capability of PowerStream to connect new load, total annual capital expenditures by investment category, outputs of the plan, material capital expenditures, regional planning, customer engagement activities, five year system development, special activities.

- 5.4.2 <u>Capital Expenditure Planning Process Overview</u>
  - Capital Expenditure Planning Objectives, identification, selection and prioritization of projects, customer engagement.

- 5.4.4 <u>Capital Expenditure Summary</u>
  - Explanatory Notes on Variances in Capital Expenditure Summary, capital expenditure summary.

- 5.4.5 Justifying Capital Expenditures
    - Investment summary reports for projects above the materiality threshold.

APPENDICES

Appendix A: Project Investment Summaries – Material Projects
Appendix B: OPA Letters
Appendix C: Distribution System Plan Review Primer – Residential
Appendix D: Distribution System Plan Review Primer – General Service over 50
Appendix E: PowerStream Work Book
Appendix F: Customer Consultation Report

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.*

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.

5.1.4.1 Regional Planning and Consultations

The Ontario Energy Board's *Report of the Board – A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach* (the "RRFE Board Report") requires a consultation process aimed at promoting the cost-effective development of electricity infrastructure through coordinated planning on a regional basis between licensed distributors and transmitters

PowerStream has participated in all levels of regional planning required to develop long-term electricity plans. This is described fully in Exhibit G, Tab 2, Section 5.2.2.

5.1.4.2 Renewable Energy Generation Investments

All information related to Renewable generation is included in Exhibit G, Tab 2, Section 5.4.3.

5.2.1 DISTRIBUTION SYSTEM PLAN OVERVIEW

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 DS Plan, including but not limited to

a) 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

b) the sources of cost savings expected to be achieved over the forecast period through good planning and DS Plan execution

c) the period covered by the DS Plan (historical and forecast years);

d) 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?);

e) 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; and

f) 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.

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 Plan

This Distribution System Plan (DS Plan) presents the summary of the processes, drivers, outcomes and justifications of the proposed capital investments, from 2015 to 2020, for PowerStream to achieve its corporate and planning objectives.

PowerStream's corporate strategic objectives are shown in Figure 1. These corporate objectives influence the DS Plan. They are used within the optimization scoring process to link value to the strategy map and they are tied to business cases. This is further described in Exhibit G, Tab 2, Section 5.3.3, pages 19 and 20.

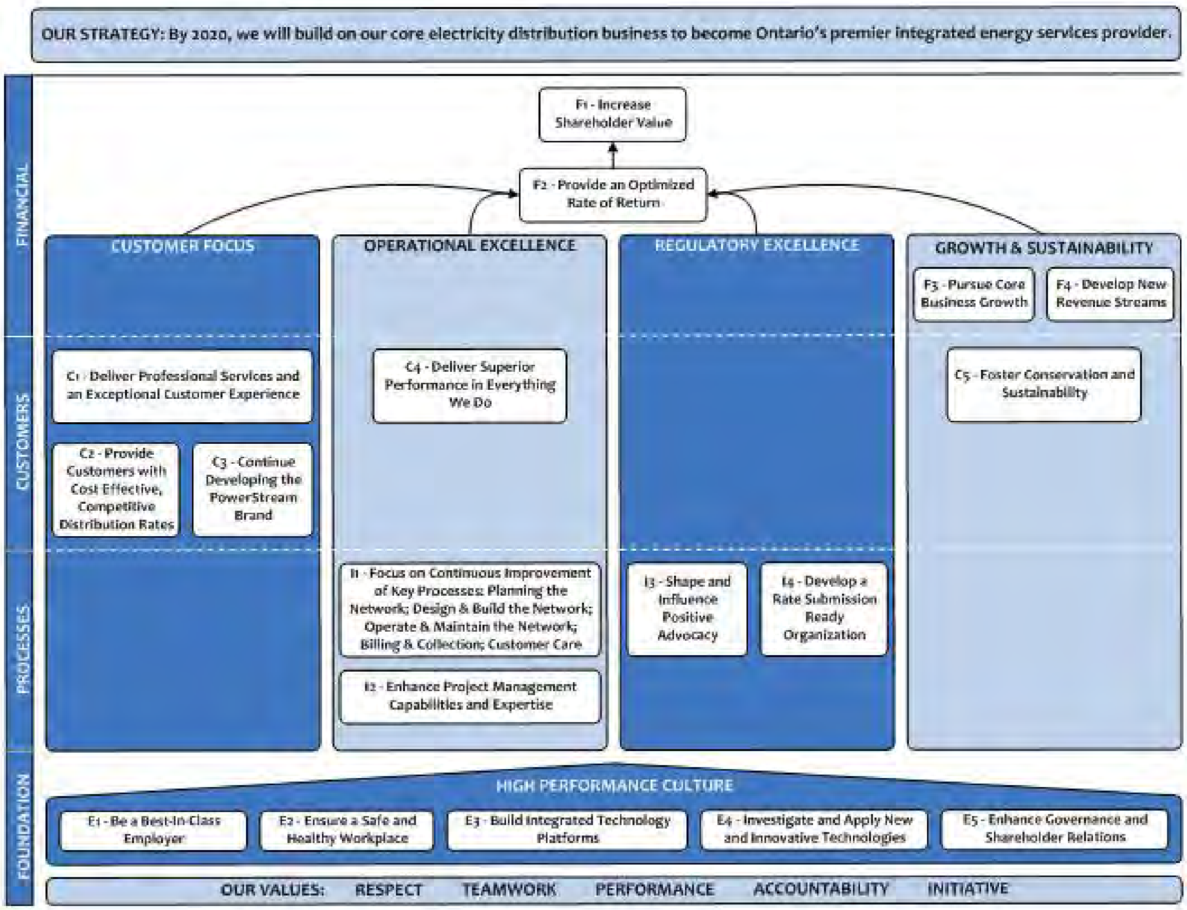


Figure1: PowerStream Corporate Strategic Objectives

The capital expenditure plan provided in this DS Plan is the product of PowerStream's Asset Management Planning and Budget Process. This is documented in Exhibit G, Tab 2, Section 5.3.1, and includes the following key elements:

a) Contributing Influences - includes corporate strategic initiatives, customers, efficiencies and policies & procedures and their impact on the process;

b) Asset Knowledge – Identifies, records and manages the condition of both distribution system and general plant assets, performs asset condition assessments, reviews asset capacity and constraints as well as the inspection and maintenance practices;

c) Asset Strategy and Planning – applies asset planning criteria, reviews capacity requirements, construction and materials standards, reliability performance, worst performing feeders and interdepartmental committees; and

d) Asset Management and Decision Making – includes the process for optimization, business cases and ongoing management of the capital portfolio.

The process for gathering data, analysing data, and forming strategic actions, acquiring customer feedback and seeking efficiencies are all key elements of the plan.

Source of Cost Savings due to the Plan

The cost savings associated with this DS Plan can be referenced in Exhibit F, Tab 1.

Period Covered by this DS Plan

This DS Plan covers 2010 to 2014 for historical years, the 2015 Bridge Year, and the years 2016 to 2020.

Data Used for Investment Drivers

All asset information used for the Asset Condition Assessment was as of December 31, 2014. Reliability metrics and analysis presented in this DS Plan include all outage information to December 31, 2014.

Changes to the Plan since the last DS Plan

PowerStream has not previously filed a DS Plan. Since the last cost of service submission, PowerStream has filed an Incremental Capital Module (ICM).

Contingent Events included in this DS Plan

The execution of distribution system capital investment programs often involves co-ordination with, and dependency on, external organizations. PowerStream's co-ordination with third parties has identified a number of projects where either the scope, timing or need for the project has external dependencies. These projects include:

- Municipal Road Relocation / Upgrade Projects – System Access investments required to facilitate road relocation projects may be dependent upon the eleven municipalities served by PowerStream;

- Regional Road Relocation / Upgrade Projects – System Access investments required to facilitate road relocation projects may be dependent upon the Region and County served by PowerStream;

- Ministry of Transportation Road Relocation Projects - System Access investments required to facilitate road relocation projects may be dependent upon the provincial agency;

- Regional Planning Projects - PowerStream is actively participating in four Regional Infrastructure Planning Processes ("RIP") with Hydro One. One RIP is in the early stages of development and projects identified to date have not required PowerStream to plan any capital investments. PowerStream continues to participate and support both the IRRP the RIP processes and will make the required investments into projects arising from the plans as identified; and

- Customer Connections – System Access investments in the expansion of PowerStream's distribution system may be required. The timing of these investments is dependent on the location and service requirements of new customers.

Third Party Reviews

PowerStream has prepared the DS Plan without the direct use of external consultants as authors. PowerStream has, however, engaged third parties for their expertise in several key areas of the business that are included in the plan. These are noted in Table 1.

Category	Consultant	Section Reference	Driver
Asset Condition Assessment	Kinectrics	5.3.3	Initial report and base models
Storm Hardening	CIMA	5.2.3	review weather patterns & other utilty experence, review Powerstream practices and make recommendations.
Asset Management	UMS	5.3.3	review current practices against PASS 55
Customer Engagement	Innovative Solutions	5.4.2	fulfill requirements of Chapter 5 filing
Optimization & Prioritization	Copperleaf	5.3.3	develop benefit and risk mitigation value questions
Cyber Security	White Hat	5.4.5	perform cyber security audit and make recommendations
DS Plan	Paul Vlahos	all	review document and provide commentary

Table 1: External Consultants and the DS Plan

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.

Overview

On October 18, 2012, the Ontario Energy Board (the "Board") issued its *Report of the Board – A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach* (the "RRFE Board Report"). The RRFE Board Report concluded a consultation process aimed at promoting the cost-effective development of electricity infrastructure through coordinated planning on a regional basis between licensed distributors and transmitters.

The objective of the regional planning process is to develop long-term electricity plans that thoughtfully integrate all relevant resource options such as conservation and demand management, distributed generation, large-scale generation transmission and distribution or other energy solutions.

Planning Process

In 2013, the Regional Planning Process was formally introduced by the Board. This process outlined the requirements for LDCs, Transmitters and Provincial Entities with respect to integrated electricity planning. An overview of the requirements is shown in Figure 1.

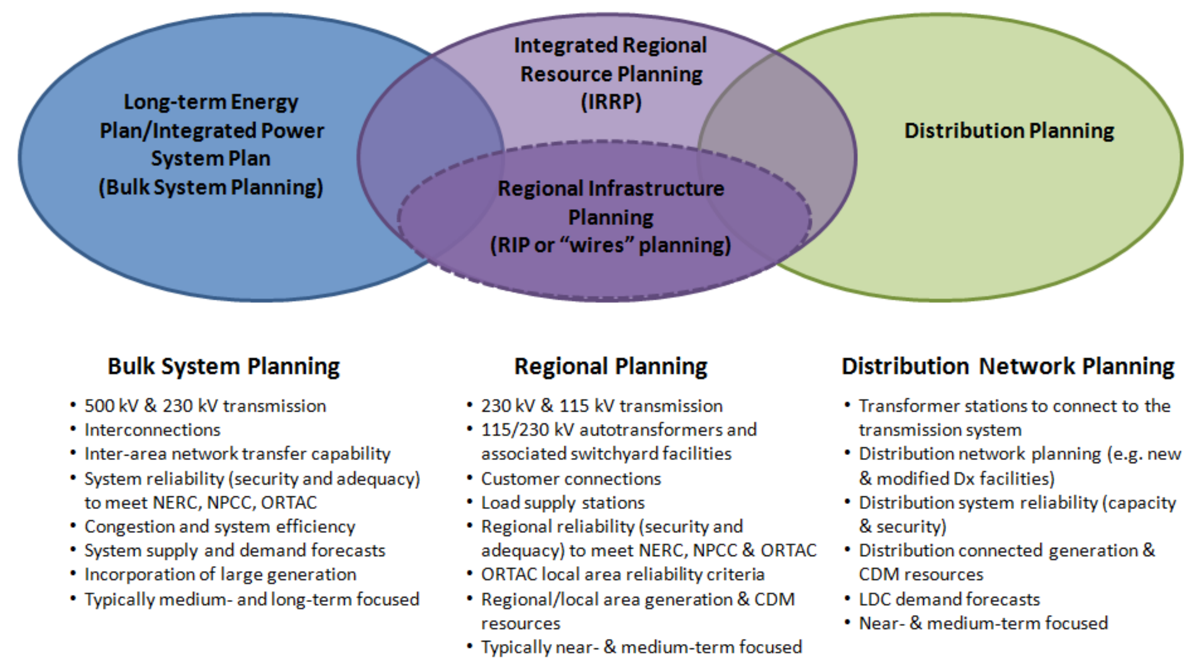


Figure 1: The Regional Planning Process

Under the Regional Planning requirements, transmitters are required to:

- Identify the need for regional planning for local areas;
- Lead the RIP process;
- Identify potential transmission solution(s); and
- Provide information required to facilitate the RIP and IRRP process

Under the Regional Planning requirements, Local Distribution Companies are required to:

- Provide information required to facilitate the RIP and IRRP process;
- Identify potential distribution solution (s) and provide input on investments that may have a direct impact on the distributors; and
- Incorporate regional planning considerations as part of their rate application submission.

The Ontario Power Authority developed a 24 month cycle, and it includes the preparation of required reports. Refer to Figure 2.

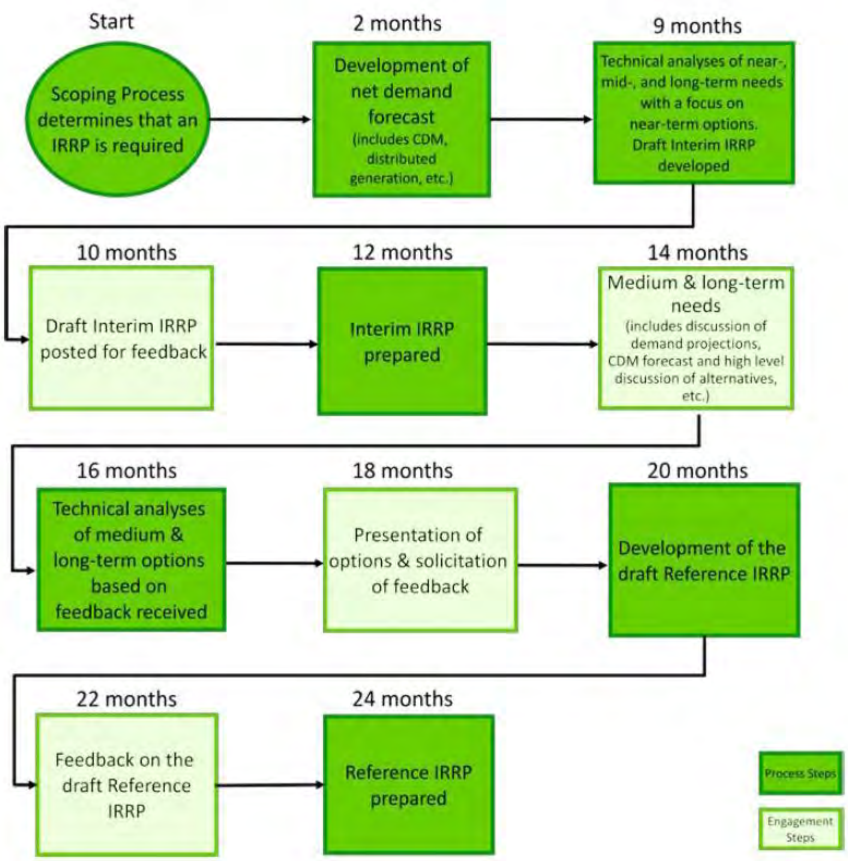


Figure 2: OPA Process

On May 13, 2013, the Planning Process Working Group (PPWG), a group of industry representatives convened by the Board, posted a **final** version of its *Report to the Board: The Process for Regional Infrastructure Planning in Ontario*. This report outlined the requirements for LDCs, Transmitters and Provincial Entities with respect to integrated electricity planning. The final PPWG report prescribes 21 regions within the Province. Within those 21 regions, PowerStream is included in four regions, namely:

- GTA North, part of Group 1 (underway in 2014) for 5 Hydro One owned stations and 9 PowerStream owned stations;
- Metro Toronto, part of Group 1 (underway in 2014) for 4 Hydro One owned stations;
- GTA North**,** Western Sub-Region, part of Group 1 for 2 Hydro One owned stations and 1 PowerStream owned station; and
- South Georgian, part of Group 2 (commences in 2015) for 5 Hydro One owned stations.

GTA North (part of Group 1)

PowerStream is part of the existing Regional Plan for York Region. In 2005, an integrated planning study for Northern York Region (NYR) considered transmission, distribution, generation, and CDM solutions, and was developed with input from local stakeholders. The plan identified several key activities. These activities and their current status are:

- Add capacitor banks at Armitage TS. *Completed*.
- Install emergency load transfer capability. *Completed*.
- Contract conservation resources 20 MW of DR, in addition to provincial conservation efforts. *Completed*.
- Construct new Holland TS. *Completed*. (in-service June 2009; 230 kV switching to be provided)
- Procure gas-fired generation. *This was placed in-service spring 2012.*
- Build a third transformer station (Aurora TS) - *not needed yet, therefore not implemented*

The 2005 study concluded that completion of these activities (with exceptions noted) would provide a reliable and adequate supply to Northern York Region.

Since the 2005 plan was adopted, the following system developments have occurred in York Region:

- The launch of the Feed-in-Tariff (FIT) program, and expression of significant interest in development of renewable energy generation in York Region and surrounding areas through FIT applications;
- Continued load growth in Northern York Region (albeit at a slower pace than initially forecasted due to economic changes);
- Load growth in Southern York Region has caused the 230 kV circuits along the Parkway Belt to reach their limit to supply new transformation facilities without transmission reinforcement;
- Forecast load growth throughout York Region is expected to outstrip transformation supply in the medium term; and
- In November 2010, PowerStream indicated to the OPA the need for additional capacity in the PowerStream south supply area (Vaughan, Richmond Hill and Markham) and in the Aurora area.

These developments called for a new regional plan to be developed that would incorporate recent system developments and system assumptions, update demand forecasts to reflect current economic conditions, and include current planning criteria.

In the fall of 2010, PowerStream requested that the OPA initiate a regional planning study for York Region. In early 2011, a working group was established to assess the reliability of supply in York Region over a 20-year period. The engagement partners for the 2011 study included PowerStream, Newmarket-Tay Power, the Ontario Power Authority, Hydro One and the IESO.

The study had the following objectives:

- Identify needs in the near term (0-5 years), medium term (5-10 years) and long term (10-20 years);
- Identify actions to address near- and medium-term needs;
- Provide direction for the long term; and

- Prepare an integrated planning study, considering CDM, local generation, transmission and distribution as potential solutions.

The working group methodology provided the initial framework for exploring the new regional planning process proposed by the OPA and adopted by the Regulator, the basis for fostering two-way communication with stakeholders about local growth and electricity needs, developing various alternatives for meeting regional needs and their associated benefits/trade-offs, gaining better understanding of local conditions and opportunities and how to refine evaluation criteria to reflect local priorities.

In November of 2012, the *York Region Study, Summary of Needs and Options* was completed, outlining near term needs (next 3 years), medium term needs (4-7 years) and long term needs 8-18 years). Refer to Figure 3.

	Near Term	Medium	Long Term
Northern York Region	Reduce Impact of Potential Supply Interruptions		Supply Capacity to New TS
Vaughan/Richmond Hill Area	Reduce Impact of Potential Supply Interruptions	Supply Capacity to New TS (Vaughan #4)	Supply Capacity to New TS (Vaughan #5)
Markham/ Buttonville Area		Reduce Impact of Potential Supply Interruptions	Supply Capacity to New TS (Markham#5)

Figure 3: High Level Study Results

On December 14, 2012, the OPA provided PowerStream with a letter to support the Working Group's choice of the option to connect PowerStream's next transformer station in Vaughan to the Claireville to Minden line.

For the medium term, the Ontario Power Authority, on December 14, 2012, issued a letter to support the connection of Vaughan #4 MTS to the Claireville-Minden line in 2017, and on June 14, 2013, issued a directive to the affected parties, providing instructions to Hydro One to initiate a Regional Infrastructure Planning (RIP) Process to develop and implement the near-term transmission component of the integrated plan to meet the near and medium-term reliability needs of York Region. The directive also handed off, from the OPA, the lead responsibility for the planning process associated with the near-term transmission component of the York Region Integrated Regional Resource Planning (IRRP) process to Hydro One to initiate the RIP process. Specifically, the projects identified were:

- The installation of switches/breakers at Holland TS (existing H1 property);
- The installation of switching station(s) on the Parkway Belt (Hwy 407 corridor).

A copy of these OPA letters are included in Appendix B. These upgrades maximize the use of the existing system, and provide for adequate supply until the early 2020's. In the long term (in the early 2020's), three additional stations will likely be needed to supply load growth in northern York Region, Markham and Vaughan, as the system is reaching its capacity. In addition, new infrastructure is required to supply these stations. Potential sources are from Parkway, Claireville/Kleinburg, local generation, conservation and demand management/response, storage or other initiatives.

In October 2013, the Technical Working group and the Communications Working group commenced, establishing a timeline for stakeholder engagement. In November of 2013, the near term projects (Holland TS and Vaughan TS#4) commenced their requisite communications and approval protocols.

In September of 2014, the Working Group met with the Directors of Planning for the municipalities in York Region to provide greater clarity on local planning initiatives. In December of 2014, the Working Group met with the CAOs for the municipalities in York Region to provide a similar presentation. The links between the various local planning activities is detailed in Figure 4.

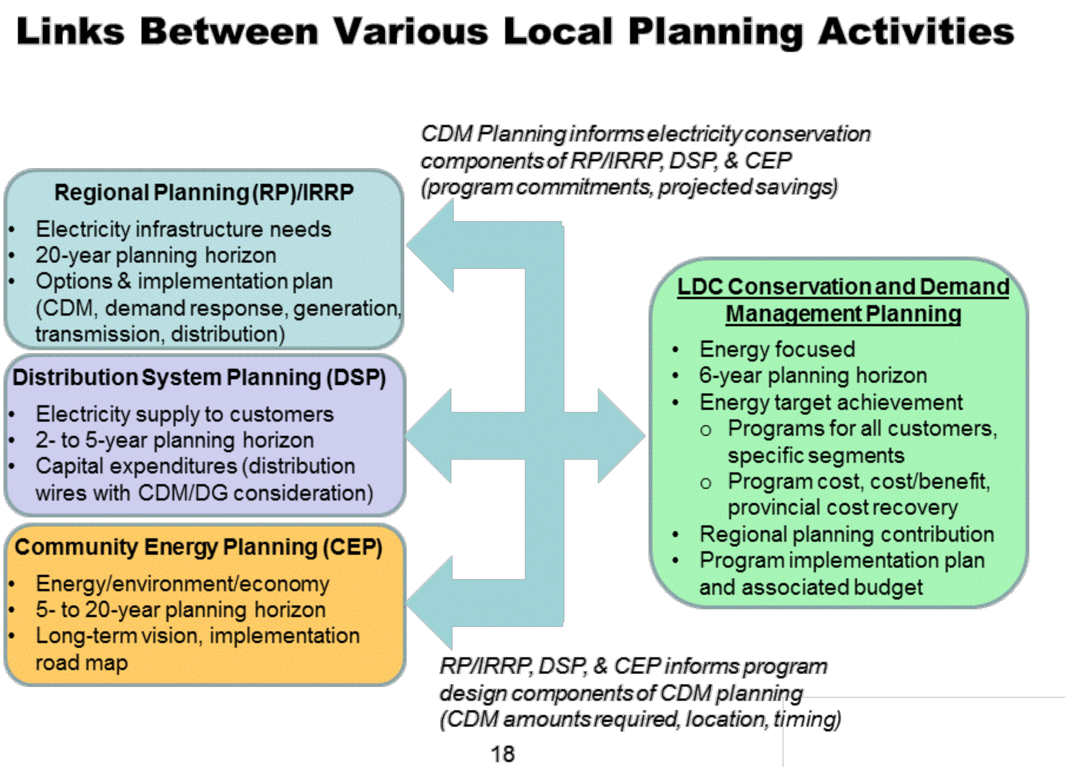


Figure 4: Local Planning Activities

The outcomes of the refreshed York Region regional plan has resulted in capital expenditure requirements by PowerStream for the construction of a new transformer station (VTS#4) and its associated feeder integration within this DS Plan timeframe, specifically in spending between 2015 and 2017 for the station and 2016 to 2019 for feeder integration. At the time of this writing, it is assumed that any costs associated with the two Hydro One projects (Parkway Belt Switches and Holland TS Switches) are to be pool funded.

The planning process for the integrated regional resource plan is moving to the next phase, involving community engagement on long-term needs and alternatives.

Metro Toronto (part of Group 1)

For this zone, regional planning from PowerStream's perspective primarily focuses on interactions with Hydro One, as PowerStream has feeders that are supplied from Hydro One owned transformer stations. Of the four Hydro One owned transformer stations, one is exclusive for PowerStream (Buttonville TS), while the other three are shared between Hydro One and Toronto Hydro.

A summary of activities is as follows:

- PowerStream has participated in the Regional Infrastructure Planning Needs Screening (NS) Process for the Metro Toronto Northern Sub-Region, and has supplied all requisite load forecasting information.
- The facilities in this sub-region which supply PowerStream include Hydro One transformer stations connected to the Richview TS to Cherrywood TS 230 kV transmission circuits.
- The study period for this Needs Screening is 2014 through 2023.
- The study phase of the NS process was initiated on April 14, 2014 and the report completed on June 11, 2014.
- Study results relevant to PowerStream are as follows:
    - The loading on the 27.6 kV windings of Leslie TS T1/T2 is forecast to reach normal supply capacity within the first five years of the study period when based on the gross demand forecast;
    - When net demand forecast is considered, the normal supply capacity of this facility is not expected to be exceeded during the 10-year study period;
    - At this time, no action is required for Leslie TS and the capacity needs for this facility will be reviewed in the next planning cycle;
    - No significant reliability and operating issues were identified for this sub-region, however, under certain contingency conditions, certain Ontario Resource and Transmission Assessment Criteria (ORTAC) restoration criteria may not be met; and
    - Further assessment regarding restoration capability and requirements is required by the transmitter.

- Study recommendations are as follows:
    - At this time, the potential needs identified in this NS study do not require further regional coordination and can be adequately and more efficiently addressed by Hydro One and the relevant Local Distribution Companies.

<u>GTA North, Western Sub-Region (part of Group 1)</u>

For this zone, regional planning from PowerStream's perspective primarily focuses on interactions with Hydro One, as PowerStream has feeders that are supplied from Hydro One owned transformer stations, which are shared with Brampton and Enersource. A summary of activities is as follows:

- PowerStream has participated in the Regional Infrastructure Planning Needs Screening (NS) Process for the GTA North, Western Sub-Region which includes the Claireville TS to Kleinburg TS 230 kV transmission circuits and the three connected transformer stations in York Region, namely Vaughan MTS#3, Kleinburg TS and Woodbridge TS. PowerStream has supplied all requisite load forecasting information;
- The study phase of the NS process was initiated on April 28, 2014 and the report was completed on June 27, 2014;
- The study period for this NS is 2014 through 2023;
- Study results relevant to PowerStream are as follows:
    - Transformer stations in this sub-region have sufficient capacity to accommodate forecast loading requirements during the study period;
    - Peak load at Vaughan MTS#3 is at its normal supply capacity;
    - Vaughan MTS#4, which is planned for in service in 2017, will provide capacity relief for Vaughan MTS#3;
    - The other two transformer stations supplied from these circuits, namely Woodbridge TS and Kleinburg TS, have sufficient capacity to meet the forecasted demand during the study period;
    - No major equipment in this sub-region is expected to reach the end of its useful life during the study period; and

  - No significant reliability and operating issues were identified for this sub-region, however, under certain contingency conditions, certain Ontario Resource and Transmission Assessment Criteria (ORTAC) restoration criteria may not be met.

- Study recommendations are as follows:
  - The Ontario Power Authority (OPA) will include the affected LDCs in the Integrated Regional Resource Plan (IRRP) process for the GTA West, Northern Sub-Region with respect to load restoration needs in this sub-region;
  - The sub-region's needs will be revisited in the next planning cycle which is expected to be within the next five years.

South Georgian Region (part of Group 2)

The planning studies for this region will commence in 2015, and includes Hydro One Distribution, Innisfil Hydro, Orangeville Hydro, Veridian, and Newmarket-Tay Hydro

Municipal Energy Plans

Although the Chapter 5 requirements do not explicitly require commentary on Municipal Energy Plans, PowerStream is actively involved in these within its southern service territory.

In July of 2013, the provincial government announced its continuing support for local energy planning and conservation through the Municipal Energy Plan (MEP). The MEP program supports municipalities' efforts to better understand their local energy needs, identify opportunities for energy efficiency and clean energy, and develop plans to meet their goals.

MEPs will help municipalities assess their community's energy use and greenhouse gas (GHG) emissions; identify opportunities to conserve, improve energy efficiency and reduce GHG emissions; consider the impact of future growth, and options for local clean energy generation; and support local economic development.

Successful municipalities from the first round of applications within PowerStream's service territory are the City of Markham and the City of Vaughan.

In November, 2013, PowerStream provided a letter confirming PowerStream Inc.'s participation in the stakeholder engagement consultations, as well as providing electricity consumption data, towards the development of Vaughan`s Municipal Energy Plan (MEP), and that PowerStream will also participate in the stakeholder engagement process.

In January of 2014, PowerStream provided a letter confirming PowerStream Inc.'s participation in the stakeholder engagement consultations, as well as providing electricity consumption data, towards the development of Markham`s MEP, and that PowerStream will also participate in the stakeholder engagement process.

In August of 2014, after both Municipalities received the requisite funding, both Municipalities convened their own Municipal Energy Plan Stakeholder Working Groups with PowerStream as a stakeholder.

<u>Markham MEP</u>

There are three phases in the two year development of the Markham's Municipal Energy Plan.

These phases include:

- Phase 1: Stakeholder Engagement (August 2014 – January 2015);
- Phase 2: Energy Mapping & Study (February 2015 – July 2015); and
- Phase 3: Energy Plan Development (August 2015 – August 2016).

Markham's Municipal Energy Plan will meet the following objectives upon completion:

- Identify energy and water efficiency and local energy generation and water reuse opportunities throughout Markham in order to achieve net zero energy, water, waste and emissions by 2050;
- Recommend actions, strategies and short to medium term targets and long term milestones to achieve net zero by 2050;
- Set out monitoring and reporting processes and frequency in order to guide implementation;

- Integrate Communication & Engagement and Implementation Plans in the MEP to meet the recommendations set forth;
- Implement a MEP framework for Secondary Plans to meet the requirements for the community energy plan component;
- Guide other Markham strategies, plans, policies and actions by the City to increase energy efficiency, resilience and overall sustainability, including active transportation;
- Seek 2016 and future capital project funding and/or partnerships to kick start implementation; and
- Continue engagement with stakeholders to steward MEP implementation.

The MEP will be a living document to be updated on a regular basis to reflect the outcomes of the monitoring and reporting process, as well as incorporating updates.

PowerStream will continue to support the electricity component of the MEP.

<u>Vaughan MEP</u>

Vaughan's goals are detailed in Figure 5.

<u>Figure 5: Vaughan Municipal energy Plan Goals</u>

Vaughan's Municipal Energy Plan will meet the following objectives upon completion:

- Identify key geographic areas for action, type of action, allocation of resources;
- Empowering the right people and creating policies that work;
- More clarity and public education;
- Good coordination with other local policy and planning objectives;
- Have a "menu" with options due to "one size does not fit all" challenge;
- Mix of uses, options, broader objectives;
- Based on user base – residential, commercial, mixed use;
- Consider new developments vs. existing areas that are experience intensification; and
- Have flexibility for both situations.

PowerStream will continue to support the electricity component of the MEP.

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.

a) 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.*

b) 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.[15]

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.

c) 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.

Performance Methodology and Metrics

This section of the filing requirements requests that distributors identify and define the methods and measures that will be used 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.

PowerStream has developed a set of measures to monitor quality and drive continuous improvement in its distribution system planning and implementation work over the 2015-2020 planning horizon. The measures cover several distinct dimensions of PowerStream's capital planning and implementation processes and/or address directly the outcomes of such processes, motivated by customer needs, regulatory compliance obligations, or efficiency objectives. Figure 1 outlines the DS Plan ongoing performance metrics.

1	**System Average Interruption Duration Index (SAIDI)**	$SAIDI = \frac{\sum \text{Customer Minutes of Interruption}}{\text{Total Number of Customers Served}}$
2	**System Average Interruption Frequency Index (SAIFI)**	$SAIFI = \frac{\sum \text{Total Number of Customers Interrupted}}{\text{Total Number of Customers Served}}$
3	**Customer Average Interruption Duration Index (CAIDI)**	$CAIDI = \frac{\sum \text{Customer Minutes of Interruption}}{\text{Total Number of Customers Interrupted}}$
4	**Momentary Average Interruption Frequency Index (MAIFI)**	$MAIFI = \frac{\sum \text{Total Number of Customer Momentary Interruptions}}{\text{Total Number of Customers Served}}$
5	**DS Plan Spending Progress Report**	$\frac{\$\text{ spent in a year}}{\text{budget in a year}}$ plus $\frac{\$\text{ spent cumulative over n years (n=1 to 5)}}{\$\text{ cumulative budget over n years (n=1 to 5)}}$
6	**Work Order Closing Variances**	percentage of WOs that close within prescribed policy limits
7	**Cable Failure Rates**	comparison pre-remediation vs post remediation for cable projects

Figure 1: Performance Metrics

Reliability Indices: SAIDI, SAIFI, CAIDI, MAIFI

SAIDI – System Average Interruption Duration Index

SAIDI is an indicator of system reliability that expresses the average length of sustained interruptions that each customer experiences in a year. All planned and unplanned sustained interruptions are used to calculate this index. Loss of supply and major event days are excluded.

SAIFI – System Average Interruption Frequency Index

SAIFI is an indicator of system reliability that expresses the average number of sustained interruptions that each customer experiences in a year. All planned and unplanned sustained interruptions are used to calculate this index. Loss of supply and major event days are excluded.

CAIDI – Customer Average Interruption Duration Index

CAIDI is an indicator of the speed at which power is restored. All planned and unplanned sustained interruptions are used to calculate this index. Loss of supply and major event days are excluded.

MAIFI – Momentary Average Interruption Frequency Index

MAIFI is an indicator of system reliability that expresses the average number of momentary interruptions that each customer experiences in a year. All unplanned momentary interruptions are used to calculate this index. Loss of supply and major event days are excluded.

PowerStream will continue to conform with the expectations reliability performance (SAIDI, SAIFI, CAIDI) by remaining, as a minimum, within the range of its historical previous 3 year average performance.

Refer to Figure 1 to Figure 6 on pages 13 and 14 for historical information.

DS Plan Spending Progress Report

PowerStream will be monitoring its execution of the projects and programs included in the DS Plan.

On an annual basis, PowerStream's will calculate for that year, and on a cumulative basis for the five years of the DS Plan, its actual capital spending compared to the approved capital budget.

As this is the first DS Plan filing, there are no historical statistics.

Work Order Closing Variances

PowerStream will be monitoring its execution of the projects and programs included in the DS Plan. Variances, which are defined as a comparison of the actual dollars spent compared to the approved budget estimate, are reviewed are categorized within prescribed limits.

On an annual basis, PowerStream's will calculate for that year, how successful the variances on individual work orders were. PowerStream will review the variance reports and determine if incremental improvements have transpired, and based on the results, take corrective actions as are deemed necessary.

Figure 2 details the overall percentage of work orders for 2014 that were closed where the variances were within the prescribed limits.

Work Order Review	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2014
# of Reviews Issued Requiring Management Approval													
Capital	0	53	19	0	20	8	10	11	12	6	20	8	167
ICI	0	3	3	0	6	3	9	7	11	5	9	2	58
Subdivision	0	2	3	0	5	2	4	4	3	2	5	2	32
Non Paper Trail	2	12	33	0	0	5	1	0	0	6	1	1	61
TOTAL	2	70	58	0	31	18	24	22	26	19	35	13	318
# of Reviews Not Requiring Management Approval													
Capital	5	18	12	0	2	25	16	6	3	1	5	3	96
ICI	8	6	3	0	10	10	9	5	3	7	10	4	75
Subdivision	4	2	0	0	0	1	5	2	0	2	3	3	22
Non Paper Trail	0	15	20	0	0	2	1	1	0	2	1	0	42
TOTAL	17	41	35	0	12	38	31	14	6	12	19	10	235
Percent of Work Orders Completed Within Variance (Not Requiring Management Approval)													
%	89	37	38	0	28	68	56	39	19	39	35	43	42

Figure 2: 2014 Work Order Closing Results

Cable Failure Rates

PowerStream's system renewal, as detailed in Exhibit G, Tab 2, Section 5.3.3 page 7, contains several programs. Cable remediation is the only program where failure rate analysis can be readily measured.

As an area is remediated (large areas will be done in phases) and upon the completion of a rehabilitated underground area, PowerStream will review the failure rates within that area and compare the previous 5 years to the five years following project completion to assess the reduction in failures. These figures will be available at the conclusion of each year within the DS Plan horizon.

For the areas that were completed under the cable remediation program over the past three years (2012-2014), there were 86 cable and splice failures in the areas that were slated for injection. Post injection, there have been only 2 failures in those areas, demonstrating excellent results.

For the 2015 cable remediation program, over the past three years (2012-2014), the areas have experienced the following cable and splice failures.

- Cable injection areas (6 areas, 55 failures)
- Cable Replacement (7 areas, 58 failures)

These statistics will be updated annually, by area, to demonstrate improvements.

Corporate Continuous Improvement

PowerStream has a strong culture of continuous improvement in many areas. The incorporation of continuous improvements is a constant thread through all work performed within the Utility. Some customer and asset related initiatives are noted below.

<u>Journey to Excellence</u>

One of the strongest corporate commitments to this culture is PowerStream's Journey to Excellence (J2E), based on Excellence Canada's Progressive Excellence Program (PEP). One of the six driving forces behind the journey is customer experience, where the "voice of the customer" and customer satisfaction are a pillar to PowerStream's continued success.

J2E encourages continuous improvement through excellence, innovation and wellness in each of its drivers. Continuous improvement across the organization will position PowerStream as a leader in the energy sector; one that is customer-centric, innovative, results oriented, focused and accountable. With a focus on excellence, innovation and wellness, PowerStream customers will be continuously engaged to ensure they receive the energy services and solutions best tailored for their unique requirements.

<u>Customer Experience Plan</u>

A strong customer experience focus has led to many initiatives such as the creation of a Customer Experience Plan. The plan is a 2014/2015 corporate initiative that impacts staff across the organization. The Customer Experience Plan identifies short and long term steps the organization will take to continue to deliver excellent, reliable customer experiences.

Workforce Management

In 2013, PowerStream staff undertook a collective review of the systems in use for Asset Management/Asset Analytics/Work Force Management/Mobile. PowerStream concluded that its approach for managing the diverse and growing mobile workforce was no longer adequate. PowerStream determined that it would invest in a modern, mobile workforce management solution to address current business challenges. An automated solution with rationalized business processes will result in better coordination and scheduling of work leading to increased customer satisfaction.

The drivers to acquire a new Workforce Management solution include:

a) Inadequate current tools: the current tools and processes for dispatching and reporting on work were inherited from multiple predecessor utilities. These tools are no longer sufficient to manage the volume and complexity of projects. Existing processes are cumbersome and require a great deal of manual intervention;
b) Customer expectations: customers are looking for PowerStream to continually achieve efficiencies in the execution of their work and to enhance the delivery of customer service;
c) Regulatory environment: there is an increased requirement for visibility into the life cycle of projects to ensure that project execution and spend levels are in line with approved budgets; and
d) Technology: the ability to leverage advances in technology for mobile solutions to deliver field staff real-time work package information, reporting capabilities, and optimal resource schedules.

C55 Software

In 2013, PowerStream staff undertook a collective review of the systems in use for Asset Management/Asset Analytics/Work Force Management/Mobile. Through an RFP process, Copperleaf Technologies Inc. was the successful vendor for the Optimization portion of this initiative. From January to September, 2014, the Optimization tool within C55 was implemented and used for the first ever multi-year optimization.

PS-RFP-13-30 included both Phase 2 and Phase 3 of the Asset Management System. Phase 2 is a replacement of the current Capital Budget Management System (CBMS) and full Business Case input. Phase 3 is planned in 2016 and will tie the Investment Decision Tool to PowerStream's Asset Management Data so that the analytics solution can determine and communicate optimal asset program spending.

Phase 2, scheduled for 2015 implementation, will be designed for project leads to input, into one system (C55), all budget and project justifications. This will streamline the process for budget creation, business case writing and optimization.

All of these initiatives have an impact on the distribution system plan as they govern the approach PowerStream takes in developing projects and programs to deliver operational effectiveness, optimal value for capital spending and to provide value to customers while executing all works in a safe manner.

Asset Investment Planning Improvements

As outlined in Exhibit G, Tab 2, Section 5.3.1, PowerStream's Asset Management Planning Process is comprised of several components, of which several include a key element of continuous improvement.

Interdepartmental Committees

PowerStream has integrated several interdepartmental and cross functional committees to provide focus and direction on key technical issues. Of note, the *Asset Management Committee* was formed in 2013 and the *Asset Strategy Committee* was formed in 2014 to focus improvements on the quality and accuracy of distribution system assets, and to determine strategic decisions on asset deployment.

Other Committees contribute to continuous improvement through either through their post event review, or visioning. These include the:

- Reliability Committee;
- Outage Performance Committee;

- Smart Grid Committee; and
- Distribution Automation Committee.

<u>Reliability Performance</u>

On an annual basis, PowerStream reviews its reliability indices and looks at programs or projects that could be implemented to improve these metrics. An annual report is prepared, projects/programs presented and selected, and monitoring of progress is performed monthly. Refer to Exhibit G, Tab 2, Section 5.3.3, page 34 for additional information.

<u>Worst Performing Feeders</u>

PowerStream aggregates the outage records for all feeders in its entire service territory to establish annual reliability indices such as SAIFI, CAIDI and SAIDI. Even if most customers are satisfied with their current level of service, further reliability improvements can be achieved by identifying areas with exceptionally poor performance.

System Planning, on an annual basis in conjunction with System Control, identifies and issues the list of 20 Worst Performing Feeder with the intent to recommend future maintenance and capital work on the feeders.

This review is an analysis on the performance of feeders emanating from PowerStream owned transformer stations, Hydro One owned transformer stations and municipal substation feeders.

The study reviews and:

- States PowerStream's criteria for worst performing feeders (WPF);
- Identifies WPFs based feeder historical reliability data and the application of the WPF criteria;
- Analyzes root causes of outages on these feeders;
- Proposes action plans to improve reliability for each WPF; and
- Incorporates targeted reliability improvement plans into the capital budget as warranted.

2013 and 2014 Extreme Weather Events

On the weekend of December 21-22, 2013, a significant ice storm moved through Southern Ontario. Ice accumulation resulted in downed branches, trees and power lines, which resulted in over 500,000 customers losing power in Ontario. This included over 92,000 customers without power (at the peak of the event) in PowerStream's service territory, predominantly in Aurora, Markham, Richmond Hill and Vaughan.

The majority of customers were restored within 24 hours of the completion of the storm, with 85 per cent of customers restored within 48 hours, and the full restoration of PowerStream's service territory being realized on December 30, 2013. Most importantly, the restoration efforts were completed without a serious injury to PowerStream staff or the general public. This ice storm was by far the most severe outage event in PowerStream's 10-year history, based on the number and duration of customer outages.

To help offset the impact of these challenging events, PowerStream was able to leverage its Distribution Automation assets already existing and newly implemented in 2013. The Supervisory Control and Data Acquisition (SCADA) was used extensively to re-direct the flow of power through the distribution system which assisted in restoring power to many of the affected customers in a very short timeframe. Also proving itself to be a power restoration resource, was the Fault Detection, Isolation and (self) Restoration (FDIR) system. This system performs automatic sectionalizing of main line feeders should it detect a fault. The first successful automatic transfers took place in 2013 restoring power to large numbers following a fault event.

While there were many successes throughout the restoration, including the speed at which the priority sites were re-energized and the overall performance of PowerStream management and staff, there were also many lessons learned that were outlined in an internal report that were prioritized and acted upon.

The key findings and 37 action items in the internal report are intended to enhance PowerStream's emergency restoration and communication efforts, and focussed around the following areas:

- capital asset management;
- restoration management;
- communication strategy;
- emergency management philosophy;
- customer care; and
- technical issues.

One of the recommendations was to analyze and provide recommendations for improvements to PowerStream's distribution grid to make the system more resilient to these types of events. An RFP to acquire the services of an external consultant firm was issued and awarded with respect to "System Hardening". A report was prepared, and several recommendations were provided. These recommendations were reviewed internally by the Asset Strategy Committee, and the results and recommendations from the Committee were presented to Senior Leadership. A plan was developed to address system hardening, Refer to Exhibit G, Tab 2, Section 5.4.5, page 20 for details.

On June 17th 2014, twelve poles were damaged on Warden Ave in Markham during an intense thunderstorm. Environment Canada identified a micro-burst in the Markham area at the time with wind speeds approaching 130km/h.

The faulted section was isolated from the system and the pole line was rebuilt to the current PowerStream standards over a two day period. No critical injuries were reported to PowerStream.

This incident was covered in the system hardening plan. Refer to Exhibit G, Tab 2, Section 5.4.5, page 20 for details related to capital expenditures as a result of the review.

Methods and Measures used for Distribution System Planning Process Performance

There are several metrics that are calculated and applied to create projects and projects for improvement. These occur at regular intervals, or as a response to an event.

Health Index

The Health Index for distribution assets identifies the current level and future risk of equipment failure for the asset groups and corresponding level of risk in being able to provide a high level of service to customers.

The Health Index metric is also used to provide an indication of the level of investment required over a twenty year planning horizon per asset category allowing prioritization of investments within the various asset groups. This prioritization ensures that only the facilities needing rehabilitation are addressed, effectively continuously improving the capital spending value.

Large Outage Events

When a significant outage occurs (past a set customer minute interrupted threshold) the customer impact is analyzed by:

- geographic area;
- cause code;
- incidents of a similar nature;
- identifying if it is a worst performing feeder; and
- possible physical testing – as an example, a tan-delta cable test.

This information, when combined with the asset condition assessment information, is then used to develop potential projects for capital investments, which are then passed through the Asset Management Planning process.

Summary of Performance and Performance Trends

SAIDI, SAIFI and CAIDI are lagging indicators that measure performance after events to assess outcomes and occurrences. PowerStream’s interruption metrics for SAIDI, SAIFI, and CAIDI are detailed in Figure 3, Figure 4, and Figure 5 respectively. Performance for all interruptions and all interruptions excluding loss of supply are provided.

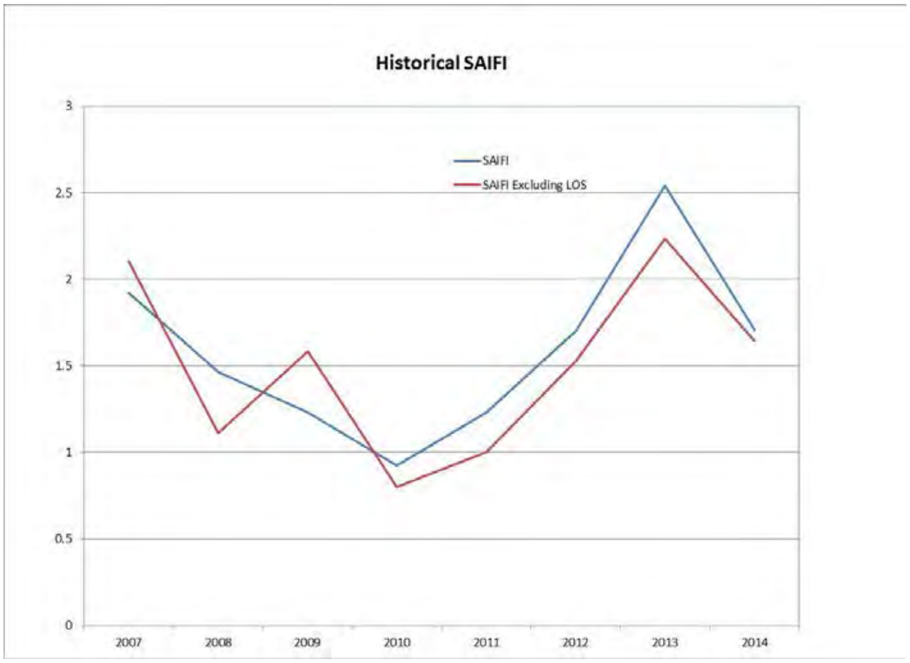


Figure 3: Historical SAIFI

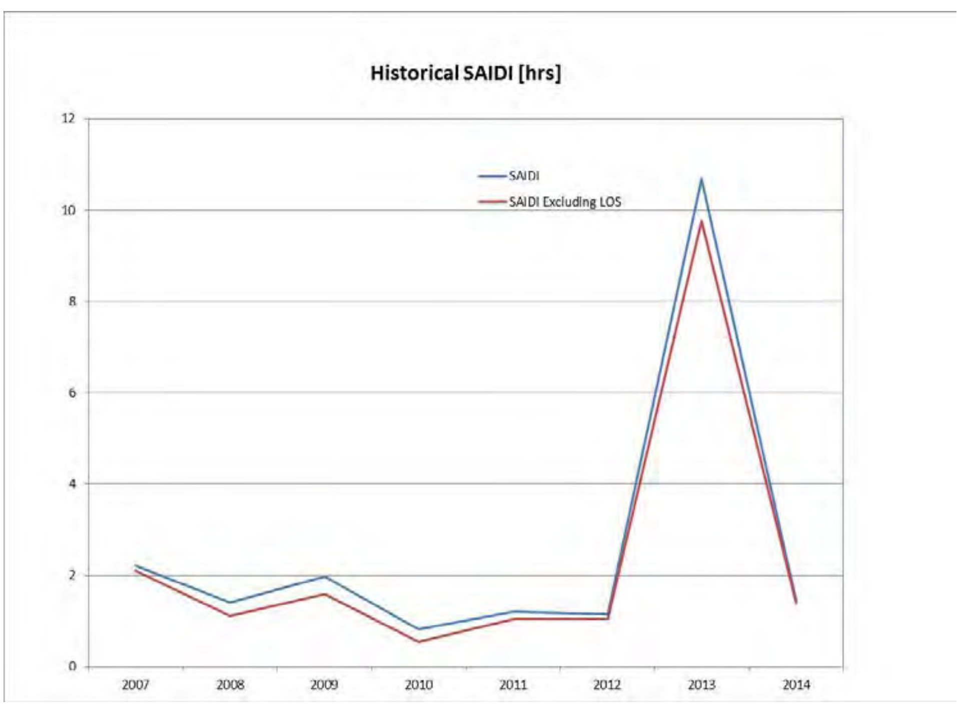


Figure 4: Historical SAIDI

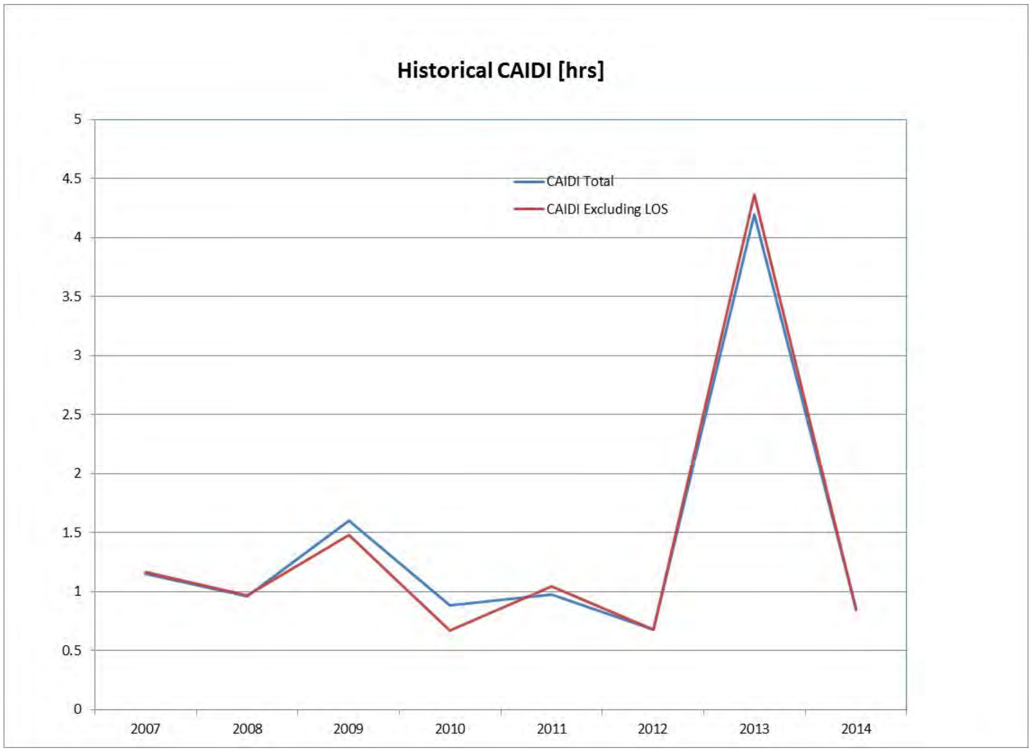


Figure 5: Historical CAIDI

PowerStream has compared itself to other CEA utilities, as is shown in Figures 6 to 8.

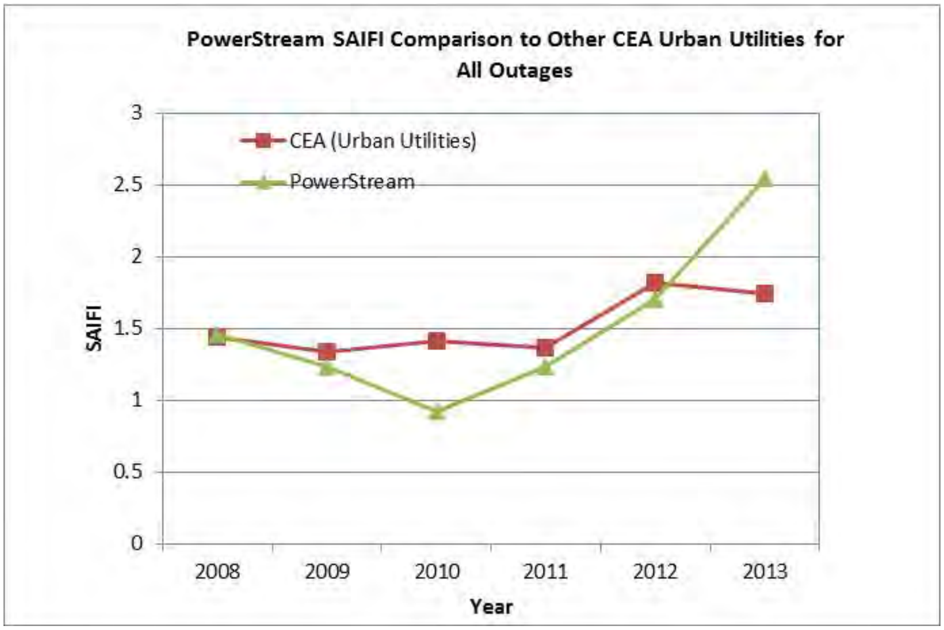


Figure 6: PowerStream compared to CEA Utilities; SAIFI

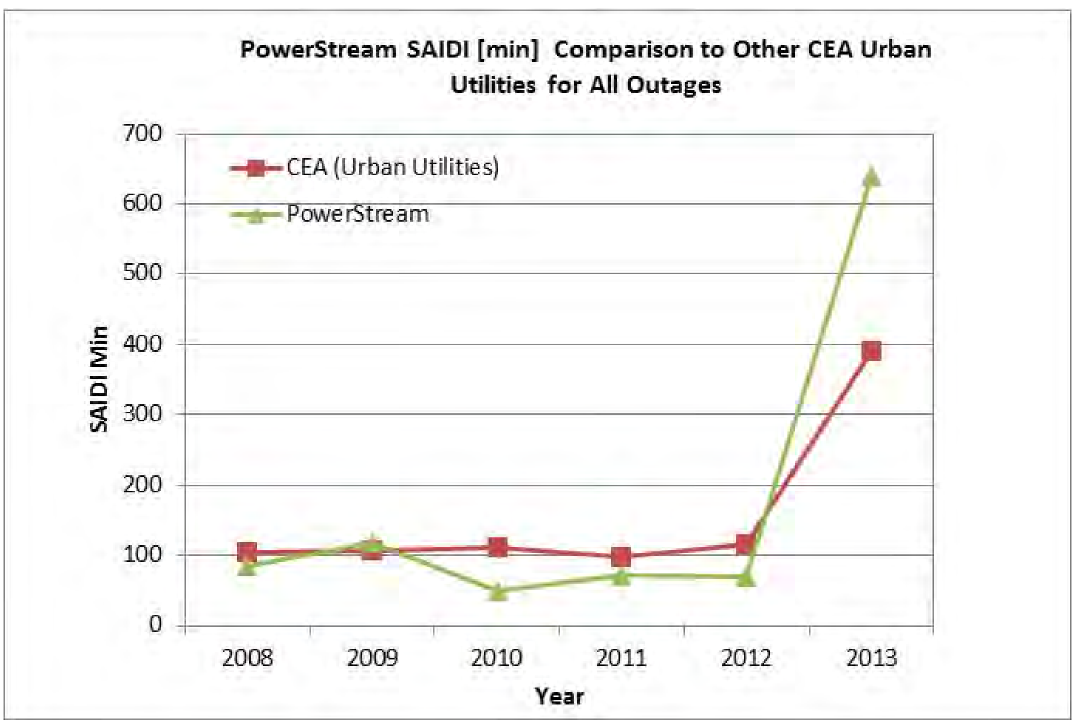


Figure 7: PowerStream compared to CEA Utilities; SAIDI

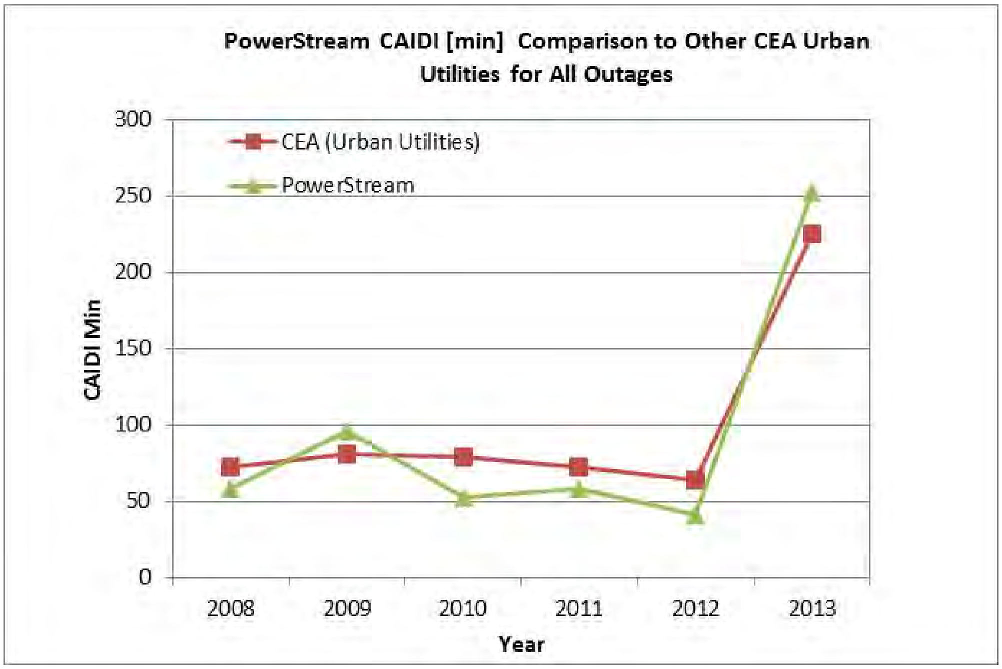


Figure 8: PowerStream compared to CEA Utilities; CAIDI

As seen in Figure 6 to Figure 8, PowerStream has been, with the exception of 2013, slightly better than the CEA average. The CEA numbers are all inclusive, in that it includes loss of supply and major events days. 2013 was a difficult year for weather related events for PowerStream, highlighted by the December ice storm.

Performance Focus

PowerStream categorizes outages in accordance with the cause codes designated by the Canadian Electricity Association (CEA). Within these codes, there are outages that can be considered “controllable” and others considered “uncontrollable”.

Although there is no accepted definitive classification within CEA, and there are events that could be debated as either controllable or uncontrollable, for practical purposes, PowerStream applies the distinction as shown in Table 1.

(CEA Code #) Controllable factors	(CEA Code #) Uncontrollable factors
(5) Defective Equipment	(9) Foreign Interference (3rd party event)
(1) Scheduled Outage (by P/S to do work)	(2) Loss of Supply (Hydro One)
(3) Tree Contact	(7) Adverse Environment *(Weather Dependent) ie salt*
(8) Human Element	(6) Adverse Weather *(Weather Dependent)*
	(4) Lightning *(Weather Dependent)*

Table 1: Controllable and Uncontrollable Outage Cause Codes

Figure 9 details the average duration of annual outages (over the past five years excluding loss of supply and major event days) to a single customer, both in total and its contributions of controllable and uncontrollable events. Figure 10 further breaks down the controllable SAIDI by cause code.

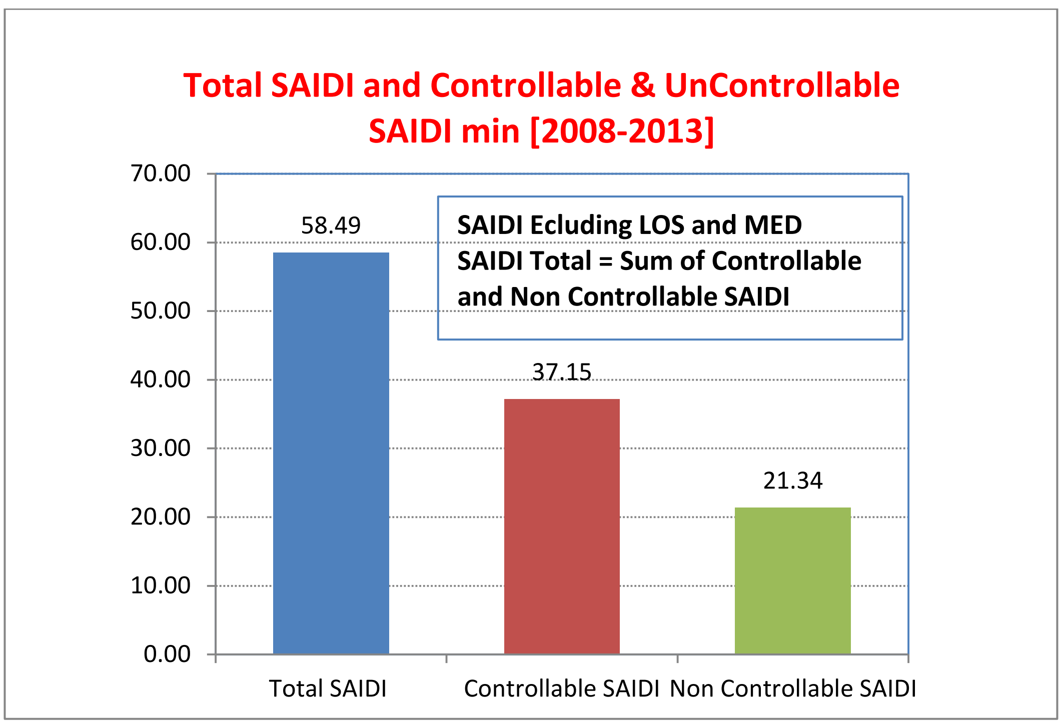


Figure 9: Total SAIDI and Controllable and Non Controllable SAIDI

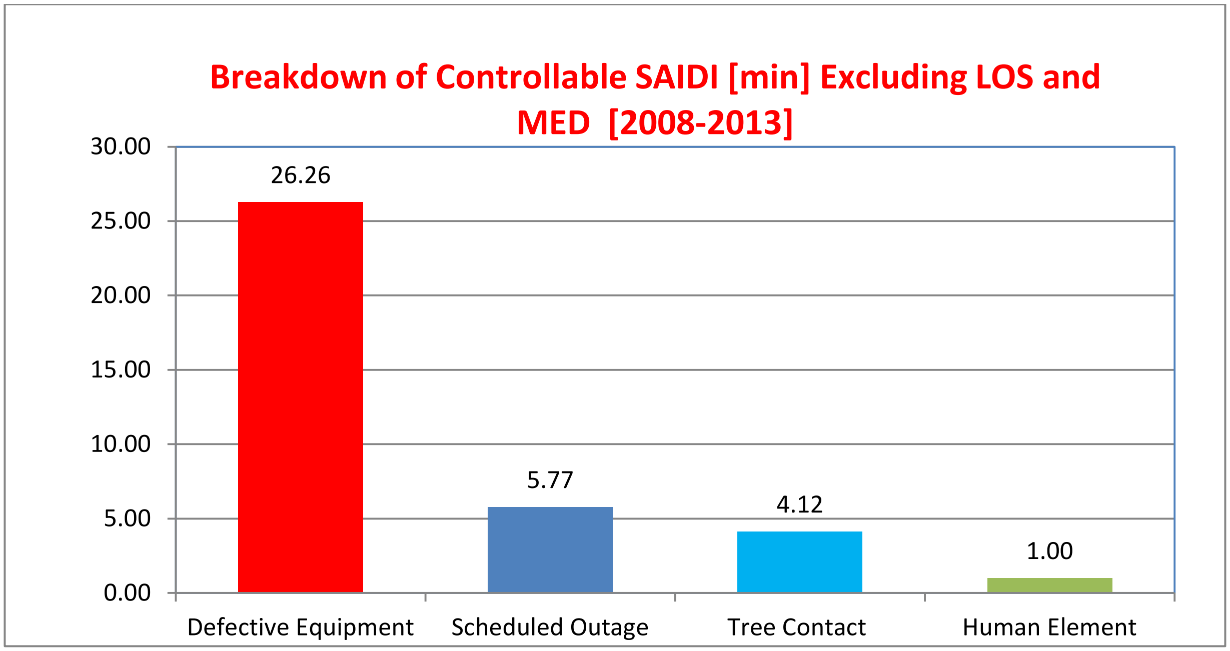


Figure 10: Controllable SAIDI Breakdown

PowerStream's approach is focused on the reduction of SAIDI due to controllable causes.

To further influence SAIDI and CAIDI, PowerStream's reliability work plan spans across many business units and includes continuous improvements and best practice implementation in the following areas:

- Asset Condition Assessment and Remediation;
- Design & Construction Practices;
- Inspection and Maintenance Programs;
- Distribution Automation and Smart Grid Technologies; and
- Outage Response & Outage Management.

Effects of Performance on the DS Plan

PowerStream has committed to maintain and achieve a modest improvement in system reliability over the next several years as part of its corporate strategy and its commitment to customers.

On an annual basis, PowerStream reviews its reliability indices and looks at programs or projects that could be implemented to improve these performance metrics. This reliability improvement initiative may result in projects/programs being proposed.

Further information can be found in Exhibit G, Tab 2, Section 5.3.3, page 34 - Impact of System Renewal on Reliability.

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. The information provided should include but need not be limited to:

a) 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;

b) 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*
- *asset condition assessment*
- *asset capacity utilization/constraint assessment*
- *historical period data on customer interruptions caused by equipment failure*
- *reliability-based 'worst performing feeder' information and analysis*
- *reliability risk/consequence of failure analyses.*

Use of a flowchart illustration accompanied by explanatory text is recommended

PowerStream's Asset Management Planning Process

The capital expenditure plan provided in this DS Plan, specifically Exhibit G, Tab 2, Sections 5.4.1, 5.4.2, 5.4.4 and 5.4.5, is the product of PowerStream's asset management planning process.

The asset management planning process, more fully documented in this Section, can be seen in Figure 1. It includes the following key elements:

a) Contributing Influences;
b) Asset Knowledge;
c) Asset Strategy and Planning;
d) Asset Management and Decision Making; and
e) Outputs: Programs and Projects.

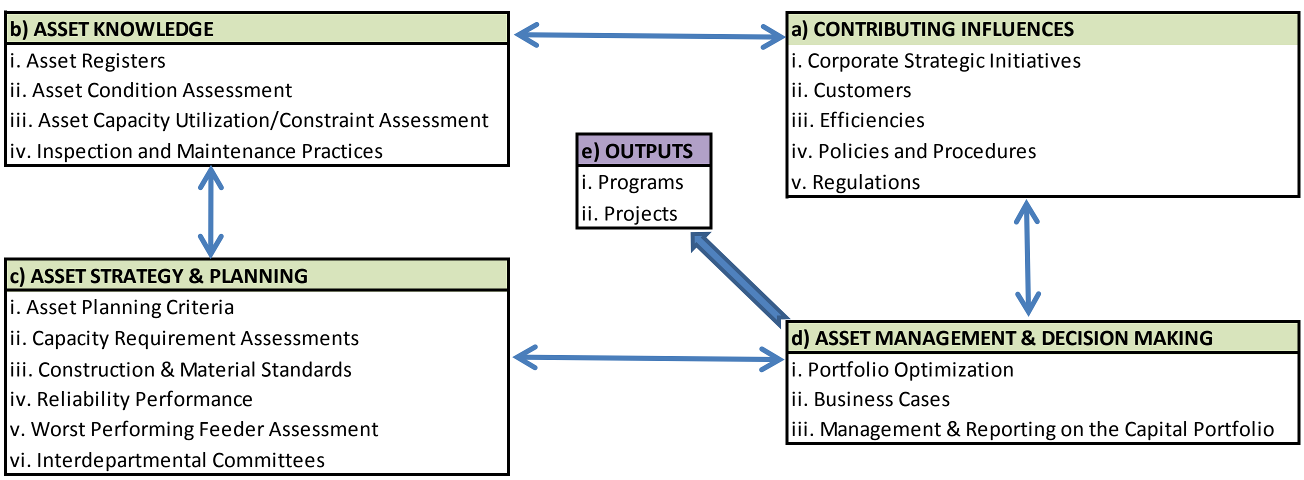


Figure 1: Asset Management Planning Process

This process, in its simplest form, asks the questions:

- How did the distribution system perform?
- What needs to be done?
- What options are available?
- Which options are best?
- What will get approved?
- How can we get the work done?
- How well did we do?

a) Contributing Influences

i. Corporate Strategic Objectives

PowerStream's asset management goals and objectives are aligned and consistent with PowerStream's corporate objectives, included specifically in Exhibit G, Tab 2, Section 5.2.1, page 2, and are summarized as follows:

- Foundation - Build integrated technology platforms;
- Processes - Focus on continuous improvement of key processes – design and build the network, operate and maintain the network;
- Customers- Provide customers with cost effective, competitive distribution rates; and
- Financial - Provide an optimized rate of return.

PowerStream's asset management planning process uses these corporate objectives as guiding principles in the decision making process to ensure that effective short and long term investment decisions are made which maximize the value of the assets to the company and provide optimal value to customers.

ii. Customers

Also integral to the process is listening to customers to determine how their needs align with the proposed capital plan. The information regarding customer engagement is described in Exhibit 2, Tab 4, Section 5.4.2.

iii. Efficiencies

As described in Exhibit F, Tab 1 PowerStream strives to be continuously improving and developing more efficient processes, including the application of technology.

iv. Policies and Procedures

As part of the overall process of making informed decisions, PowerStream makes use of disciplined policies, standards and processes for maintaining the assets of the company. These policies, standards and processes effectively form part of PowerStream's asset management planning process.

v. Regulations

PowerStream must comply with regulations, codes, guidelines, standards and practices mandated by the agencies that regulate utilities in Ontario.

b) Asset Knowledge

Asset knowledge comprises the practices for obtaining, storing and maintaining optimal attribute and asset information on the distribution system and general plant.

PowerStream has been applying more formal asset management principles for the distribution system since 2007, when the initial Kinectrics Asset Condition Assessment (ACA) study was performed. This approach concentrated its initial efforts on assets that represented the highest priority, had the highest asset value and represented the highest risk to PowerStream.

This process was accomplished by grouping the assets into logical asset classes, and these were further grouped into three priority categories, which were based on the asset value to the business. The highest priority assets were power transformers, system spare transformers, substation transformers, transformer station breakers, transformer station 230kV switches, substation breakers and Substation HV Switches and Fuses.

Since the initial report, PowerStream has been gathering asset data and failure data and have been adding assets to the ACA portfolio.

The components of Asset Knowledge are as follows:

i) Asset Registers;
ii) Asset Condition Assessment (ACA);
iii) Asset Capacity Utilization/Constraint Assessment; and
iv) Inspection and Maintenance Practices.

These components are more fully described below.

i. Asset Registers

Asset registers represent the primary sources of where information resides for the various asset types. There are several systems used to acquire, update and maintain the diverse set of assets in the company.

The primary asset registers, which are the sources of asset data for PowerStream are:

i. Supervisory Control and Data Acquisition ("SCADA") system;
ii. Geographical Information System ("GIS") system;
iii. Outage Management System ("OMS");
iv. Cascade system;
v. Station drawing repository;
vi. FileNexus;
vii. Computer Information system;
viii. Fleet system; and
ix. Facilities system.

The definitions for the various asset registers are below.

i) SCADA – Supervisory Control and Data Acquisition

PowerStream's Supervisory Control and Data Acquisition (SCADA) system provides real time (live) asset data on certain key assets that are in the field (e.g. stations, automated switches, wholesale smart meters). The key assets allow the system control operators to monitor asset status and performance and to configure the distribution system on an ongoing basis in order to optimize system performance and the supply of power to PowerStream's customers. Typical data collected through SCADA is used to operate the distribution system and includes information such as equipment status (on/off), current flow (amps) and alarms related to mission critical station equipment (relay triggers).

SCADA data is archived and provides a historical record of system performance that allows for detailed engineering and operating analysis to provide future direction and plans for improving system performance.

SCADA real time data is available to operations and engineering staff through the corporate networks via a web browser. Archived SCADA data is available to select users through a data historian application located on the corporate network.

ii) Geographical Information System

PowerStream's Geographical Information System ("GIS") holds both locational and attribute data on electrical distribution assets within PowerStream's service territory. PowerStream's GIS data is relied upon by many departments within the organization for operational, maintenance and design requirements.

The GIS department receives data from multiple sources which is subsequently captured in the GIS. This process ensures an accurate record of the electrical distribution network and connectivity is available. In addition, the key attributes associated with each asset are also recorded. The information can then be queried and extracted to satisfy specific requests for information (e.g. electrical connectivity, age of assets, testing records, etc.).

Maintenance of GIS records is controlled by the GIS Department. The GIS Department has instituted processes and procedures to capture, update and maintain PowerStream's electrical distribution asset data. All GIS data entry including, but not limited to, new plant, attribute updates, plant removal and any other spatial data must be completed in the ESRI ArcFM environment following a version management convention (ESRI ArcFM is a vendor name and product). All versions are put through a quality assurance and quality control process by a senior GIS employee before posting to the GIS production environment.

The majority of GIS information input (70%) is from capital programs that result in additions of plant to the distribution system. Examples of this are drawings pertaining to new subdivisions, new commercial and residential installations and capital works on roads.

PowerStream has developed an Asset Tracking Form ("ATF") which is used to capture individual asset information. In 2012, this moved from a paper based system to an electronic system. The function of the ATF is to provide a standard form to capture asset information gathered by the Lines & Construction staff in PowerStream. Lines & Construction staff complete the ATF for asset installations, removals and inspections of major equipment such as transformer, switchgears, switches, poles, and splices. Upon completion of the ATF, the data is automatically provided to the GIS Department. The GIS Department updates the required database systems with the attribute information.

The remaining 30% of GIS information input comes from operational sources (e.g. open points on feeders, discrepancy verification), maintenance sources (e.g. attribute information arising from inspection or maintenance), and other discrete sources (e.g. joint use, street lighting, land base, orthographic imaging, etc).

iii) Outage Management System

The Outage Management System ("OMS") utilizes the GIS connectivity model and inputs from smart meters, SCADA, Customer Information System ("CIS"), Interactive Voice Recognition ("IVR") and manual input to provide dynamic system and outage information and status. Outage calls, whether input automatically (as in smart meters) or manually, are automatically grouped together as appropriate and predictive device operation is generated. This application brings together multiple operational inputs and provides a dynamic picture of PowerStream's distribution network performance. Reliability performance statistics are generated from the OMS.

Asset performance reports (e.g. operations performance reports) are produced on a regular basis and are provided to senior management for information and review.

Outage notification alerts and other reliability related notifications are produced in real time as required.

iv) Cascade

Cascade is a Computerized Maintenance Management System ("CMMS"). This application aids in the efficient and timely maintenance of PowerStream's transformer and municipal substation assets.

Cascade receives real-time operational SCADA data, inspection data, test data, equipment diagnostic data (and many other inputs) from the stations. Cascade data is input, used and accessed by operational divisions such as Station Maintenance and Protection and Control.

Handheld field devices or computer notebooks are used to upload and download data to/from the database for operational field use. Advanced algorithms in the Cascade software generate preventative maintenance orders and alerts based on operating conditions.

v) Station Drawing Repository

The Station Drawing Depository ("SDR") holds data, predominately reference drawings, related to PowerStream's station facilities. Engineering drawings pertaining to PowerStream's transformer stations and municipal stations are relied on by both the Engineering and Operations departments who reference Station drawings during their day to day work. One common set of electronically stored drawings, controlled in a managed database, ensures accurate and efficient creation, editing, modification and access to Stations Drawings.

The Stations Design department leads the preparation and issue of design, construction, and as-built drawings for PowerStream's transformer stations, municipal stations, and telecommunication network. These drawings, once issued, are electronically stored in the SDR which is located on a file management system (SharePoint).

The types of drawings residing in the Stations Drawing Repository are

- System Drawings (communication drawings, etc.);
- Transformer Stations civil, mechanical, wiring and electrical drawings;
- Municipal Stations civil, mechanical, wiring and electrical drawings; and
- Control Centres layout and schematics.

The process to add, modify, delete drawings in the SDR is strictly controlled and administered by the Station Design department. Through the SDR, stakeholders in engineering and operations can access draft drawings, construction drawings, "as-built" drawings and archived (obsolete) drawings.

vi) FileNexus

FileNexus is a data repository that holds lines project construction drawings for new services, new subdivisions, new construction projects, line relocations and line rehabilitations. Engineering drawings are relied upon by design, construction and operations staff in their day-do-day work. One common place for storage is used so approved drawings, as-built drawings and any related documents to projects are available for access.

The process to add, modify, delete drawings is laid out as part of the process flow for each type of work and stage of work completion. Through FileNexus, design, construction and operations staff access the drawings throughout various stages of project completion.

vii) Information Systems

PowerStream manages the diverse information system related assets in various manners.

- Software:
  - Microsoft SCCM (System Centre Configuration Manager) – scans the networks and tracks software applications in use, keeps usage statistics, release levels, licensing details, and can be coordinated with Microsoft licensing agreements to help address differences.
  - License tracking is online through vendors portals and licensing VAR (Value Added Reseller) – which tracks licensing compliance and renewals.

- Hardware:
  - SCCM – (System Centre Configuration Manager) scans the network and logs all hardware existing on system.
  - SCOM – (System Centre Operations Manager) – integrates with SCCM and helps operate the hardware by monitoring and reporting the condition and changes in the network.

- Configuration Item (CI)/ Configuration Object Inventory (COI):

  This encompasses items within the IT architecture. As an example, a CI could be "email" – which is complex combination of a number of assets such as hardware, software, as well as proprietary information such as PowerStream's email data – so a CI is used to encapsulate and refer to the complete asset (which is more than the sum of its parts). COIs are tracked at the helpdesk (HEAT) system – so that changes and service request can be associated to them.

viii) Fleet

PowerStream has implemented Web Fleet Assistant (WFA) as a fleet maintenance software system.

This software maintains a complete list of all fleet assets and their:

- assigned preventive maintenance schedule;

- mandatory annual, semi-annual, quarterly inspections as per Highway Traffic Act and CSA/ANSI and ESA standards;
- current age and repair history. Once a unit is removed from fleet the status changes to sold and the repair history stays in the system; and
- km travelled.

Data stored in this system can be analysed to develop capital replacement plans.

ix) Facilities

PowerStream does not have a formal computer tracking software system for building assets.

There are formal maintenance contracts in place for building systems, such as HVAC, back-up generators and Security Systems. Part of those contacts includes scheduled regular maintenance for the units being serviced. The service includes recommendations about preventative maintenance and recommendations for potential capital remediation.

Summary

As described, there are several key asset registers which contain a diverse amount of assets, multiple sources of information and various procedures for obtaining the data. Although these may appear separate and disparate, which could lead to challenges, procedures that document the necessary steps have been created. Staff are knowledgeable and periodic reviews of data quality are undertaken.

ii. Asset Condition Assessment

Asset Condition Assessment (ACA) is the process of analysing the data from the asset registers and determining a specific asset's health along with determining any potential need for remediation.

PowerStream's asset condition assessment data is maintained, within the various asset registries, on the following key electrical distribution and general plant assets:

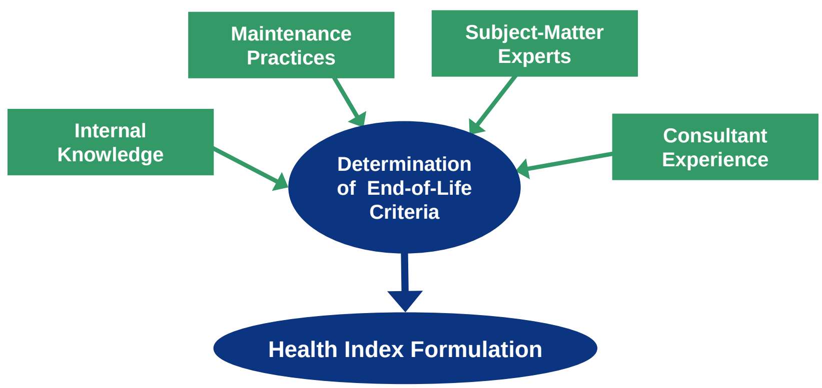
i) Distribution transformers
ii) Distribution Switchgear
iii) Wood Poles
iv) Load interrupter switches
v) Underground primary cables
vi) Mini-rupter switches
vii) Automated switches
viii) Power transformers
ix) Switchgear
x) Primary switches
xi) Circuit breakers
xii) 230kV switches
xiii) Reactors
xiv) Capacitors
xv) Information systems
xvi) Facilities
xvii) Fleet

The ACA program includes the development of Health Indices, risk-based economic analyses (probability of failure and criticality), and recommended Asset Sustainability Plans (replacements).

The ACA involves collecting and interpreting condition and performance data to enable informed investment decisions. The primary purpose of the ACA is to detect and quantify long-term degradation, which would necessitate major capital expenditures. The result of the ACA is an optimized life-cycle plan based on real asset sustainability.

Health Index

Asset Evaluations involve a technical condition assessment, wherein condition information is translated into a quantitative Health Index (HI). The HI is based on information such as equipment age, historical utilization, maintenance, and visual inspections.



The HI establishes the condition of the asset population relative to end of life. A summary of the assets covered by ACA is below.

i) Distribution Transformers

Distribution Transformers condition data is collected in conjunction with PowerStream's distribution transformer inspection process.

PowerStream will continue to operate overhead transformers on a run-to-failure basis. It is expected that PowerStream will be able to manage the replacement of overhead transformers as they fail.

Single phase residential padmount transformers as three phase transformers are generally run-to-failure assets. PowerStream, however, proposes to replace selected single and three phase padmount transformers annually for the five years of this DS Plan (and beyond). The units will be prioritized based on the results of the inspection program and their loading history (based on overloading).

It is expected that PowerStream will be able to manage the replacement of padmount transformers as they age either to the point of failure, or deteriorate to the point of the unit being deemed a safety hazard.

ii) Distribution Switchgear

Distribution switchgear condition data is collected on an ongoing basis as a result of PowerStream's Switchgear inspection process.

Distribution switchgear units comprise of Air, Oil, SF6, and Solid Dielectric units. They are either manually operated or motor operated and SCADA controllable.

All switchgear units are visually inspected on a 3-year cycle. Dead front units (PVI, Oil, Solid Dielectric) will have Infra-Red scan every 6 years. Air insulated units will have a detailed inspection every 6 years, which will be completed during the dry ice cleaning maintenance cycle (on a 6-year cycle).

PowerStream plans to replace switchgear units annually for the five years of this DS Plan (and beyond). The units will be prioritized based on the results of the inspection program.

The replacement strategy is to either eliminate the existing switchgear location (if feasible), or replace existing switchgear unit with a new unit. PVI (SF6 style) or SD (Solid Dielectric style) switchgear will be used for 27.6 kV, and PMH (Air) switchgear will be used for 13.8 kV and below.

iii) Wood Poles

Wood pole condition data is collected on an ongoing basis as a result of PowerStream's pole testing program.

Remediation recommendations are based on condition test results and minimum physical life remaining. The Health index formulation is based on condition, criticality of the location, number of circuits, number of attachments (indicating level of risk at time of failure) and asset data collected on an ongoing basis.

PowerStream plans to remediate poles annually for the five years of this DS Plan (and beyond).

iv) Underground Primary Cable

The condition of underground cable is correlated to the age of the cable. Other factors exist such as loading and mechanical stress. Cable age and cable failure statistics are the first step in prioritizing further testing to determine cable condition.

PowerStream performs Tan Delta cable tests to assist with the assessment of cable condition. This testing data is used to:

- Determine which intervention method (replacement vs. injection) is more suitable for a specific location;
- Determine the appropriate quantity and timing of cable intervention (replacement/injection); and
- Validate and prioritize the cable replacement/injection projects.

Cable remediation is performed either by cable injection (a process that extends cable life) or cable replacement.

v) Mini-Rupter Switches

Mini-Rupter switch condition data is collected on an ongoing basis as a result of PowerStream's inspection program.

PowerStream plans to replace switches annually for the five years of this DS Plan (and beyond). The units will be prioritized based on the results of the inspection program.

vi) Automated Switches

Automated switch condition data is collected on an ongoing basis as a result of PowerStream's inspection program.

PowerStream plans to replace switches annually for the five years of this DS Plan (and beyond). The units will be prioritized based on the results of the inspection program.

vii) Transformer Stations

Transformer stations are a highly complex set of individual assets working together to provide a functioning station. Demographic and condition data are available. Health Indices on components of the station were formulated based on industry best-practices through the Kinectrics model, and asset data collected on an ongoing basis.

Planned replacements are based on poor health indices, obsolescence such that the equipment is not able to be maintained, poor reliability statistics or issues with inability to operating the equipment.

viii) Municipal Sub-stations

Municipal stations are a highly complex set of individual assets working together to provide a functioning station. Demographic and condition data are available. Health Indices on components of the station are based on industry best-practices through the Kinectrics model and asset data collected on an ongoing basis.

Planned replacements are based on poor health indices, obsolescence such that the equipment is not able to be maintained, poor reliability statistics or issues with inability to operating the equipment.

ix) Computer Information Systems

Similar to the distribution system, PowerStream's computer assets are required to be reasonably current and in good working order. In 2012, PowerStream adopted the International Financial Reporting Standards (IFRS) system for accounting purposes. In doing so the "useful life" of a number of asset classes were reviewed. This serves as a guideline for planning purposes. Other factors such as reliability and the impact (cost) of failure remain the primary factors considered in IT asset management remediation decisions. This includes metering and billing related systems.

x) Facilities

Similar to the distribution system, PowerStream's building facilities are required to be reasonably current and in good working order. The four facilities are of various age demographics. The Cityview location is several years old, the north facility is in relatively fair condition but some items will require work as a result of aging. Lease hold improvements at Markham Operations Centre facility will also result in increased capital requirement and the Jane Street office is new and does not require work.

The areas of concern for PowerStream's facilities are:

- Exterior (i.e. pavement, fencing, lighting, stores yard);
- Interior (i.e. furniture);
- Mechanical (i.e. Plumbing);
- Structural (i.e. windows, doors, wall partitions);
- HVAC (Heating & air conditioning); and
- Equipment (major tools, lifts).

xi) Fleet

PowerStream's fleet assets are required to be in good working order. Depending on the class of vehicle (heavy duty, medium duty, light duty or miscellaneous class) replacement is required when the vehicle reaches a prescribed odometer reading or a prescribed engine hours reading and shows an upward trend in unscheduled maintenance costs for last three years. Also taken into account is the projected unscheduled maintenance cost based on a technical assessment.

iii. Asset Capacity Utilization/Constraint Assessment

With respect to annual system utilization, PowerStream annually undertakes planning studies in the spring and produces a *Feeder Balancing and System Reconfiguration Plan,* based on approved Planning Standards and PowerStream's Planning Philosophy. The goal of this plan is to review system loading and make recommendations to balance both transformer and feeder loading to within established guidelines. The loading of PowerStream's transformer stations should not exceed the limited time rating (LTR) for that station. Feeders should not be loaded above the planning feeder limits. In order to meet summer peak, loads on all assets must be reviewed against guidelines, and timely corrective actions taken to ensure limits are respected.

By implementing this plan, stations and feeders will be balanced and utilization of assets will be optimized.

iv. Inspection and Maintenance Practices

Inspection and maintenance comprise the physical gathering of attribute data on assets and making immediate or planned corrections as required.

The Inspections and Maintenance Practices are governed by the following internal Procedures:

- Vegetation Management Procedure;
- Distribution Switchgear Inspection and Maintenance Procedure;
- Inspection of Vault Rooms;
- Overhead Plant Inspection and Maintenance;

- Tan Delta Cable Testing;
- Underground Transformer and Inspection and Maintenance Procedure;
- Load Interrupter Switch/Recloser Inspection and Maintenance Procedure;
- Pole Inspection and Testing; and
- Vault Inspection and Maintenance.

As a result of continuous inspection and maintenance, projects/programs are developed to address safety issues or operating issues.

c) Asset Strategy & Planning

Asset strategy and planning provide the framework for defining how projects and programs must be designed to maintain compliance with standards, codes, policies and procedures.

The inputs for Asset Strategy and Planning are as follows:

i) Asset Planning Criteria;
ii) Capacity Requirement Assessments;
iii) Construction and Material Standards;
iv) Reliability Performance;
v) Worst Performing Feeder Assessment; and
vi) Interdepartmental Committees.

i) Asset Planning Criteria

PowerStream has set criteria for planning limits and operational limits of the distribution system. These are summarized as follows:

a. The Deterministic Planning Technique and the (N-1) contingency Criterion in planning for station capacity has been adopted. This standard calls for zero interruptions to customers as a result of any single outage to a major network element, such as a station transformer or transmission line.

b. The continued practice of DESN (dual element spot network) station construction has been adopted. This requires two supply sources and two transformers at each station.

c. The overloading values will be in accordance with the transformer's 10 day LTR. The 10 day LTR is the rating designed to respect conditions that can cause hot-spot temperatures of the transformer to create loss of life.

d. Feeders that egress from transformer stations are typically designed to carry in excess of 600A in emergency conditions. PowerStream's Planning Philosophy calls for adopting a feeder planning capacity of 400 Amps for normal conditions and 600 Amps for contingency conditions, since;
   - 400A is well within the rated current of components of all equipment on the system;
   - For contingency conditions, load on one feeder will go to two adjacent feeders so that the other two feeders will have a loading of less than 600A which is within the rated current of components of all equipment on the system, specifically load interrupter switches;
   - 600A for backup feeders requires system reconfiguration; and
   - 600A load carrying capability for back-to-back represent the industry defined first contingency.

e. For the north territory, a triad model is applied for municipal sub-stations. This model requires that at least three stations are tied together through open points such that if one station is lost, all load from the triad supplied stations can be supplied by the remaining stations.

f. An "open grid" feeder design will be applied and provide for full backup capability over peak loading periods through switching of load to an adjacent feeder or multiple adjacent feeders.

ii) Capacity Requirement Assessments

At a minimum of every second year, PowerStream undertakes a planning study to review system peaks compared to system capacity, to determine if expansion to the transformation or distribution system is required. The objective is to identify the need for additional facilities with sufficient lead time for permit approvals, design, procurement, construction and commissioning prior to the load exceeding available capacity.

iii) Construction and Material Standards

PowerStream has an extensive array of construction standards that have been approved by a provincially licensed professional Engineer. These standards cover:

- Engineering and Construction Standards Guidelines;
- Technical Data;
- Voltages, Line Locations, and Clearances;
- Poles and Footings;
- Material Illustrations;
- Overhead Distribution Standards;
- Underground Distribution Standards;
- Services and Metering;
- Street Lighting; and
- Overhead and Underground Markings and Numbering.

PowerStream has an extensive array of material standards that have been approved by a provincially licensed professional Engineer to support the construction standards. These standards cover:

- Anchors and guying;
- Cables and cable accessories;
- Splices and terminations;
- Conductors and connectors;
- Fault indicators;

- Fusing;
- Overheard hardware and accessories;
- Underground hardware and accessories;
- Poles;
- Switches and switchgear;
- Transformers; and
- Metering.

iv) Reliability Performance

PowerStream has committed to improve system reliability over the next several years as part of the corporate "Strategic Direction - Five Years Critical Success Factors". PowerStream will strive towards meeting the reliability target set for 2020.

On an annual basis, PowerStream reviews its reliability indices and looks at programs or projects that could be implemented to improve these metrics. This reliability improvement initiative exceeds the minimum regulatory service quality standard expected of PowerStream.

A reliability work plan has been developed to provide a general road map for moving towards the reliability target over the next several years. Refer to Exhibit G, Tab 2, Section 5.3.3, page 33 for further information.

v) Worst Performing Feeders Assessment

Annually, the System Planning department, in conjunction with the System Control department, identify and issue a list of the 20 Worst Performing Feeders, with respect to reliability and outages that exist in PowerStream's service territory. This report recommends future maintenance and capital work on these feeders with the intent to improve their reliability. This is a reliability focused initiative that identifies the worst performing feeders by their performance indices. These are feeders that demonstrate a pattern of higher incidence of outages over a three year period.

Once the work has been performed on the worst performing feeders for a given year, these feeders typically move off the list, and are replaced with the next group of worst performing feeders that were next on the list. This annual ongoing review and remediation should result in the improvement in feeder performance and, over time, should contribute to maintaining the overall reliability of the distribution system.

In September 2009, PowerStream adopted the average of FAIDI (feeder average interruption duration index – how long a customer has an outage) and FAIFI (feeder average interruption frequency index- how many times a customer has an outage) method to determine the worst performing feeders (10 in the South service territory and 10 in the North service territory). One of the drawbacks of selecting feeders based on FAIDI/FAIFI method is that it looks at the feeder level indices and ignores the impact the feeder has on overall system reliability indices and directing resources on these feeders would not significantly improve the system level statistics.

In 2012, System Planning developed an updated methodology which ranked feeders based on outage duration, the number of customers impacted and the total number of outages (including momentary outages).

In order to not ignore smaller feeders with chronic issues, a blended approach was selected, whereby 10 feeders would be selected from the FAIDI/FAIDI list and 10 feeders were selected from the customer minutes interrupted list plus the customer interrupted list and the outage list.

vi) Interdepartmental Committees

PowerStream has several interdepartmental and cross functional committees to provide focus and direction on key technical issues. The functioning committees are:

- Asset Management Committee;
- Asset Strategy Committee;

- Distribution Automation;
- Standards Committee;
- Reliability Committee;
- Outage Performance Committee;
- Smart Grid Committee and
- Optimization Committee.

These committees have the mandate to review specific system issues, industry innovations and recommend programs or projects that will rectify respective issues or suggest pilot projects.

d) Asset Management & Decision Making

Asset management and decision making provide the framework for deciding which projects and programs will be selected to become part of the capital expenditure plan.

To generate potential projects or programs, the asset management and decision making process considers:

- Inputs from the asset registers;
- Asset Condition Assessment criteria as applicable;
- Asset capacity utilization/constraint assessments;
- Inspection and maintenance data;
- Asset planning criteria;
- Standard related issues;
- Reliability performance; and
- Worst performing feeder analysis.

The process also considers input from customers and recommendations from interdepartmental committees. The proposed projects are then placed into the optimization process and applied within the capital budget threshold to generate the optimal list of projects/programs for a given year (projects with the highest value are included in the year's portfolio).

The inputs for asset management and decision making are as follows:

i. Portfolio Optimization
ii. Business Cases
iii. Management and Reporting of the Capital Portfolio

i. Portfolio Optimization

PowerStream has a robust capital planning process that utilizes software and a multi-disciplinary review that helps to determine the relative value and risks associated with a portfolio of projects. Refer to Exhibit G, Tab 2, Section 5.3.3, page 15 for a more detailed outline of Asset Optimization.

The annual business planning and budgeting process starts early in the year with the Board of Directors revisiting the corporate strategy (which could lead to changes to the Strategy Map). Operating and capital budgets are then prepared that align with and support the corporate strategy. At the end of the year, the Five Year Budget Outlook is presented to the Board of Directors for approval. The timeline is further outlined in Table 1.

Timeline	Activity
February/March	Executive Management Team ("EMT") and Board of Directors hold a Strategic Planning Session and establish and re-affirm or adjust the corporate strategy. There may be some resulting edits to the Strategy Map.
April/May	The corporate strategy is communicated to the organization through the use of the Strategy Map.
May	There is an official "kick-off" of the budget process.
May to August	Detailed budgets for the next five years are prepared. Business unit leaders are asked to prepare business cases for those projects and programs that exceed a prescribed threshold.
September	Optimization of the proposed programs and projects occur. The Audit & Finance Committee and the Board of Directors are updated on the status of budget preparation.
October/November	The EMT reviews and finalizes the Five Year Budget.
December	The Five Year Budget is presented to the Audit and Finance Committee and then the Board of Directors for approval.
January/February	Performance reporting of the previous year baseline to actual is performed.

Table 1: Annual Business Planning and Budget Process Cycle

ii. Business Cases

Business cases, either mini or full, are required to support all capital requests. Business cases are prepared in advance of the Optimization process to ensure consideration for capital requests. Business cases can also be prepared during the year for requests of current year's capital funds (outside of the capital budget process).

The required business case format is determined by:

- Dollar value requested;
- Program vs. non-program (specific projects) capital investment ; and
- Inclusion within approved capital budget or after-the-fact.

Business cases are used to support a request for capital funding and must contain:

- an objective to be achieved;

- background information of the current state;
- detailed analysis of status quo, including risk of not maintaining it;
- review of possible alternatives;
- detailed review of recommended alternative and the value it brings and why it was chosen;
- timeframes / dates to show duration of project;
- financial details associated with each alternative; and
- financial analysis to capture both capital and OM&A.

Full business cases are to be used for capital requests ≥ $500K for specific projects, and ≥$100k for information system related projects, and are completed for those projects that are provided through the optimization process, or for capital requests ≥ $250K after the capital budget has been approved for that year. Mini business cases are required for all other capital requests regardless of the point in the budget cycle.

iii. Management and Reporting on the Capital Portfolio

Good governance of the capital portfolio requires a consistent approach to reviewing the status of spending, controlling the additions and removals of projects and approvals of over expenditures as projects progress.

PowerStream has procedures that outline the process and approval requirements for these scenarios, and these are applied on an ongoing basis.

Future Outlook

PowerStream's Asset Management Planning Process continues to evolve and recent focus has been on three fronts.

First, bringing to a common level, for all assets, the practices, guidance and directives for managing distribution and station asset condition information and understanding of required capital spend for renewal of aging assets. This will continue through the efforts of the Asset Management Committee and Asset Strategy Committee.

Second, to continue to acquire and refine the current status of the condition of the assets through refinement of the inspection and maintenance program to ensure accurate and up-to-data exists within the appropriate asset registers.

Third, ensuring a robust capital planning and budgeting process for all capital spending in the corporation, including optimizing all capital using the same “lens”. This commenced with the introduction of the Copperleaf’s C55 asset management product and will continue with its development and refinement.

e) Outputs

The output of the asset management planning process is either a program or a specific project.

- *Programs:* These are annual repetitive works, such as pole remediation, that are ongoing with different locations set yearly, but with the same type of work performed.
- *Projects*: Specific location and type of work that is required to be performed to meet the identified need.

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, including but not necessarily limited to:

a) 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;

b) 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;

c) 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; and

d) 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.

PowerStream's Service Territory

PowerStream's service territory is divided into two distinct geographic regions: north and south. As depicted in Figure 1, the north consists of the municipalities of Barrie, Tottenham, Thornton, Alliston, Beeton Bradford and Penetanguishene. The south consists of Vaughan, Markham, Richmond Hill and Aurora.

As of December 31, 2013, the north territory and the south territory are described with respect to customer counts and loads, in Table 1.

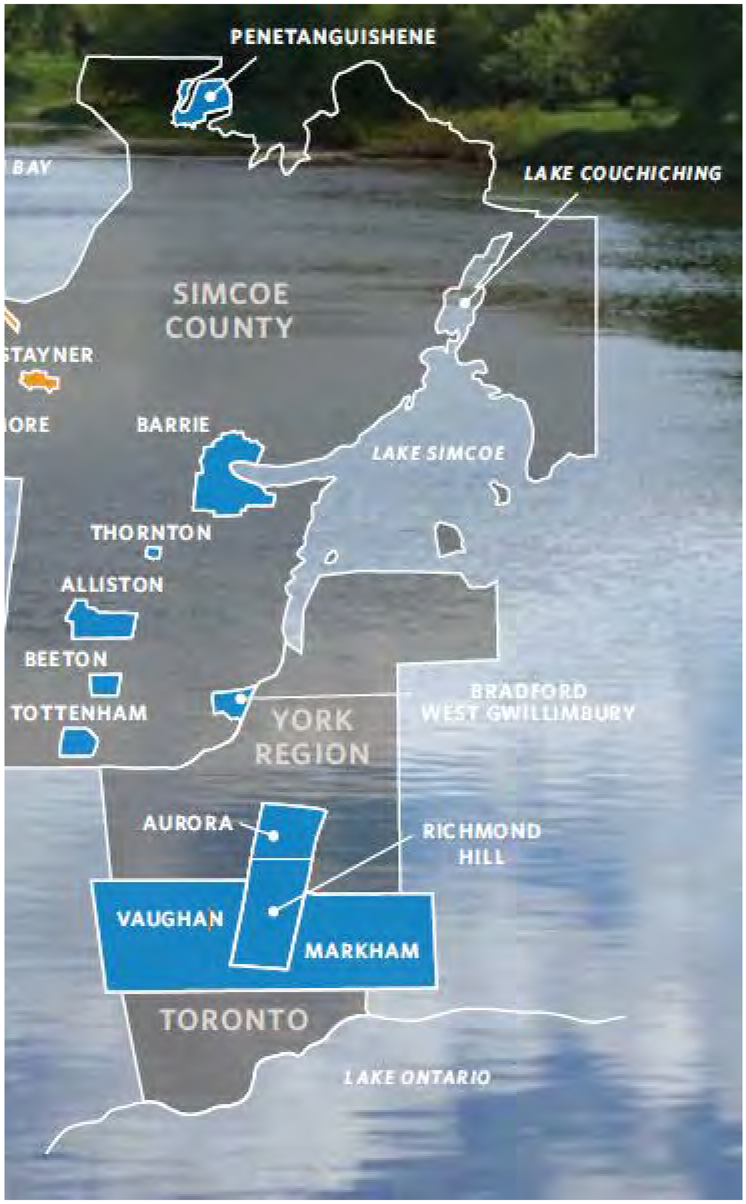


Figure 1: Map of Service Territory

	Customer Count		
	South	North	
Residential	247,269	69,496	89%
Under 50 kW	25,623	6,242	
USL	2,211	679	
Over 50 kW	3,973	816	
Large User > 5000kW	2	0	
Sentinel	107	0	
SL Customers	34	9	
Total	279,219	77,242	
S/L Conn.	69,463	16,527	

	Consumption (kWh)		
	South	North	
Residential	2,100,631,280	577,688,364	32%
Under 50 kW	825,280,512	210,335,080	
USL	11,446,580	3,098,971	
Over 50 kW	3,734,870,670	782,097,326	
Large User > 5000kW	78,428,435	0	
Sentinel	363,189	0	
S/L Customers	0		
Total	6,751,020,664	1,573,219,740	
S/L Conn.	47,355,824	12,812,619	

Table 1: South and North Territories Statistics

As shown in Table 1, the majority of the customer count is residential (89%), however, they represent only about 32% of the load.

PowerStream's service territory is a mixture of urban and rural (mostly urban), as indicated in Table 2.

PowerStream Service Area South

Municipality	Rural (sq km)	Urban (sq km)	Total (sq km)	Urban %
Markham	71	141	212	67%
Richmond Hill	22	80	102	78%
Vaughan	64	210	274	77%
Aurora	11	38	49	78%
Total/Average	168	469	637	74%

PowerStream Service Area North

Municipality	Rural (sq km)	Urban (sq km)	Total (sq km)	Urban %
Barrie	8	69	77	90%
Bradford	0	17	17	100%
Penetanguishene	6	10	16	63%
Tottenham	5	10	15	67%
Alliston	4	32	36	89%
Beeton	5	4	9	44%
Total/Average %	28	142	170	84%

Table 2: Urban / Rural Mix within PowerStream

PowerStream has been a rapidly growing LDC, particularly in the south. Refer to Figure 2.

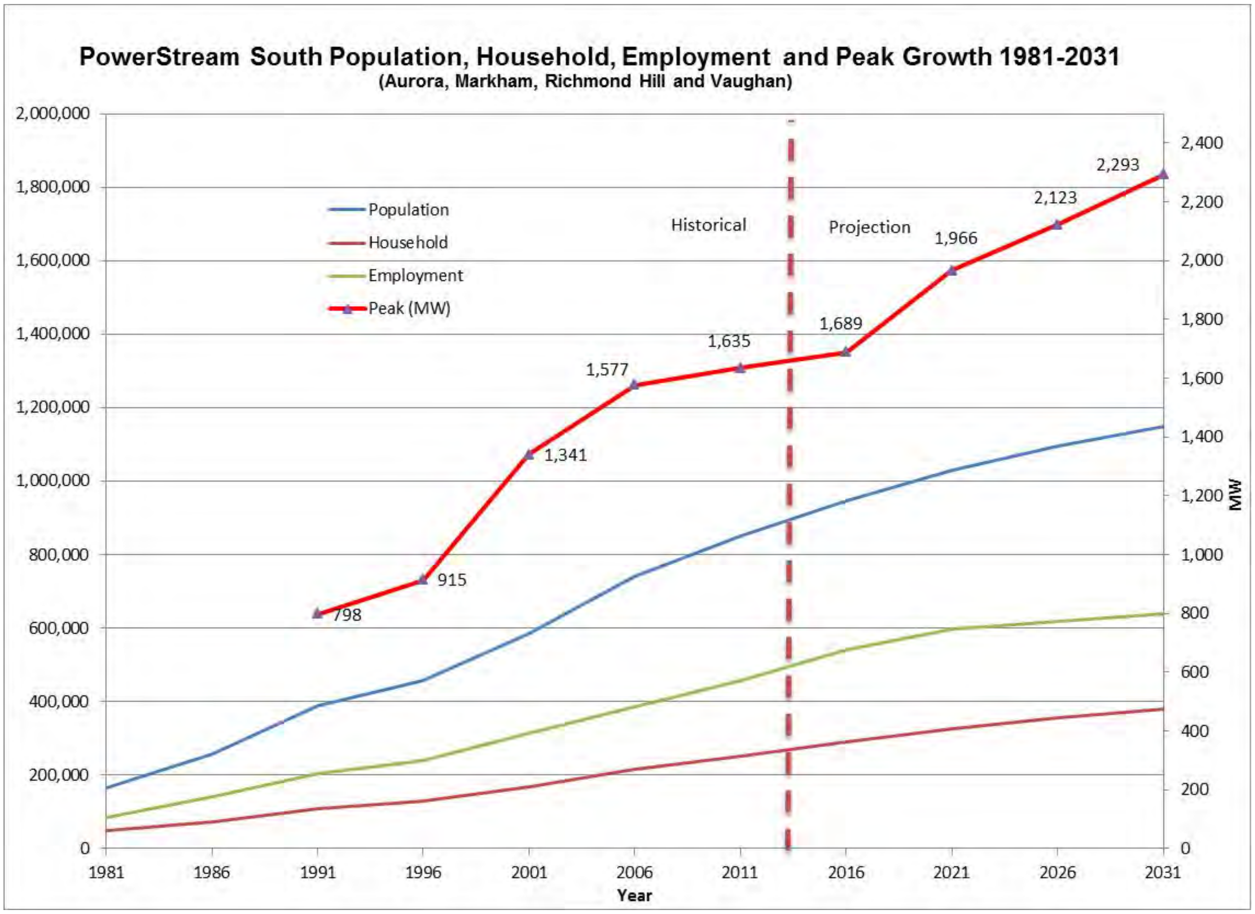


Figure 2: Growth in PowerStream South

Heat maps, which represent areas of expanding capacity that require additional distribution system facilities, are shown in Figures 3 to Figure 8. These areas will drive expansion of the distribution system.

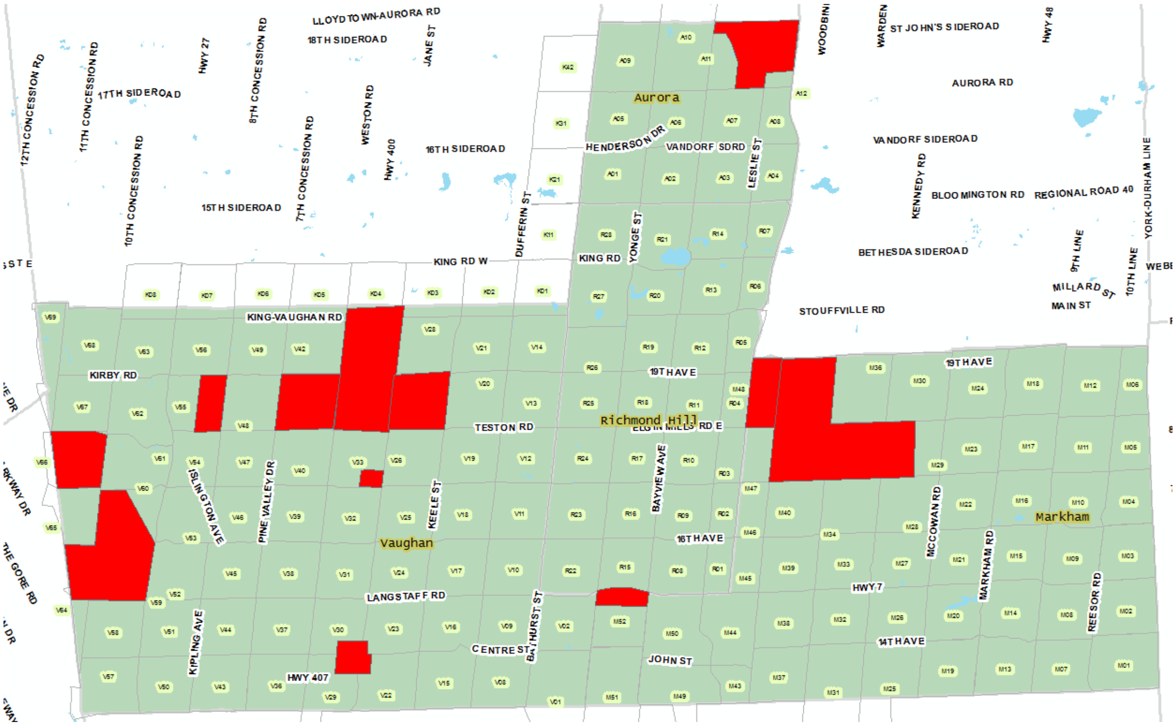


Figure 3: Heat Map - PowerStream South

Figure 4: Heat Map - Barrie

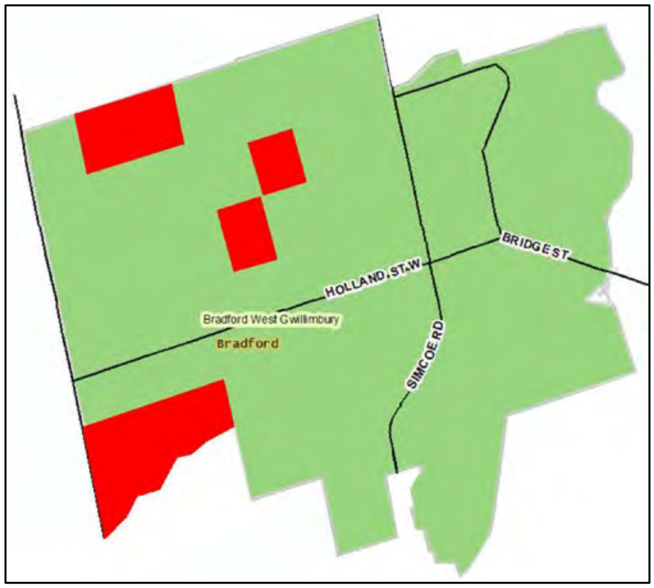


Figure 5: Heat Map - Bradford

Figure 6: Heat Map - Alliston

Figure 7: Heat Map - Beeton

Figure 8: Heat Map - Tottenham

System Configuration

PowerStream distributes electricity through its three phase primary distribution systems. These are the 44 kilovolt (kV) sub-transmission, the 27.6 kV primary distribution system and the 13.8 kV, 8.32 kV and 4.16 kV primary distribution systems.

Although PowerStream has three primary distribution voltage levels, not all voltage levels are available throughout the PowerStream service territories.

Sub-transmission or distribution supply circuits, known as feeders, are typically arranged to run radially out from transformer stations (owned by PowerStream or Hydro One Networks Inc). Transformer stations “step” the voltage down from a transmission voltage of 230kV to a voltages of 44kV or 27.6 kV.

Open points exist between feeders and determine the feeder geographical coverage. Open points are the physical end points of a feeders, and usually represent tie points between adjacent feeders.

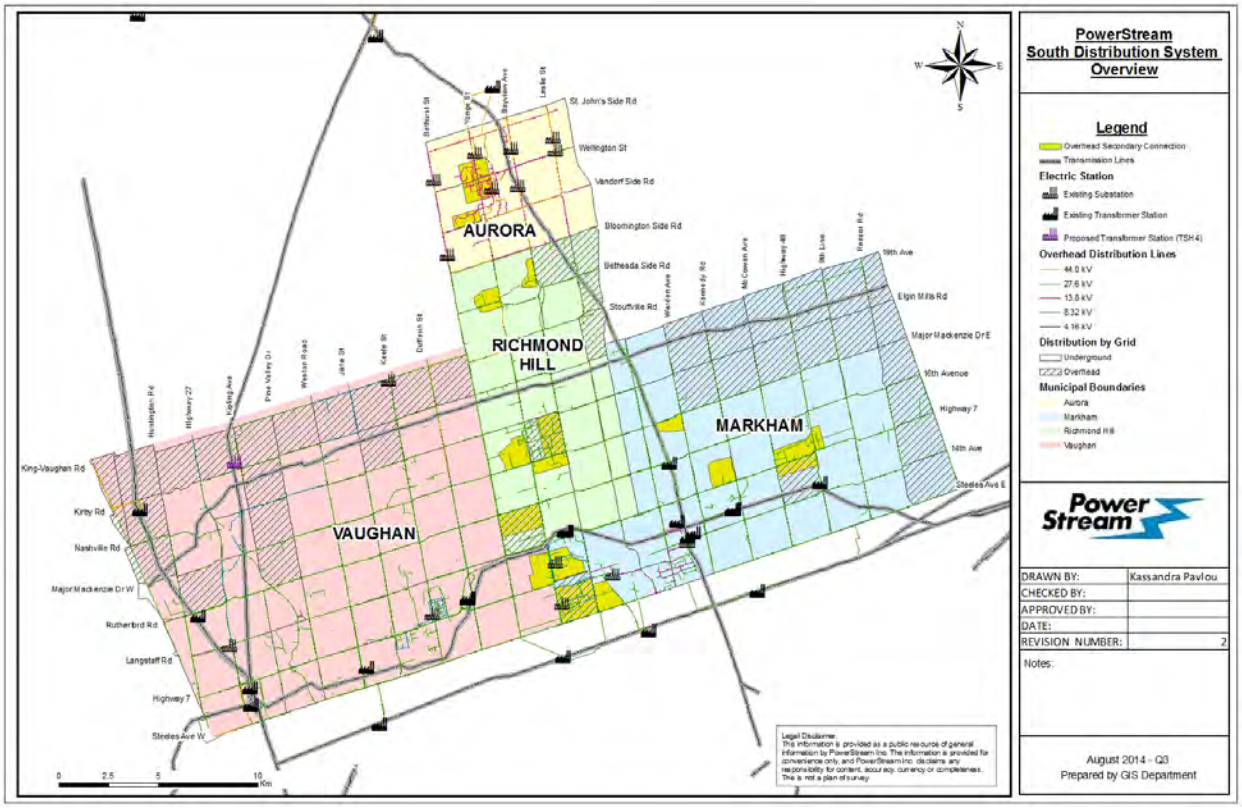
Feeders directly supply pole mounted, pad mounted or vault type distribution transformers that reduce the operating voltage to customer levels.

It is not possible to define the length of individual circuits in the distribution system, as the primary distribution system is constantly being assessed and open points changed to respect operational and planning limits.

<u>PowerStream South</u>

In the south service territory (except Aurora), PowerStream services customers directly at 27.6 kV from feeders emanating from transformer stations (PowerStream owned or Hydro One owned). In some cases, municipal substations “step” the voltage down from 27.6 kV to a lower primary distribution voltage. There are some customers supplied at 27.6 kV in Aurora.

Figure 9 depicts the south distribution system on an high level basis.



<u>Figure 9: South Distribution System Overview</u>

Tables 3 and 4 and Figure 10 specifically detail transformer stations.

PowerStream's south Municipal substations are shown in Table 5, and the locations are shown in Figures 11 to Figure 14.

For both transformer and municipal stations, values shown are for 2013 peaks, and depict asset utilization.

TS	Transformer Capacity	Number of Feeders	10 day LTR (MVA)	Peak (MW)	Peak (MVA)	Ratio of Peak to LTR
Markham TS#1	2 x 83 MVA	8	90	91	100	112%
Markham TS#2	2 x 83 MVA	8	112	131	137	123%
Markham TS#3	2 x 83 MVA	8	112	143	153	68%
Markham TS#3E	2 x 83 MVA	8	112			
Markham TS#4	2x125 MVA	12	170	99	109	64%
Richmond Hill TS#1	2x125 MVA	12	170	170	184	108%
Richmond Hill TS#2	2x83 MVA	8	112	105	113	101%
Vaughan TS#1	2 x 125 MVA	12	170	200	223	131%
Vaughan TS#1E	2 x 125 MVA	12	170	135	151	89%
Vaughan TS#2	2 x 125 MVA	12	170	147	156	92%
Vaughan TS#3	2 x 125 MVA	12	170	150	163	96%
Total		112	1,558	1,371	1,490	96%

Table 3: PowerStream South: PowerStream Owned Transformer Stations

TS	Number of Feeders	Feeder Rating (MVA)	Peak (MW)	Peak (MVA)	Ratio of Peak to LTR
Agincourt TS*	2	30	0	0	0%
Leslie TS	3	45	31	34	77%
Fairchild TS*	3	45	19	21	47%
Finch TS	2	30	9	10	33%
Woodbridge TS	4	60	47	52	87%
Buttonville	12	170	103	106	62%
Kleinburg	2	30	2	2	6%
Total	28	410	211	225	55%

* 2 feeders were out of service in 2013

Table 4: PowerStream South: Hydro One Owned Transformer Stations

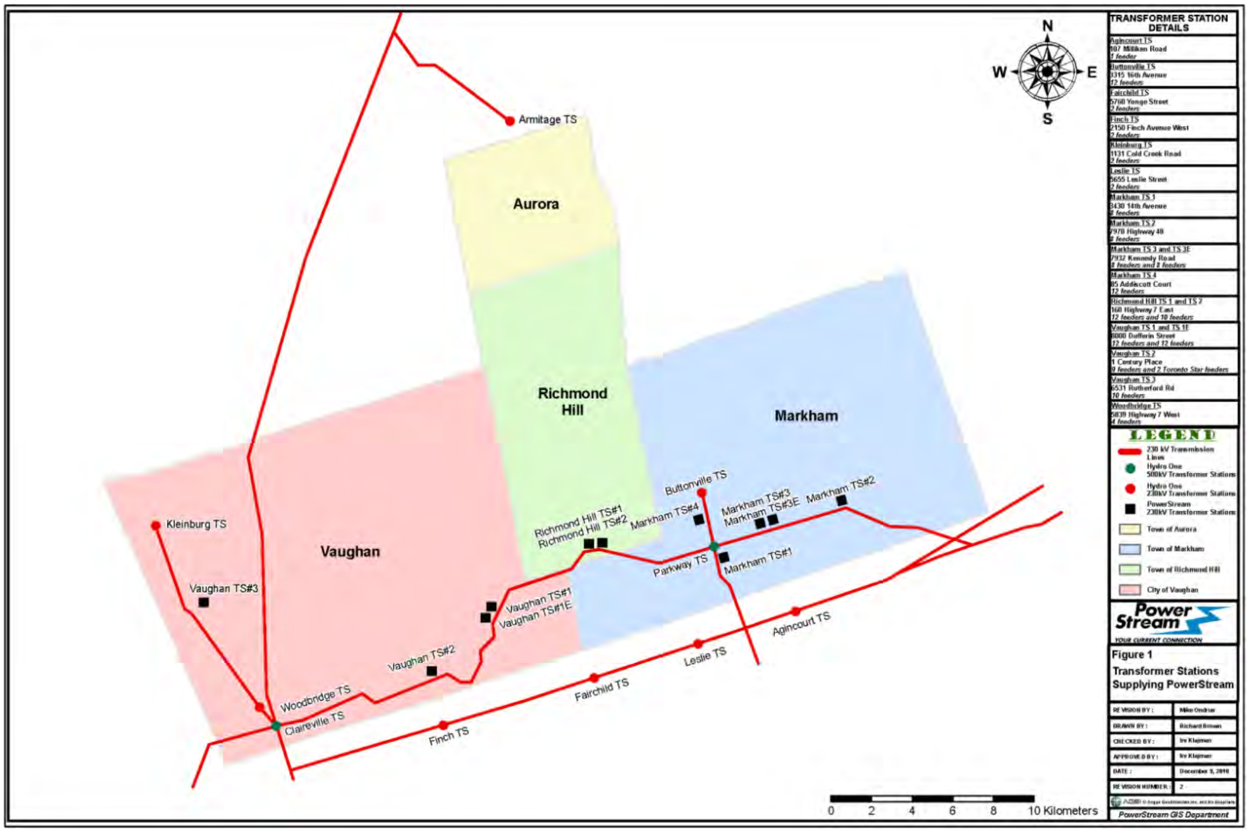


Figure 10: South Transformer Stations

Transformer Stations

The optimal ratio of peak to limited time rating (LTR) is 90% to 95%. This leaves capacity for high loading periods. Values that exceed 95% are not desirable.

The transformer's LTR 10 day is used as the transformer station loading guide line for following reasons:

- If one transformer fails in a typical dual element spot network (DESN) station, the remaining transformer will carry the load of the entire station. The transformer will lose

2% additional life in 10 days if it loaded at its LTR rating. It is not desirable to degrade the transformer's life on purpose;

- Replacing the failed transformer with a system spare transformer is estimated to take 10 days; and
- For a transformer outage longer than 10 days, the transformer loading must be brought to its name plate rating. This can be accomplished by load transfers of above name rating to adjacent stations or by load shedding.

Where the values in Table 3 are low (64%) at MTS#4 (the newest station), new developments in the area will be adding capacity in the near term. The same is true for MTS#3 (68%).

Where the values in Table 4 were low (0% and 47%) these Hydro One feeders were out of service during the 2013 peak loading, and the loads appeared on the stations that were above 100% as seen in Table 3.

Where the values above in Table 4 were low (6% and 33%), new developments in the area will be adding capacity in the near term.

In summary, the transformer station assets are, or are soon to be, at optimal limits. They are being prudently utilized.

Municipal Substations

Figures 11-13 detail the locations of the south municipal substations.

Figure 11: Aurora Substation Locations

Figure 12: Vaughan Substation Locations

Figure 13: Markham Substation Locations

Table 5 indicates the loading on the south municipal substations. The south municipal sub-stations are lightly loaded. The loads on these stations have been passively converted to the 27.6 kV system as development and system changes occur.

MS Name	Transformer ID	Transformer Capacity	Peak (MVA)	Ratio of Peak to Name Plate Rating	Municipality
Amber MS	T1	10	3.0	19%	Markham
	T2	10	0.8	5%	
John MS	T1	10	0.8	5%	
	T2	10	3.7	23%	
Morgan MS	T1	5	0.8	5%	
Baythorn MS	T1	7.5	0.4	3%	
	T2	7.5	3.8	24%	
King MS**	T1	5	1.5	9%	Vaughan
Concord MS	T1	15	4.6	29%	
Elder Mills MS**	T1	5	0.5	3%	
AMS#1	T1	10/13/16	6	37%	Aurora
	T2	10/13/16	8	48%	
AMS#2	T1	10/13/16	11	68%	
AMS#3	T1	10/13/16	7	42%	
	T2	10/13/16	11	66%	
AMS#4	T1	10/13/16	9	56%	
	T2*	10/13/16	0	0%	
AMS#5	T1	10/13/16	7	42%	
	T2	10/13/16	5	30%	
AMS#6	T1	10/13/16	11	66%	
	T2*	10/13/16	0	0%	
AMS#7	T1 (44/27.6kV)	10/13	1	5%	
AMS#8	T1 (44/27.6kV)	10/13	4	31%	

Table 5: PowerStream South Municipal Substations

In 2015, a study will be performed to develop a long term strategy for conversion of the low voltage systems to the 28kV system.

PowerStream North

PowerStream's north territory is characterized by a 44kV sub-transmission feeder distribution system serviced from Hydro One owned transformer stations. These feeders are the primary supply for the sub-stations that step-down a lower primary voltage for distribution. Refer to

Table 6 to Table 9 and Figure 14 to Figure 20. Values shown are for 2013 peaks and depict asset utilization.

In the north service territory (including Aurora), on the 44 kV sub-transmission system, PowerStream services directly multiple municipal substations and multiple customer-owned substations. The municipal substations transform the 44 kV sub-transmission voltage to primary distribution voltages of 4.16 kV, 8.32 kV and 13.8 kV. Direct customer connections are at the 44kV level, and are used for connections above a connected kVA load threshold.

Region	MS Name	Station Name	Number of Feeders	Transformer Capacity (ONAN/Max/Contingency)	2013 Peak (MVA)	Ratio of Peak to Contingency TX Rating in 2013	N-1 Contingency Ratio in 2013	Load of Proposed Developments and Annual Growth by 2018 (MVA)	N-1 Contingency Ratio with Developments by 2018
Barrie North (13.8kV)	MS301 (13.8kV)	Anne North	4	22.5/25/39.9	13.2	33%	75%	8.8	97%
	MS306 (13.8kV)	Little Lake	4	22.5/25/39.9	16.9	42%			
Barrie South-West (13.8kV)	MS303 (13.8kV)	Ferndale South	4	22.5/25/33.5	21.4	64%	90%	4.6	97%
	MS305 (13.8kV)	Holly	4	22.5/25/33.5	23	69%			
	MS302 (13.8kV)	Saunders	4	22.5/25/39.9	15.7	39%			
Barrie South-East (13.8kV)	MS307 (13.8kV)	Huronia	3	11.2/18.8/24.7	10.8	44%	79%	6.2	88%
	MS304 (13.8kV)	Big Bay Point	4	22.5/25/39.9	23.5	59%			
	MS308 (13.8kV)	Park Place	4	22.5/25/39.9	16.5	41%			
Barrie Allandale (4.16kV)	MS406 (4.16kV)	Burton	3	5/7.6	3.6	47%	64%	1.4	73%
	MS414 (4.16kV)	Little	2	5.6/7.6	2.9	38%			
	MS411 (4.16kV)	Innisfil	3	5/7.6	3.2	42%			
Barrie West Village (4.16kV)	MS410 (4.16kV)	Ferndale	2	5/7.6	3.5	46%	85%	1.8	97%
	MS402 (4.16kV)	Anne Temp	2	5.6/7.6	3.8	50%			
	MS413 (4.16kV)	Letitia	3	5/7.6	5.6	74%			
Barrie Downtown (4.16kV)	MS405 (4.16kV)	Brock	4	11.2/15.1	4.9	32%	59%	2.6	68%
	MS419 (4.16kV)	Perry	4	11.2/15.1	6.6	44%			
	MS415 (4.16kV)	Mary	4	11.2/15.1	6.4	42%			
Barrie Queens Park (4.16kV)	MS408 (4.16kV)	Cundles West	3	5/7.6	3.5	46%	79%	1.7	90%
	MS407 (4.16kV)	Cundles East	3	5/7.6	3.7	49%			
	MS409 (4.16kV)	Duckworth	3	5/7.6	4.8	63%			
Barrie Grove (4.16kV)	MS418 (4.16kV)	Wellington	4	11.2/15.1	6.8	45%	56%	3.0	64%
	MS417 (4.16kV)	St. Vincent	4	11.2/15.1	6.5	43%			
	MS404 (4.16kV)	Blake	4	11.2/15.1	4.4	29%			
	MS412 (4.16kV)	Johnson	2	5/7.6	3.4	45%			

Table 6: PowerStream North - Barrie Municipal Substations

Region	MS Name	Station Name	Number of Feeders	Transformer Capacity (ONAN/Max/Contingency)	Peak (MVA)	Ratio of Peak to Contingency TX Rating	N-1 Contingency Ratio	Load of Proposed Developments and Annual Growth by 2018 (MVA)	N-1 Contingency Ratio with Developments by 2018
Bradford	MS321 (13.8kV)	John	4	10/13.3/18	6.4	36%	62%	10.3	81%
	MS322 (13.8kV)	Melbourne	3	10/13.3/18	9.8	54%			
	MS323 (13.8kV)	8th Line	3	10/13.3/18	9.6	53%			
	MS324 (13.8kV)	Reagans	3	11.2/15/20.2	7.8	39%			

Table 7: PowerStream North - Bradford Municipal Substations

Region	MS Name	Station Name	Number of Feeders	Transformer Capacity (ONAN/Max/Contingency)	Peak (MVA)	Ratio of Peak to Contingency TX Rating	N-1 Contingency Ratio	Load of Proposed Developments and Annual Growth by 2018 (MVA)	N-1 Contingency Ratio with Developments by 2018
Alliston (13.8kV)	MS330 (13.8kV)	8th Avenue	2	11.2/15.1	10	66%	74%	9.5	101%
	MS331-T1 (13.8kV)	14th Line	2	11.2/15/20.2	8.7	43%			
	MS331-T2 (13.8kV)	14th Line	2	11.2/15/20.2	7.3	36%			
Alliston (4.16kV)	MS431 (4.16kV)	Dufferin	3	5/7.6	2.4	32%	79%	1.0	92%
	MS432 (4.16kV)	Fletcher	2	5/7.6	3.6	47%			
Beeton (13.8kV)	MS336 (13.8kV)	Patterson	2	7.5/10.1	4.8	48%	48%	2.2	69%
Tottenham (8.32kV)	MS834 (8.32kV)	Nolan	2	10/15.2	4	26%	77%	3.2	112%
	MS835 (8.32kV)	Mill	2	6/9.1	3	33%			

Table 8: PowerStream North – New Tecumseth Municipal Substations

Region	MS Name	Station Name	Number of Feeders	Transformer Capacity (ONAN/Max/Contingency)	Peak (MVA)	Ratio of Peak to Contingency TX Rating	N-1 Contingency Ratio	Load of Proposed Developments and Annual Growth by 2018 (MVA)	N-1 Contingency Ratio with Developments by 2018
Penetanguishene (4.16kV)	MS421 (4.16kV)	Fox	2	5.6/7.6	3.4	45%	53%	1.6	60%
	MS422 (4.16kV)	Robert	2	5.6/7.6	2.8	37%			
	MS423 (4.16kV)	Bellisle	2	5.6/7.6	3.4	45%			
	MS424 (4.16kV)	Centennial	4	6/9.1	2.5	27%			

Table 9: PowerStream North – Penetanguishene Municipal Substations

PowerStream's system planning philosophy for municipal sub-stations in the north requires a "triad" model of supply – where at least three stations (or 3 transformers) are tied together through open points such that loss if one station is lost, all load from the triad supplied stations can be supplied by the remaining stations. This criteria considers individual substation transformer ratings as well as the network's contingency capacity. The triad model ensures that adequate capacity is available at adjacent substations during contingency conditions in which there is a loss of a single substation in the network (N-1 scenario).

To determine the municipal substation utilization factor for networks that adhere to the triad model, the historical peak substation loading should be evaluated against the combined contingency maximum load capacity of N-1 substations divided by the total number of substations in the area:

- N-1*(Contingency Maximum Load [MVA])/N.

For example, if a service territory has four 10MVA substations with Oil Natural Air Forced (ONAF cooling), maximum normal load, and contingency maximum load (dual fan) ratings of 10MVA, 13.3MVA and 18MVA, respectively, then the substation utilization factor would be a ratio of the historical peak substation loading to the combined contingency maximum load of all remaining substations operating during the loss of a single substation divided by the total number of available substations under normal operating conditions:

- historical peak loading/(18MVA*[4-1]/4).

The “N-1 Contingency Ratio in 2013” column illustrates the utilization factor for each region in the service territory relative to the adjacent substations during contingency conditions when a substation is out of service and loads must be distributed to surrounding stations. The N-1 Contingency Ratio uses the contingency maximum rating at the substation. Regions were established based on the existing feeder network and transfer capability during contingency conditions.

The “Load of Proposed Developments and Annual Growth by 2018 (MVA)” column indicates the amount of load growth expected to be experienced in each region until 2018. For those regions where large developments are proposed or currently under construction the total load was used, while all other regions assumed the annual growth rate identified in the PowerStream North Load Forecast. It should be noted that 2018 was selected as the load growth horizon since

PowerStream requires a minimum of three years to construct a new substation (Year 1: land purchase, Year 2: design, Year 3: construct), therefore the analysis assumes a land purchase in 2015.

The "N-1 Contingency Ratio with Developments by 2018" column was added to illustrate the utilization factor in each respective region by 2018 following the implementation of the forecasted load.

The optimal ratio of "N-1 Contingency Ratio with Developments by 2018" is 90%, to leave room for high loading periods. Higher values are not desirable. Based on these ratios, the substations are being prudently utilized. As noted in Exhibit 2, Tab 2, Section 5.4.5, additional stations are included in this DSP to meet the triad criteria.

Figure 14: Alliston Substation Locations

Figure 15: Barrie Substation Locations

Figure 16: Beeton Substation Locations

Figure 17: Bradford Substation Locations

Figure 18: Penetanguishene Substation Locations

Figure 19: Thornton Substation Locations

Figure 20: Tottenham Substation Locations

Asset Inventory

The summary inventory of major assets, including quantity, age and serviceability, are found in Figures 21 to 50. A summary of the quantity of distribution system assets is shown in Tables 10 and 11.

PowerStream ACA 2014 Asset Counts	
Asset	**Total**
Distribution Transformer	44,112
Distribution Switchgear	1,821
Wood Poles	38,070
Underground Primary Cable (km)	8,220
Min-Rupter Switch	433
Automated Switch	360

Table 10: Summary of Distribution System Assets

PowerStream ACA 2014 Asset Counts		
Asset		**Total**
Power Transformers	TS	24
	MS	72
Circuit Breakers	TS	188
	MS	210
Primary Switches	TS	22
	MS	58
230kV Primary Meting Units	combined	18
	separate	12
Station Reactors	TS	34
Station Service Transformers	TS	20
includes spares		

Table 11: Summary of Station Assets

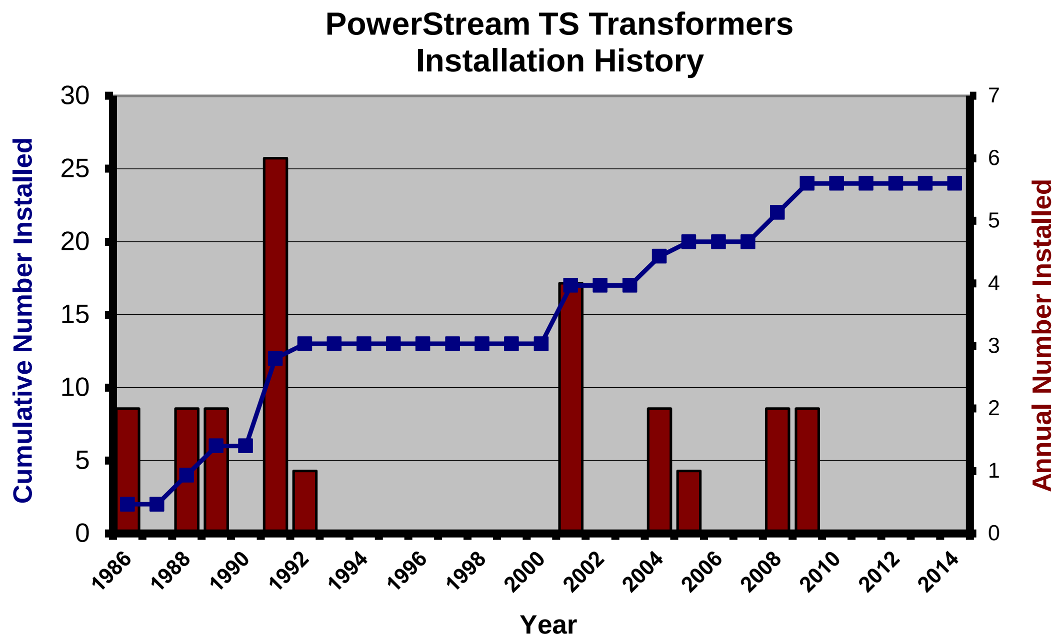


Figure 21: Installation Dates - Transformer Station Power Transformers

Figure 21 indicates that there are thirteen power transformers that are 22 years and older, and nine power transformers between 6 and 13 years old.

Location	Position	Manufacturer	MVA Nameplate	Age	Health Index Category	Health Index
Lazenby MTS1 - Richmond Hill MTS#1	T1	Hyundai	125	24	Good	74
J.V. Fry - Markham MTS#1	T1	Ferranti Packard	83	29	Good	75
Greenwood -Vaughan MTS #1	T2	TTI	125	26	Good	75
A.M. Walker - Markham MTS#2	T1	TTI	83	27	Good	75
Lazenby MTS1 - Richmond Hill MTS#1	T2	Hyundai	125	24	Good	75
Lazenby MTS2 - Richmond Hill MTS#2	T1	Pauwels	83	14	Good	77
D.H. Cockburn - Markham MTS#3 Expansion	T4	Pauwels	83	11	Good	77
D.H. Cockburn - Markham MTS#3 Expansion	T3	Pauwels	83	11	Good	77
D.H. Cockburn - Markham MTS#3	T2	ABB	83	24	Good	78
D.H. Cockburn - Markham MTS#3	T1	ABB	83	24	Good	78
A.M. Walker - Markham MTS#2	T2	TTI	83	27	Good	78
Torstar - Vaughan MTS #2	T1	ABB	125	24	Good	79
Lazenby MTS2 - Richmond Hill MTS#2	T2	Pauwels	83	14	Good	80
Greenwood -Vaughan MTS #1 Expansion	T4	ABB	125	10	Good	81
J.V. Fry - Markham MTS#1	T2	Ferranti Packard	83	29	Good	82
Greenwood -Vaughan MTS #1	T1	TTI	125	26	Good	85
Lorna Jackson - Vaughan MTS #3	T2	ABB	125	14	Good	85
Fabro TS -Markham TS#4	T1	ABB	125	7	Good	85
Fabro TS -Markham TS#4	T2	ABB	125	7	Good	85
Greenwood -Vaughan MTS #1 Expansion	T3	ABB	125	23	Very Good	86
Torstar - Vaughan MTS #2	T2	ABB	125	24	Very Good	89
Lorna Jackson - Vaughan MTS #3	T1	ABB	125	14	Very Good	91
D.H.Cochburn	Spare	Siemens	83	6	Very Good	98
Greenwood	Spare	ABB	125	6	Very Good	98

Figure 22: Health Index - Transformer Station Power Transformers

Figure 22 indicates that the power transformers are either in good or very good health.

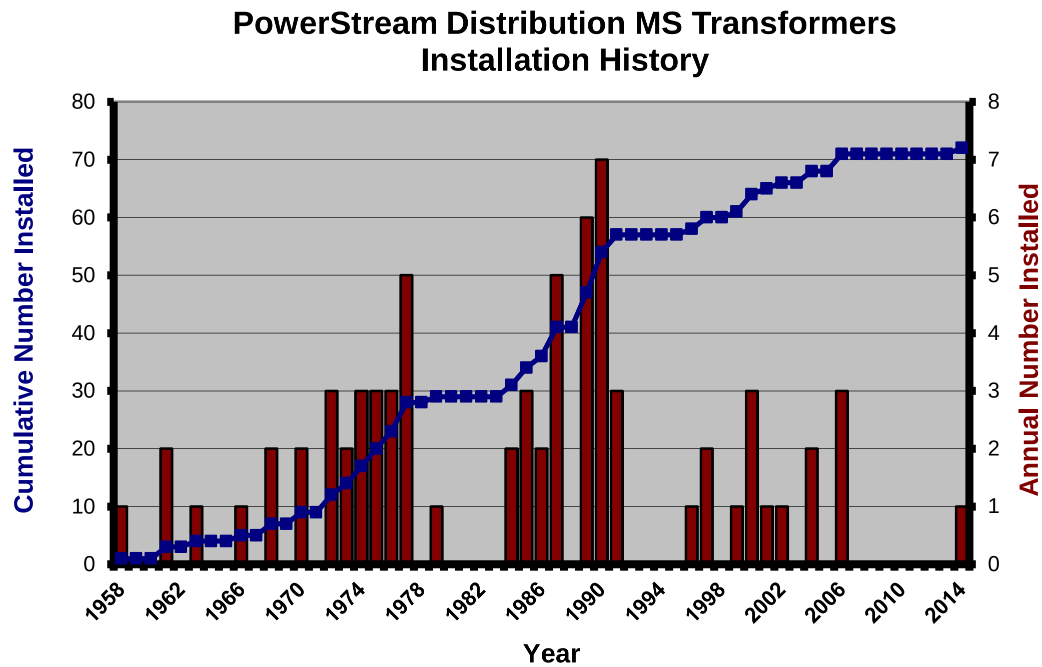


Figure 23: Installation Dates - Substation Power Transformers

Figure 23 indicates that substation power transformers are widely dispersed in age, from new to 56 years of age.

Location	Position	Status	Manufacturer	MVA Nameplate	Age	Health Index Category	Health Index
Melborne-322-T1	322-T1	Inservice	Federal Pioneer	10	39	Fair	64
BLAKE-404-T1	404-T1	Inservice	TTI	10	26	Good	72
John-321-T1	321-T1	Inservice	Moloney	10	38	Good	73
Dufferin-431-T1	431-T1	Inservice	Westinghouse	5	54	Good	73
8th Line-323-T1	323-T1	Inservice	Northern	10	25	Good	75
CUNDLES EAST-407-T1	407-T1	Inservice	General Electric	5	52	Good	78
ST. VINCENT-417-T1	417-T1	Inservice	TTI	10	28	Good	78
WELLINGTON-418-T1	418-T1	Inservice	TTI	10	24	Good	78
Nolan-834-T1	834-T1	Inservice	Westinghouse	10	30	Good	78
LITTLE LAKE-306-T1	306-T1	Inservice	Federal Pioneer	20	25	Good	79
MARY-415-T1	415-T1	Inservice	TTI	10	25	Good	79
Bellisle-423-T1	423-T1	Inservice	Porter	5	40	Good	80
FERNDALE-410-T1	410-T1	Inservice	Westinghouse	5	30	Good	82
PERRY -419-T1	419-T1	Inservice	Federal Pioneer	10	24	Good	82
Centennial-424-T1	424-T1	Inservice	Markham Electric	6	22	Good	82
Mill St.-835-T1	835-T1	Inservice	Markham Electric	6	40	Good	82
Aurora MS#1-T2	T2	Inservice	FPE	7.5	39	Good	83
Aurora MS#3-T2	T2	Inservice	Northern Transformer	10	9	Good	83
ANNE TEMP-402-T1	402-T1	Inservice	C.G.E.	5	49	Good	83
Aurora MS#2-T1	T1	Inservice	Ferranti Packard	10	36	Good	84
ANNE NORTH-301-T1	301-T1	Inservice	Federal Pioneer	20	26	Good	84
BIG BAY POINT-304-T1	304-T1	Inservice	Federal Pioneer	20	25	Good	84
8th Ave-330-T1	330-T1	Inservice	Northern	10	24	Good	84
CUNDLES WEST-408-T1	408-T1	Inservice	Federal Pioneer	5	40	Good	84
INNISFIL-411-T1	411-T1	Inservice	Federal Pioneer	5	38	Good	84
JOHNSON-412-T1	412-T1	Inservice	Federal Pioneer	10	28	Good	84
LETITIA-413-T1	413-T1	Inservice	Federal Pioneer	5	38	Good	84
LITTLE-414-T1	414-T1	Inservice	C.G.E.	5	43	Good	84
Patterson-336-T1	336-T1	Inservice	B.G. High Voltage	7.5	25	Good	85
DUCKWORTH-409-T1	409-T1	Inservice	Westinghouse	5	47	Good	85
Amber MS-T2	T2	Inservice	Northern Transformer	7.5	39	Very Good	86
Amber MS-T1	T1	Inservice		10	41	Very Good	87
Aurora MS#3-T1	T1	Inservice	Northern Transformer	10	45	Very Good	87
Baythorn MS-T2	T2	Inservice	West	10	9	Very Good	87
John Street MS-T1	T1	Inservice	West	10	43	Very Good	87
Concord MS-T1	T1	Inservice	West	10	42	Very Good	88
Morgan MS-T2	T2	Inservice	West	5	42	Very Good	88
Aurora MS#6-T1	T1	Inservice	Northern Transformer	10	54	Very Good	89
FERNDALE SOUTH-303-T1	303-T1	Inservice	Federal Pioneer	20	9	Very Good	89
BROCK-405-T1	405-T1	Inservice	TTI	10	26	Very Good	89
BURTON-406-T1	406-T1	Inservice	Moloney	5	25	Very Good	89
Robert-422-T1	422-T1	Inservice	Federal Pioneer	5	29	Very Good	89
Aurora MS#5-T2	T2	Inservice	Moloney	5	41	Very Good	91
Reagans-324-T1	324-T1	Inservice	Northern	10	38	Very Good	91
Aurora MS#4-T1	T1	Inservice	Moloney	10	41	Very Good	92
Aurora MS#5-T1	T1	Inservice	Federal Pioneer	10	16	Very Good	92
John Street MS-T2	T2	Inservice	Ferranti Packard	5	25	Very Good	92
King MS-T1	T1	Inservice	Ferranti Packard	10	19	Very Good	92
SAUNDERS-302-T1	302-T1	Inservice	Federal Pioneer	20	31	Very Good	92
HURONIA-307-T1	307-T1	Inservice	Northern	10	26	Very Good	92
14th Line-331-T2	331-T2	Inservice	Northern	10	1	Very Good	92
Fox-421-T1	421-T1	Inservice	ABB	5	11	Very Good	92
Aurora MS#4-T2	T2	Inservice	Northern Transformer	10	18	Very Good	93
Aurora MS#6-T2	T2	Inservice	Northern Transformer	10	13	Very Good	93
Baythorn MS-T1	T1	Inservice	Federal Pioneer	10	19	Very Good	93
Aurora MS#1-T1	T1	Inservice	Northern Transformer	10	26	Very Good	94
Aurora MS#8-T1	T1	Commiss	Ferranti Packard	10	18	Very Good	94
HOLLY-305-T1	305-T1	Inservice	Ferranti	20	15	Very Good	94
Park Place-308-T1	308-T1	Inservice	Ferranti	20	15	Very Good	94
Aurora MS#7-T1	T1	Commiss	Moloney	5	38	Very Good	95
14th Line-331-T1	331-T1	Inservice	Northern	10	11	Very Good	96

Figure 24: Health Index - Substation Power Transformers

Figure 24 indicates that only one of the distribution power transformers is in fair condition, with all others in good or very good condition.

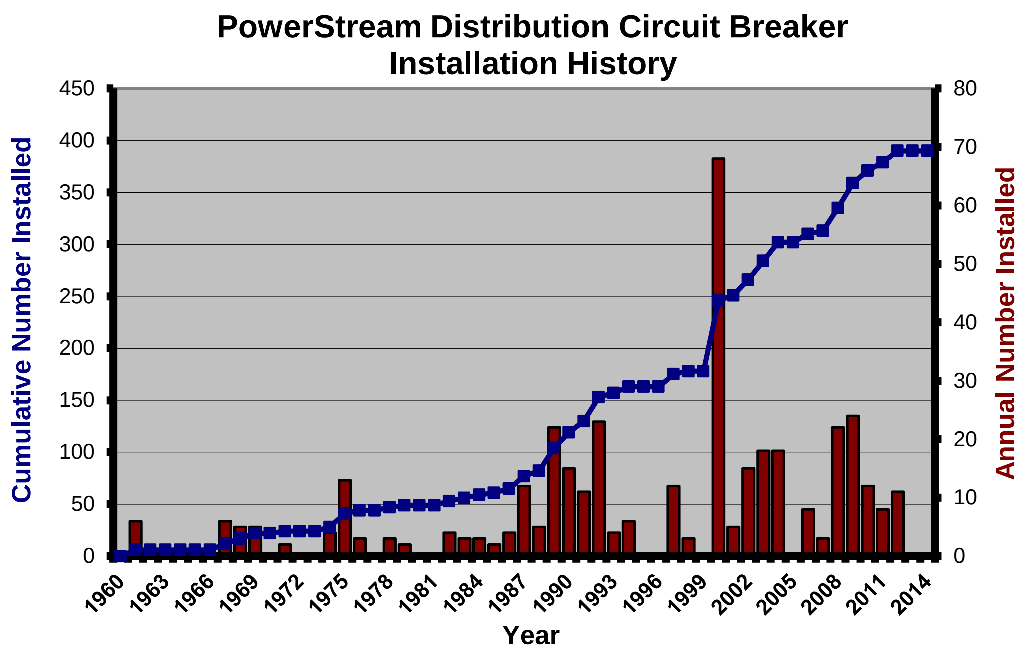


Figure 25: Installation Dates: Circuit Breakers

Figure 25 indicates that circuit breakers are widely dispersed in age, from two to 52 years of age.

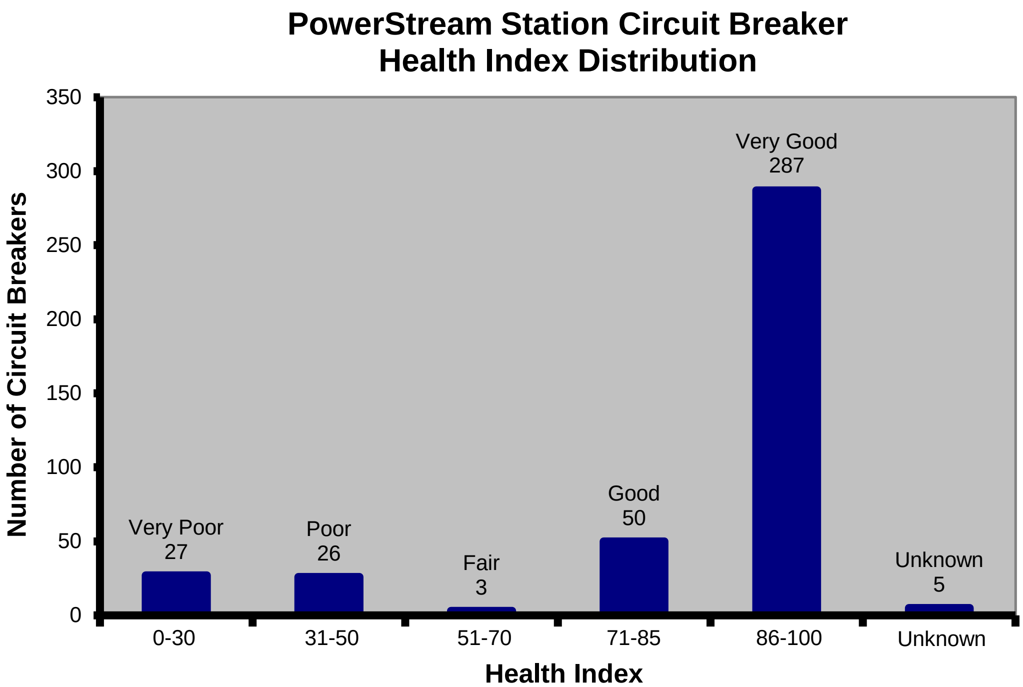


Figure 26: Health Condition – Circuit Breakers

Figure 26 indicates that the vast majority of circuit breakers are in good or very good condition, and 56 breakers range from fair to very poor.

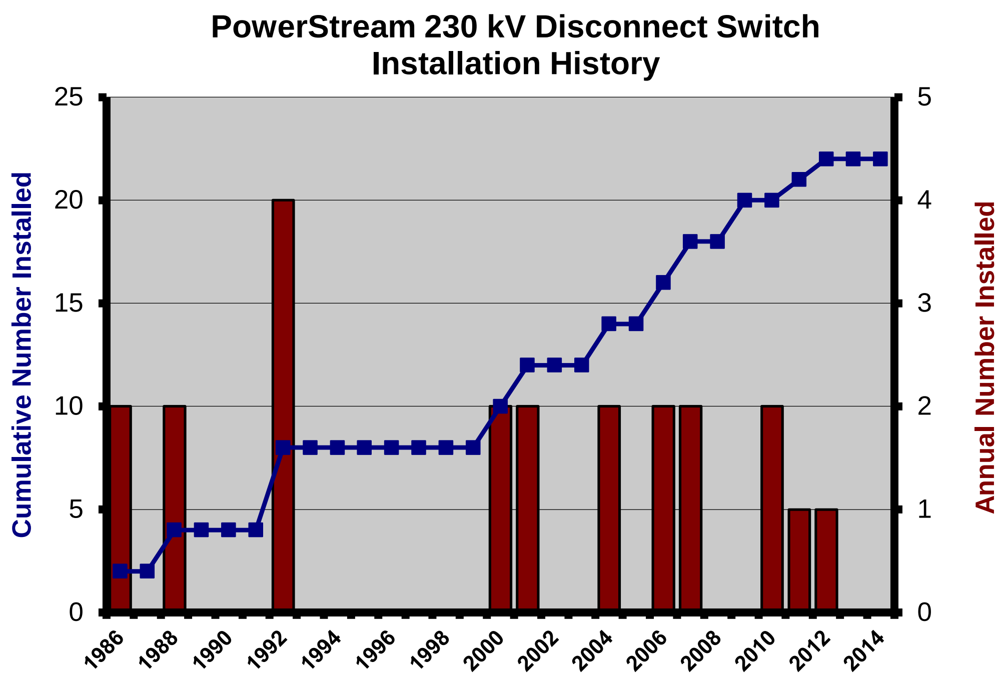


Figure 27: Installation Dates: Transformer Station 230kV Disconnect Switches

Figure 27 indicates that the 230 kV disconnect switches are widely dispersed in age, from two to 28 years of age.

Transformer Station	Switch Designation	Manufacturer	Switch Type	Age	Health Index Category	Health Index
J.V. Fry - Markham MTS#1	8122T1-P21R	Markham Electric	4415-9 or	6	Good	81
J.V. Fry - Markham MTS#1	8122T2-P22R	Markham Electric	AA-0036	6	Good	81
D.H. Cockburn - Markham MTS#3	8126T1-C35P	Southern States	EV-2	6	Good	81
D.H. Cockburn - Markham MTS#3	8126T2-C36P	Southern States	EV-2	6	Good	81
Lazenby MTS1 - Richmond Hill MTS#2	8136T3-V71RP	GS T&D	AVB2301200M	9	Good	83
Lazenby MTS1 - Richmond Hill MTS#2	8136T4-V75RP	GS T&D	AVB2301200M	9	Good	83
A.M. Walker - Markham MTS#2	8124T1-C35P	Markham Electric	4415-9 or	6	Very Good	88
A.M. Walker - Markham MTS#2	8124T2-C36P	Markham Electric	AA-0036	6	Very Good	88
Torstar - Vaughan MTS #2	5121T1-V71RP	ABB	TTR-6	6	Very Good	91
Torstar - Vaughan MTS #2	5121T2-V75RP	ABB	TTR-6	6	Very Good	91
Lorna Jackson - Vaughan MTS #3	5122T1-V75RP	Alstom	CGVB	9	Very Good	98
Lorna Jackson - Vaughan MTS #3	5122T2-V74R	Alstom	CGVB	9	Very Good	98
D.H. Cockburn - Markham MTS#3 Expansion	8126T3-C35P	S&C	197031-BE12H1KMPTUVW1Y	9	Very Good	98
D.H. Cockburn - Markham MTS#3 Expansion	8126T4-C36P	S&C	197031-BE12H1KMPTUVW1Y	9	Very Good	98
Greenwood -Vaughan MTS #1	5120T1-V71RP	Southern States	EV-2	12	Very Good	100
Greenwood -Vaughan MTS #1	5120T2-V75RP	Southern States	EV-2	12	Very Good	100
Greenwood -Vaughan MTS #1 Expansion	5120T3-V71RP	Southern States	EV-2	12	Very Good	100
Greenwood -Vaughan MTS #1 Expansion	5120T4-V75RP	Southern States	EV-2	12	Very Good	100
Lazenby MTS1 - Richmond Hill MTS#1	8127T1-V71RP	Southern States	EV-2	12	Very Good	100
Lazenby MTS1 - Richmond Hill MTS#1	8127T2-V75RP	Southern States	EV-2	12	Very Good	100
Fabro TS - Markham TS#4	7110T1-P45	Southern States	EV-2	12	Very Good	100
Fabro TS - Markham TS#4	7110T2-P46	Southern States	EV-2	12	Very Good	100

Figure 28: Health Indices: Installation Dates: Transformer Station 230kV Disconnect Switches

Figure 28 indicates that all of the 230kV disconnect switches are in good or very good health.

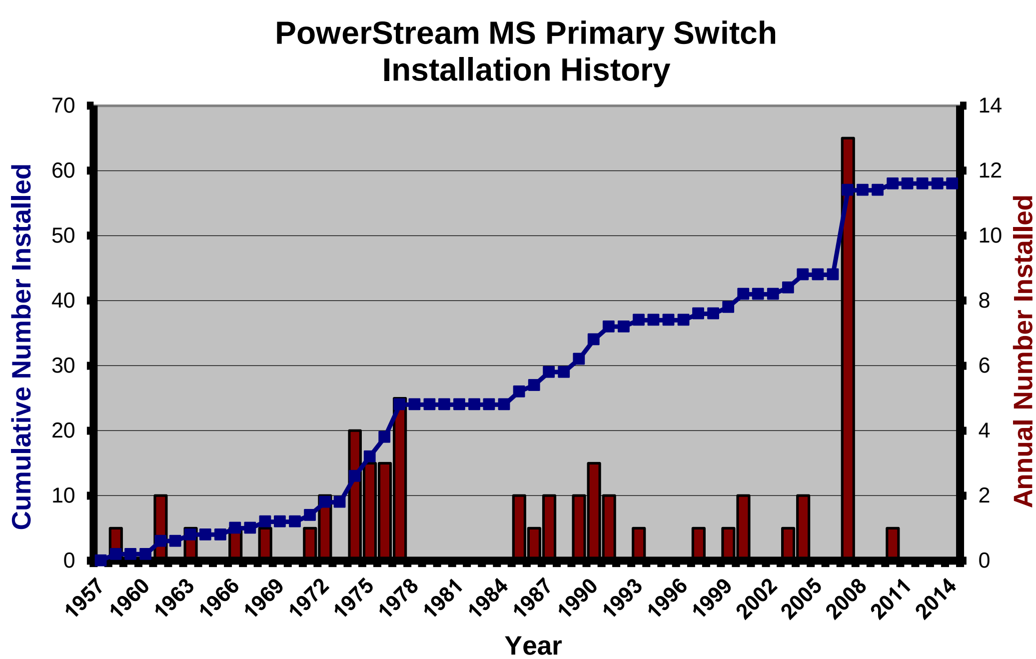


Figure 29: Substation Primary Disconnect Switches

Figure 29 indicates that that substation primary disconnect switches are widely dispersed in age, from four to 56 years of age.

Municipal Station	Switch ID	Switch Type		Switch Manufacturer	Fuse Type	Fuse Size	Primary Voltage	Age	Health Index Category	Health Index
MS431-Dufferin	AB-431	Pole Mounted 46 kV ABS	Pole		SMD-2C	80E-119-1	44	54	Good	73
MS307 - Huronia Rd	AB-307	Pole Mounted 46 kV ABS	Pole		SMD-2C	300E-153-1	44	12	Good	73
King MS	KINGT1_SW1	Outdoor Pole Mounted 46 kV ALDUTI LIS	Pole	S&C Electric	1A	125E	27.6	54	Good	74
MS432-Fletcher	AB-432	Pole Mounted 46 kV ABS	Pole		SMD-2C	100E-153-1	44	44	Good	75
MS305 - Holly	AB-305	Pole Mounted 46 kV ABS	Pole			N/A	44	15	Good	75
MS406 - BURTON AVE	AB-406	Pole Mounted 46 kV ABS	Pole		SMD-2C	100E-119-1	44	41	Good	75
MS409-Duckworth	AB-409	Pole Mounted 46 kV ABS	Pole		SMD-2C	100E-153-1	44	47	Good	75
MS413 - Letitia	AB-413	Pole Mounted 46 kV ABS	Pole		SMD-2C	150E-153-1	44	38	Good	75
MS418-Wellington	AB-418	Pole Mounted 46 kV ABS	Pole		SMD-2C	150E-119-1	44	41	Good	75
MS423-Bellisle	AB-423	Pole Mounted 46 kV ABS	Pole		SMD-2C	80E-119-1	44	40	Good	75
MS835-MILL St.	AB-835	Pole Mounted 46 kV ABS	Pole		SMD-2C	100E-153-1	44	40	Good	75
Aurora MS#2	AURMS2T1_SW1	46 kV Metalclad ALDUTI LIS	Enclosure	S&C Electric	SMD 2C	200E	44	8	Good	76
MS404 - Blake	AB-404	Pole Mounted 46 kV ABS	Pole		SMD-2C	200E-153-1	44	26	Good	77
MS405-Brock	AB-405	Pole Mounted 46 kV ABS	Pole		SMD-2C	200E-153-1	44	26	Good	77
MS410 - FERNDALE DR	AB-410	Pole Mounted 46 kV ABS	Pole		SMD-2C	100E-119-1	44	30	Good	77
MS415-T1-Mary	LT-415	Pole Mounted 46 kV ABS	Pole			N/A	44	25	Good	77
MS417 - St. Vincent	AB-417	Pole Mounted 46 kV ABS	Pole		SMD-2C	200E-153-1	44	28	Good	77
MS336-Patterson	LT-336	46 kV Metalclad ALDUTI LIS	Enclosure	S&C	SMD-2C	150E-153-1	44	25	Good	77
MS422-Robert	AB-422	Pole Mounted 46 kV ABS	Pole		SMD-2C	100E-153-1	44	29	Good	77
Amber MS	AMBERT1_SW1	Outdoor Pole Mounted 46 kV ALDUTI LIS	Pole	S&C Electric	SM-5	200E	27.6	43	Good	78
John Street MS	JOHNT1_SW1	SMD-40	Enclosure	S&C Electric	SMU-40	250E	27.6	41	Good	78
John Street MS	JOHNT2_SW2	SMD-40	Enclosure	S&C Electric	SMU-40	250E	27.6	41	Good	78
Aurora MS#5	AURMS5T2_SW2	Outdoor Pole Mounted 46 kV ALDUTI LIS	Pole	S&C Electric	SMD 2C	200E	44	8	Good	78
MS330-8th Ave.	LT-330	46 kV Metalclad ALDUTI LIS	Enclosure	S&C	SMD-2C	150E-119-1	44	24	Good	78
MS308 - Park Place	AB-308	Pole Mounted 46 kV ABS	Pole			N/A	44	5	Good	79
MS407-Cundles East	AB-407	Pole Mounted 46 kV ABS	Pole		SMD-2C	100E-119-1	44	52	Good	79
MS321-John	AB-321	Pole Mounted 46 kV ABS	Pole	Dominion Cutout	SMD-2C	150E-119-1	44	38	Good	79
MS322-Melborne	AB-322	Pole Mounted 46 kV ABS	Pole		SMD-2C	150E-119-1	44	39	Good	79
MS421-Fox	AB-421	Pole Mounted 46 kV ABS	Pole		SMD-2C	80E-119-1	44	18	Good	79
Baythorn MS	BAYTHT1_SW1	Outdoor Pole Mounted 46 kV ALDUTI LIS	Pole	S&C Electric	SM-5	300E ?	27.6	39	Good	80
Baythorn MS	BAYTHT2_SW2	Outdoor Pole Mounted 46 kV ALDUTI LIS	Pole	S&C Electric	SM-5	300E ?	27.6	39	Good	80
Concord MS	CONCT1_SW1	Outdoor Pole Mounted 46 kV ALDUTI LIS	Pole	S&C Electric	SM-5	Unknown	27.6	15	Good	80
Aurora MS#3	AURMS3T2_SW2	46 kV Metalclad ALDUTI LIS	Enclosure	S&C Electric	SMD 2C	200E	44	8	Good	80
MS402 - ANNE TEMP	AB-402	Pole Mounted 46 kV ABS	Pole		SMD-2C	100E-119-1	44	49	Good	81
MS408-Cundles West	LT-408	Pole Mounted 46 kV ALDUTI LIS	Pole	S&C	SMD-2C	100E-119-1	44	40	Good	81
MS411 - INNISFIL ST	AB-411	Pole Mounted 46 kV ABS	Pole		SMD-2C	100E-119-1	44	38	Good	81
MS412-Johnson	LT-412	Pole Mounted 46 kV ABS	Pole		SMD-2C	100E-119-1	44	28	Good	81
MS414 - LITTLE AVE	AB-414	Pole Mounted 46 kV ABS	Pole		SMD-2C	100E-119-1	44	43	Good	81
MS419 - PERRY ST	AB-419	Pole Mounted 46 kV ABS	Pole			N/A	44	24	Good	81
MS323-8th Line	LT-323	Enclosed S&C 46KV LIS	Pole	S&C	SMD-2C	150E-119-1	44	25	Good	81
Morgan MS	MORGT2_SW2	SMD-20	Enclosure	S&C Electric	SMU-20	100K	27.6	38	Good	82
Aurora MS#3	AURMS3T1_SW1	46 kV Metalclad ALDUTI LIS	Enclosure	S&C Electric	SMD 2C	200E	44	8	Good	82
Aurora MS#4	AURMS4T1_SW1	46 kV Metalclad ALDUTI LIS	Enclosure	S&C Electric	SMD 2C	200E	44	8	Good	82
Aurora MS#4	AURMS4T2_SW2	46 kV Metalclad ALDUTI LIS	Enclosure	S&C Electric	SMD 2C	200E	27.6	8	Good	82
Aurora MS#5	AURMS5T1_SW1	Outdoor Pole Mounted 46 kV ALDUTI LIS	Pole	S&C Electric	SMD 2C	200E	44	8	Good	82
MS324-Reagens	LT-324	Pole Mounted 46 kV ALDUTI LIS	Pole	S&C	SMD-2C	175E-119-1	44	16	Good	83
MS424-Centennial	AB-424	Pole Mounted 46 kV ABS	Pole		SMD-2C	100E-153-1	44	22	Good	84
MS834-Nolan Rd.	AB-834	Pole Mounted 46 kV ABS	Pole		SMD-2C	150E-153-1	44	30	Good	84
Morgan MS	MORGT1_SW1	Outdoor Pole Mounted 46 kV ALDUTI LIS	Pole	S&C Electric	SM-5	125E	27.6	38	Very Good	88
Elder Mills MS	ELDERT1_SW1	Outdoor Pole Mounted 46 kV ALDUTI LIS	Pole	S&C Electric	SM-5	200E	27.6	57	Very Good	91
Aurora MS#6	AURMS6T1_SW1	Outdoor Pole Mounted 46 kV ALDUTI LIS	Pole	S&C Electric	SMD 2C	200E	44	8	Very Good	93
Aurora MS#6	AURMS6T2_SW2	Outdoor Pole Mounted 46 kV ALDUTI LIS	Pole	S&C Electric	SMD 2C	200E	44	8	Very Good	93
Aurora MS#1	AURMS1T2_SW2	Outdoor Pole Mounted 46 kV ALDUTI LIS	Pole	S&C Electric	SMD 2C	200E	44	8	Very Good	96
Aurora MS#1	AURMS1T1_SW1	Outdoor Pole Mounted 46 kV ALDUTI LIS	Pole	S&C Electric	SMD 2C	200E	44	8	Very Good	100
Aurora MS#7	AURMS7T1_SW1	Outdoor Pole Mounted 46 kV ALDUTI LIS	Pole	S&C Electric	SMD 2C	200E	44	8	Very Good	100
Aurora MS#8	AURMS8T1_SW1	Outdoor Pole Mounted 46 kV ALDUTI LIS	Pole	S&C Electric	SMD 2C	200E		8	Very Good	100
MS331-T1-14TH LINE	LT-331-T1	Pole Mounted 46 kV ALDUTI LIS	Pole	S&C	SMD-2C	300E-153-1	44	11	Very Good	100
MS331-T2-14TH LINE	LT-331-T2	Pole Mounted 46 kV ALDUTI LIS	Pole	S&C	SMD-2C	300E-153-1	44	11	Very Good	100

Figure 30: Health Indices: Substation Primary Disconnect Switches

Figure 30 indicates that all of the substation primary disconnect switches are in good or very good health.

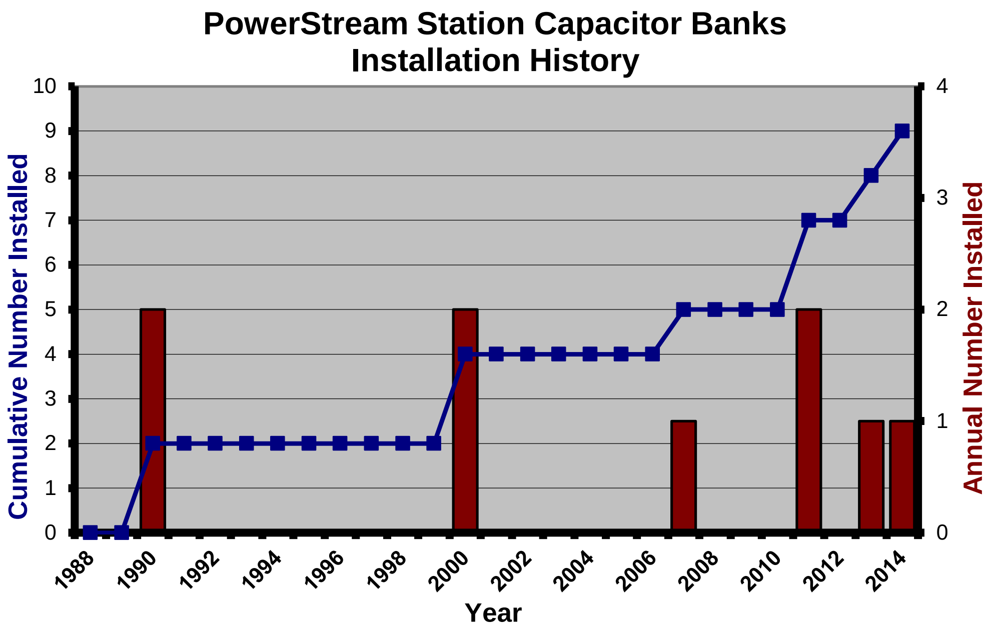


Figure 31: Transformer Station Capacitor Banks

Figure 31 indicates that the capacitor banks range in ages from new to 24 years old.

Transformer Station Name	Capacitor ID	Capacitor Designation	Capacitor Manufacturer	MVAR	Age	Health Index Category	Health Index
Greenwood -Vaughan MTS #1	VTS1_CAP1	SC-A	ABB (open rack type, with externally fused units)	21.6	25	Good	81
Greenwood -Vaughan MTS #1	VTS1_CAP2	SC-B	ABB (open rack type, with externally fused units)	21.6	25	Good	81
Lorna Jackson - Vaughan MTS #3	VTS3_CAP1	SC-1	ABB (indoor, metal enclosed internally fused units)	20	15	Very Good	100
Lorna Jackson - Vaughan MTS #3	VTS3_CAP2	SC-2	ABB (indoor, metal enclosed internally fused units)	20	15	Very Good	100
J.V. Fry - Markham MTS#1	MTS1_CAP1	SC-1	ABB (open rack type, with externally fused units)	22.5	8	Very Good	100
Fabro TS - Markham MTS#4	MTS4_CAP1	SC-1	ABB (open rack type, with externally fused units)	20	1	Very Good	100
Fabro TS - Markham MTS#4	MTS4_CAP2	SC-2	ABB (open rack type, with externally fused units)	20	2	Very Good	100
Torstar - Vaughan MTS#2	VTS2_CAP1	SC-A	ABB (open rack type, with externally fused units)	20	4	Very Good	100
Torstar - Vaughan MTS#2	VTS2_CAP2	SC-B	ABB (open rack type, with externally fused units)	20	4	Very Good	100

Figure 32: Health Indices: Transformer Station Capacitor Banks

Figure 32 indicates that all capacitor banks are either in good or very good condition.

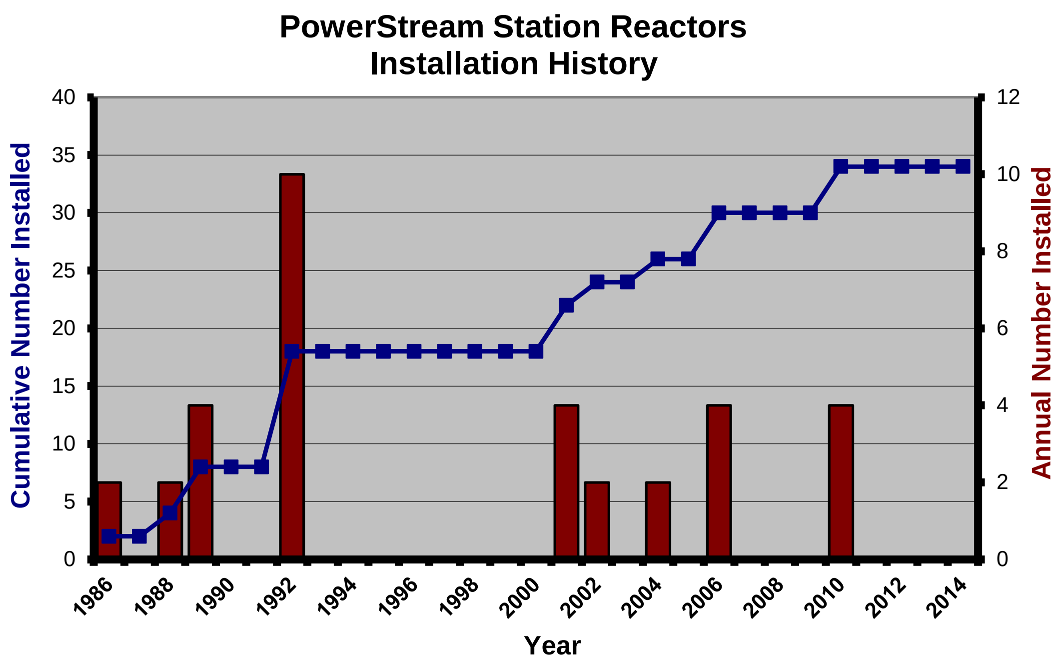


Figure 33: Installation Dates: Station Reactors

Figure 33 indicates that the station reactors are widely dispersed in age, from four to 28 years of age.

Transformer Station Name	Transformer ID	Manufacturer	Age	Health Index Category	Health Index
A.M. Walker - Markham MTS#2	T1	Trench	27	Very Good	96
A.M. Walker - Markham MTS#2	T2	Trench	27	Very Good	96
D.H. Cockburn - Markham MTS#3	T1	Trench	23	Very Good	96
D.H. Cockburn - Markham MTS#3	T2	Trench	23	Very Good	96
D.H. Cockburn - Markham MTS#3 Expansion	T3	Trench	11	Very Good	96
D.H. Cockburn - Markham MTS#3 Expansion	T4	Trench	11	Very Good	96
Fabro TS - Markham TS#4	T1X	Trench	5	Very Good	96
Fabro TS - Markham TS#4	T1Y	Trench	5	Very Good	96
Fabro TS - Markham TS#4	T2X	Trench	5	Very Good	96
Fabro TS - Markham TS#4	T2Y	Trench	5	Very Good	96
Greenwood -Vaughan MTS #1	T1X	Trench	26	Very Good	96
Greenwood -Vaughan MTS #1	T1Y	Trench	26	Very Good	96
Greenwood -Vaughan MTS #1	T2X	Trench	26	Very Good	96
Greenwood -Vaughan MTS #1	T2Y	Trench	26	Very Good	96
Greenwood -Vaughan MTS #1 Expansion	T3X	Trench	9	Very Good	96
Greenwood -Vaughan MTS #1 Expansion	T3Y	Trench	9	Very Good	96
Greenwood -Vaughan MTS #1 Expansion	T4X	Trench	9	Very Good	96
Greenwood -Vaughan MTS #1 Expansion	T4Y	Trench	9	Very Good	96
J.V. Fry - Markham MTS#1	T1	Trench	29	Very Good	96
J.V. Fry - Markham MTS#1	T2	Trench	29	Very Good	96
Lazenby MTS1 - Richmond Hill MTS#1	T1X	Trench	23	Very Good	96
Lazenby MTS1 - Richmond Hill MTS#1	T1Y	Trench	23	Very Good	96
Lazenby MTS1 - Richmond Hill MTS#1	T2X	Trench	23	Very Good	96
Lazenby MTS1 - Richmond Hill MTS#1	T2Y	Trench	23	Very Good	96
Lazenby MTS2 - Richmond Hill MTS#2	T1	Trench	13	Very Good	96
Lazenby MTS2 - Richmond Hill MTS#2	T2	Trench	13	Very Good	96
Lorna Jackson - Vaughan MTS #3	T1X	Trench	14	Very Good	96
Lorna Jackson - Vaughan MTS #3	T1Y	Trench	14	Very Good	96
Lorna Jackson - Vaughan MTS #3	T2X	Trench	14	Very Good	96
Lorna Jackson - Vaughan MTS #3	T2Y	Trench	14	Very Good	96
Torstar - Vaughan MTS #2	T1X	Trench	23	Very Good	96
Torstar - Vaughan MTS #2	T1Y	Trench	23	Very Good	96
Torstar - Vaughan MTS #2	T2X	Trench	23	Very Good	96
Torstar - Vaughan MTS #2	T2Y	Trench	23	Very Good	96

Figure 34: Health Indices: Station Reactors

Figure 34 indicates that all the station reactors are in very good health.

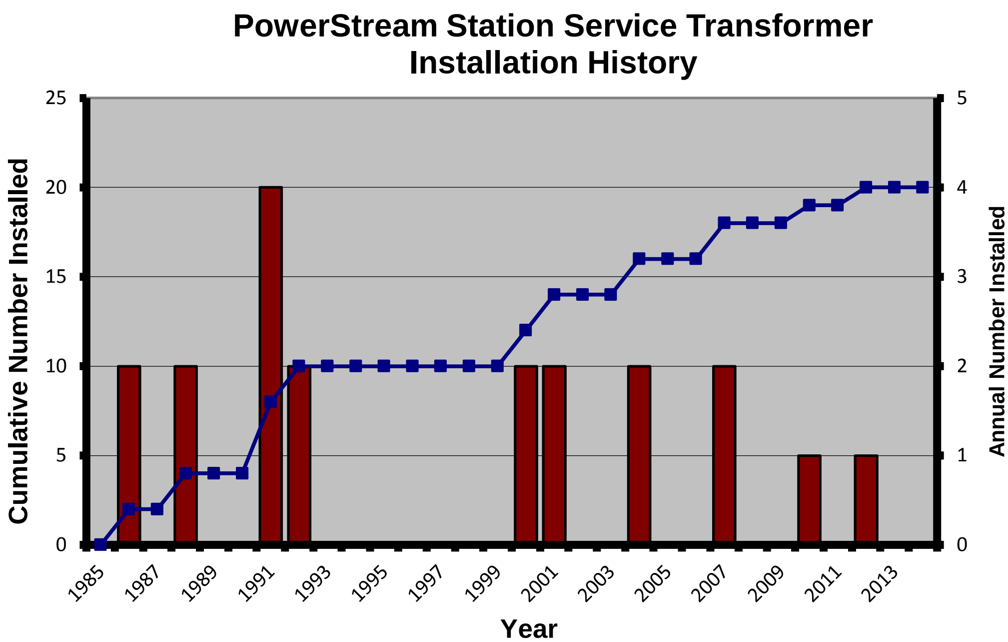


Figure 35: Installation Dates: Station Service Transformer (TS Stations)

Figure 35 indicates that the station service transformers are widely dispersed in age, from four to 28 years of age.

TS ID	Power Transformer ID	SS Transformer Rating (KVA)	Age	Health Index	Health Index Category
J.V. Fry - Markham MTS#1	T1	225	29	75	Good
J.V. Fry - Markham MTS#1	T2	225	29	75	Good
A.M. Walker - Markham MTS#2	T1	225	27	75	Good
A.M. Walker - Markham MTS#2	T2	225	27	75	Good
Torstar - Vaughan MTS #2	T1	225	24	95	Very Good
Torstar - Vaughan MTS #2	T2	225	24	95	Very Good
Lazenby MTS1 - Richmond Hill MTS#1	T1	225	23	95	Very Good
Lazenby MTS1 - Richmond Hill MTS#1	T2	225	23	95	Very Good
D.H. Cockburn - Markham MTS#3	T1	225	24	95	Very Good
D.H. Cockburn - Markham MTS#3	T2	225	24	95	Very Good
Greenwood -Vaughan MTS #1	T1	225	8	100	Very Good
Greenwood -Vaughan MTS #1	T2	225	8	100	Very Good
Lorna Jackson - Vaughan MTS #3	T1	300	14	100	Very Good
Lorna Jackson - Vaughan MTS #3	T2	300	14	100	Very Good
Lazenby MTS1 - Richmond Hill MTS#2	T1	225	15	100	Very Good
Lazenby MTS1 - Richmond Hill MTS#2	T2	225	15	100	Very Good
D.H. Cockburn - Markham MTS#3 Expansion	T3	225	11	100	Very Good
D.H. Cockburn - Markham MTS#3 Expansion	T4	225	11	100	Very Good
Fabro TS - Markham TS#4	T1	150	3	100	Very Good
Fabro TS - Markham TS#4	T2	150	5	100	Very Good

Figure 36: Health Indices: Station Service Transformer (TS Stations)

Figure 36 indicates that the station service transformers are in good or very good health.

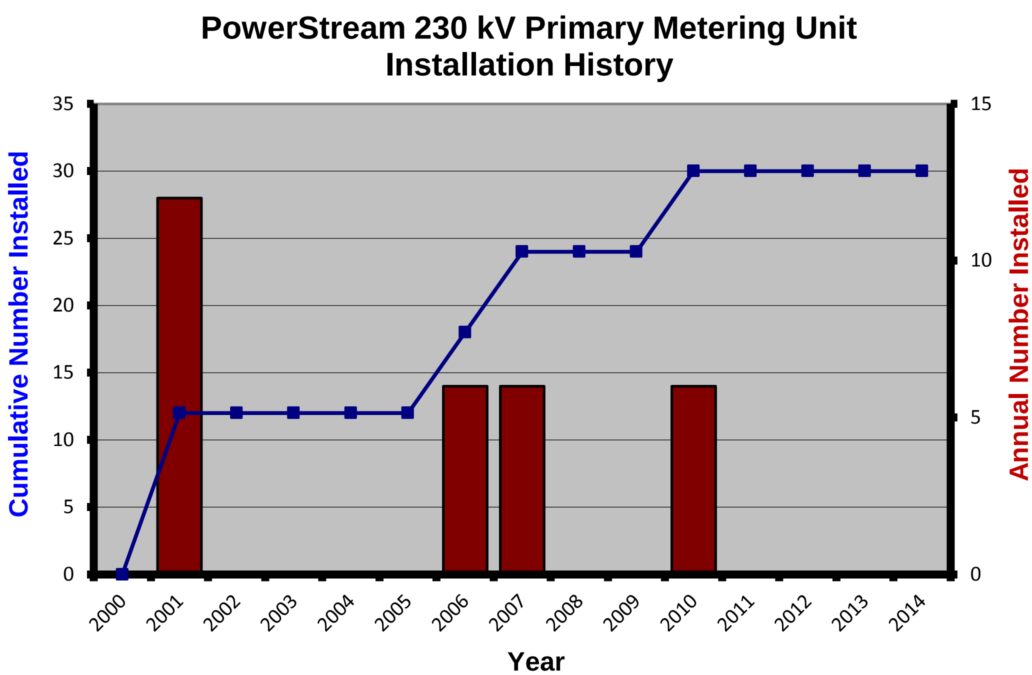


Figure 37: Installation Dates: Primary Metering Units (Transformer Stations)

Figure 37 indicates that the primary metering units ranges from four to 14 years of age.

TS ID	PMU ID	PMU MANUFACTURER	PMU MODEL NUMBER	PMU TYPE	INSULATING MEDIUM	Age	Health Index	Health Index Category
Greenwood -Vaughan MTS #1	5120-T1-PMU-W	Trench	N5-1050	Combined	Oil	8	93	Very Good
Greenwood -Vaughan MTS #1	5120-T1-PMU-B	Trench	N5-1050	Combined	Oil	8	93	Very Good
Greenwood -Vaughan MTS #1	5120-T2-PMU-R	Trench	N5-1050	Combined	Oil	8	93	Very Good
Greenwood -Vaughan MTS #1	5120-T2-PMU-W	Trench	N5-1050	Combined	Oil	8	93	Very Good
Greenwood -Vaughan MTS #1	5120-T2-PMU-B	Trench	N5-1050	Combined	Oil	8	93	Very Good
Greenwood -Vaughan MTS #1 Expansion	5120-T3-PMU-R	Trench	N5-1050	Combined	Oil	8	93	Very Good
Greenwood -Vaughan MTS #1 Expansion	5120-T3-PMU-W	Trench	N5-1050	Combined	Oil	9	93	Very Good
Greenwood -Vaughan MTS #1 Expansion	5120-T3-PMU-B	Trench	N5-1050	Combined	Oil	9	93	Very Good
Greenwood -Vaughan MTS #1 Expansion	5120-T4-PMU-R	Trench	N5-1050	Combined	Oil	9	93	Very Good
Greenwood -Vaughan MTS #1 Expansion	5120-T4-PMU-W	Trench	N5-1050	Combined	Oil	9	93	Very Good
Greenwood -Vaughan MTS #1 Expansion	5120-T4-PMU-B	Trench	N5-1050	Combined	Oil	9	93	Very Good
Lorna Jackson - Vaughan MTS #3	5122-T1-CT-R	Trench	OSKF-1050	CT	Oil	9	93	Very Good
Lorna Jackson - Vaughan MTS #3	5122-T1-CT-W	Trench	OSKF-1050	CT	Oil	14	93	Very Good
Lorna Jackson - Vaughan MTS #3	5122-T1-CT-B	Trench	OSKF-1050	CT	Oil	14	93	Very Good
Lorna Jackson - Vaughan MTS #3	5122-T2-CT-R	Trench	OSKF-1050	CT	Oil	14	93	Very Good
Lorna Jackson - Vaughan MTS #3	5122-T2-CT-W	Trench	OSKF-1050	CT	Oil	14	93	Very Good
Lorna Jackson - Vaughan MTS #3	5122-T2-CT-B	Trench	OSKF-1050	CT	Oil	14	93	Very Good
Lorna Jackson - Vaughan MTS #3	5122-T1-PT-R	Trench	UTS-1050-230	PT	Oil	14	93	Very Good
Lorna Jackson - Vaughan MTS #3	5122-T1-PT-W	Trench	UTS-1050-230	PT	Oil	14	93	Very Good
Lorna Jackson - Vaughan MTS #3	5122-T1-PT-B	Trench	UTS-1050-230	PT	Oil	14	93	Very Good
Lorna Jackson - Vaughan MTS #3	5122-T2-PT-R	Trench	UTS-1050-230	PT	Oil	14	93	Very Good
Lorna Jackson - Vaughan MTS #3	5122-T2-PT-W	Trench	UTS-1050-230	PT	Oil	14	93	Very Good
Lorna Jackson - Vaughan MTS #3	5122-T2-PT-B	Trench	UTS-1050-230	PT	Oil	14	93	Very Good
Fabro TS - Markham TS#4	7110-T1-PMU-R	Trench	N5-1050	Combined	Oil	14	100	Very Good
Fabro TS - Markham TS#4	7110-T1-PMU-W	Trench	N5-1050	Combined	Oil	5	100	Very Good
Fabro TS - Markham TS#4	7110-T1-PMU-B	Trench	N5-1050	Combined	Oil	5	100	Very Good
Fabro TS - Markham TS#4	7110-T2-PMU-R	Trench	N5-1050	Combined	Oil	5	100	Very Good
Fabro TS - Markham TS#4	7110-T1-PMU-W	Trench	N5-1050	Combined	Oil	5	100	Very Good
Fabro TS - Markham TS#4	7110-T1-PMU-B	Trench	N5-1050	Combined	Oil	5	100	Very Good

Figure 38: Health Indices: Primary Metering Units (Transformer Stations)

Figure 38 indicates that all the primary metering units are in good health.

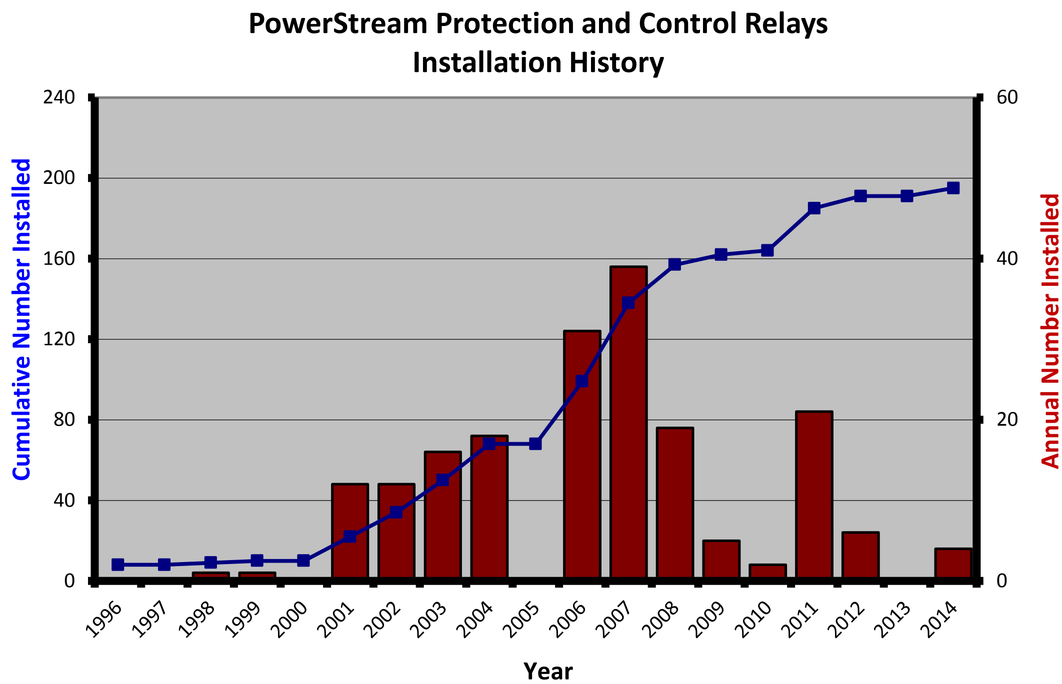


Figure 39: Installation Dates: Protection and Control Relays

Figure 39 indicates that the protection and control relays range from new to 18 years of age.

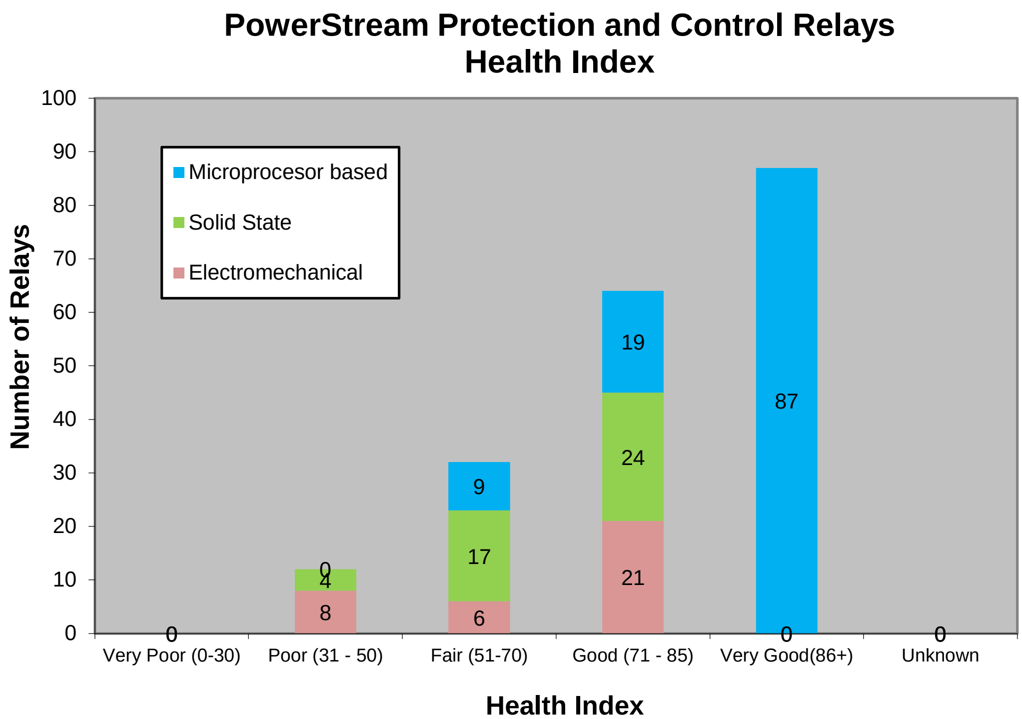


Figure 40: Health Indices: Protection and Control Relays

Figure 40 indicates that the majority of the relays are in good or very good condition, but that there are quite a few that are fair or poor.

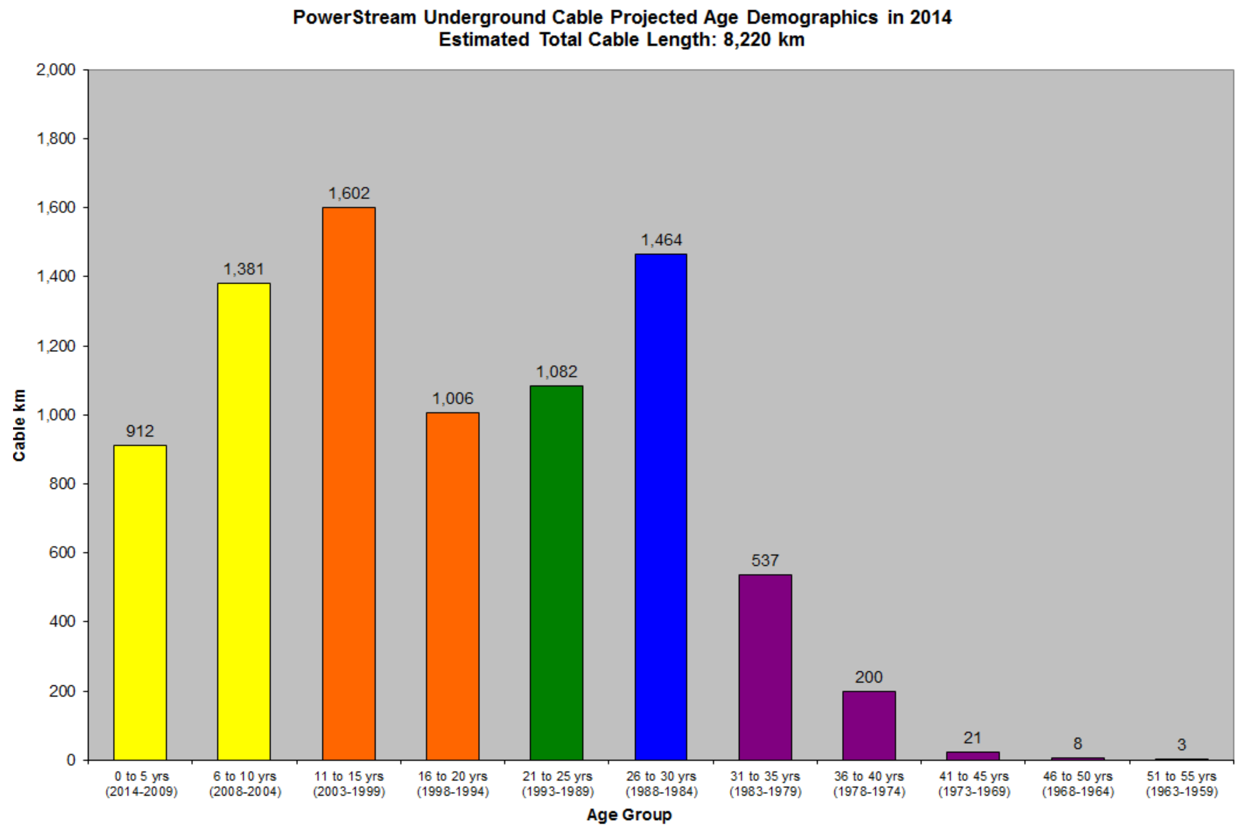


Figure 41: Underground Cable Demographics

Figure 41 indicates that there is a significant amount of cable that is older than 25 years of age.

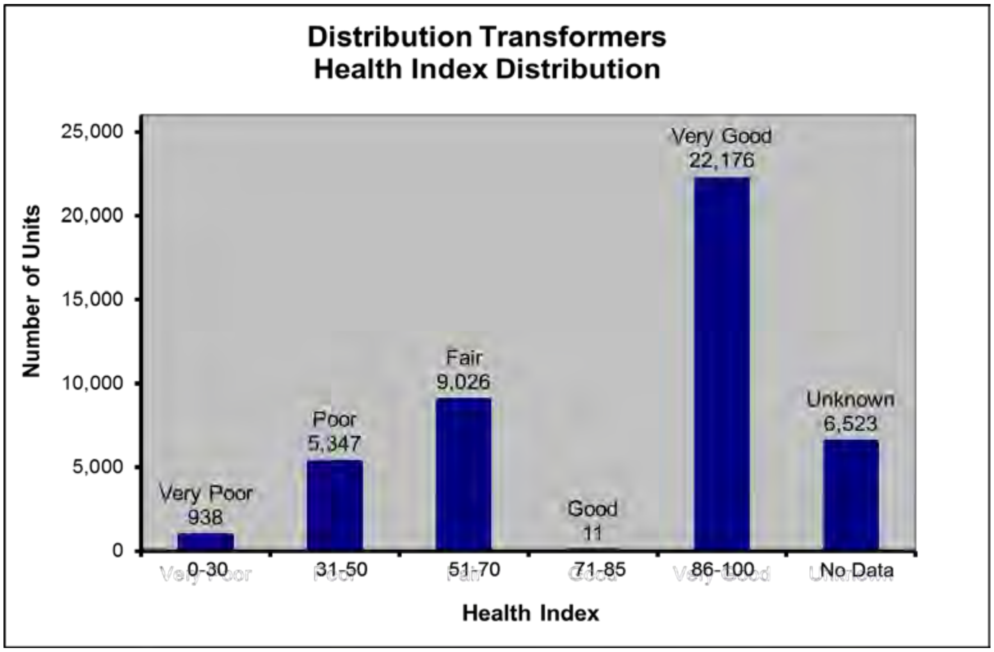


Figure 42: Distribution Transformer Health Assessment

Figure 42 indicates roughly half of the transformers are in very good health, and that information is missing on quite a few units, while there are still a considerable number of transformers in poor or very poor health.

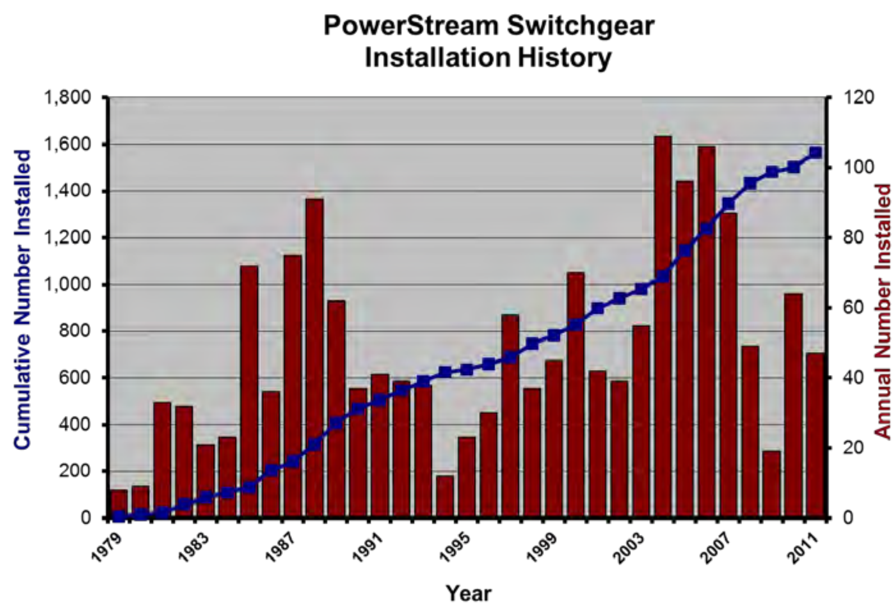


Figure 43: Installation Dates: Distribution Switchgear

Figure 43 indicates that the switchgear range from new to 35 years of age.

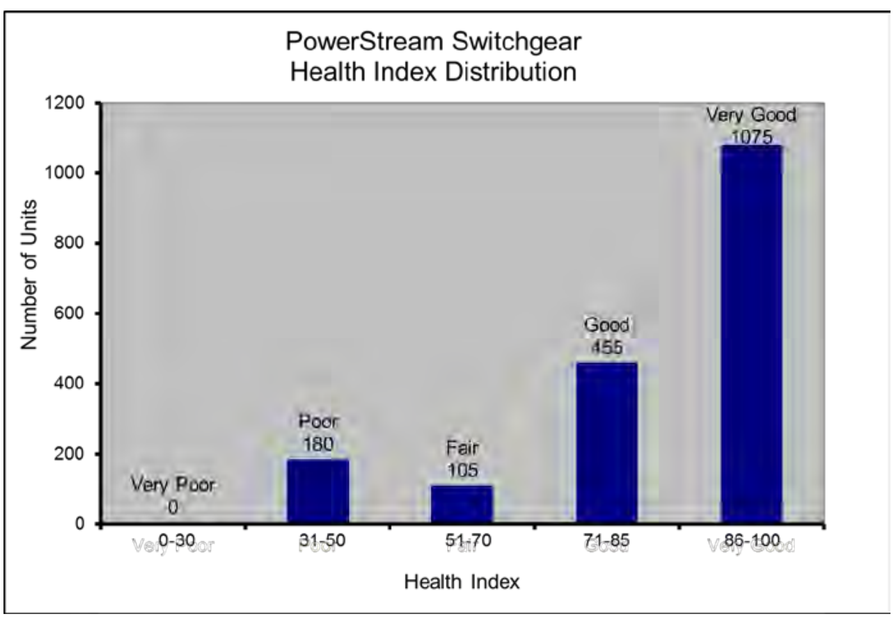


Figure 44: Switchgear Health Assessment

Figure 44 indicates that the majority of switchgear are in fair to very good health

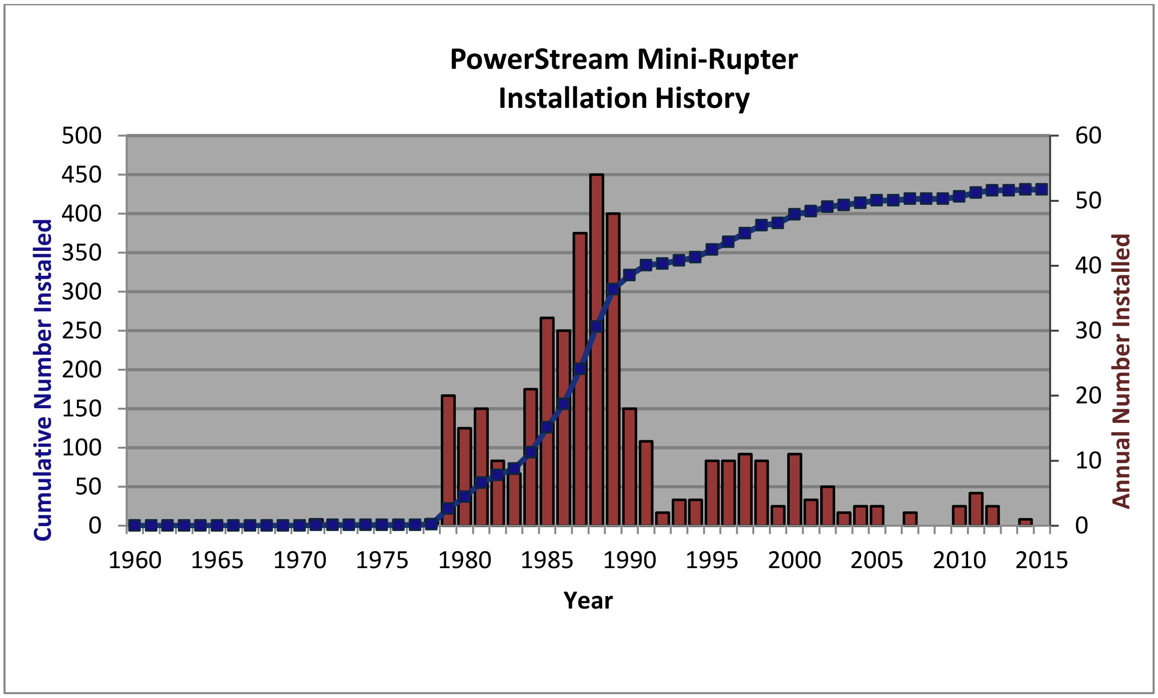


Figure 45: Installation Dates: Mini-Rupters

Figure 45 indicates that the mini-rupters range in age from two to 54 years old.

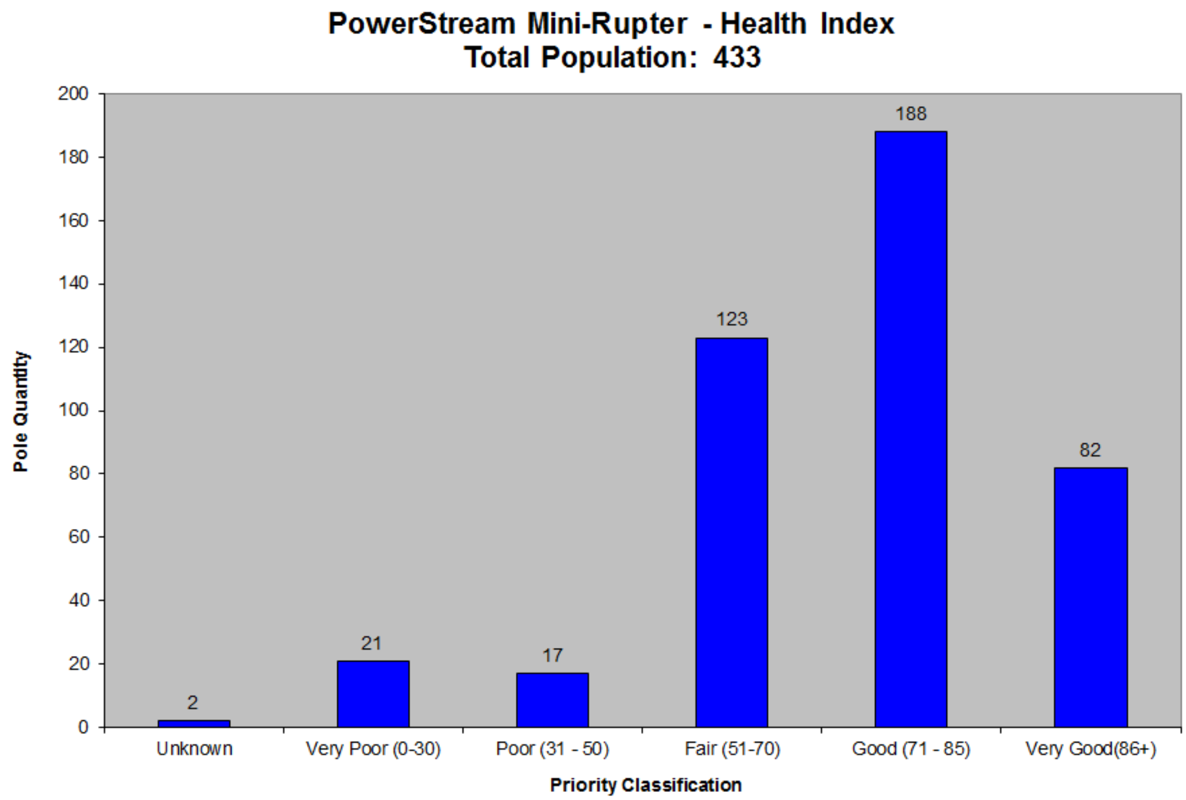


Figure 46: Health Indices: Mini-rupters

Figure 46 indicates that the majority of min-rupter switches are in fair to very good health.

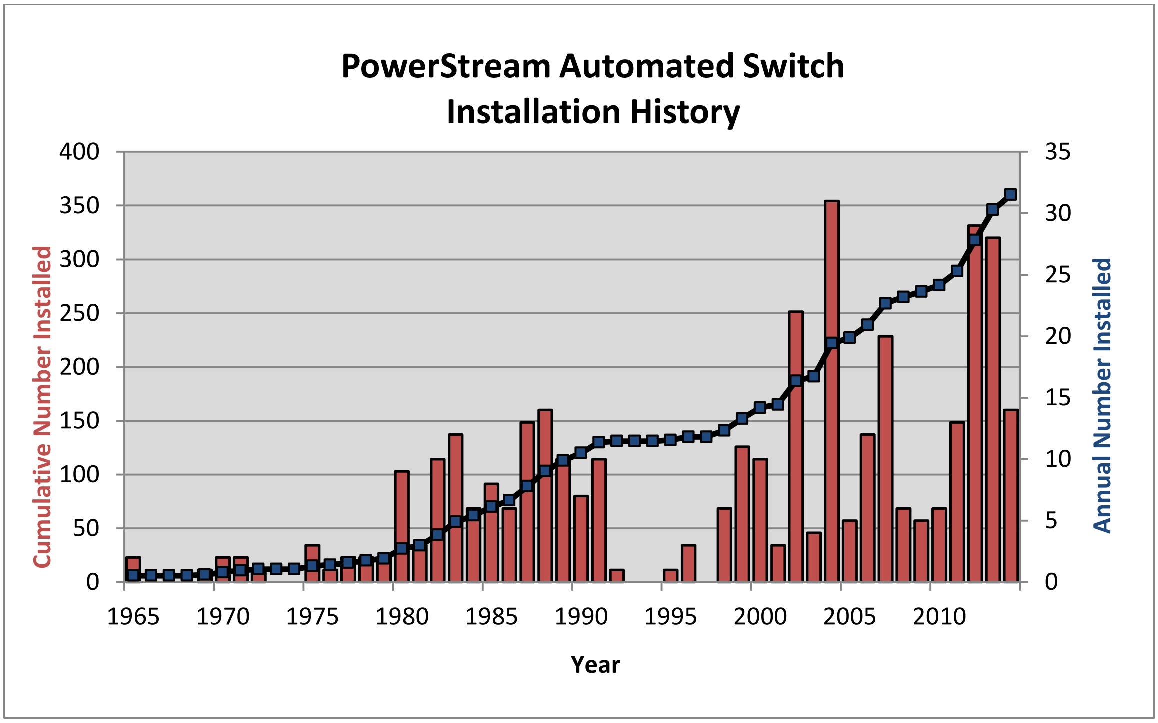


Figure 47: Installation Dates: Automated Switches

Figure 47 indicates that the automated switches range in age from new to 49 years old.

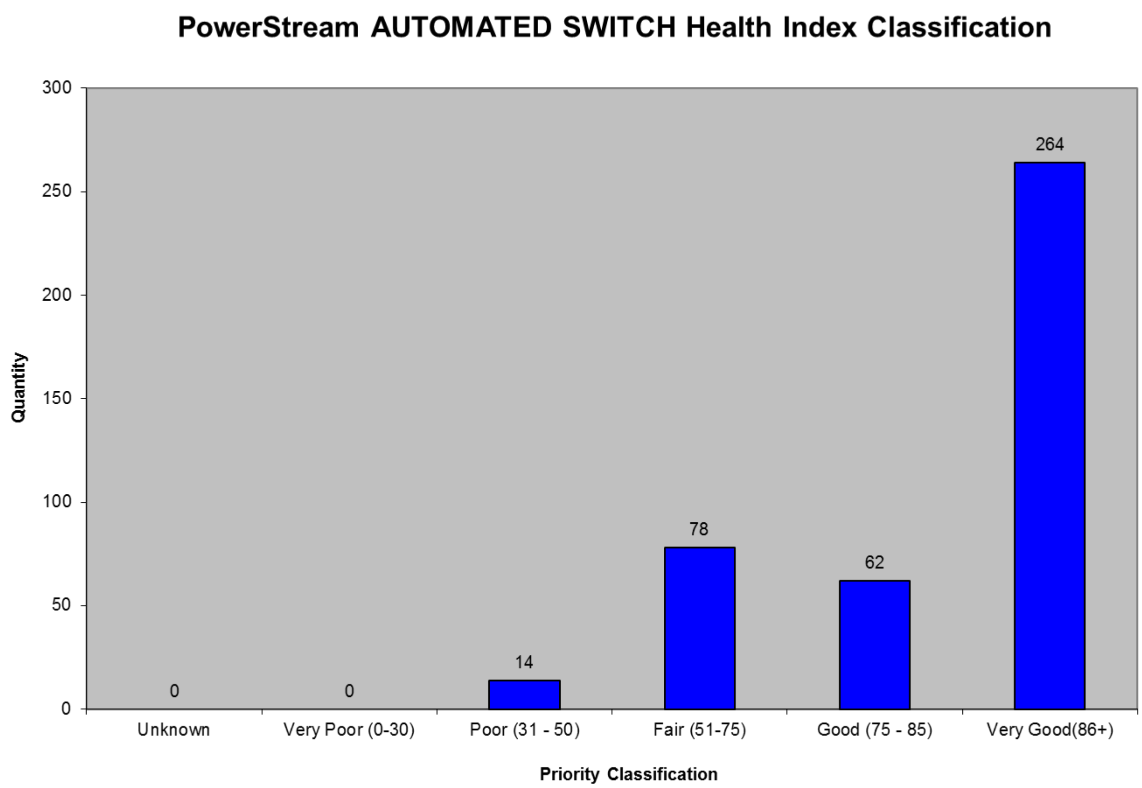


Figure 48: Health Indices: Automated Switches

Figure 48 indicates that the almost all of the automated switches are in fair to very good health.

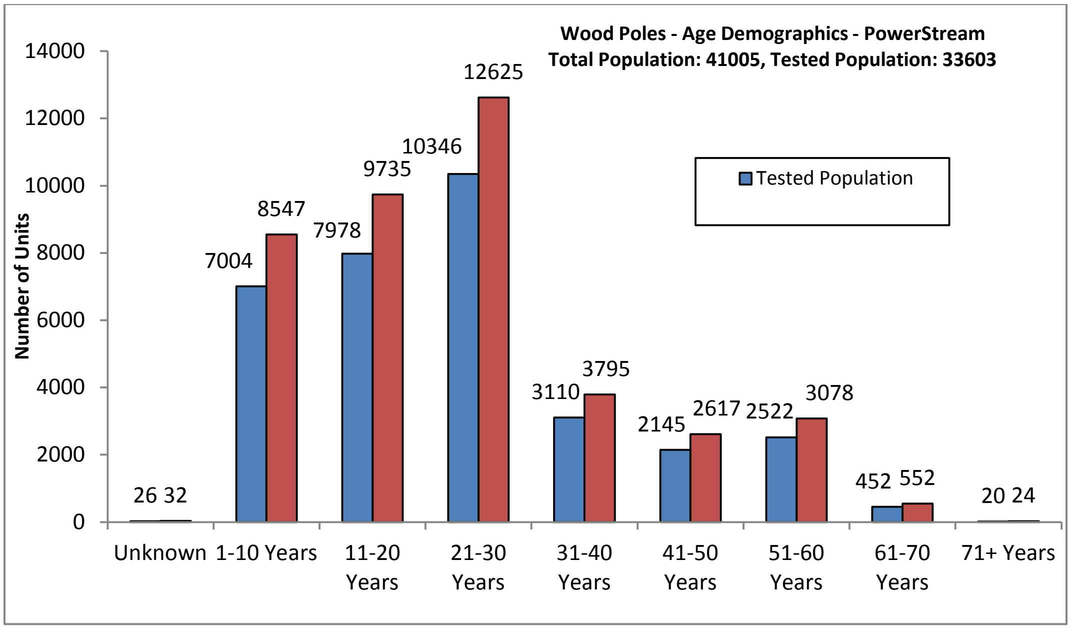


Figure 49: Wood Poles Demographics

Figure 49 indicates that there are a considerable amount of wood poles greater than 30 years of age.

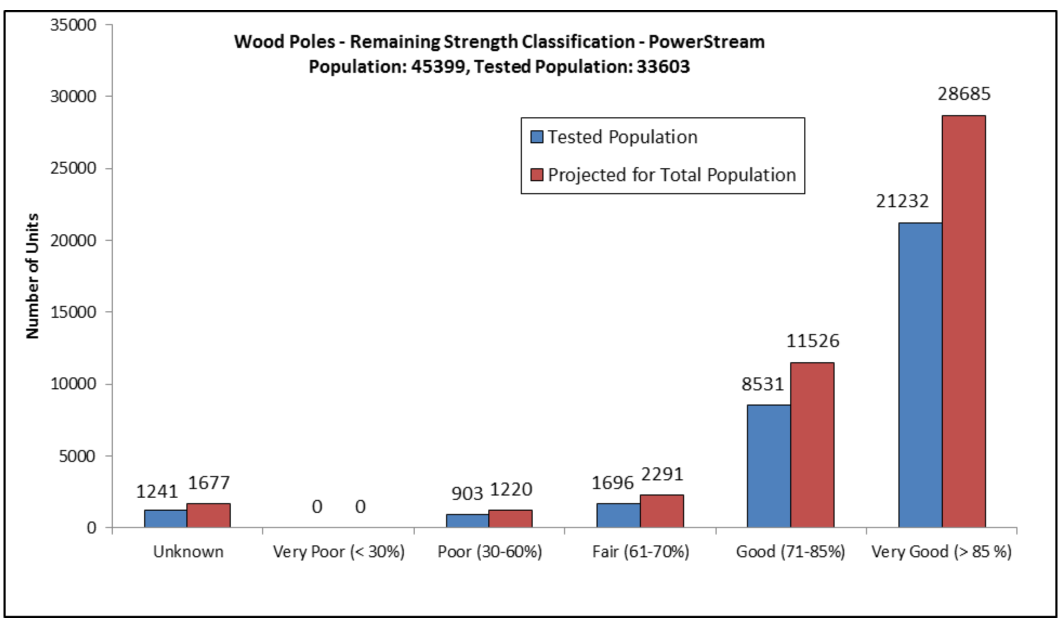


Figure 50: Wood Poles Health Assessment

Asset Utilization

As outlined in Exhibit G, Tab 2, Section 5.3.1, page 18, PowerStream undertakes planning studies to review system peaks relative to system capacity, either in the short term or the long term, in order to determine if expansion to the transformation or distribution system is required. For longer term projects, the objective is to identify the need for additional facilities with sufficient lead time to permit approvals, design, procurement, construction and commissioning prior to the peak demand load exceeding available capacity.

In November 2012, PowerStream completed a comprehensive long-term load forecast for a ten year planning period (2013 to 2022) for the south service territory (Vaughan, Markham, Richmond Hill and Aurora).

The results for PowerStream's south territory identified that additional power capacity in the Vaughan area is needed to supply the projected load growth in southern York Region in 2017. In 2017, all existing transformer stations will have reached their LTRs and the existing capacity of 1,750 MW will be exceeded.

The results for PowerStream's north territory identified the need for five municipal substations (plus land acquisition for a sixth) over the 2015 to 2020 time horizon within this DS Plan.

As indicated in Table 3 to Table 8, which detail the ratio of peak to planning limits, on pages 11-17 in this Section:

- Transformer station utilization is higher on some stations, and will become acceptable when a new station is added in 2017 in the Vaughan area;
- Hydro One station utilization is acceptable;
- South municipal substations are lightly loaded, and are being converted to 28kV only as part of any coincident work in the area;
- The north substations have acceptable utilization as they provide for operational flexibility through the triad model.

Capital Investment Key Drivers

In this DS Plan, PowerStream has developed a list of capital investment drivers and proposes capital investment programs based on these key drivers. The definition of the key drivers are below. Refer to Figure 51 on page 55.

- Service Requests (system access)
  PowerStream has an obligation to connect a customer to its distribution system. This includes both traditional demand customers and distributed generation (DG) customers. Requests also can include system modifications for property or infrastructure development by government agencies, road authorities, developers or other entities

- Mandated Compliance (system renewal)
  Compliance with all legal and regulatory requirements and government directives, such as compliance with the Ministry of Energy, Measurement Canada, the Ontario Energy Board, the Independent Electricity System Operator and/or other regulations.

- Obsolescence (system renewal)
  Assets/asset installations that no longer align with PowerStream's current operating practices or current standards. This can include those assets that:
    - Are no longer manufactured;
    - lack spare parts;
    - lack of accessibility;
    - lack the ability to have maintenance performed on them; or
    - have operational constraints or conflicts, which can result in increased reliability and/or safety-related risks.

- Mitigate Failure Risks (system renewal)
  Where there is the imminent risk of failure due to age or condition deterioration, and these potential failures will result in severe reliability impacts to customers as well as potential safety risks to crew workers or to the public, remediation, through refurbishment or replacement, is required.

- Reliability (system service)

  PowerStream has a mandate to maintain or improve reliability at a system level. In pursuit of improved reliability, projects may be developed to improve feeder, station or multiple feeder performance.

- Support Capacity Delivery (system service)

  Where there are forecasted changes in load that will constrain the ability of the system to provide consistent service delivery, or where forecasted load growth will render the distribution system incapable of supplying the demand requirements, system relief, through new builds or expansion, is required.

- System Efficiency (system service)

  To provide customers with the best service possible, there is always a need to improve restoration capability. This may also include projects to reduce system losses, configuration of taps or open points to match loading or other projects to improve local issues.

- Safety (system service and system renewal))

  Where assets are known to have safety related hazards or risks, either to workers or the general public, or where assets are an integral part of maintaining safe work practices, and the failure of those assets would result in safety-related hazard/risk exposure, then remediation, through refurbishment or replacement, is required.

- Capital Investment Support (general plant)

  In order to support the resources (both human and machine) that are required to operate, analyze, maintain and generally support the distribution system, renewal, refurbishment, replacement or enhancement of assets (ie vehicles, buildings, IT systems), are required.

- <u>Customer Service (general plant)</u>

  In order to provide improved customer service and an overall exceptional customer experience, replacement or enhancement of assets, are required.

		Primary Driver	Source
System Access	New Connections and Subdivisions	service requests	Developers, Customers, Road Authorities
	Road Authority		
	Metering		
	Other Customer Initiated Work		
	RGEN New Connections		
	Other Misc		
System Renewal	UG Lines Planned Asset Replacement	mandated compliance obsolescence mitigate failure risks safety	Regulator Safety Authority PowerStream
	Distribution Lines - Emergency/Reactive		
	Overhead - Lines Planned Asset Replacement		
	Storm Hardening & Rear Lot Conversion		
	Stations/P&C-Planned and Emergency		
	Other Misc		
System Service	Additional Capacity - Stations	reliability support capacity delivery system efficiency safety	PowerStream
	Additional Capacity - Lines		
	Reliability Including Distribution Automation		
	Station Safety & Security		
	Smart Grid/RGEN - System Related		
	Other Misc		
General Plant	Customer Information System (CIS)	capital investment support customer service	PowerStream
	IT and Info/Communication Systems		
	Buildings and Emerging Operations		
	Fleet		
	Tools		
	Interest Capitalization		
	Smart Grid - Other		
	Other Misc		

<u>Figure 51: Key Capital Investment Drivers</u>

The sub-categories within each of the four main categories are described below.

New Connections and Subdivisions

This sub-category covers the costs to connect new customers to the system. The work is divided into four programs – Layouts, New Services, New Subdivisions, and Secondary Services.

Layouts consist of work to make ready the system for new residential infill services, upgrading of residential services and small commercial services. A layout is completed for each customer. The customer's service could be underground or overhead and is the connection from the main plant on the boulevard to the building. Costs are shared between the customer and PowerStream in accordance with the Distribution System Code ("DSC").

New Services consists of new and/or upgraded primary services to industrial, commercial and institutional customers. These services are normally underground from the existing distribution or sub-transmission system and up to and including the padmount transformer. In accordance with the DSC, these services are considered a connection and are 100% recoverable (deemed as 'Lies Along' – these are new services where facilities exist to service the customers).

New Subdivisions consist of the primary and secondary underground cables as well as transformers installed to the street line of each lot within a new residential "greenfield" subdivision development. In accordance with the DSC, the development cost is subject to an economic evaluation to determine the LDC share and the Developer share based on revenues generated from the development.

Secondary underground services are installed from the street to the meter base for each lot. This work allows for the connection of the secondary service to the padmount transformer which in turn provides power to the customer's unit. These services are installed as the houses within the development are built and are normally installed within five years of the new subdivision being installed. In accordance with the DSC, these service costs are put through the economic evaluation model and shared at time of the Offer to Connect ("OTC").

Road Authority

As communities within PowerStream's service territory continue to grow, road construction, re-alignment and widening of existing roads as well as the installation of new water and sewer infrastructure occur. This development work is controlled by Provincial, Regional and Municipal authorities. Because PowerStream's distribution system is located on the road allowance, at the request of the road authority, it must be relocated to accommodate this development work. Each year, PowerStream reviews the five and ten year road authority plans for development to identify where distribution system conflicts exist and to budget for resolution of these conflicts. The majority of these projects involve relocating portions of the distribution system. These projects are usually cost shared with the road authority. This sub-category covers the costs for these relocations.

Metering

This sub-category involves the installation or replacement of meters. The work involves the upgrades or replacement of wholesale or retail meters and includes Wholesale Meter Upgrades, Failed Meter/Transformer Replacements, Meter Re-verifications and Smart Meters.

Other Customer Initiated Work

This sub-category covers large customer projects due to the customer's emerging needs throughout the year. Projects are typically required due to either a relocation required by a customer or the expansion of the distribution system for the customer. In the case of relocations, the customer typically pays 100% of the costs. In the case of a required expansion of the distribution system, costs are shared as per the requirements of the Distribution System Code ("DSC") and PowerStream's Conditions of Service ("COS").

This sub-category also covers the costs to connect new distributed generation customers to the system. In accordance with the DSC, these costs are shared by the customer and PowerStream. The customer is responsible to cover the cost of connection. PowerStream will cover system expansion costs at or below a distributed generation customer's renewable energy expansion cap.

RGEN New Connections

This sub-category covers the work required to connect FIT and microFIT renewable generators to the distribution system.

Other Miscellaneous

This sub-category exists to permit the comparison and translation of historical data to future proposed expenditures within the four categories (these exist is each of the four categories).

UG Lines Planned Asset Replacement

This sub-category covers the remediation of underground assets as identified through the asset condition assessment process. These yearly programs include:

- cable remediation (replacement and injection);
- switchgear replacement;
- mini-rupter switch replacement;
- submersible transformer replacement; and
- distribution transformer (padmount) replacement.

Distribution Lines - Emergency / Reactive Replacement

This sub-category covers capital costs of repair and restoration of the distribution system. Work is required as a result of on-going power outages or identified through inspection as needing repair due to a hazardous safety condition or potential imminent failure. The work is divided into programs, specifically, replacement of failed distribution equipment, replacement of distribution equipment due to storm events, replacement of distribution equipment due to accidents and joint use pole removal.

Overhead - Lines Planned Asset Replacement

This sub-category covers the replacement of overhead assets as identified through the asset condition assessment process. These yearly programs include:

- pole remediation (replacement or reinforcement);
- automated switch replacement;
- fault indicator replacement; and

- 44kV porcelain insulator replacement.

Storm Hardening & Rear Lot Conversion

This sub-category covers construction of end-of-life rear lot supplied residential subdivisions by conversion to front lot servicing and structural integrity projects for the overhead system.

Stations/P&C Planned and Emergency

This sub-category is for those Municipal Stations ("MS" – stations that transform from 44kV or 27.6 kV to a lower distribution voltage such as 13.8 kV) and Transformer Stations ("TS" – stations greater than 100 MVA that transform from high voltages 230 kV to 27.6 kV). These projects are not capacity driven, but are required to sustain PowerStream's fleet of transformer and municipal substations. Sustainment activities include projects to replace worn out equipment, improve reliability, enhance operability and maintainability as well as improve and maintain safety.

Additional Capacity – Stations

This sub-category covers construction projects of new or upgrade of existing transformer and municipal station capital projects that PowerStream must complete to provide sufficient capacity to supply new customers and load growth from existing customers. Every year PowerStream prepares a load forecast and studies the system to identify capacity short falls and recommends projects to ensure sufficient capacity for customer load growth demands.

Additional Capacity - Lines

This sub-category covers construction of new or upgrade of existing distribution or sub-transmission lines that PowerStream must complete to provide sufficient feeder and component capacity to supply new customers and load growth from existing customers. PowerStream uses the load forecast and studies the system to identify capacity short falls and recommends projects to ensure sufficient capacity for customer load growth demands.

<u>Reliability including Distribution Automation</u>

This sub-category is for those projects required to sustain the distribution system and ensure reliability. These projects are identified through technical studies or through an identified reliability need. Included in this category are Voltage Conversion Projects, System Re-configuration Projects, Radial Supply Remediation Projects, Distribution Automation Projects, Reliability Driven Projects and remote Fault Indicator Installation projects.

<u>Station Safety and Security</u>

This sub-category covers projects to deal with either cyber or physical asset security.

<u>Smart Grid/RGEN System Related</u>

This sub-category covers smart grid projects that would not have been completed in the normal course of PowerStream's everyday business and are pilots of new technology that may be considered for incorporation into the grid or are pilots to understand the impact of new technologies such as the electric vehicle. These projects were previously funded through a smart grid deferral account up to and including 2015.

<u>Customer Information System (CIS)</u>

This sub-category covers projects that support the Customer Service division and technology to enhance service to customers.

<u>Information Systems and Info/Communication Systems</u>

This sub-category consists of new projects or upgrades to PowerStream's information technology or communication systems across the organization, covering hardware and application software.

<u>Buildings and Emerging Operations</u>

This sub-category involves the purchase, replacement or rehabilitation of major assets related to one of PowerStream's four main centres of operation.

Fleet

This sub-category involves the purchase or refurbishment of vehicles.

Tools

This sub-category involves the purchase of tools that are required for the ongoing operation, construction, maintenance, and repair of the distribution system. Tools include power measuring equipment, cutters and crimpers; relay testing equipment, communications testing equipment, meter testing equipment and locating equipment. These purchased tools replace worn out or broken tools used by the staff on a daily basis for their work.

Interest Capitalization

This sub-category covers monies for interest capitalization. Under Internal Financial Reporting Standards ("IFRS"), interest capitalization is defined as the borrowing costs that are directly attributable to the acquisition or construction of a qualifying asset cost. A qualifying asset is an asset that necessarily takes a substantial period of time to get ready for its intended use. PowerStream has determined this period of time as those projects that span over four months in duration. To assist in project management these costs are tracked in one category within the capital budget.

Smart Grid – Other

This sub-category covers projects that support PowerStream's Smart Grid Implementation Plan, such as electric vehicle connections, home energy management technologies and data analytics.

Safety

Safety is an integral component of all projects/programs.

5.3.3 ASSET LIFECYCLE OPTIMIZATION POLICIES AND PROCEDURES

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, and should include but need not be limited to:

a) *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).*

b) *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.*

Asset Replacement and Refurbishment (Remediation) Program and Policies

PowerStream has several asset remediation programs for maintaining distribution system and general plant integrity.

PowerStream makes assessments on whether an aged asset is suited for refurbishment or replacement based on criteria that are pertinent to a given asset class.

A large contributor to the assessment process is the annual inspection of critical assets. Annual inspections are completed on the distribution system for the overhead system, load interrupter switches, padmount switchgear, vault rooms, padmounted switchgear, stations and poles. An assessment is made and an asset will be categorized as a Code A, Code B or Code C:

- Code A: Corrective measures/follow-up are required at the earliest possible opportunity (address immediately);
- Code B: Assessment required for corrective action for the next budget cycle; and
- Code C: No corrective measures are required. Follow the regular maintenance cycle.

Additionally, testing is performed on cables to determine the health of the cable, and testing is performed on wood poles to determine remaining strength.

These designations are applied to the distribution system assets as seen in Figure 1. This table depicts, by asset, what the health index scores mean, what the inspection results mean, and how the scores are prioritized

Program	Health Index (max score = 100)	Inspection Results (Code A, B, C)	Prioritization Score (max score = 100)
Pole Replacement	not applicable	Used field inspection results to select replacement candidates. **Code A**= Very Bad, immediate replacement **Code B**= Fair, replacement candidate for next budget cycle **Code C**= Good condition, no replacement needed and maintain inspection	A higher point total yields greater replacement priority. (scored from % Remaining Strength, Condition, # of Transformers, # of Primary Conductors, # of Switches, Criticality of Pole and Age of Pole.) **NOTE**: Candidates will belong to one of the following groupings: - Remaining strength is less than 60 % - Remaining strength is greater than 60%, however other aspects of the pole are bad. (i.e.. butt rot, insect infestation, decay, splitting, bending, leaning)
Cable Remediation: Cable Replacement	not applicable	**TAN DELTA TEST RESULTS** **Code A** = Critically Aged. Intervention Required **Code B** = Aged. Further study required. (Repeat testing evey 2 years based on test reults) **Code C** = No Action Required/Repeat after 5 Years	A higher point total yields greater replacement priority. (scored from Age, Cable Condition, Service Quality and Financial Impact)
Cable Remediation: Cable Injection	not applicable	**TAN DELTA TEST RESULTS** **Code A** = Critically Aged. Intervention Required **Code B** = Aged. Further study required. (Repeat testing very 2 years based on test results) **Code C** = No Action Required/Repeat after 5 Years	A higher point total yields greater replacement priority. (scored from Age, Cable Condition, Service Quality and Financial Impact)
Switchgear Replacement	**Good Condition**= high Health Index, >70 **Fair Condition**= middle Health Index, 51-70 **Poor Condition**= low Health Index, <51	Used field inspection results to select replacement candidates. **Code A**= Very Bad, immediate replacement **Code B**= Fair, replacement candidate for next budget cycle **Code C**= Good condition, no replacement needed and maintain inspection	not applicable
Mini-Rupter Switch Replacement	**Good Condition**= high Health Index, >70 **Fair Condition**= middle Health Index, 51-70 **Poor Condition**= low Health Index, <51	Used field inspection results to select replacement candidates. **Code A**= Very Bad, immediate replacement **Code B**= Fair, replacement candidate for next budget cycle **Code C**= Good condition, no replacement needed and maintain inspection	not applicable
Automated Switch Replacement	(**Good Condition**= high Health Index, >70 **Fair Condition**= middle Health Index, 51-70 **Poor Condition**= low Health Index, <51	Used field inspection results to select replacement candidates. **Code A**= Very Bad, immediate replacement **Code B**= Fair, replacement candidate for next budget cycle **Code C**= Good condition, no replacement needed and maintain inspection	not applicable
Submersible Transformer Replacement	**Good Condition**= high Health Index, >70 **Fair Condition**= middle Health Index, 51-70 **Poor Condition**= low Health Index, <51	Used field inspection results to select replacement candidates. **Code A**= Very Bad, immediate replacement **Code B**= Fair, replacement candidate for next budget cycle **Code C**= Good condition, no replacement needed and maintain inspection	not applicable
Distribution Transformer Replacement	**Good Condition**= high Health Index, >70 **Fair Condition**= middle Health Index, 51-70 **Poor Condition**= low Health Index, <51	Used field inspection results to select replacement candidates. **Code A**= Very Bad, immediate replacement **Code B**= Fair, replacement candidate for next budget cycle **Code C**= Good condition, no replacement needed and maintain inspection	not applicable
Station Equipment Replacement	**Good Condition**= high Health Index, >70 **Fair Condition**= middle Health Index, 51-70 **Poor Condition**= low Health Index, <51	**NOTE:** Inspection & testing results are used to generate the health index and replacement candidates.	not applicable

Figure 1: Summary of Health Index Results, Inspection and Testing

The remediation programs for maintaining the distribution system are:

- Pole Remediation (replacement or reinforcement);
- Cable Remediation (replacement and injection);
- Switchgear Replacement;
- Mini-Rupter Switch Replacement;
- Automated Switch Replacement;
- Submersible Transformer Replacement;
- Distribution Transformer Replacement;
- Station Equipment Replacement (Substations & Transformer Stations);
- 44kV Porcelain Insulator Replacement;
- Fault Indicator Replacement;
- Storm Hardening and Rear Lot Remediation;
- Information Systems;
- Facilities;
- Information systems;
- Facilities Remediation; and
- Fleet Replacement.

These are further described below.

<u>Pole Remediation</u>

Through an annual inspection and testing program, PowerStream monitors the condition of its poles to ensure that they meet minimum requirements for safety and reliability. Among other factors, PowerStream is guided in its pole assessment process by Clause 8.3.1.3 of CSA Standard C22.3 No. 1-10, which states that:

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

In the quote from the CSA standard, the reference to capacity is interchangeable with pole strength for this program.

Other considerations include pole condition information such as rot, decay, splitting, insect infestation, bending, and leaning. PowerStream believes that the remediation of poles exhibiting poor (or worse) condition is non-discretionary. The remediation is required to maintain compliance with the CSA code, as well as considerations for safety of the public and for workers operating in, on, or around the poles and their associated equipment.

When an existing pole is replaced, PowerStream must install the new pole according to the current standards. In most cases the existing associated components attached to the existing pole are also at end-of-life and therefore must also be replaced. Examples of the associated components are brackets, cross arms, down guys, anchors, ground wires, insulators, arresters, and fasteners. If in any particular case, the pole has transformers, switches, or other equipment with significant remaining life, these are salvaged and re-used.

When a pole in reinforced, the base will be restored to full strength. See Figure 2.

Figure 2: Pole Reinforcement Installation

PowerStream annually inspects and tests a portion of pole population. The pole remediation candidates are selected based on the combination worst candidates of the following two groupings:

- Poles that have less than 60% remaining strength (CSA reference); or
- Poles that have more than 60% remaining strength but exhibit worsening conditions such as rot, decay, splitting, insect infestation, bending, and leaning.

Poles are prioritized based on their assessed health index, the worst being selected for replacement or reinforcement. See Figure 3 below.

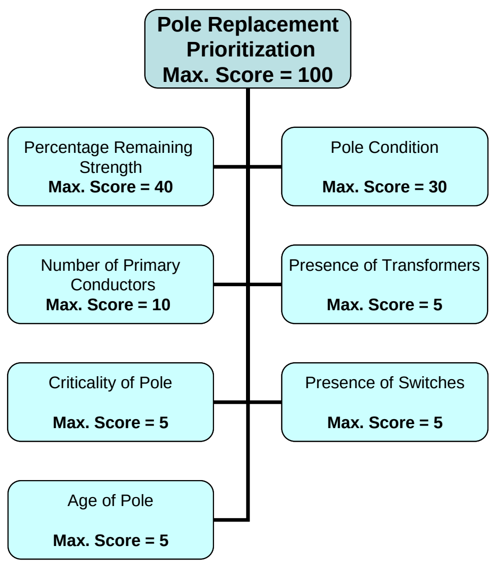


Figure 3: Pole Prioritization Matrix

Cable Remediation

PowerStream monitors the condition of its primary cables to ensure that they meet minimum requirements for safety and reliability. The asset demographics indicate that the oldest cables of the PowerStream cable population are at end-of-life, are deteriorating and are failing. To mitigate the effects of this, annual remediation efforts are required.

To manage the risk of large-scale primary cable failures, PowerStream has implemented a cable remediation plan. The plan includes continuous work on assessing, prioritizing, and remediating the worst cable segments by a combination of cable injection and cable replacement.

PowerStream's approach to managing the high risk cable population is summarized below:

- Use a cable prioritization system to select cable segment "candidates" for replacement or injection;
- Designate prioritized cable candidates for cable injection or cable replacement;
- Address the cable aging issue by a combination of cable injection and cable replacement on a prioritized basis;
- Conduct testing to assess the condition of the cable; and
- Select the preferred method.

In 2011, PowerStream's System Planning division introduced cable injection (a process that restores the insulation in a cable). This process extends cable life at approximately 15% of the cost of cable replacement. PowerStream's preference is to inject cables as a first choice for remediation. Research indicates that cable injection extends the life of cable for another 20 years, however, injection is only suitable and economical for some cable types and field conditions. The initial trials were very successful – low cost and no subsequent failures. The initial cable candidates were limited in age due to technical factors. In 2014, PowerStream did additional research related to the technical factors, and determined that additional cable candidates would be eligible for injection. This efficiency permits the remediation of the same amount of cable at a lower overall cost, or alternatively, permits additional lengths to be accomplished with an equivalent budget.

The cable replacement option is more expensive than the cable injection option with respect to the initial capital cost, but it has the advantage of resulting in new cable that will be utilized for a longer time. In comparing the two options, the extra life expected from injected cable is 20 years while the life of new cable is expected to be 50-55 years.

In order to determine the cable candidates to be selected for replacement or injection remediation means, PowerStream has developed a prioritization methodology which takes into consideration the physical condition of the cable along other factors such as age, impact to customer service and financial benefit. Figure 4 depicts the methodology used to screen and prioritize the candidates selected for injection or replacement.

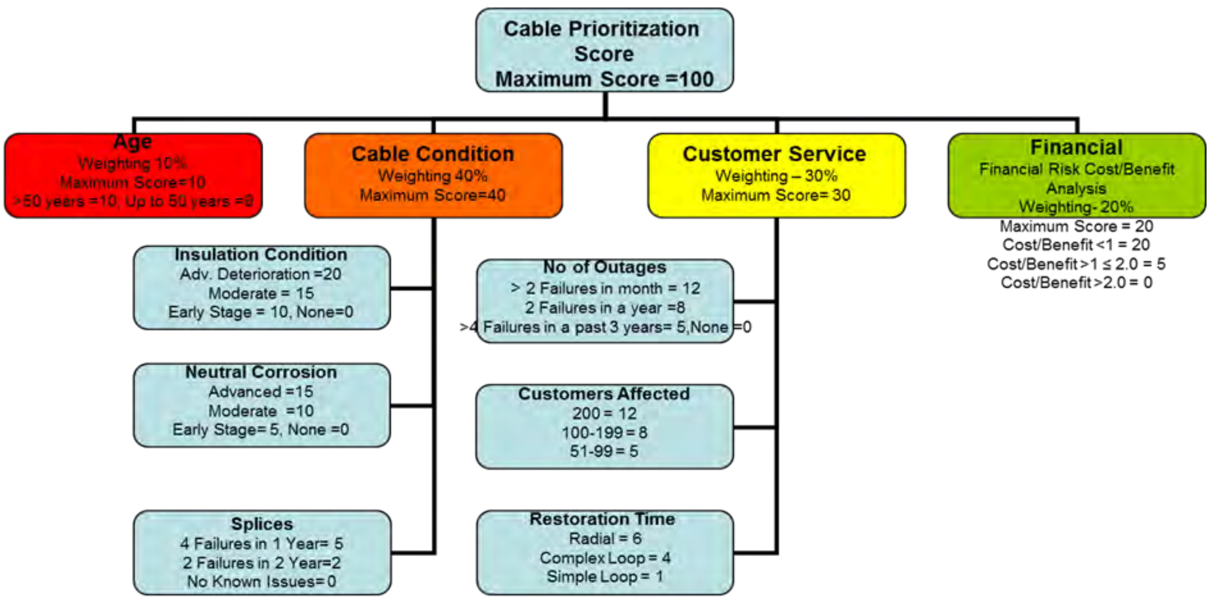


Figure 4: Cable Prioritization Matrix

Cable condition is the key driver and most heavily weighted factor in terms of determining cables for replacement/injection.

The cables that are proposed for remediation exhibit Code A results (advanced insulation degradation) indicating that intervention is required.

In 2010, PowerStream's System Planning division introduced Tan Delta cable testing, a diagnostic method of testing cables to determine the quality of the cable insulation. This testing, when applied within the cable remediation program, provides improved data to assist in determining the optimal approach to remediation – does the cable need remediation, and if so, is injection or replacement the preferred approach? This efficiency results in ensuring that only poor cables are selected and if injected if appropriate. This lowers the overall cost of the program.

The remaining factors in the prioritization matrix (customer service, financial, age) have decreasing factor weights with age being the lowest. In the absence of any other empirical data, age is the default indicator of when the cable approaches end of life.

Switchgear Replacement

Pad- Mounted Switchgear units are used in distribution loops supplying residential subdivisions and commercial/industrial customers. Switchgear units are used to isolate/control other equipment, and to reconfigure the loops for maintenance, restoration or other operating requirements.

Switchgear degradation depends on a number of factors, such as condition of mechanical components, contamination due to dirt, moisture and corrosion. The other important issues are obsolescence or product specific/generic defects.

Pad-mounted switchgear represent critical assets for the underground distribution system and have been identified to carry a significant reliability and safety risk due to condition, age, past design and installation practices. The population targeted for replacement consists of air and oil switchgears, based on safety and reliability concerns.

Appendix C (Table-1) of the Distribution System Code (DSC) sets out minimum inspection requirements for the distribution system and accordingly for urban environments the underground plant is inspected on a three year cycle. In addition ESA regulation 22/04 mandates that the distribution plant be inspected and any potential safety issues be rectified.

Based on the inspection results each year, and the health index calculation, a number of distribution switchgear are recommended for replacement due to safety concerns, age, and asset condition assessment information.

Mini-Rupter Switch Replacement

Mini-rupter switches are found in distribution loops supplying industrial commercial/industrial customers and are three pole-gang operated interrupter switches used for switching between underground distribution circuits.

Mini-rupter degradation depends on a number of factors, such as condition of mechanical components, contamination due to dirt, moisture and corrosion.

Mini-rupter switches are critical assets that are typically installed in vault rooms and have been identified to carry a significant reliability and safety risk due to condition, age and arc quenching design. There have been several failures of the switches where there has been an arc flash created between an energized component and ground potential. In this case the risk of injury is more pronounced as these switches are located in confined vault rooms. Due to the safety risk associated with failure of units, PowerStream's standard work practices have placed restrictions on switching of these units live, which is contrary to the units performing their intended function.

Based on the inspection results each year, and the health index calculation, a number of switches are recommended for replacement due to safety concern, age, and ACA information.

Automated Switch Replacement

High service reliability and rapid response to power outages is critical to maintain reliability and customer satisfaction.

Remotely controlled switches provide many benefits, which include:

- a rapid transfer of loads in emergencies;
- a reduction in restoration time (which improves reliability);
- a reduction in the number of customers affected by outages;
- flexibility to reconfigure the system to avoid feeder and station over loads during summer peak intervals;
- real time system readings;
- a reduction to the risk of personnel injury; and

- a platform for a complete distribution automation system.

There are identified locations where the automated switches are the end of life and cannot be operated remotely. These locations are selected for replacement.

Submersible Transformer Replacement

This particular model of submersible transformers (known as pole trans or rocket ships) are installed at the bottom of the street light poles, and are used to step down the primary voltage to the lower secondary voltage to supply residential customers. These are a unique installation that includes non-load break primary connections, submersible transformer, NX type fusing and a metal clad covering supporting a municipal street light fixture.

These units date back to 1967 and are at their end-of-life. They are obsolete, are no longer manufactured and spare parts non-existent.

PowerStream has identified the population of transformers of this vintage type and commenced a program to replace transformers each year. The program will be completed within the five years included in this DS Plan.

Distribution Transformer Replacement

Distribution transformers are used in the underground distribution to step down the primary voltage to the lower secondary voltage for use by customers. These transformers may be single-phase or three-phase depending on the customer and type of load. Pad-mount transformers in PowerStream's distribution system consist of a range of transformers from single phase 50kVA units typically supplying residential customers to three phase 3,000 kVA units supplying industrial customers. These transformers are liquid filled, with mineral insulating oil and employ sealed tank construction.

Single phase distribution transformers are generally a run-to-failure asset, unless through inspection, the units present a safety or environmental hazard. For larger three phase distribution transformers supplying commercial or industrial customers, where reduction in reliability impacts may be high, transformers may be replaced as they near the end-of-life or where they have been identified as overloaded.

Station Equipment Replacement

Transformer stations are a highly complex set of assets working together to supply electricity to the distribution system. Based on demographic and condition data, health indices have been developed and asset data collected on an ongoing basis. Replacements are made as indicated by the health indices.

44kV Porcelain Insulator Replacement;

PowerStream is experiencing a growing number of power interruptions due to insulator failure. It has been found that the older vintage of 44kV porcelain insulators are prone to tracking and flash over. PowerStream is proposing to replace all remaining legacy 44 kV porcelain insulators with polymer type insulators (over the next four years).

Fault Indicator Replacement

PowerStream has deployed fault indicators throughout its distribution system, and the location of the installations are result of mergers of several predecessor utilities. There are several different types of fault indicators currently deployed on PowerStream distribution systems. Some areas have fault indicators heavily deployed, while others have limited numbers installed or no fault indicators at all. This program is a combination of adding fault indication to areas where fault indication is absent, as well as replacing older technology fault indicators that are obsolete or prone to malfunction.

Fault Indicators are significant to the distribution system to reduce fault locating times, improving outage response and, consequently, outage restoration times. The deployment of functional fault indicators are crucial to maintaining high levels of reliability and customer service and to achieving gains in operational efficiency.

<u>Storm Hardening and Rear Lot Remediation</u>

PowerStream has a number of pockets of customers supplied by rear lot (backyard) construction. In general, these areas are older neighbourhoods and the electrical supply systems were installed between 1950 and 1970. As a result, the electrical components are ageing and the assets are deteriorating.

Rear lot supply systems pose reliability, operations, safety, and customer service issues for PowerStream. These concerns are either from a subdivision (many customers), or an individual customer requesting an underground service in a rear lot supply area.

In 2012, a review of the rear lot pockets was performed. There are thirty-six (36) areas of various sizes. These assets are aging, with an average age of years forty-two (42) years, with the oldest being sixty-six (66) years old. These assets pose a potential safety risk to the public due to planting of trees and the installation of sheds and pools close to the lines. The assets are also more inaccessible compared to standard front lot design. Several potential options and associated costs were presented.

In the 2013 ice storm, the longest outage times were faced by customers supplied with rear lot overhead systems. As a result, a second review of the options was performed, and PowerStream is proposing to annually replace areas of the rear lots supplies with front lot standard construction, until they are remediated. Additionally, PowerStream will be reinforcing pole lines and moving equipment located in the basement in transformer stations to above grade (to avoid flooding).

<u>Information Systems</u>

PowerStream's computer assets are required to be reasonably current and in good working order, and the "useful life" has been determined in accordance with current accounting principles. Other factors such as reliability and the impact (cost) of failure remain the primary factors considered in IT asset management decisions.

Table 1 outlines the useful life of information system hardware. PowerStream continuously looks for opportunities to extend the useful life of hardware (and software). The introduction of virtualization, both on the client and server side, has the potential to reduce the dependency on physical hardware.

Asset Class	Useful Life (years)
Switches/Routers	6
Servers (including servers and SAN)	5
MFP's (including all printers)	5
Desktops/Laptops (includes immaterial monitors)	4
Computer Software Application	4
Computer Software Operations (Operating Systems)	3

Table 1: Information System Hardware

PowerStream's policy, with respect to system software, is to maintain software as current as practical, based on the version releases and the impacts of upgrades. Software is only upgraded once all reasonable options are considered and deemed inadequate to meet current business needs. Reasons to upgrade include:

- Lack of vendor support;
- Costly vendor support;
- Lack of compatibility with versions used by business partners and customers;
- New features can be obtained which provide additional functionality to improve efficiency;
- Lack of compatibility with new software or hardware;
- Probability of failure/service interruption;
- Support costs (once systems are beyond warranty); or
- Challenges with interoperability and integration.

There is a direct benefit to our customers as the computer systems, such as the Customer Information (billing) System or Outage Management System, are used to process information necessary to provide the high level of service that our customers expect.

Facilities Remediation

PowerStream has four facilities with various age demographics. The Cityview Blvd head office in Vaughan is seven years old and in good condition while the Patterson Road north office and work yard facility in Barrie was built in the early nineties and is in fair condition. Lease hold improvements at Markham Addiscott Road Operations Centre facility will also result in increased capital requirement and the Jane Street in Vaughan office is new and does not require work.

The areas of concern for PowerStream's facilities are:

- Exterior (pavement, fencing, lighting, stores yard);
- Interior (furniture);
- Mechanical (Plumbing);
- Structural (windows, doors, wall partitions);
- HVAC (Heating & air conditioning); and
- Equipment (major tools, lifts).

Fleet Replacement

PowerStream's fleet assets are required to be in good working order. Depending on the class of vehicle (heavy duty, medium duty, light duty or miscellaneous class) replacement is required when the vehicle reaches:

- a prescribed odometer reading: or
- a prescribed Engine Hours reading and shows an upward trend in Unscheduled Maintenance cost for last three years, and
- a high projected unscheduled maintenance cost (based on a technical assessment).

Optimized, Prioritized Spending Procedures and Risk Management

PowerStream's Capital Investment Process commences with the annual business planning and budgeting process in the first quarter of each year, as described in Exhibit G, Tab 2, Section 5.3.1, page 25.

The following principles are applied on an annual basis to the process:

- Business Units develop their initial five year capital plans as part of the annual capital planning cycle;
- Business units prepare detailed budgets, justifications and business cases for projects, and enter these into the Optimization tool;
- A Corporate Five Year Plan is compiled based on the submitted business unit five proposed projects/programs as part of the capital planning cycle;
- The five year detailed budgets for all business units are prioritized through the Optimization process; and
- Approved and prioritized projects for years one and two are designed and readied for execution in the next business year(s). Approved and prioritized projects for the remaining three years are identified and design can be commenced only if warranted.

For the five year budget cycle, these principles are applied across ten key steps as shown in Figure 5. The detailed activities in each step are discussed in the following pages.

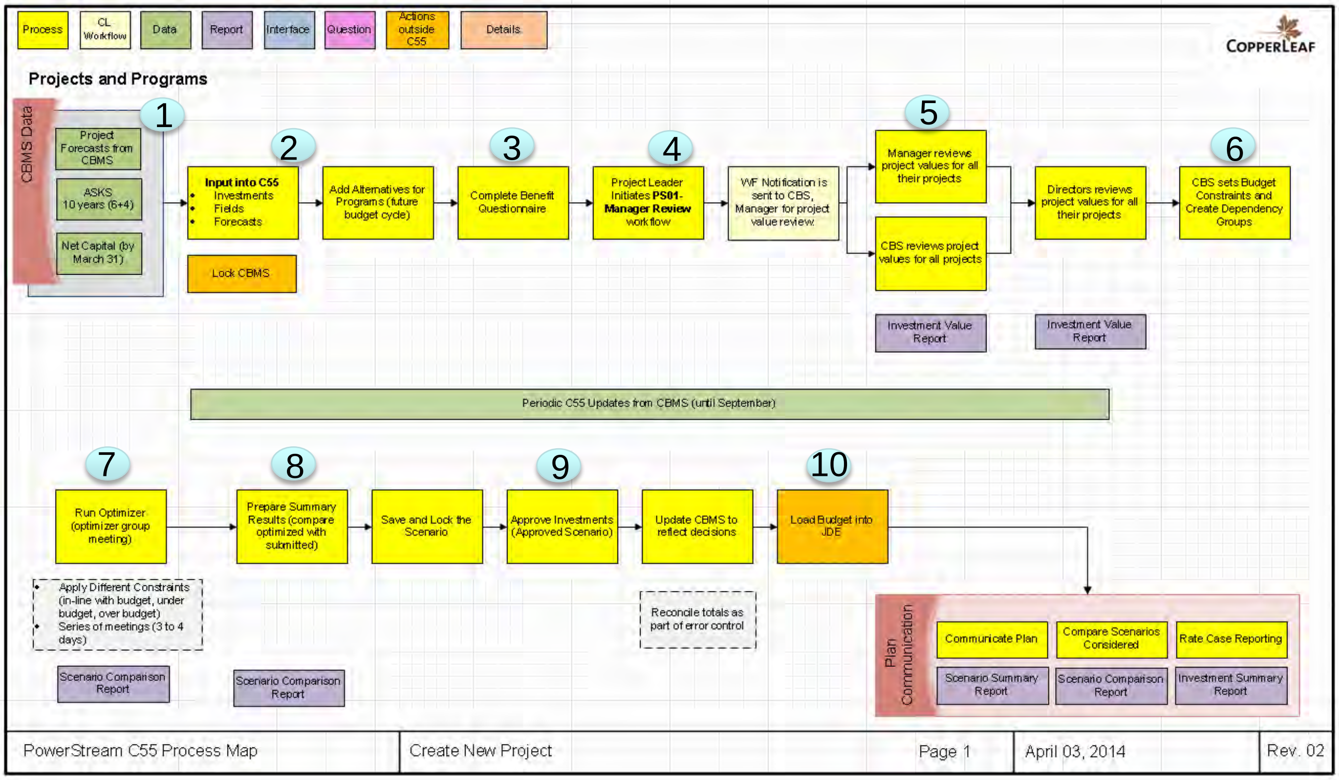


Figure 5: Capital Budget Cycle

Key Step One – Capital Budget Management System (CBMS) Entry

The Capital Budget Management System is one of the first tools applied in the budget cycle. PowerStream's Capital Investment Process incorporates a ten year forward looking plan. Business units that have major capital expenditures put together their own ten year departmental capital expenditure plans and five year budgets.

The business unit ten year capital expenditure plans are summarized into a Corporate Ten Year Capital Expenditure Plan. The information is combined from the following business units:

- Asset Investment Planning;
- Distribution Design;
- Operations;
- Lines;
- Supply Chain Services;

- Smart Grid & Metering; and
- Information Services.

Early in the calendar year a request is sent out by Asset Investment Planning to all business units in PowerStream to prepare ten year capital expenditure plans and five year budgets. These plans are developed over the January to March period. The information in the Corporate Ten Year Capital Expenditure Plan is used by the Finance Department in their financial models to consider affordability. In addition, information in the first five year plan is used in rate planning for the forward looking years.

In 2014, all project leads entered their project information (costs, year of expenditure, rationale etc.) into the Capital Budget Management System (CBMS) tool, which is then loaded into the Optimization tool for review and consolidation. In 2015, for efficiency gains, a project will be proposed to allow direct entry of the budget data into the optimization tool. Refer to Exhibit G, Tab 2, Section 5.2.3 page 7, for additional information.

These five year plans serve as the starting base for the development of the Corporate Capital Expenditure Plan.

The business unit capital plans serve three purposes:

i) assist business units in their future planning and enable the business units to provide solid five year budgets;
ii) forms the basis of the information provided in a rate application for the forward looking years; and
iii) provides the Finance team with information for financial planning.

Business units provide details in their five year budgets on forecast capital spending requirements and describe the process by which they have determined the capital spending requirements. Specific projects/programs and costs identified in the plans are generally preliminary and the projects/programs identified in the plans may or may not be approved for execution at this point.

Key Step Two – Input Data into Optimization Tool (Input into C55)

Data is entered into the Copperleaf C55 Optimization tool. Critical fields are entered including details on the proposed investment, forecasts of the expenditures over the five year budget horizon, answers to specific questions asked, based on the investment type, for both benefit and risk.

The value and risk questionnaire was created using vendor expertise, existing practices and the contribution of project leads as experts who request capital projects or programs.

Within Copperleaf's C55 program, all projects are valued (and optimized) based upon a Value Function. The Value Function is a weighting of a number of Value Measures. Value Measures can include risk mitigation, financial benefits, impacts on Key Performance Indicators (KPI), and cost. The Value Function was configured to reflect how projects contribute to PowerStream's strategic objectives as shown below. Questions were designed to provide value and scoring for these strategic elements, as noted in Exhibit G, Tab 2, Section 5.2.1, Figure 1.

Financial Benefits:

- Hard Financial Benefits
- Soft Financial Benefits

Productivity

4 Pillars	Corporate Strategic Objective
Financial	F2 (provide an optimized rate of return)
Processes	I1 (focus on continuous improvement)

KPI Impacts:

- Reliability
- Reliability for Spares
- Customer Communication
- Customer Service
- Rate Ready Organization
- Environmental Improvements
- Employee Wellness
- Technological Innovation

Customers	C1 (deliver professional services and exceptiopnal customer experience)
Customers	C1 (deliver professional services and exceptiopnal customer experience)
Customers	C3 (continue developing the PowerStream brand)
Customers	C1 (deliver professional services and exceptiopnal customer experience)
Processes	I4 (develop a rate submission ready organization)
Foundation	E2 (ensure a safe and healthy workplace)
Foundation	E1 (be a best in class employer)
Foundation	E4 (investigate and apply new and innovative technologies)

Risk Mitigation:

- IT Capacity
- Financial
- Environmental
- Safety
- Distribution
- Compliance

Foundation	E3 (build integrated technoogy platforms)
Financial	F2 (provide an optimaized rate of return)
Foundation	E1 (be a best in class employer)
Foundation	E2 (ensure a safe and healthy workplace)
Customers	C2 (provide customer swith cost effective, competive distribution rates)
Processes	I3 (Shape and Influence positive advocacy)

Cost:

- Project Cost

Financials	F1 (increase shareholder value)

<u>Key Step Three – Complete Benefit Questionnaire</u>

Once project identification is complete, the business units, in conjunction with the Capital Budget Supervisor, answer a series of questions about each project/program. The questions posed are aligned with PowerStream's corporate goals and risk matrix.

The answers to the questions form the basis for scoring both the value of the project to the corporation and its customers if the project is undertaken and the risk to the corporation and its customers if the project is not completed in the planned year. The Capital Budget Supervisor coordinates the business units across the organization to ensure that timelines are met, and consistent interpretations of the answers are applied.

In addition to answering the benefit and risk questions required for scoring the projects/programs, for those projects/programs that exceed the materiality threshold, additional questions with respect to Chapter 5 of this rate filing are posed and business leads are required to provide the requisite information. Business cases, as appropriate, are also created. Once the questions on the projects are all answered, the data on the projects is ready for optimization. PowerStream utilizes Copperleaf's C55 product for optimizing multi-year portfolios.

The current configuration of PowerStream's Value Function and the Value Measures that comprise the Value Function is summarized below:

- Each of the Value Measures is calibrated to the same scale (1 value point approximately equal to $1000). Consequently, within the Value Function, each of the Value Measures (except Project Cost) is weighed with the same value of +1. As Project Cost is a negative contributor to Project Value it is weighted with a cost of -1.
- All Value Measures are computed on an annual basis (e.g. the financial benefits for 2017 can be specified as being different than 2018). The stream of benefits (or costs) is converted to a single value for the Value Measure, by taking the Present Value of the stream, back to the beginning of the current fiscal year. The PV calculation uses the system defined discount rate.

- The Value of Risk Mitigation in all risk categories is computed using the same methodology. The project owner specifies the Baseline Risk and the risk present if the project is not completed.
- Residual Risk: The risk present if the project is completed. The value of Risk Mitigated is computed as: Baseline Risk – Residual Risk.
- For each risk the project owner specifies both the consequence and the probability of Consequence
- Projects in the following categories have been identified as Mandatory or Must Do investments as PowerStream is mandated to complete these investments, specifically:
    - Emergency Restoration;
    - Subdivision Services;
    - Road Authority Projects;
    - Emerging Development Capital;
    - Customer RGEN;
    - ICI projects;
    - Subdivisions;
    - Layouts; and
    - Emerging customers.

These projects are flagged as “must do” and are considered as mandatory as part of the optimization process. These projects have mitigated risk value as they are mitigating a compliance risk. These projects are subtracted, by the system, from the constraint amount, effectively reducing the amount of money available for competing projects and programs.

The value function combines all the value measures to compute the overall value of an investment. The value of an investment reflects the total value that the project is bringing to PowerStream, taking into account all of its financial benefits, impact on KPIs, risk mitigation and costs.

Key Step Four – Initiate Manager Review

Once a project lead has completed a project/program entry into C55, and automatic workflow notification is produced to advise the Manager, Director or VP and the Capital Budget Supervisor that the item is ready for review.

Key Step Five – Manager Review Projects/Program Values

Once a project/program, or series of projects/programs have been entered by project leads, their respective managers, directors or vice-presidents can review, on an individual or comparative basis, projects under their purview. Once reviewed and any follow-up questions answered, the projects/programs are then ready for the optimization process.

Key Step Six – Set Budget Constraint

The Finance department sets several budget funding level constraints to allow for analysis and to establish financial criteria to permit the optimization results to be compared to the optimal funding amount. These levels are available for optimization runs to create varied constraint scenarios.

Key Step Seven – Run the Optimization

The C55 tool is capable of running multiple scenarios with the project/program list being optimized for the greatest annual value. All capital projects/programs in the corporation are run through the Optimizer tool with projects from IT, fleet, planning, station construction and lines construction competing on value through the same tool. The multiple scenarios permit the results to be compared under various constraints and risks. The software tool takes all the projects/programs within the capital portfolio, calculates a numeric dollar value based on the benefit and risk calculations and the initial capital cost, and uses that value in the optimization process.

The C55 optimizer selects the combination of start dates of projects that brings the highest total value to PowerStream while fitting within the specified financial constraints.

Until projects are compared with one or another and the financial constraints are specified it is not known whether a project will be funded or not – so a project lead cannot know for certain whether or not a project will be funded.

Key Step Eight – Prepare the Results of the Various Scenarios

With the constraints set and the "must do" projects/programs accounted for, the results of the various scenarios are presented and reviewed by a multi-departmental senior optimization team, who discuss which projects must be approved as part of the five year capital budget. Members of the senior optimizer team include key leaders from each of the business units who have major capital spend across the corporation, as well as Rates & Regulatory department and Organizational Effectiveness department representatives.

Projects that were scored negative, are generally deferred beyond the six year horizon but are also discussed to ensure that any intangible benefits are considered. Once reviews and dependencies are considered, optimization can be run several times to achieve that optimal balance between the computation (science) and human element (art).

A decision is made on the preferred constraint scenario, and any project/program adjustments and deliberations occur prior to finalizing the preferred listing.

Key Step Nine - Determining and Approving the Portfolio of Projects/Programs

The result from the senior optimization team is a proposed scenario of multi-year projects and programs that will be approved by the PowerStream's Executive Management Team (EMT) and the Audit and Finance Committee for approval prior to approval by the Board of Directors.

The proposed scenario is submitted for approval with the appropriate business case details. For projects less than $500,000 the information is in its "mini-business case" format for each project. For any specific project or program that is greater than $500,000 or for IT related projects greater than $100,000, a full business case is provided and submitted for approval.

In conjunction with this process, for a rate filing year, the DS Plan's Customer Engagement process, as detailed in Exhibit G, Tab 2, Section 5.4.2, considers the responses of PowerStream's customers and a detailed review is held to correlate the proposed plan to the engagement results.

Key Step Ten – Load the Approved Portfolio into JD Edwards

The approved first year portfolio of projects/programs is loaded into the JD Edwards financial system so that it is available for all departments use within the project execution process, enabling project/program implementation.

Maintenance Planning Criteria and Assumptions

PowerStream has two main capital activities related to maintenance, which are planned and unplanned maintenance.

Planned (Proactive) Inspection and Maintenance

Activities associated with PowerStream's annual distribution inspection and preventative maintenance program are detailed in Table 2. When an inspection is performed on a given set of assets, a rating code is assigned. If the rating code assigned warrants immediate replacement, the replacement cost will generally be capitalized, while repairs will generally be expensed.

	2015	2016	2017	2018	2019	2020
O & M COSTS	**3,290,425**	**3,824,791**	**4,364,492**	**4,909,270**	**5,459,443**	**6,014,538**
insulator washing	140,000	141,400	142,814	144,242	145,684	147,142
pole testing	185,000	186,850	188,719	190,606	192,512	194,437
underground cable testing	51,945	53,177	54,431	55,506	56,521	57,417
dry ice cleaning	353,295	356,829	360,397	363,999	367,640	371,317
infrared scanning	146,856	148,516	150,193	151,841	153,490	155,104
overhead switch maintenance	353,329	357,419	361,532	365,606	369,752	373,528
vegetation management	2,060,000	2,580,600	3,106,406	3,637,470	4,173,844	4,715,593

Table 2: Annual O & M Spending

A description of these is below.

Insulator Washing

Overhead line insulator washing is required annually to prevent failure in the distribution system. Insulators become contaminated by road salt or other airborne contaminants which can result in flashovers and interruption of power. Insulator washing is carried out without necessitating isolation of the overhead circuits and the resulting customer interruptions. It also includes visual inspection and identification of any damaged equipment in the main feeder infrastructure.

Pole Testing

As part of PowerStream's Asset Condition Assessment (ACA) Program, wood poles are inspected and tested. This work is performed by a contractor who submits electronic records of their inspections/tests to the Asset Investment Planning department. Results of the testing are used to determine candidates for pole remediation. Refer to Exhibit 2, Tab 4, Section 5.3.3 for information on the pole remediation program.

Underground Cable Testing

In 2012, PowerStream commenced a program to perform Very Low Frequency ("VLF") Tan Delta testing of its underground cable to determine if there has been any deterioration in the cable insulation. Targeted areas, based upon cable age and deteriorating performance, are identified and tested, and the results and taken into consideration for the selection of areas for cable remediation. Refer to Exhibit G, Tab 2, Section 5.3.3 for information on the cable remediation program.

Dry Ice Cleaning

The dry-ice cleaning program for air-insulated pad-mounted switchgear and vault room switchgear is a cleaning method that allows an efficient and cost effective maintenance of switchgear. Air-insulated switchgear become contaminated with dirt, dust and road salt that can lead to flashovers and equipment failure. The high pressure dry ice method of cleaning allows for air-insulated switchgear to be cleaned without the necessity of isolating the equipment and removing the unit from service. Switchgear is typically cleaned on a six year cycle unless a location is determined to require more frequent cleaning due to high levels of contamination.

Infrared Scanning

PowerStream's Lines Department also uses infrared scanning to identify overheating components on its overhead and underground distribution system. As a result of the infrared scanning, equipment showing signs of overheating is scheduled for repair or replacement on a priority level based on the severity of the overheating.

Overhead Switch Maintenance

Maintenance of three phase gang operated switches, both manually operated and remotely operated, is required to ensure the switches are free of contamination and operate smoothly and efficiently. PowerStream currently maintains the switches over a five year cycle. Maintenance of overhead switches requires isolation of the switches.

Vegetation Management

PowerStream's vegetation management program was historically based on a five-year tree trimming cycle, with adjustments for more densely treed, overhead areas. Targeted tree trimming that is not part of the regular five-year cycle was carried out directly as a result of outages caused by trees and as part of the worst performing feeder program. In assessing the effectiveness of the tree trimming program, it became evident that there was a trend toward increased “reactionary” tree trimming as a result of outages and to meet the needs of the worst performing feeder program. This was diverting resources away from the annual cycle trimming program and upon review it was determined that the five year trimming cycle was not adequate to keep up with tree growth across the service territory. As such the tree trimming cycle has been adjusted to a three year cycle across the territory.

Additionally, further vegetation management strategies were recommended by the System Hardening review as a result of the ice storm. PowerStream has changed its policy for rear yards and heavily treed front yards from a five year cycle to a two year cycle. Rural areas now have a 4 year tree trimming cycle where previously they were not part of the tree trimming cycle.

Unplanned (Reactive) Maintenance

Activities in this category are typically associated with equipment failures that are usually accompanied by outage trouble shooting and restoration. Power interruptions on the distribution system result from a variety of causes as indicated by the multitude of Canadian Electrical Association (CEA) cause codes. Responses to outages are performed by trouble crews.

Where the repairs made to the distribution system are minor, maintenance work orders are charged. This includes work such as splicing conductors, repairing guying and down grounds on poles, tightening loose attachments, painting rusted tanks, levelling uneven pad bases or repositioning shifted transformers and repairing secondary failures.

Impact of System Renewal on Routine O&M and Emergency/Reactive Repairs

Routine O&M

Although System Operations and Maintenance (O&M) and capital investments are interrelated, a significant portion of System O&M expenditures are directed to activities that are independent of specific capital expenditure, including:

- Testing of assets for health condition assessments necessary to provide the information that is used to plan the capital programs;

- Regular maintenance activities to preserve asset performance over its expected life, such as minor repairs, equipment adjustments or cleaning;
- Vegetation management to maintain minimum clearance requirements for overhead conductors and equipment, both annually, and increased amounts as a result of recommendations from the ice storm;
- Cyclical patrols and inspections undertaken as good utility practice and to comply with minimum Distribution System Code requirements; and
- Corrective maintenance activities to address deficiencies caused by animal, pest, or tree contacts or asset deterioration.

The information captured through O&M programs is necessary to enable the prioritization of asset replacements for capital work and to ensure that the assets that remain in-service have not surpassed their useful life.

As can be seen in Figure 6, PowerStream continues to add distribution system assets, steadily increasing the volume of equipment that needs to be maintained and inspected. PowerStream continues to monitor, test, inspect and maintain/repair all components of the distribution system to ensure safety for its personnel and the public and to provide acceptable service to customers.

GIS Annual Facts 2009 vs 2014				
	2009	**2014**	**Difference**	
			#	%
Total Primary UG KM of Conductor Material	**7172.4**	**8137.5**	**965.1**	**13.46%**
Distribution Transformers	**40241**	**44192**	**3951.0**	**9.82%**
Switchgear	**1744**	**1847**	**103.0**	**5.91%**
Meters (Service Points)	**313880**	**356210**	**42330.0**	**13.49%**

Figure 6: Annual Fast Facts (2009-2014)

PowerStream anticipates additions from 2015 to 2020 to increase at a similar rate. The result is that the O&M budget requirement is not expected to decrease and in fact increases annually. With the exception of vegetation management, the year-over-year growth in O&M budgets are small, despite the growing asset base (as shown in Table 2, page 26).

Emergency/Reactive Replacements

Although system renewal projects and emergency/reactive replacements are interrelated, a portion of emergency/reactive replacements are directed to activities that are independent of particular capital expenditure levels, including:

- corrective maintenance activities to address deficiencies caused by animal, pest, or tree contacts;
- emergency maintenance resulting from vehicular accidents/vandalism;
- emergency maintenance resulting from severe weather and storms;
- equipment failure due to deteriorated condition; and
- equipment in poor condition as identified during system inspections.

PowerStream's system renewal program has been designed to:

- Hold system failures, and consequently, reliability, at a constant level (not get worse);
- Strike a balance between affordable spending and tolerable risk; and
- Result in the levelling of capital reactive spending (emergency replacements).

Within PowerStream's ACA models, curves have been developed to indicate a correlation between asset condition/age and failures, and depict the likely expected number of failed units over time. If proactive replacement of the worst assets can be performed, the level of anticipated failures can be held to a steady state.

If the levels of proactive system replacement, when combined with the reactive system replacements, fall within the anticipated annual failure rates within various asset classes, a steady state can be achieved. This approach results in levels of capital spending that are acceptable with the risk mitigated, provide level, paced capital spending and do not increase the capital costs for reactive replacement.

Replacing selected unhealthy units with new units will improve reliability due to the failure on the unhealthy units being avoided. Additionally, since the total population increases annually, and this applies to all assets, there is an increased probability for asset failure as time goes on. This balance of renewal and aging holds the overall system reliability at the same level.

As detailed in Exhibit G, Tab 2, Section 5.4.5, page17, proposed spending for *Distribution Lines – Emergency/Reactive Replacements* are summarized in Table 3. Additionally, reactive O&M is summarized. Expenditures will either be allocated to capital or O&M based on the required repair and magnitude of the work performed.

	Actuals				Proposed					
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Distribution Lines - Emergency/Reactive Replace Capital	***$7,194,378***	***$7,918,155***	***$8,219,497***	***$8,697,396***	***$8,416,283***	***$8,636,001***	***$8,729,603***	***$8,888,091***	***$8,924,606***	***$8,504,138***
a) LIS - Unscheduled Replacement of Failed (end of useful Life) Distribution Equipment		$334,123.00	$51,210.00	$125,384.00	$350,776.00	$346,168.00	$331,291.00	$321,119.00	$276,190.00	$275,612.00
b) Non Recoverable replacement of Distribution Equipment due to accident/vandalism	$103,434.00	$126,031.00	$138,680.00	$208,789.00	$210,774.58	$220,581.01	$220,972.56	$220,972.47	$211,280.95	$191,499.23
c) Recoverable Replacement of distribution equipment due to Accidents/Vandalism	$137,439.00	$714,253.00	$807,981.00	$816,842.00	$530,442.20	$530,600.67	$545,432.33	$560,875.95	$570,984.37	$580,023.22
d) Storm damage - Replacement of distribution equipment due to storm.	$428,418.00	$482,911.00	$767,149.00	$1,160,050.00	$999,784.75	$1,000,232.43	$1,005,602.71	$1,005,624.45	$1,010,352.34	$1,010,159.38
e) Switchgears - Unscheduled Replacement of Failed (end of useful Life) Distribution Equipment		$1,381,861.00	$1,663,004.00	$1,495,974.00	$1,420,148.09	$1,431,383.51	$1,420,147.96	$1,421,218.32	$1,400,444.11	$1,140,858.02
f) Unscheduled Replacement of Failed (end of useful Life) poles, conductors & devices (S)	$5,472,537.00	$3,771,553.00	$4,051,060.00	$4,157,571.00	$4,004,267.00	$4,136,745.00	$4,195,526.00	$4,298,340.00	$4,349,171.00	$4,266,252.00
g) Unscheduled Replacement of Failed (end of useful Life) Distribution Equipment - Poles, conductors & devices (N)	$1,052,550.00	$1,107,423.00	$740,413.00	$732,786.00	$900,090.00	$970,290.00	$1,010,630.00	$1,059,941.00	$1,106,183.00	$1,039,734.00
Distribution Lines -Reactive O & M	***$5,400,663.80***	***$5,107,963.06***	***$6,862,122.52***	***$5,857,601.24***	***$5,888,034.00***	***$6,028,513.00***	***$6,172,551.00***	***$6,307,553.00***	***$6,440,120.00***	***$6,572,121.00***
h) Inspections, Patrol, Testing	$478,946.45	$558,421.79	$501,527.00	$434,200.74	$728,443.00	$739,101.00	$749,929.00	$759,915.00	$769,619.00	$778,996.00
i) Accidents & Vandalism	$530,023.70	$348,177.74	$355,100.84	$528,236.75	$408,551.00	$417,861.00	$427,351.00	$435,491.00	$443,139.00	$450,133.00
j) Poles and Lines Hardware	$686,710.96	$630,138.29	$524,338.75	$683,144.97	$577,254.00	$589,761.00	$602,520.00	$613,512.00	$623,834.00	$633,461.00
k) Storm Damage	$522,403.45	$337,871.22	$2,130,447.97	$265,277.83	$369,686.00	$377,037.00	$384,538.00	$391,068.00	$397,211.00	$403,090.00
l) Cable Faults - Primary	$1,488,438.22	$1,608,997.25	$1,725,815.28	$1,949,015.66	$2,201,209.00	$2,258,403.00	$2,317,214.00	$2,374,693.00	$2,432,340.00	$2,491,112.00
m) Cable Faults - Secondary	$1,042,341.74	$1,013,225.11	$968,755.14	$1,392,126.37	$1,030,677.00	$1,059,857.00	$1,089,858.00	$1,119,514.00	$1,149,470.00	$1,179,856.00
n) Customer Premises	$368,158.01	$335,833.91	$323,042.73	$312,657.00	$304,889.00	$312,771.00	$320,873.00	$327,565.00	$333,602.00	$339,707.00
o) Switching for Control Room	$102,177.94	$138,348.30	$160,101.14	$120,907.91	$101,848.00	$104,271.00	$106,746.00	$108,849.00	$110,808.00	$112,626.00
p) Permanent Removals	$181,463.33	$136,949.45	$172,993.67	$172,034.01	$165,477.00	$169,451.00	$173,522.00	$176,946.00	$180,097.00	$183,140.00

Table 3: Annual Emergency/Reactive Replacements (Capital and O&M)

On an overall annual basis, the total *for Distribution Lines – Emergency/Reactive Replacements* (capital) increases between 2015 to 2019, and commencing in 2020, the overall cost is expected to commence decreasing. The *Distribution Lines – Reactive O&M,* increases annually. Each individual line element has its own trending, as described below.

Item a) LIS - Unscheduled Replacement of Failed (end of useful Life) Distribution Equipment: This subcategory is trending downwards from 2015 to 2020 as a result of improved inspection and maintenance procedures and activities.

Items b), c) and i) - Non Recoverable replacement of Distribution Equipment due to accidents/vandalism: This subcategory is trending upwards by inflationary amounts from 2015 to 2107, and trends downwards from 2018-2020 on recoverable as a focus on recovering these costs will be implemented.

Items d) and k) - Storm Damage - Replacement of distribution equipment due to storms: This sub-category is expected to trend upwards from 2015-2018, and then is expected to trend downwards in 2019 and beyond as a result of storm hardening initiatives.

Item e) Switchgears - Unscheduled Replacement of Failed (end of useful Life) Distribution Equipment: This sub-category is expected to trend upwards from 2015-2018, and then is expected to trend downwards as a result of proactive replacement programs.

Items f), g) and k) - Unscheduled Replacement of Failed (end of useful Life) Poles, Conductors and Devices: This sub-category is expected to trend upwards from 2015-2018, and then is expected to commence trending downwards as a result of remediation programs.

Item h) Inspections, Patrol, Testing: This sub-category is expected to trend upwards by inflationary amounts.

Item l) Cable Faults – Primary: This sub-category is expected to trend upwards by inflationary amounts as the cable remediation program is expected to maintain the current levels.

Item m) Cable Faults – Secondary: This sub-category is expected to trend upwards as the secondary system ages and additional plant is installed. There is no proactive replacement program for this asset (run to failure).

Item n) Customer Premises: This sub-category is expected to trend upwards by inflationary amounts.

Item o) Switching for Control Room: This sub-category is expected to trend upwards by inflationary amounts.

Item p) Permanent Removals: This sub-category is expected to trend upwards by inflationary amounts.

Impact of System Renewal on Reliability

As seen in Figure 7, 2013 was a difficult year for PowerStream. Since reliability indices are lagging, the rolling three year average SAIDI will have increased. Even though PowerStream will be within its historical three year average, PowerStream will not be using this as its indication of reliability improvement. Instead, PowerStream will be striving for targets determined by its Reliability Model.

In 2014, PowerStream created its Reliability Model. This model was designed to calculate a five year forward looking reliability projection in terms of SAIDI performance based on the past five years of reliability history and future planned capital system renewal reliability related improvements.

Within the model, outage causes are associated with controllable and uncontrollable factors that are included in the Canadian Electrical Association outage cause codes. These are listed in Table 4.

(CEA Code #) Controllable factors	(CEA Code #) Uncontrollable factors
(5) Defective Equipment	(9) Foreign Interference (3rd party event)
(1) Scheduled Outage (by P/S to do work)	(2) Loss of Supply (Hydro One)
(3) Tree Contact	(7) Adverse Environment *(Weather Dependent) ie salt*
(8) Human Element	6) Adverse Weather *(Weather Dependent)*
	(4) Lightning *(Weather Dependent)*

Table 4: Controllable and Uncontrollable Outage Cause Codes

The model breaks down SAIDI into its controllable and uncontrollable factors and identifies contributions made by factors tied to weather, as weather has a significant impact on reliability and makes up most of the uncontrollable SAIDI. Refer to Figure 7.

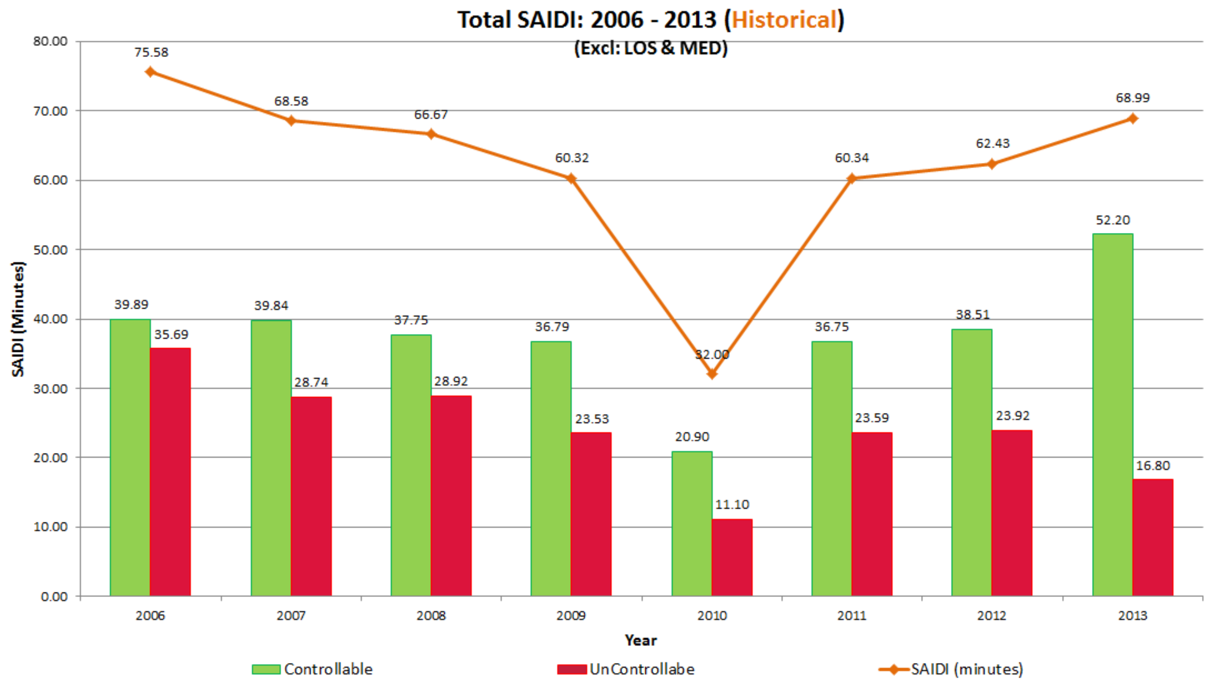


Figure 7: Historical Values for SAIDI to depict Weather Variability

The model, for each of the years between 2015 and 2020, makes future performance predictions based on the variables outlined in the following relationship:

Predicted SAIDI = Baseline SAIDI (Avg last 5 yr) + Weather Outages + Increase in Scheduled Outages - Reliability Improvements

These are defined below:

- 'Baseline SAIDI' or starting point CMI (Customer Minutes of Interruption) is calculated by averaging the past five years SAIDI performance due to non-weather related outages.
- 'Weather Outages' is calculated by averaging the SAIDI performance due to weather related outages over the past five years.
- 'Increase in Scheduled Outages' is calculated using the yearly increase in capital spend as a proportional guideline.
- 'Reliability Improvements' is calculated based on the CMI Savings achieved from each technical project or work program accounted for in the 5 Year Reliability Work Plan.

A list of the technical projects and work programs included in the 2015 to 2019 Reliability Work Plan that impact SAIDI are shown in Table 5. The distribution system programs are described starting on page 4 of this Section (5.3.3).

#	Description	Capital	O&M
1	Worst Performing Feeders (WPF)		X
2	Inspection and Maintenance		X
3	Pole Remediation	X	
4	Cable Remediation	X	
5	Switchgear Replacement	X	
6	Mini-Rupter Switch Replacement Program	X	
7	Automated Switch Replacement	X	
8	Submersible Transformer Replacement	X	
9	Distribution Transformer Replacement	X	
10	44kV Insulators Replacement Program	X	
11	Fault Indicator Program	X	
12	Storm Hardening & Rear Lot Remediation	X	
13	Distribution Automation	X	

Table 5: 2015 to 2019 Reliability Based Projects and Programs

Based on the Reliability Model calculations, the 5 year reliability forecast for 2015 to 2019 is depicted in Figure 8.

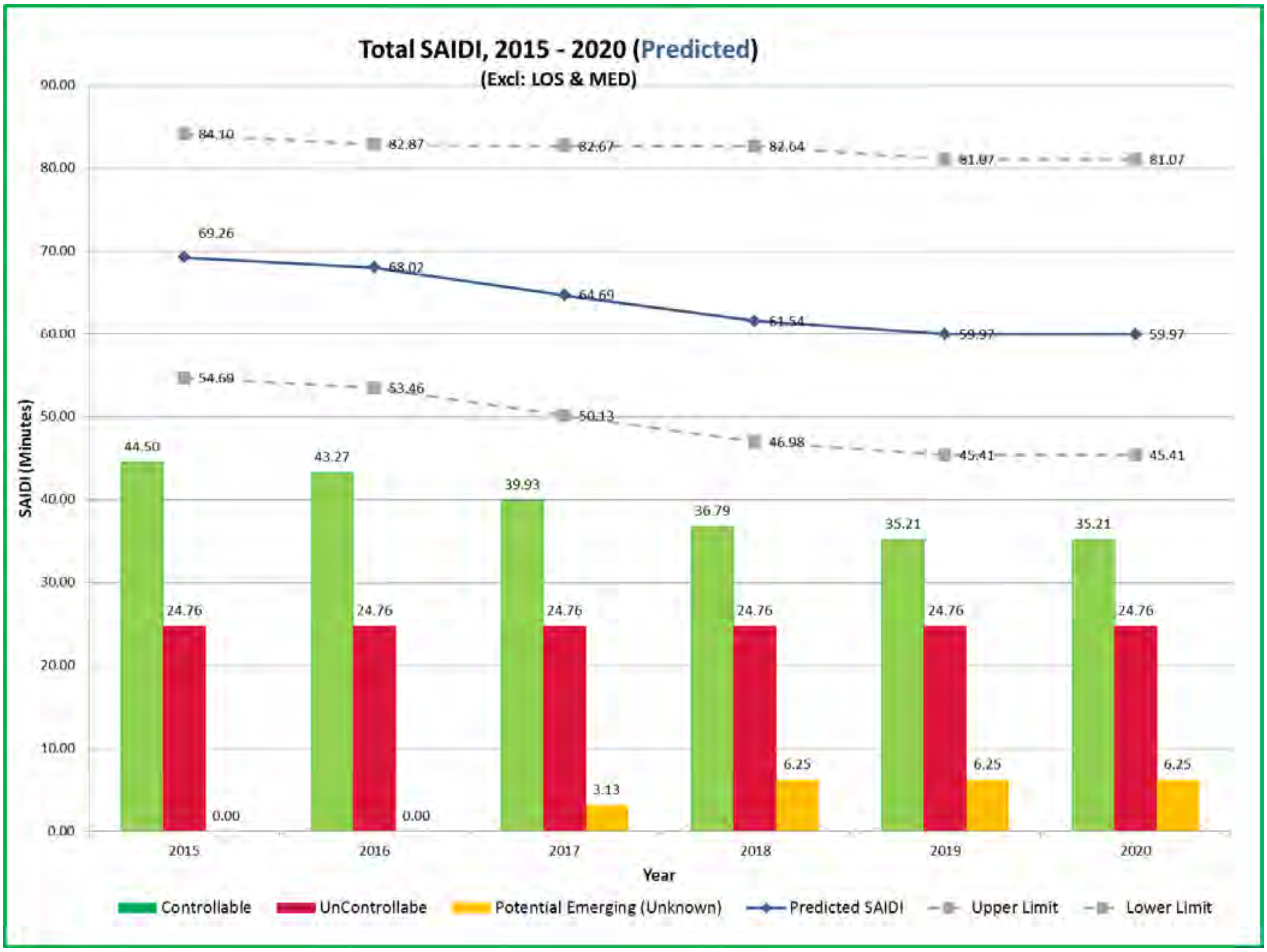


Figure 8: 2015 to 2019 Reliability Projection

Figure 8 breaks down the Future years' predicted SAIDI into its controllable and uncontrollable codes. The green bars indicate contributed SAIDI from controllable factors and red bars indicate contributed SAIDI from uncontrollable factors. The yellow bars are included to account for a certain level of uncertainty that arises in future years due to potential emerging reliability problems that are yet unknown. The blue line on the chart illustrates the total SAIDI prediction for each year.

Since weather has appeared to be relatively unpredictable based on the analysis of previous year's performance, an upper and lower limit are included to create boundaries for the SAIDI targets. These are represented using grey dotted lines.

The upper and lower bounds are there to account for the unpredictable nature of the weather and other emerging outages that could disrupt the targets. The upper limit is calculated using three Standard Deviations of the average performance. The lower limit is calculated based on the minimum SAIDI experienced in previous years, as it is expected that weather would not be milder than has been in the past.

In summary, there is an expectation that the projects and programs will lead to a modest improvement in reliability to customers as the controllable portion of the SAIDI will decrease as the capital projects/programs and the O& M projects are implemented.

5.4.1 CAPITAL EXPENDITURE PLAN 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.*

Capability of PowerStream to Connect New Load

As indicated in Exhibit G, Tab 2, Section 5.3.2 Table 3, PowerStream will have the capacity to connect new customers with the construction of transformer and substations as proposed in Exhibit G, Tab 2, Section 5.4.5.

As indicated in Exhibit G, Tab 2, Section 5.4.3 page 14, PowerStream should have the capacity to connect new generation customers.

Total Annual Capital Expenditures by Investment Category

The annual capital expenditures by investment category is shown in Table 1, and is fully described in Exhibit G, Tab 2, Section 5.4.4 and 5.4.5.

	Historical					Proposed				
CATEGORY	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Plan	2016 Plan	2017 Plan	2018 Plan	2019 Plan	2020 Plan
Rate Base	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000
System Access	21,007	19,888	17,030	26,229	24,145	28,232	28,470	29,561	28,726	31,867
System Renewal	11,527	16,974	22,254	39,186	42,388	48,715	51,500	52,052	52,971	52,406
System Service	22,885	13,770	34,780	17,946	27,322	38,322	32,072	29,920	26,963	23,022
General Plant	7,877	24,200	19,593	26,148	24,545	17,531	19,458	13,867	16,741	18,106
Sub-Total	63,297	74,832	93,657	109,509	118,400	132,800	131,500	125,400	125,401	125,400
Non-Rate Base	2,278	1,196	2,628	1,364	2,489	-	-	-	-	-
Grand Total	65,575	76,028	96,285	110,873	120,889	132,800	131,500	125,400	125,401	125,400
System O&M	2,055	2,438	2,523	2,627	3,290	3,825	4,365	4,909	5,459	6,015

Table 1: Capital Expenditures by Investment Category

Outputs of the Plan

PowerStream's Asset Management Planning Process affects the proposed capital expenditures of the main categories in the manner described below.

<u>System Access</u>

The inputs and criteria of the Asset Management Planning Process plays a limited role in determining capital expenditures within the System Access category. Instead, projects and capital expenditures are determined from Business Cases primarily based on the following:

a) Subdivision and New Connections: Short and long-term forecasts of growth in customer connections and load growth, based on historical figures. These are categorized as "must-do" projects.
b) Road Authority Projects: Information obtained from municipalities, regions, etc, of future projects and proposed scopes. These are categorized as "must do" projects.
c) Metering: Business Unit needs assessment of new and/or replacement retail and/or wholesale metering. The majority of these projects are considered "must-do".
d) Other Customer Initiated Work: Business Unit needs assessment of expenditures required to facilitate customer work based on historical requests and costs. These are categorized as "must-do" projects.

The total dollar amount of the System Access category is determined from the sum of the individual projects within the category. Due to the "must-do" nature of most of the projects within System Access, they are not impacted by the C55 Optimization process. The total dollar amount of the System Access category is not set or impacted by an allocation of PowerStream's overall capital budget.

<u>System Renewal</u>

As more fully described in Exhibit G, Tab 2, Section 5.3.1, the Asset Management Planning Process, with its various inputs and criteria, is the main determinant of proposed projects and their expenditures within the System Renewal category. In particular, the recommendations from Asset Condition Assessments constitute the main driver for the origin of the majority of projects in the System Renewal category.

The level of spending for the majority of projects within System Renewal is determined by an individual project-by-project assessment of criticality, asset condition, reliability and safety.

As more fully described in Exhibit G, Tab 2, Section 5.3.3 page 18, the allocation of the overall capital budget to the System Renewal category, and the projects within that category, is determined using Copperleaf's C55 Optimization software, limited by a fixed financial constraint of the overall PowerStream capital budget. Projects determined to be "must-do" projects are not optimized by the C55 software program.

The process is simplified to:

- Business Units develop their initial five year capital plans as part of the annual capital planning cycle;
- Business units prepare detailed budgets, justifications and business cases for projects, and enter these into the Optimization tool;
- A Corporate Five Year Plan is compiled based on the submitted business unit five proposed projects/programs as part of the capital planning cycle; and
- The five year detailed budgets for all business units are prioritized through the Optimization process.

Approved and prioritized projects for years one and two are designed and readied for execution in the next business year(s). Approved and prioritized projects for the remaining three years are identified and design can be commenced only if warranted

<u>System Service</u>

Similar to the System Renewal category, the composition of the projects in the System Service category are driven by the Asset Management Process. The main difference is that the Asset Condition Assessment plays a lesser role in the Asset Management Process for determining the projects and capital expenditures within the System Service category.

The various components (inputs) of the Asset Management Process result in a project-by-project listing that addresses the needs identified within the Process. The capital budget for each of the projects within the System Service category is determined from the scope of each project.

The allocation of the overall capital budget to the System Service category, and the projects within that category, is determined using the Copperleaf C55 Optimization software, limited by a fixed financial constraint of the overall PowerStream capital budget. Projects determined to be "must-do" projects are not optimized by the C55 software program. The same process, as stated in system renewal above, is applied.

<u>General Plant</u>

Depending on the type of project, Business Cases for individual projects constitute the main driver within the Asset Management Process for the majority of projects within the General Plant category.

The allocation of the overall capital budget to the General Plant category, and the projects within that category, is determined using the Copperleaf C55 Optimization software, limited by a fixed financial constraint of the overall PowerStream capital budget. Projects determined to be "must-do" projects are not optimized by the C55 software program. The same process, as stated in system renewal above, is applied.

Material Capital Expenditures

PowerStream's Capital Expenditure Plan includes a total of 71 Material Investment categories or projects, allocated as:

- 8 as System Access;
- 14 as System Renewal;
- 38 as System Service; and
- 11 as General Plant.

In accordance with OEB Guidelines, PowerStream's 2014 Materiality Threshold is calculated to be $771k, based on 0.5% of PowerStream's 2013 distribution revenue of $154M. A listing of the individual Material Investment Projects, sorted by category, is shown in Table 2 to Table 5.

Material Investments	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
System Access	**($)**	**($)**	**($)**	**($)**	**($)**	**($)**
New Connections and Subdivisions						
New Commercial Subdivision Development	1,600,010	1,601,908	1,603,808	1,605,707	1,607,607	1,609,506
New Residential Subdivision Development	7,895,964	8,633,109	9,392,346	9,759,944	10,135,066	10,517,394
New Subdivision Development - Secondary Service Lateral	1,989,034	2,173,796	2,364,815	2,458,773	2,554,113	2,650,954
O/H and U/G Residential Service Upgrades	928,921	984,657	1,043,737	1,106,360	1,172,741	1,243,109
Road Authority						
Road Authority Expenditures	6,258,891	9,701,973	8,678,858	8,356,668	5,718,617	6,221,949
Metering						
GS>50 MIST Meter Program Implementation	1,592,952	1,196,859	1,303,795	1,308,610	1,195,725	574,761
Residential Meter "ICON F" Meter Replacement Program	411,051	494,361	494,746	872,435	2,280,384	4,517,454
Other Customer Initiated Work						
Unforeseen Projects Initiated by the Customer	329,005	786,802	929,401	1,080,390	1,255,781	1,414,541
Total Material Investments System Access	**21,005,828**	**25,573,466**	**25,811,508**	**26,548,888**	**25,920,034**	**28,749,669**

Table 2: Material Investments - System Access

Material Investments	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
System Renewal	**($)**	**($)**	**($)**	**($)**	**($)**	**($)**
UG Lines - Planned Asset Replacement						
Cable Injection Program	4,024,219	4,138,312	4,255,465	4,375,771	4,499,323	4,626,219
Cable Replacement Program	11,718,862	12,538,684	13,607,273	14,288,297	15,085,861	15,340,181
Emerging Cable Replacement Projects	491,687	520,801	1,050,756	1,081,576	1,113,287	1,145,915
Submersible Transformer Replacement	1,040,300	620,000	-	-	-	-
Switchgear Replacement Program	2,003,445	2,327,404	2,462,129	2,533,373	2,606,624	2,681,945
Distribution Lines - Emergency/Reactive Replace						
Storm damage - Replacement of Distribution Equip due to Storms	999,785	1,000,232	1,005,603	1,005,624	1,010,352	1,010,159
Switchgears - Unscheduled Replacement of Failed Switchgear	1,420,148	1,431,384	1,420,148	1,421,218	1,400,444	1,140,858
Unscheduled Replacement of Other Failed Distribution Equip	4,904,357	5,107,035	5,206,156	5,358,281	5,455,354	5,305,986
Overhead Lines - Planned Asset Replacement						
Pole Replacement Program	4,645,383	4,933,143	5,570,700	5,870,246	6,241,483	6,244,377
Unforeseen Projects Initiated by PowerStream	1,046,472	1,070,527	1,093,812	1,117,360	1,141,172	1,165,266
Storm Hardening						
Storm Hardening & Rear Lot Supply	3,499,998	7,900,017	7,999,752	7,499,834	6,900,540	7,200,072
Stations/P&C - Planned & Emergency						
Planned Circuit Breaker Replacement Markham TS1&2, Lazenby TS1	747,766	-	-	1,087,788	1,119,281	-
Station Switchgear Replacement (ACA) 8th Line MS323	-	-	412,339	1,106,666	-	-
Station Switchgear Replacement (ACA) Patterson MS336	-	-	-	421,896	895,805	-

Table 3: Material Investments - System Renewal

Material Investments	2015	2016	2017	2018	2019	2020
System Service	**($)**	**($)**	**($)**	**($)**	**($)**	**($)**
Additional Capacity - Stations						
Letitia MS (MS413)- Increase Capacity from 5MVA to 10MVA Year 1 of 2	-	-	-	644,864	1,389,927	-
Painswick South MS: New 44-13.8kV, 20 MVA, 4-Feeder Substation- yea	2,690,054	-	-	-	-	-
Patterson MS#2 - New 44-13.8kV, 2x5 MVA, 2-feeders MS, Year 1 of 2	-	-	-	-	749,000	1,931,978
New MS, Dufferin South MS#2 - Alliston	-	749,000	2,299,074	4,899,189	-	-
New MS, Harvie Rd. MS - Barrie	-	749,000	-	-	-	1,700,333
New MS, Little Lake MS#2 - Barrie	1,125,311	1,603,656	3,095,457	-	-	-
New MS, Melbourne MS#2 - Bradford	-	749,000	1,651,393	3,187,430	-	-
New MS, Mill Street MS#2 - Tottenham	-	642,000	1,821,953	3,529,079	-	-
Vaughan TS #4 - Build Station	10,249,162	11,226,183	422,915	-	-	-
Additional Capacity -Lines						
2x44kV circuits (23M22 & 23M23) from Midhurst TS2 to Essa Rd. and M	5,011,705	3,606,692	4,460,060	-	-	-
Add one 27.6 kV Cct on Steeles Ave From Jane St to Keels St	-	-	-	-	1,110,310	-
Add one Additional 27.6 kV Cct on Major Mack and 9th Line	-	-	-	-	-	1,248,939
Build double ccts 27.6kV pole line on 19th Ave between Leslie St and Ba	-	-	1,221,747	-	-	-
Install 2x13.8kV ccts Pole Line on Leslie St from Wellington St to St.John	-	1,131,418	-	-	-	-
Install Double Cct Pole Line on Major Mackenzie - Hwy 27 to Huntington	-	-	-	1,819,608	-	-
Install Double Ccts 27.6 kV Pole Line on 16th Ave from 9th Line to Reeso	-	-	-	-	1,302,301	-
Install one 44kV cct on Mapleview Drive West - Essa to Veterans	-	-	-	855,914	-	-
Install Two 27.6kV Ccts on 16th Ave from Hwy 404 to Woodbine Ave	-	1,108,593	-	-	-	-
Install two additional 27.6 kV ccts on Hwy 7 from Jane St to Weston Rd	-	-	-	-	-	2,084,275
Installation of two new circuits on Leslie Street - 19th Ave to Stouffville S	-	-	-	-	-	1,392,644
Markham TS #4 Feeder Egress Part 3	-	-	-	-	-	4,910,872
New 27.6kV Pole Line on 19th Ave from Leslie to Woodbine Ave	-	-	-	-	1,020,587	-
New 44 kV Feeder (13M7) Barrie TS X Huronia & Big Bay Pt. Rd. - Design	76,925	4,726,805	-	-	-	-
Pole Line Installation Double Cct on Major Mack - Huntington Rd to Hwy	-	-	-	-	1,307,147	-
Rebuild 27.6 kV pole line for 4 Ccts on Warden Ave from Major Mack to	-	-	-	2,061,719	-	-
Rebuild 27.6 kV pole line into 4 Ccts on Warden Ave from Hwy 7 to 16th	-	2,039,163	-	-	-	-
Rebuild 27.6 kV pole line on Warden Ave into 4 ccts from 16th Ave to M	-	-	2,050,441	-	-	-
Rebuild Pole Line on 14th Ave into 4 cct -From Warden Ave to Kennedy	-	-	1,206,790	-	-	-
Two Ccts on Birchmount Rd from ROW to 14th Ave	-	-	-	-	-	1,502,063
Two Ccts on Birchmount Rd from ROW to Enterprise	1,201,150	-	-	-	-	-
Vaughan TS#4 Feeder Integration	-	-	7,341,955	3,176,402	9,630,000	-
27.6 kV Pole Line on 14th Ave from Hwy 48 to 9th Line	-	2,039,163	-	-	-	-
27.6 kV Pole Line on Reesor Rd from Hwy 7 to 14th Ave	-	1,496,942	-	-	-	-
Double Circuit existing 23M8 Circuit from Bayfield & Livingstone to Little	-	-	-	-	2,395,509	-
Highway Crossing Remediation - Hwy 400/ Brock St.	-	-	-	1,038,486	-	-
Highway Crossing Remediation - Hwy 407/ East of Dufferin	1,100,409	-	-	-	-	-
Reliability including Dist. Auto.						
Distribution Automation Switches / Reclosers	1,850,276	1,530,249	2,080,457	2,283,805	2,354,895	2,409,740
Purchase of a Mobile Unit Station	-	-	-	-	-	885,481
Total Material Investments System Service	**23,304,991**	**33,397,865**	**27,652,242**	**23,496,497**	**21,259,677**	**18,066,325**

Table 4: Material Investments - System Service

Material Investments	2015	2016	2017	2018	2019	2020
General Plant	**($)**	**($)**	**($)**	**($)**	**($)**	**($)**
Customer Information System (CIS)						
CIS Modifications	1,403,400	3,884,100	6,708,900	2,996,000	2,996,000	2,996,000
CIS Replacement Project	10,300,000	-	-	-	-	-
IT & Info/Communication Systems						
JD Edwards Application Upgrade	-	-	-	-	2,396,800	-
MSBPI	-	10,000	60,000	899,999	50,000	10,000
Phone System enhancement Upgrade	-	-	-	-	50,500	908,999
Storage Expansion (Data)	321,000	300,000	300,000	300,000	1,000,000	400,000
Work Force Management / Mobile Dispatch	1,605,000	2,675,000	802,500	802,500	535,000	535,000
Buildings & Emerging Operations						
Barrie Building Renovation Project 2015	3,149,489	-	-	-	-	-
Fleet						
Replace various Light and Medium Duty Vehicles	-	-	-	-	829,250	888,100
Replace various Single Bucket and Double Bucket Trucks	-	-	-	2,193,500	1,605,000	1,391,000
Interest Capitalization						
Interest Capitalization	1,000,000	1,020,000	1,040,000	1,061,000	1,082,000	1,104,000
Total Material Investments General Plan	**17,778,890**	**7,889,100**	**8,911,400**	**8,252,999**	**10,544,550**	**8,233,100**

Table 5: Material Investments - General Plant

Regional Planning

As indicated in Exhibit G, Tab 2, Section 5.1.4, PowerStream has participated in Regional Planning, and as a result of this, PowerStream has capital expenditures related to Vaughan Transformer Station #4, and the integration of the feeders from this station to the distribution system. The total proposed capital expenditure for the station and related system integration is $42,046,617 between 2015 and 2020.

Customer Engagement Activities

As described fully in Exhibit G, Tab 2, Section 5.4.2, PowerStream performed a comprehensive customer engagement process, and have reviewed those results against the proposed plan.

Five Year System Development

PowerStream's distribution system will continue to expand to accommodate:

- new transformer and municipal station construction;
- the integration of feeders from the stations to the distribution system;
- enhancement of pole lines to accommodate growth areas; and

- smart grid.

These projects are noted within the categories of system access and system service.

Special Activities

PowerStream has a number of initiatives that are related to customer preferences, technology or innovation. These are shown on Table 6. All these initiatives belong to the Smart Grid category, and were initially submitted in PowerStream's GEA Plan, Exhibit B2, Tab 1, Schedule 2 in EB-2012-0161.

Innovation Projects	2015	2016	2017	2018	2019	2020
Smart Grid	**($)**	**($)**	**($)**	**($)**	**($)**	**($)**
System Service						
Operations Technologies Rate Based	-	535,000	535,000	535,000	535,000	535,000
Storage Technologies Rate Based	-	535,000	535,000	535,000	535,000	535,000
General Plant						
Data Analytics	-	267,500	267,500	267,500	267,500	267,500
Electrical Vehicle Technologies	-	535,000	535,000	535,000	535,000	535,000
Home Technologies	-	535,000	535,000	535,000	535,000	535,000
Total	**-**	**2,407,500**	**2,407,500**	**2,407,500**	**2,407,500**	**2,407,500**

Table 6: Special Activity Initiatives

Note: In accordance with OEB Filing Requirements, Smart Grid expenditures for Year 2015 are recorded in deferral account 1534, and are not shown as part of this Capital Expenditure Plan.

A description of each of these categories is detailed below.

Alternative Energy Sources

Alternative Energy Sources is a new focus area that will investigate new distributed energy sources and their integration with the distribution system. Examples include distributed storage systems and microgrids. Integrating distributing energy assets into grid control systems has the potential to address real-time power management issues and improve both grid and distributed asset utilization.

As renewable energy sources continue to be developed throughout PowerStream's service territory and as electric vehicles continue to be introduced to the Southern Ontario marketplace, there is an increased need to better understand the electricity storage options available to local distribution companies. There have been significant technical advances in electricity energy storage systems such as inertial flywheels, pneumatic storage, hydraulic storage and advanced battery systems.

PowerStream considers energy storage to be an integral component of its Smart Grid strategy. In that regard, it plans to investigate specific applications of various storage technologies and, where practical and justifiable from an operational and financial viewpoint, recommend larger scale deployment of the technology to the distribution grid as part of PowerStream rate based capital expenditure program.

PowerStream has installed an operating microgrid at its Cityview Head Office and is using the technical and economical learnings from this project in microgrid discussions and planning.

Data Analytics

The Smart Meter/AMI system collects an enormous amount of data on customer energy usage, power quality and system performance. To be useful, this data must be made accessible to several key departments within PowerStream, namely System Planning, Engineering Design and Operations Control.

Over the five year plan period, PowerStream, with the assistance of contract personnel, will develop user friendly Geographic User Interface (GUI) type database queries to provide easy access to those personnel requiring this data. This real information on customer loading and operational performance (outages, voltage levels, power quality, system & equipment loading, efficiency and losses) will enhance existing tools used by technical staff and provide more comprehensive and accurate information for planning, design and operational purposes. PowerStream has developed a transformer loading tool that leverages smart meter data and is replacing the existing CIS based transformer loading tool. Future Analytics work will leverage this tool database (which integrates all PowerStream meter databases into one database) and system and expand into new analysis opportunities.

<u>Electric Vehicles (EV)</u>

PowerStream has engaged in projects to better understand the impact of EV technology on its distribution system. PowerStream is now working to identify and develop the potential benefits EVs can provide. PowerStream recently deployed a vehicle-to-grid charging system that is connected to its head office microgrid. Any learnings will be used to identify how this opportunity can potentially provide storage services on the distribution system. Other EV investigations include smart charger control, EV for load shifting purposes and re-purposing of spent EV battery equipment. PowerStream engages closely with provincial and national EV industry groups to identify and bring relevant learnings to our distribution system operations and customers.

<u>Smart Home</u>

Recently, the provincial government, the Ontario Energy Board and the IESO Smart Grid Forum have placed an increased emphasis on Home Energy Management (HEM) applications and have suggested that LDC's participate in some manner.

PowerStream has implemented two-way communication and control on its AMI network. This is being leveraged in the Home Area Network (HAN) residential project to provide real-time consumption data to customers over Zigbee meters as well as *verifiable* load control events. PowerStream is the LDC partner on Energate's Residential Dynamic Pricing project and Rogers Smart Home project, both of which are underway and are funded by the Ministry of Energy's Smart Grid Fund. PowerStream is leveraging the solutions and learnings of these projects to increase the energy savings and services provided to customers.

Information and trial results obtained from these initiatives are open to the industry stakeholders and are shared at regular Smart Grid information exchange meetings.

5.4.2 CAPITAL EXPENDITURE PLANNING PROCESS OVERVIEW

The information a distributor should provide includes, but need not be restricted to:

a) 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;

b) 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;

c) a description of the process(es), tools and methods (including where relevant linkages to the distributor's asset management process) used to identify, select, prioritise and pace the execution of projects in each investment category (e.g. analysis of impact of planned capital expenditures on customer bills);

d) 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; and

e) 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).

Capital Expenditure Planning Objectives

The capital expenditure planning objectives are detailed in Exhibit G, Tab 2, Section 5.3.3.

Identification, Selection and Prioritization of Projects

The identification, selection and prioritization of projects is detailed in Exhibit G, Tab 2, Section 5.3.3.

Customer Engagement - General

PowerStream provides electricity and energy related services to more than 370,000 customers throughout a large and diverse service territory, and has undertaken customer consultation activities as part of specific outreach on this DS Plan. PowerStream routinely communicates frequently with customers through a number of communication methods, including:

- Customer transaction telephone survey;
- Key Accounts outreach and management;
- Customer Satisfaction Survey;
- Customer Experience Plan;
- Communications and Social Media;
- Enhanced Communication Activities – December 2013 Ice Storm Review; and
- Conservation and Demand Management outreach and activities.

<u>Ongoing Customer Engagement</u>

PowerStream interacts with its residential and commercial customers regularly through its normal business practices.

PowerStream's customers range from small residential customers to large commercial and industrial enterprises. PowerStream's service territory is home to some of the largest internet and banking data centres, as well as major manufacturers and commercial service providers.

Focusing on customers and striving to be efficient while providing optimum service, in a safe and reliable way is at the forefront of PowerStream's operating philosophy. PowerStream's interactions with customers occur most frequently within the Customer Service Department, as well as through the Conservation and Demand Management (CDM) and Corporate Communications groups.

In addition to the ongoing communication efforts, PowerStream engages with its customers when capital work is to be performed in their area in order to address and alleviate any potential stakeholder concerns. Town halls, presentations and focus groups are used to communicate with specific customer groups ahead of any major projects being conducted in their area to ensure transparency and to encourage the customer base to become more educated about any ongoing projects that may impact them.

Customer Transaction Telephone Survey

The OEB has established service quality measures and standards that all distributors must meet. It is PowerStream's view that the OEB-regulated customer service requirements are a minimum requirement. PowerStream seeks to provide customers with the best experience possible when interacting with all LDC staff. Practices and procedures are reviewed based on changing customer needs and preferences. Focus groups are used to review practices and gather customer input in order to make revisions to the services provided.

In January 2014, a customer feedback process was implemented whereby customers are called back seven days after they contact PowerStream's Call Centre. Approximately 800 residential customers are contacted through this process on a weekly basis. Early results show that 79% of customers are very or somewhat satisfied with their interaction with PowerStream. PowerStream has moved from a reactive position to being proactive with customer needs by learning from past situations and feedback surveys in order to mitigate the occurrence of similar issues and deliver an exceptional customer experience.

Key Accounts

PowerStream's large commercial and industrial users are provided with a specialized service designed to accommodate their unique needs. The Key Accounts team meet regularly with these large users to provide an update on PowerStream's activities and to address any concerns they may have. This feedback is shared internally and has led to targeted reliability investments in areas that were experiencing higher levels of service disruptions. This program also allows these customers to learn about CDM initiatives that may work to their advantage in managing their energy consumption.

Customer Satisfaction Survey

Since 2007, PowerStream has engaged a consultant group to conduct a customer satisfaction study in order to gather third-party feedback from customers with the objective of using this information to develop process improvements, implement new service offerings, and to better understand the needs and preferences of customers.

Focus groups are held annually for residential customers and in-depth interviews are conducted with key commercial account holders within the service territory. This research is conducted to supplement quantitative data from the UtilityPulse Study, Rehab Study, Customer Transaction Survey and an Online Customer Study.

In 2013, PowerStream's overall customer satisfaction score was 91 per cent, slightly above the average, and for PowerStream, higher than any of the previous four years. Each year, the results of the Customer Satisfaction Survey are used to develop and execute improvements. For 2014, based on the 2013 survey results, the top action areas were:

- Better communicate the extent to which PowerStream works with and assists local communities;
- work to ensure that customer newsletters are concise and address topics important to customers such as ways to keep electricity costs down through energy conservation;
- focused assistance for key account customers, such as online energy usage tracking; and
- reinforce with customers that PowerStream is community owned.

Customer Experience Plan

As part of its commitment to continuous improvement, PowerStream drafted a Customer Experience Plan in 2012 as a corporate initiative that touches all areas of the utility. Existing PowerStream work was leveraged for the plan, including PowerStream's corporate strategy, present customer satisfaction studies and customer segmentation work. The project involved extensive employee and stakeholder engagement, including:

- Interviews with executives, directors and managers;
- Interviews with senior Ontario Energy Board staff and an intervener;
- Completion of a survey by over 260 PowerStream staff;
- A Customer Experience Attribute Workshop;
- Focus Groups with front line staff; and
- Regular Steering Committee and Project Team meetings.

Prioritizing the customer experience, engaging with customers and ensuring accountability are some of PowerStream's priorities coming out of the Customer Experience Plan. Near term priorities focus on driving cultural change, while longer term priorities focus on developing the tools and insights to effectively deliver and ensure that customer experience is a corporate priority.

Communications and Social Media

PowerStream is committed to providing customer-focused communications and to reaching out to customers in the ways in which they want to be communicated with and where and when they want the conversations to take place. Social media helps PowerStream to better understand, respond to and attract the attention of specific audiences. It enables interactive communication – the exchange of information, perspective and opinion – among multiple audiences, effectively, efficiently, and in places where those conversations are taking place. The use of social media also enhances the ability to engage PowerStream's customers and offers greater accessibility to them including being able to reach out to them on specific issues.

Enhanced Communication Activities – December 2013 Ice Storm Review

In the aftermath of the December 2013 Ice Storm, PowerStream initiated a review conducted by a third-party consultant in order to revise the utility's ability to respond to major events. The task force made 35 key recommendations in a number of categories including external communications and customer care, emergency restoration, capital asset management, system hardening, and technical considerations. In response to the findings of this review, PowerStream took actions to implement these recommendations. The utility is committed to maintaining a customer focus as a core part of its operating philosophy and is making improvements to its customer communications strategy as a result of the report's recommendations:

- Implemented a "live agent" option in the Outage Interactive Voice Response (Outage IVR) system - previously, customers could only leave a message, but now can speak to a Customer Service Representative (CSR) 365/24/7;
- CSRs are provided with better tools to assist customers with outages;

- Implemented a "One Number" solution where all published PowerStream phone numbers will be routed to the same location. Customers have the choice to either report an outage or speak to Customer Service to deal about typical issues (bill questions, etc.). The system also has the capability for broadcast type messages to let customers know about significant outages and updates in a given area;
- Developed a Crisis Communications Plan;
- Implemented a Customer callback option for customers who wish to receive a call after their power has been restored;
- Created an Outage E-mail Notification Service;
- Developed an information package for Councils and municipal staff on utility operations and Emergency Preparedness; and
- Began Implementing an out-of-province Call Centre to be deployed in the event of very widespread outages.

Conservation and Demand Management

The Conservation and Demand Management team interacts with residential and business customers. In addition to customer interviews and focus groups undertaken for specific objectives, they participate in over 15 community events per year and hold events in retail stores, reaching over 3,000 customers during events. PowerStream also engages customers through the promotion of CDM programs by distributing handouts, placing print advertisements in local newspapers, adding bill inserts, sending out direct mail pieces, GO Train Posters and online advertisements.

The CDM group conducts ongoing market research studies to determine motivations, barriers and satisfaction levels of our customers related to conservation program participation. They also collect information related to preferred methods of communication. Through outreach surveys, PowerStream discovered that a high proportion of customers indicated that their communication preference is email. The CDM team therefore implemented an email marketing communication system to deliver conservation program messages as a result of the learnings obtained through the survey.

The CDM team has also undertaken a Residential Customer Segmentation Study in order to classify PowerStream's residential customer base into distinct segments to further develop an understanding of its customers and their needs. Over the course of this study, over 3,500 customer interviews were conducted. The segmentation work will assist in the utility's efforts to tailor programs and services to the wants and needs of customers and will improve the organization's understanding of customer perspectives on a number of topics, including:

- Consumption habits & understanding of the impact of their electricity consumption on the environment;
- PowerStream as a local hydro company & level of trust;
- Customer Service Metrics; and
- General attitudes and behaviours including feelings towards conservation, social pressures, and motivations and barriers towards participation.

Customer Engagement - DS Plan

PowerStream developed a customer engagement process with its residential and commercial customers designed specifically to obtain feedback on this DS Plan.

In the spring of 2014, PowerStream engaged Innovative Research Group Inc. ("Innovative"), a national research and strategy firm to assist in determining how to incorporate customer needs and preferences into the DS Plan.

Throughout the summer and fall of 2014, PowerStream conducted a series of customer engagement activities in preparation for completion of the DS Plan.

The activities were focused specifically on the DS Plan and were designed to determine customer preferences related to PowerStream's proposed capital plans. The DS Plan specific engagement plan responded to OEB expectations articulated in the RRFE report that distributor plans should take customer preferences into account.

The DS Plan specific engagement activities are described below, as is PowerStream's response to incorporating customer preferences into the DS Plan, per the Chapter 5 filing requirement.

<u>Engagement Methods</u>

There were four engagement methods.

i) <u>Online DSP Primer</u>

The primer developed for this consultation process was available online to all PowerStream customers from November 17, 2014 to December 22, 2014.

ii) <u>Residential and GS>50 Focus Groups</u>

These consultation sessions were led by Innovative and were structured around the themes of the primer. Primer booklets were distributed and participants were asked to read and complete the feedback questions. A subsequent discussion of each section was facilitated by the moderator.

- Barrie – November 17, 2014
- Markham – November 18, 2014
- Vaughan – November 19, 2014

iii) <u>GS< 50 – Workshops</u>

These sessions were structured around the content of the primer and the DS Plan. PowerStream made a detailed presentation with customers having the opportunity to pose questions to staff. Innovative then facilitated breakout groups where participants were guided through the primer sections and then asked to fill in their answers to the questions independently. A subsequent discussion of each section was facilitated by the moderators.

- Barrie – December 9, 2014
- Richmond Hill – December 10, 2014

iv) <u>Key Accounts – Presentation and Feedback</u>

These sessions were structured around the content of the primer and the DS Plan. PowerStream made a detailed presentation with customers having the opportunity to pose questions to staff. Innovative then facilitated a feedback session where participants were guided through the primer sections and then asked to fill in their answers to the questions independently. A subsequent discussion of each section was facilitated by the moderator.

- December 10, 2014

PowerStream developed a primer to be used as the predominant consultation tool for the variety of engagement methods used in this process. The goal of the primer was to translate PowerStream's proposed plans for the distribution system into a plain language document that customers could relate to. The primer discussed the challenges the distribution system faces and how the utility intends to address them. Feedback was collected through relevant questions posed after each section of the primer with the intent of educating customers about the electricity distribution system and gathering their input on specific plans and projects proposed in the DS Plan.

Participants were generally satisfied with the service being provided by PowerStream, with 91 per cent reporting that they were either very satisfied (46 per cent) or somewhat satisfied (45 per cent), though many indicated that they were only somewhat familiar with the electricity system and PowerStream's services.

<u>Rate Impacts</u>

Proposed estimated bill impacts were presented for each rate class and major capital projects discussed to provide a background for PowerStream's proposed activities for 2016-2020.

Generally, customers accepted the proposed rate increases, but there was a concern from some business customers that PowerStream had not demonstrated that they had looked for internal efficiencies prior to going to customers for the increase. There was some discussion during focus groups of PowerStream paying for increased capital budget requirements through the company's profits.

The majority of customers surveyed online and in focus groups indicated that they were supportive of the increase. These customers believe that the rate increase is reasonable and that they support it, or that they don't like it but think that the rate increase is necessary:

Of 1,553 online survey respondents, 67 per cent were supportive of the increase, or which 19 per cent thought it was reasonable, and 48 per cent didn't like it but thought it was necessary. 26 per cent were opposed to the rate increase and thought it was unreasonable. Similar results were seen in focus groups, however both key accounts and GS > 50 customers were slightly less supportive, with greater numbers indicating that they opposed the increase.

<u>PowerStream Focus</u>

System Reliability and Restoration Time

PowerStream was pleased to discover that most customers are satisfied with the levels of reliability they currently receive. This is consistent with the capital expenditure plan which is designed to maintain current reliability levels (no degradation). Modest improvements due to the remediation of worst performing assets are expected (refer to Exhibit G, Tab 2, Section 5.3.3 p.34). An example of remediation projects that will have a positive effect on system reliability is cable remediation, described in Exhibit G, Tab 2, Section 5.2.3.

Approximately seven in ten customers identified that they have experienced at least one outage during unusual weather and six-in-ten reported having experienced an outage excluding during times of extreme weather situations. However, when asked to describe the length of their outages, most reported having had their power restored within one hour and 29 per cent had their power restored within 15 minutes. No serious concerns regarding current restoration times were identified by the majority of customers.

Despite these results, some commercial customers expressed concerns about small, momentary outages that can negatively affect sensitive machinery. A small number of key accounts customers pointed to poor reliability as a serious concern for their businesses. PowerStream addresses concerns these through the worst performing feeder assessments and ongoing reliability committee discussions on problematic areas.

Aging Infrastructure

When presented with PowerStream's plans for addressing the concern of aging equipment, it was found that customers generally accepted PowerStream's current practices for replacing distribution assets. More than half of the participants in the online survey indicated that their preference is to continue investing to reduce power outages as opposed to scaling back infrastructure investment to reduce the impact on electricity rates.

Investment in New Technologies

Customers were able to see some benefits of investing in new technologies as they indicated a desire for increased communication from the utility. At the same time, PowerStream received some specific feedback regarding the implementation of the new CIS system. Some customers were unable to see the added benefit of implementing a new system.

- GS < 50 customers in focus groups were most likely to question the need for the new billing system. They reported consistently receiving bills and did not see how this investment would improve their reliability.
- The results of the online primer survey indicated that 48 per cent of respondents view investments in technology as important and should be a priority for PowerStream. Just over a third (34 per cent) indicated that investments in new technology are more of a luxury than a necessity and should therefore be a low priority for PowerStream.
- New technology was seen as a solution to improving communication for key accounts customers. This particular customer class had 62 per cent of respondents who believed that investments in new technology should be a priority for PowerStream.

There was a sense during the in-person focus group sessions that PowerStream had not made the business case for this major investment and that the perceived value of implementing this system was not shared across all customer classes. PowerStream has strengthened its business case for this expenditure. Refer to Appendix A, Material Investments, for detailed project information.

Storm Hardening

PowerStream customers had varying views on the need to prepare for extreme weather events. Some see it as a necessary investment in order to ensure safety, however, because future weather is seen as unpredictable, and past experiences during major events have been generally positive, this is seen as an area in which major investments are not necessary.

PowerStream's approach to storm hardening is consistent with customer preferences because a modest approach to investments is being taken in order to balance risks and cost. PowerStream commissioned a review of the utility's response the 2013 Ice Storm. The purpose of the review was to identify lessons learned and to develop action plans to enhance performance should another major incident occur. The report outlined 15 recommendations, of which four were chosen for capital projects, including a project to replace all rear lot supplies on an annual basis until all are remediated.

Customers expressed concern related to the improvement of communication during outages. Many participants in residential focus groups and the online survey indicated that better communication from the utility was the main way that PowerStream could improve its service to customers during extreme weather events. This was also identified as an area for improvement coming out of the review conducted in 2014. As a result, PowerStream has made a number of improvements to increase the volume and accuracy of communications to customers during outages. Two of these process improvements are described below:

I. PowerStream has implemented an Outage Notification Service which allows customers to register to receive emails when an outage occurs at their location. These notifications include status updates if there are changes to the incident as well as a final notification once power has been restored; and
II. A social media strategy has been developed in order to leverage best practices from emerging communication technology to enable PowerStream to effectively address the volume of messages and to provide the best information to customers.

PowerStream derived significant benefits from the enhanced level of customer engagement conducted during the preparation of the DS Plan. The utility values input from customers and was extremely pleased to confirm the level of general support customers have for the utility's plans and approach to investment.

Refer to Appendix C to Appendix F for the materials used and the reports provided by Innovative.

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.

In relation to renewable or other distributed energy generation connections, the information that must be considered by a distributor and documented in an application (where applicable) includes:

- *a) applications from renewable generators over 10kW 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 IESO 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); and*
- *e) constraints for an embedded distributor that may result from the connections*

Applications from Renewable Generators over 10kW

As of August 1st 2014, PowerStream has connected eighty four Feed-In Tariff (FIT) applications for a total of 16,016 kW of generation (item F3 from Table 1). In addition, there are 203 projects, totaling 36,448 kW (item F4 from Table 1), that have been approved by PowerStream for connection and are currently being constructed. PowerStream's FIT breakdown is seen in Table 1.

Item	Process Description	Project Count	Capacity (kW)
F1	Total FIT applications *received* by IESO	314	56,326
F2	Total FIT applications *approved* by IESO	204	36,583
F3	Total FIT applications *approved* by PowerStream	203	36,448
F4	Total FIT projects *connected* by PowerStream	84	16,016

Table 1: FIT Projects

The 203 connected, or about to be connected FIT generators, are dispersed throughout PowerStream's territory. Projects are located predominately in Markham, Richmond Hill, Barrie and Vaughan however, there are also scattered projects located in the smaller communities of Aurora, Alliston, and Bradford. Table 2 details the FIT Generators by geographic region (as of Aug.1 2014):

		FIT	
		Projects	Generation (kW)
Northern Region	Allliston	2	135
	Barrie	23	2,892
	Beeton		
	Bradford	4	590
	Penetang	2	325
	Thornton		
	Tottenham	2	350
	Northern Sub Total	33	4,292
Southern Region	Aurora	6	831.8
	Markham	59	9,353
	Richmond Hill	17	3,743
	Vaughan	88	18,229
	Southern Sub Total	170	32,156
Total Projects		**203**	**36,448**

Table 2: FIT Generators by Geographic Region

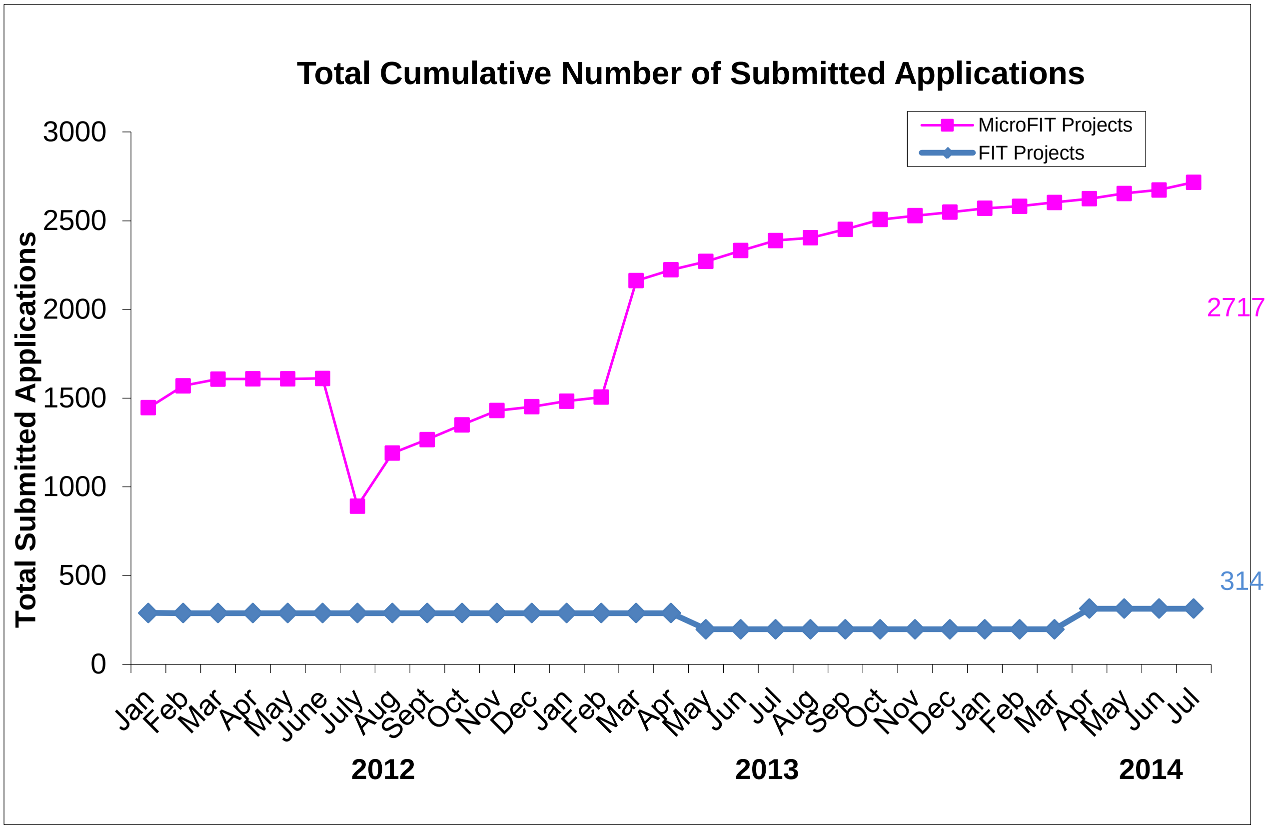
Number and Capacity (MW) of Renewable Connections Anticipated

Planned Development

PowerStream has projected Renewable Generation growth for 2015-2020 based on existing FIT data and industry expectations.

Renewable Generation growth for 2015-2020 has been estimated based on PowerStream's existing FIT/MicroFIT data from 2009-2014 and the expected evolution of the IESO's FIT program.

As of August 1st 2014, PowerStream customer FIT and microFIT submissions to the IESO have totaled 3,031 applications, grossing over 76MW of potential generation. The 2012-2014 application data, illustrated in Figure 1, indicates a strong average monthly growth rate to date.



<u>Figure 1: Cumulative Submitted Application by Month</u>

Source: IESO LDC Portal

Although Renewable Generation installations in PowerStream's service area have been increasing, they are mainly focused on roof top solar applications. Renewable Generation by source is broken down as shown in Table 3:

Fuel Type	FIT	MicroFIT
Solar photovoltaic - Roof Top	314	2,717

<u>Table 3: Fit/MicroFIT Volumes</u>

The project size distribution is seen in Figure 2, which illustrates limited interest in projects over 250kW and no interest in projects greater than 500kW.

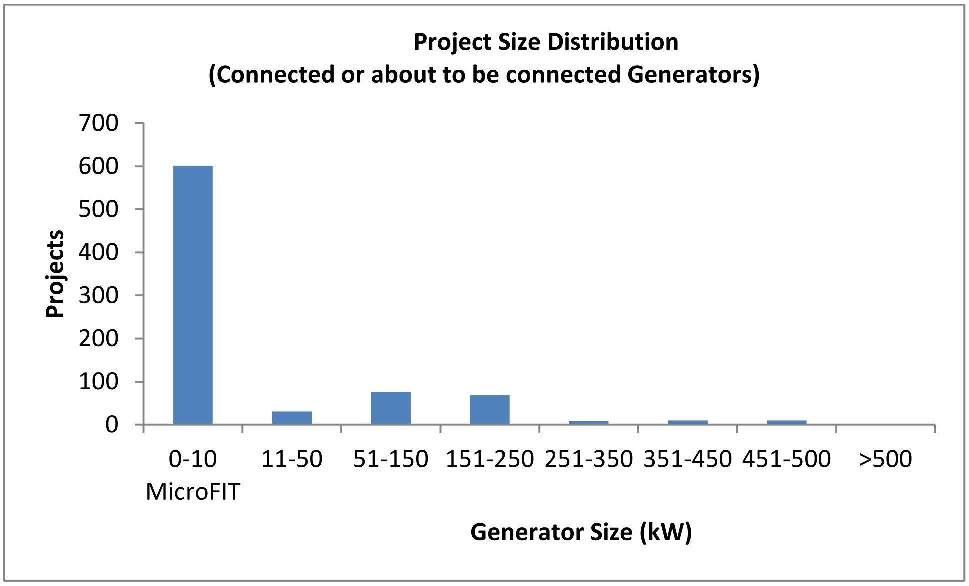


Figure 2: Project Size Distribution

PowerStream's regions are predominantly made up of urban areas which are ideal for roof top solar, but less attractive for larger ground mount solar or wind installations. Therefore, because there is limited potential for major wind or other ground mount projects, and economically viable roof tops are finite, installations are expected to slow down over the next six years. This assumes that FIT program pricing continues to provide less than ten year payback for commercial rooftop installations.

Program Progression

In order to create a six year projection of FIT growth in PowerStream's distribution area, some assumptions were made regarding the program's future direction.

The IESO's FIT Program has been relatively unchanged since its inception in 2009. Following three years of Renewable Generation experience, valuable insight has been gained into the public demand for green energy and potential capacity constraints caused by the distribution grid. Based on these lessons learned, IESO made adjustments to the FIT program in 2012, considering some of the following potential changes:

- Price Point Drop to reflect the current market per unit costs of retail generation equipment;
- New Funding Model to make smaller FIT projects more financially feasible; and
- Generation Caps to slow the FIT program down to manageable levels but still maintain the current job creation model.

The above items were taken into consideration when developing PowerStream's six year Anticipated Generator Connections model.

Anticipated Generator Connection Applications

Based on PowerStream's 2009-2014 FIT/microFIT data and future assumptions regarding the IESO's FIT program, it is expected that application submissions will remain steady through 2015, begin to decline in 2016, and continue to descend through 2018. Table 4 outlines the expected decline:

	Applications/year	Cumulative Applications
2010	666	666
2011	1038	1704
2012	36	1740
2013	1005	2745
2014	286	3031
2015	215	3245
2016	161	3467
2017	121	3527
2018	60	3587
2019	0	3587
2020	0	3587

Table 4: Actual and Projected Application Volumes

The IESO currently has Renewable Generation applications totaling 76MW for PowerStream's service territory. Based on PowerStream's anticipated FIT connection model, projected growth for Renewable Generation in PowerStream's territory will pursue the trend depicted in Figure 3.

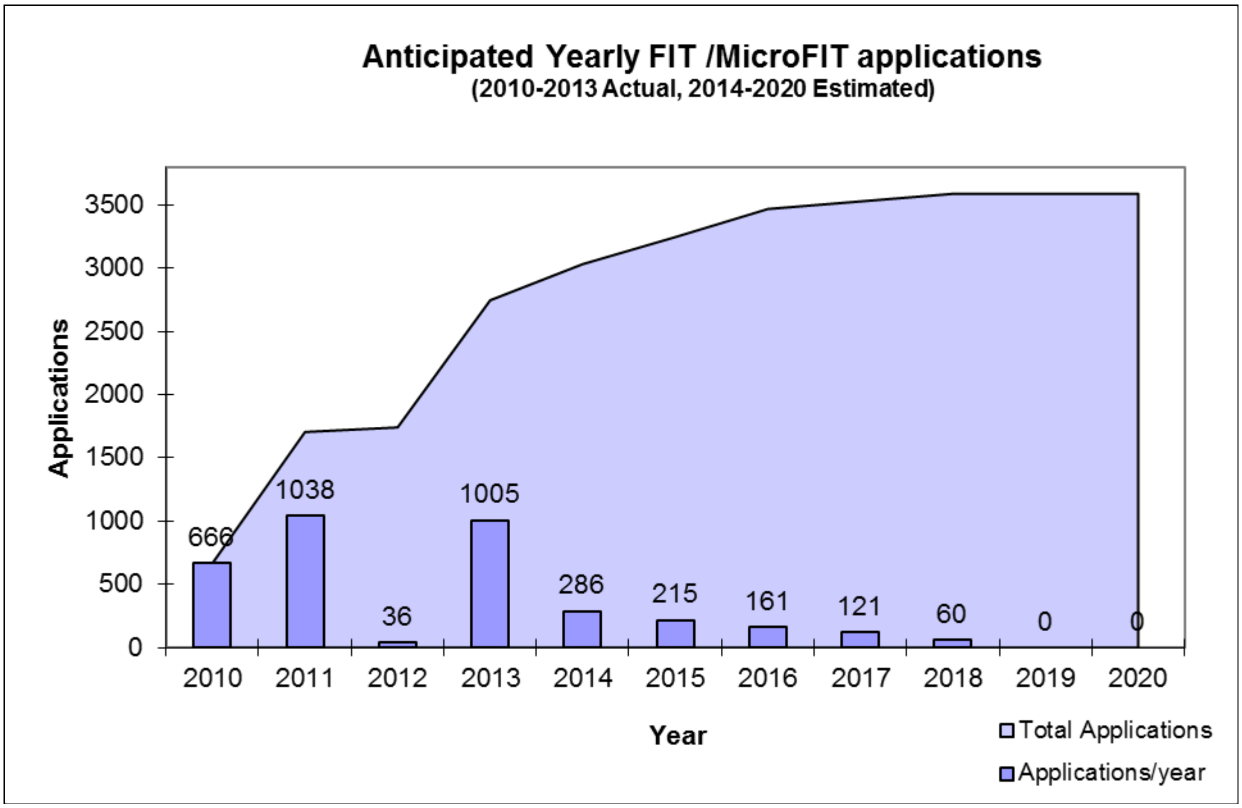


Figure 3: Annual FIT Applications

PowerStream Renewable Generation Growth

Following steady growth through 2014, the Renewable Generation growth rate is expected to peak and begin to decline in 2016 through 2018. PowerStream's Renewable Generation load is expected to reach 107.7MW by 2020. Refer to Figure 4.

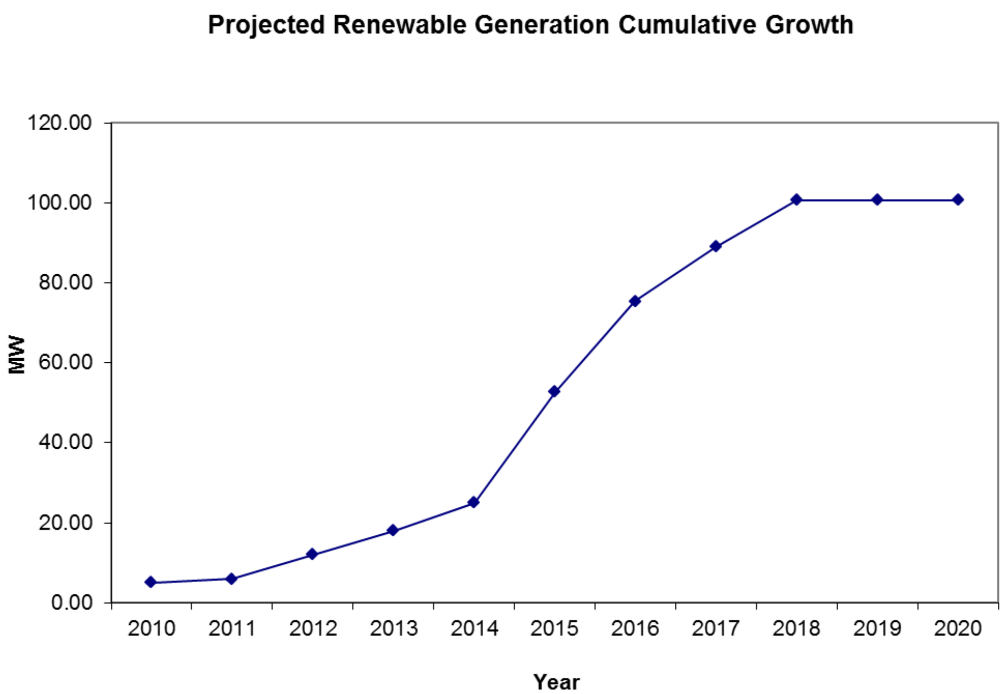


Figure 4: Projected Connected Growth

PowerStream North Renewable Generation Growth

The IESO currently has Renewable Generation applications totaling 11.044MW for PowerStream North. Based on projected growth PowerStream expects this number to reach 16.11 MW by 2018. Figure 5 illustrates Renewable Generation growth in the North between 2009 and 2020.

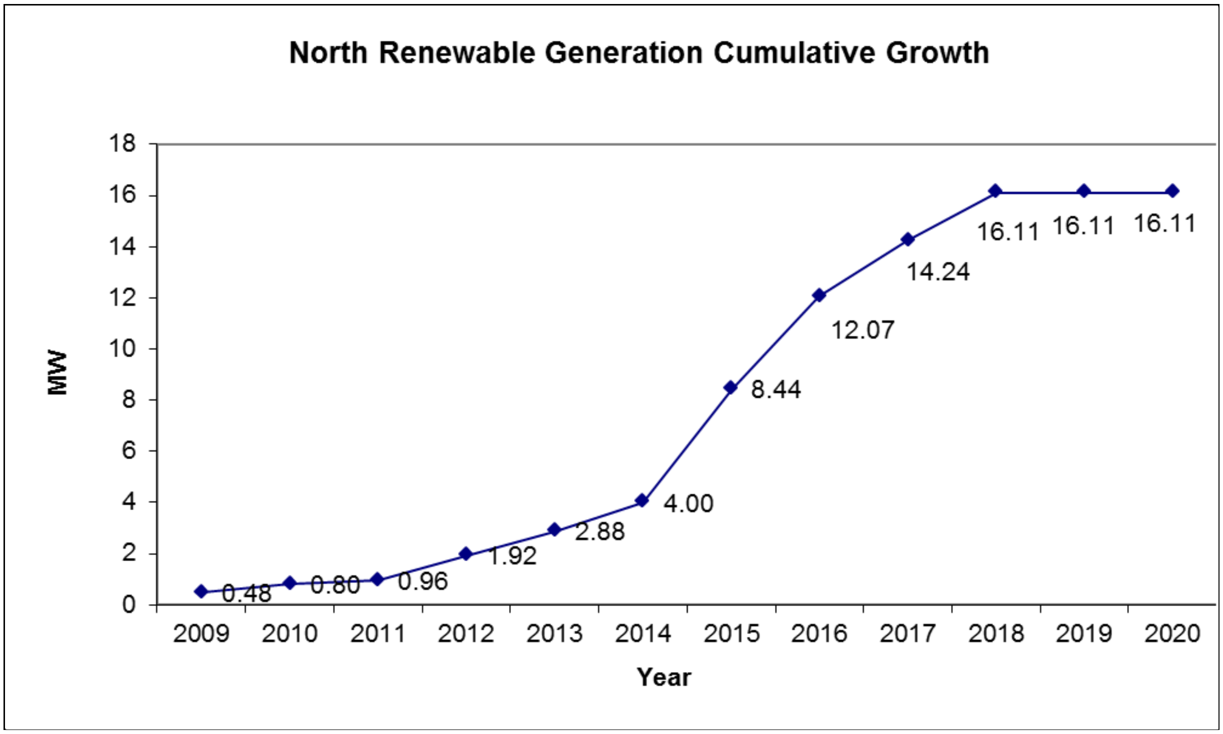


Figure 5: Growth in PowerStream North

PowerStream South Renewable Generation Growth

The IESO currently has Renewable Generation applications totaling 57.96MW for PowerStream South. Based on projected growth PowerStream expects this number to reach 84.59MW by 2018. Figure 6 illustrates Renewable Generation growth in the South between 2010 and 2020.

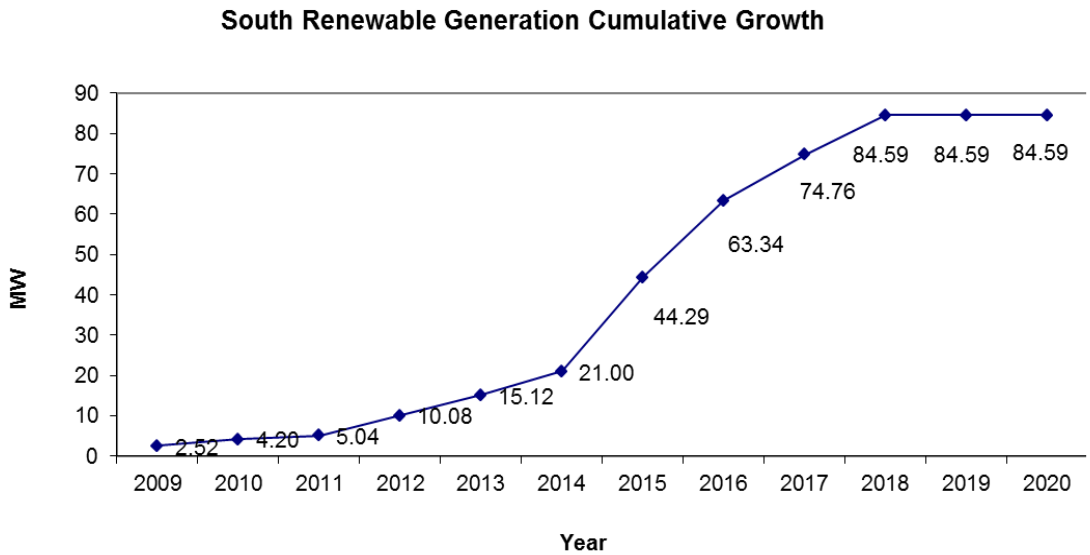


Figure 6: Growth in PowerStream South

PowerStream Capacity (MW) for Connection per Station

North Distribution System Assessment

PowerStream North consists of the municipalities of Alliston, Barrie, Beeton, Bradford West Gwillimbury, Penetanguishene, Thornton, and Tottenham. The North area contains thirty-nine Municipal Stations and six Hydro One owned Transformer Stations (“TS”). Due to the size of FIT projects, most are connected directly to Hydro One TS’s.

Station Capacity:

PowerStream North currently has 33 FIT projects that are connected or about to be connected to five of Hydro One’s TS’s, resulting in the allocation and capacity shown in Table 5:

Connected Transformer Station / Hydro One Owned	TS Thermal Capacity (kW) (Max Rating)	Hydro One Allocated Capacity (kW)	PowerStream Allocated Capacity (kW)	Estimated Remaining TS Capacity (kW)
EVERETT TS	63,800	2,000	716	1,284
HOLLAND TS	96,600	2,000	736	1,264
MIDHURST TS DESN1	119,400	3,500	2,237	1,263
MIDHURST TS DESN2	71,500	5,000	1,918	3,082
BARRIE TS	68,500	5,000	1,957	3,043
			Maximum North Capacity (kW)	9,936 *

Table 5: North TS Allocation

**Note: PowerStream North's Potential Capacity incorporates upstream Hydro One TS Allocated Capacity.*

Hydro One TS Thermal Capacity is much higher and is shared with Hydro One on a first come, first serve basis. Therefore, remaining TS capacity can be increased when required by PowerStream.

Limiting Factors:

Customer accessibility to Hydro One Transformer Stations in and around the Barrie area provides a significant attraction for FIT projects.

There are potential access constraints for larger projects connecting in the North. Typically, PowerStream will require projects greater than 1MW to connect directly to 44kV lines which are only available in specific locations throughout the Northern region.

South Distribution System Assessment

PowerStream South consists of the municipalities of Aurora, Markham, Richmond Hill, and Vaughan. The South area contains eleven PowerStream owned Transformer Stations and six Hydro One Transformer Stations.

Station Capacity:

PowerStream South currently has 170 FIT projects that have been connected or about to be connected, resulting in in the allocation and capacity shown in Table 6 and Table 7.

Connected Transformer Station PowerStream Owned	TS Capacity (kW) (Max Rating)	Current Load from FIT projects (kW)	Remaining TS Capacity (kW)
VAUGHAN MTS #1	13,600	5,414	8,186
VAUGHAN MTS #1 E	97,500	2,964	94,535
VAUGHAN MTS #2	10,200	5,056	5,143
VAUGHAN MTS #3	125,500	8,816	116,683
RHMTS#1	12,000	2,461	9,538
RHMTS#2	48,000	1,730	46,269
MARKHAM MTS #1	56,000	1,930	54,069
MARKHAM MTS #2	56,000	2,093	53,906
MARKHAM MTS #3	102,400	788	101,611
MARKHAM MTS #3 E	89,600	9,955	79,645
MARKHAM MTS #4	97,500	771	96,729
		Max PowerStream South Capacity (kW)	666,314 Max

Table 6: South TS Allocation, PowerStream Owned TS

**Note: PowerStream South's Potential Capacity incorporates upstream Hydro One TS Capacity.*

Connected Transformer Station / **Hydro One Owned**	**TS Thermal Capacity (kW) (Max Rating)**	**Hydro One Allocated Capacity (kW)**	**PowerStream Allocated Capacity (kW)**	**Remaining TS Capacity (kW)**
AGINCOURT TS	59,600	1,000	200	**800**
ARMITAGE TS DESN 1	119,600	2,000	504	**1,496**
ARMITAGE TS DESN 2	120,400	2,000	1,446	**554**
BUTTONVILLE TS TS Z Bus	34,000	5,000	1,166	**3,834**
BUTTONVILLE TS TS Q Bus	38,800	5,000	2,416	**2,584**
FINCH TS DESN 1	40,700	2,000	500	**1,500**
LESLIE TS DESN 1	18,400	2,000	71.4	**1,929**
WOODBRIDGE TS DESN1	23,600	3,000	558	**2,442**

Maximum Hydro One South Capacity (kW)	15,139 Max*

Table 7: South TS Allocation, Hydro One Owned TS

**Note: PowerStream South's Potential Capacity incorporates upstream Hydro One TS Capacity.*

Hydro One's TS Thermal Capacity is much higher and is shared with Hydro One on a first come, first serve basis, and as such, the remaining TS capacity can be increased when required by PowerStream.

System Constraints

PowerStream has mitigated system constraints in terms of short circuit limits at Markham TS's by installing fault level reduction reactors to increase the station short circuit capacity. In addition, PowerStream completed the WiMax Communication Network for the purpose of Data Transfer and Generator Tripping.

In 2014, 2015 and 2016, PowerStream will complete Station Wiring Modifications for WiMax. These projects will accommodate connection of future FIT projects to stations and be able to facilitate remote shutdown and transfer trip protection function.

Station capacity constraint exists with the following Hydro One stations:

1. Kleinburg TS
2. Leslie TS DESN 2

The following is a summary of Renewable Generation expenditures planned for 2014 to 2020.

1. 2014 - Station Wiring Modifications for WiMax
2. 2015 - Station Wiring Modifications for WiMax
3. 2016 - Station Wiring Modifications for WiMax

Based on a calculated remaining maximum capacity of 691MW and a projected load of only 75.7MW by 2020, PowerStream feels confident that it has capacity in place to accept future renewable generation projects.

In conclusion, PowerStream's proactive Renewable Generation planning since 2009 has created a solid foundation for generator connections, and has developed a robust strategy to accommodate generation in the next six years.

Customer Constraints

Commencing in 2009, and up to the present time, no customer constraints were experienced.

The potential constraints are as follows:

- Insufficient individual pad mount or pole mount transformer capacity; or
- Increased voltage at the customer end due to number of DG connections.

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.*

This section is designed to provide a summary of PowerStream's capital expenditures over a 10 year period. This includes five historical years and five forecast years. As this is PowerStream's first Application with a DS Plan, pursuant to the Chapter 5 Requirements, there is no data provided as to the 'Plan' values for the historical period. Only actual data is provided for the purpose of this summary.

Explanatory Notes on Variances in Capital Expenditure Summary

PowerStream has completed Appendix 2-AB in compliance with the Chapter 2 Filing Requirements and Chapter 5 Requirements. PowerStream has provided a summary of Appendix 2-AB by category below.

Tables that provide a summary of the historical 2011-2014 and proposed 2015-2020 capital expenditures are provided immediately below in Table 5.4.4.1, and at the end of this Section in Table 5.4.4.2.

	Historical					Proposed				
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
CATEGORY	Actual	Actual	Actual	Actual	Plan	Plan	Plan	Plan	Plan	Plan
Rate Base	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000
System Access	21,007	19,888	17,030	26,229	24,145	28,232	28,470	29,561	28,726	31,867
System Renewal	11,527	16,974	22,254	39,186	42,388	48,715	51,500	52,052	52,971	52,406
System Service	22,885	13,770	34,780	17,946	27,322	38,322	32,072	29,920	26,963	23,022
General Plant	7,877	24,200	19,593	26,148	24,545	17,531	19,458	13,867	16,741	18,106
Sub-Total	63,297	74,832	93,657	109,509	118,400	132,800	131,500	125,400	125,401	125,400
Non-Rate Base	2,278	1,196	2,628	1,364	2,489	-	-	-	-	-
Grand Total	65,575	76,028	96,285	110,873	120,889	132,800	131,500	125,400	125,401	125,400
System O&M	2,055	2,438	2,523	2,627	3,290	3,825	4,365	4,909	5,459	6,015

Table 5.4.4.1: Capital Expenditure Summary

a) System Access

System Access investments are comprised of projects outside of PowerStream's control that are required to meet customer service obligations in accordance with the Distribution System Code ("DSC") and PowerStream's Conditions of Service.

These projects include:

- New Connections for customers (subdivisions, industrial/commercial/institutional (ICI), service layouts);
- Metering;
- Road Authority projects; and
- Other customer initiated work.

PowerStream uses an economic evaluation methodology as prescribed by the DSC to determine the amount, if any, of capital contributions for each project; with such capital contribution amounts incorporated into the annual capital budget. These investments are typically a high priority, cannot be deferred, and must proceed as planned.

Historical year over year variances between 2011, 2012, 2013 and 2014 are primarily due to increased Road Authority projects for York Region, Simcoe County and the eleven Municipalities.

The level of system access expenditures in each of 2011 to 2014 historical years was as follows:

- 2011 actuals (IFRS) were $21,007,331 (net), with capital contributions of $29,560,811.

- 2012 actuals (IFRS) were $19,887,614 (net), with capital contributions of $30,943,103. The decrease from 2011 of $1,119,717 (net) was primarily due a decrease in Road Authority projects.

- 2013 actuals were $17,030,429 (net), with capital contributions of $19,271,865. The decrease of $2,857,185 (net) from 2012 was primarily due to a decrease in Road Authority projects and Subdivision projects.

- 2014 actuals were $26,228,894 (net), with capital contributions of $22,876,343. The increase of $9,198,465 from 2013 was mainly due to an increase in Road Authority projects.

The level of System Access expenditures from 2015 to 2020 is as follows:

- The forecast for 2015 is $24,145,118 (net), with capital contributions of $19,804,601. The decrease from 2014 is $2,083,776, primarily due to a decrease in Road Authority projects, offset by increased expenditures in Metering (for installing interval meters for GS customers over 50kW).

- The forecast for 2016 is $28,232,154 (net), with capital contributions of $21,499,743. The increase from 2015 is $4,087,036 is primarily due to an increase in Road Authority Projects, and also an increase in New Connections.

- The forecast for 2017 is $28,469,723 (net), with contributions of $22,623,132. The modest increase from 2016 is $237,569, is primarily due to an increase in New Connections, offset by a slight decrease in Road Authority projects.

- The forecast for 2018 is $29,560,667 (net), with capital contributions of $23,383,253. The increase from 2017 of $1,090,944 is primarily due to an increase in Metering and New Connection projects.

- The forecast for 2019 is $28,726,052 (net), with capital contributions of $23,203,090. The decrease compared to 2018 of $834,615 is primarily due to a significant decrease in Road Authority expenditures, offset by increased expenditures in both Metering and New Connections.

- The forecast for 2020 is $31,866,709 (net), with capital contributions of $24,573,604. The increase compared to 2019 of $3,140,657, is primarily due to increased Metering project expenditures, and also smaller increases in Road Authority and New Connections project expenditures.

Overall, System Access expenditures over 2016 to 2020 remains consistent within the range of $28M to $32M, with variations year to year due to adjustments to the priorities of the relative mix of initiatives being proposed each year.

b) System Renewal

PowerStream's System Renewal investments are for the purposes of the replacing or refurbishing distribution assets (primarily overhead lines, underground lines, and stations equipment) which extend the service life of assets. These assets are replaced either due to aging and/or deteriorating condition.

Historic system renewal expenditures from 2011 to 2014 years were as follows:

- 2011 actuals (IFRS) were $11,527,321 (net);

- 2012 actuals (IFRS) were $16,974,392 (net). The increase from 2011 of $5,447,071 was due to a higher level of investment in the overhead lines replacement projects and programmes, and to a lesser degree, increases in the cable replacement and cable injection projects and programs.

- 2013 actuals were $22,253,782 (net). The increase from 2012 of $5,279,390 was due to a significant increase in work and expenditures for cable replacement and cable injection programs. There were also increase expenditures for distribution transformer replacement projects.

- 2014 actuals were $39,185,754 (net). The increase from 2013 of $16,931,972 was due to a large increase in expenditures for cable replacement and cable injection projects and programs.

The level of system renewal expenditure from 2015 to 2020 is as follows:

- The forecast for 2015 is $42,388,193 (net). The increase from 2014 of $3,202,439 is primarily due increased investments in rear lot conversions and overhead line assets replacement projects.

- The forecast for 2016 is $48,714,625 (net). The increase from 2015 of $6,326,432 is due to new investments in storm hardening initiatives.

- The forecast for 2017 is $51,500,169 (net). The increase from 2016 of $2,785,544 is due to increased investments in cable replacement and injection projects and programs, with modest increased investments in overhead line assets replacement projects.

- The forecast for 2018 is $52,051,932 (net). The increase from 2017 $551,763 is primarily due to increased investment in the cable replacement and injection projects and also increased investment in station equipment renewal projects.

- The forecast for 2019 is $52,970,854 (net). The increase from 2018 of $918,922 is primarily due to increased investments in cable replacement and injection projects and programs.

- The forecast for 2020 is $52,405,780 (net). The modest decrease from 2019 of $565,074is primarily due to further reductions in investments related to stations equipment renewal projects.

Overall, System Renewal expenditures over the 2016 to 2020 Test Years remains consistent within the range of $48M to $52M, with variations year to year due to adjustments to the priorities of the relative mix of assets being proposed to be replaced each year.

c) System Service

Investments in this category are modifications to PowerStream’s distribution system that ensure operational objectives are met and future customer requirements can be addressed. Projects are driven by initiatives to improve system reliability and/or system capacity constraints. These are necessary as greater demands are placed on the system from increasing customer requirements, increased capacity for stations and lines, distribution automation, embedded generation (RGEN), and Smart Grid initiatives (distribution related) including energy storage.

These investments are required to support the operation, reliability and expansion of the distribution system. PowerStream classifies these investments in sub-categories of capacity, reliability, and security.

The level of System Service expenditure in each of the 2011 to 2014 historical years is as follows:

- 2011 actuals (IFRS) were $22,885,200 (net);

- 2012 actuals (IFRS) were $13,770,295 (net). The significant decrease from 2011 of $9,114,905 is due to a large decrease in expenditures related to transformer and municipal substation projects, and also decreased expenditures in line extension projects.

- 2013 actuals were $34,780,350 (net). The large increase from 2012 of $21,010,055 was due to increased expenditures for cable replacement and cable injection projects and programmes, increase expenditures in additional capacity lines projects (new feeders), increased expenditures for overhead lines projects, and increased expenditures for distribution automation.

- 2014 actuals were $17,946,354 (net). The large decrease from 2013 of $16,833,996 was primarily due to re-categorization of cable replacement and cable injection projects from the System Service category into the System Renewal category. However, the total PowerStream cable replacement and cable injection expenditures increased slightly in 2014 compared to 2013.

The level of System Service expenditure from 2015 to 2020 is as follows:

- The forecast expenditure for 2015 is $27,321,977 (rate base net). If capital spending recorded in the smart grid deferral account is included, the total is $28,473,343 (net). The increase from 2014 of $9,375,623 is a result of increased investments for capacity-driven lines projects, and also increased investments for capacity-driven stations projects. The major of the increased expenditures is a result of the new Vaughan VTS#4 (capacity-driven stations project).

- The forecast expenditure for 2016 is $38,321,819 (net). The significant increase from 2015 of $10,999,842 is primarily due to increased expenditures in capacity-driven lines projects.

- The forecast expenditure for 2017 is $32,071,882 (net). The decrease from 2016 of $6,249,937 is due to a significant decrease in investments for capacity-driven stations projects partially offset by a increase in investments for capacity-driven lines projects.

- The forecast expenditure for 2018 is $29,920,325 (net). The decrease from 2017 of $2,151,557 is primarily due to significant decreases in investments for capacity-driven lines projects partially offset by an increase in capacity-driven stations projects.

- The forecast expenditure for 2019 is $26,963,080 (net). The decrease from 2018 of $2,957,245 is primarily due to a large decrease in investments for capacity-driven stations projects, partially offset by an increase in capacity-driven lines projects.

- The forecast expenditure for 2020 is $23,022,061 (net). The decrease from 2019 of $3,941,019 is primarily due to decreased investments in capacity-driven lines projects and line extension projects, offset by increased investments in capacity-driven stations projects.

Overall, System Service expenditures generally decline over the 2016 to 2020 Test Years from a high of $32M to a low of $23M, with variations year to year due to adjustments to the priorities of the relative mix of initiatives being proposed each year.

d) General Plant

Investments in this category are modifications, replacements or additions to PowerStream's assets where these assets are not part of the electrical distribution system. General Plant projects include investments in information systems, communication systems, vehicles, buildings/facilities and tools and equipment necessary to support the operation and maintenance of the distribution system. General Plant also includes specific Smart Grid pilot projects and initiatives that do not pertain to the distribution system, such as home technologies and electric vehicles.

The level of general plant expenditure in the historical period 2011 to 2014 was as follows:

- 2011 actuals (MIFRS) was $7,876,939 (net);

- 2012 actuals (MIFRS) was $24,199,799 (net). The increase of $16,322,860 versus 2011 actuals was primarily due to increased expenditures for the replacement CIS system, furniture and ancillary requirements to equip the new Jane Street operations centre, and land purchase next to PowerStream's head office at 161 Cityview Boulevard in Vaughan.

- 2013 actuals were $19,592,930 (net). The decrease from 2012 of $4,606,869 was primarily due to the large one-time expenditure incurred in 2012 for the land purchase in Vaughan not recurring in 2013, offset by a significant increase in expenditures for the 2nd year of the implementation of the new CIS system.

- 2014 actuals were $26,148,062 (estimated net), an increase of $6,555,132 from 2013. The multi-year initiatives to replace PowerStream's Customer Information System continued into 2014.

The level of general plant expenditure from 2015 to 2020 is provided below.

- The forecast for 2015 is $24,544,709 (rate base net). If capital spending recorded in the smart grid deferral account is included, the total is $25,882,209 (net). The decrease from 2014 of $1,603,353 is primarily due to a decrease in investments for the new CIS system, offset by increased investments in buildings, and also increased investments for IT information and communication systems.

- The forecast for 2016 is $17,631,419 (net). The decrease from 2015 of $6,913,290 is primarily due to decreased investments in the new CIS system.

- The forecast for 2017 is $19,557,978 (net). The increase from 2016 of $1,926,559 is primarily due to increased investments in CIS and also increased investment in IT information and communication systems.

- The forecast for 2018 is $13,966,910 (net). The decrease from 2017 of $5,591,068 is primarily due to decreased investments for CIS-related systems, along with decrease investments for IT information and communication systems.

- The forecast for 2019 is $16,840,554 (net). The increase from 2018 of $2,873,644 is primarily due to increased investments in IT information and communication systems.

- The forecast for 2020 is $18,205,522 (net). The increase from 2019 of $1,364,968 is primarily due to increased investments in IT information and communication systems.

Overall, General Service expenditures remain generally consistent through the 2016 to 2020 Test Years within the range of $14M to $19M, with variations year to year due to adjustments to the relative mix of initiatives being proposed each year.

	2015 Proposed	2016 Proposed	2017 Proposed	2018 Proposed	2019 Proposed	2020 Proposed	Total
General Plant	$24,544,709	$17,631,419	$19,557,978	$13,966,910	$16,840,554	$18,205,522	$110,747,091
System Access	$24,145,118	$28,232,154	$28,469,723	$29,560,667	$28,726,052	$31,866,709	$171,000,423
System Renewal	$42,388,194	$48,714,625	$51,500,169	$52,051,933	$52,970,854	$52,405,780	$300,031,555
System Service	$27,321,977	$38,321,819	$32,071,882	$29,920,325	$26,963,080	$23,022,061	$177,621,144
Grand Total	$118,399,998	$132,900,017	$131,599,752	$125,499,835	$125,500,540	$125,500,071	$759,400,213

	2015 Proposed	2016 Proposed	2017 Proposed	2018 Proposed	2019 Proposed	2020 Proposed	Overall Total
General Plant	21%	13%	15%	11%	13%	15%	15%
System Access	20%	21%	22%	24%	23%	25%	23%
System Renewal	36%	37%	39%	41%	42%	42%	40%
System Service	23%	29%	24%	24%	21%	18%	23%
Grand Total	100%	100%	100%	100%	100%	100%	100%

Table 5.4.4.2: Summary of Proposed Expenditures All Categories 2015-2020

Charts 5.4.4.3 to 5.4.4.8 are visual depictions, in pie chart form, of the annual percentages of each of the four categories within the proposed capital expenditure plan for each of the years from 2015 to 2020. Chart 5.4.4.9 depicts the total split of the 4 categories for the entire plan.

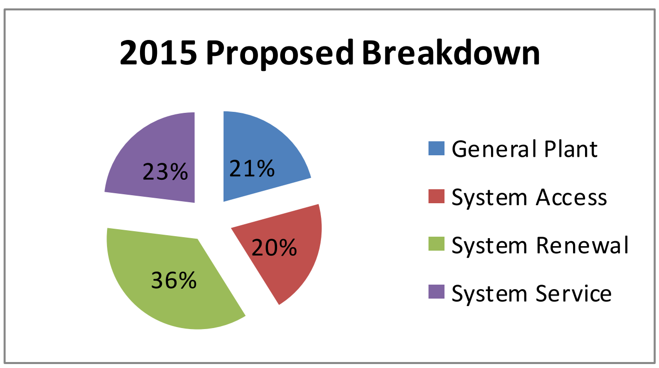


Chart 5.4.4.3: Breakdown of Proposed Expenditures 2015

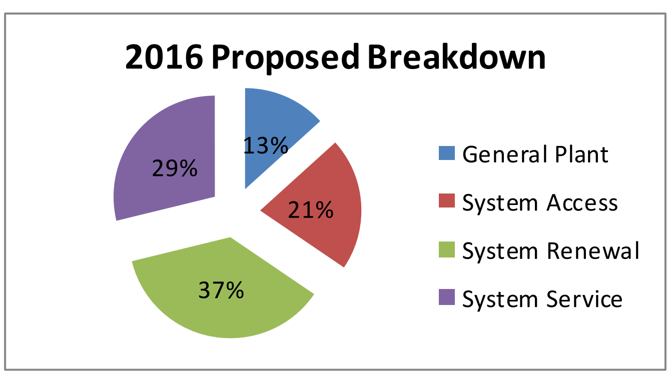


Chart 5.4.4.4: Breakdown of Proposed Expenditures 2016

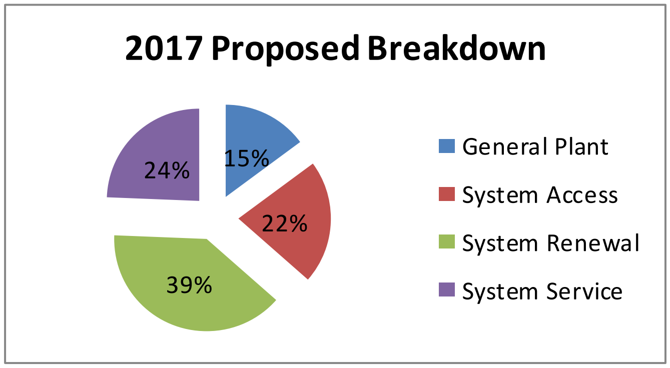


Chart 5.4.4.5: Breakdown of Proposed Expenditures 2017

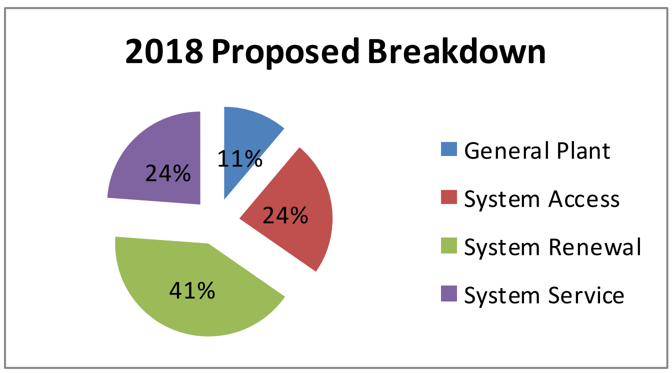


Chart 5.4.4.6: Breakdown of Proposed Expenditures 2018

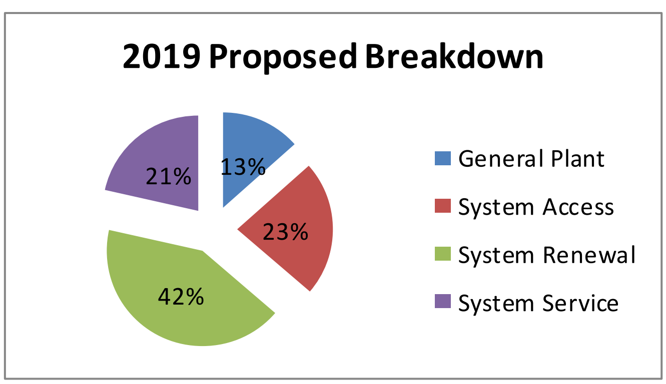


Chart 5.4.4.7: Breakdown of Proposed Expenditures 2019

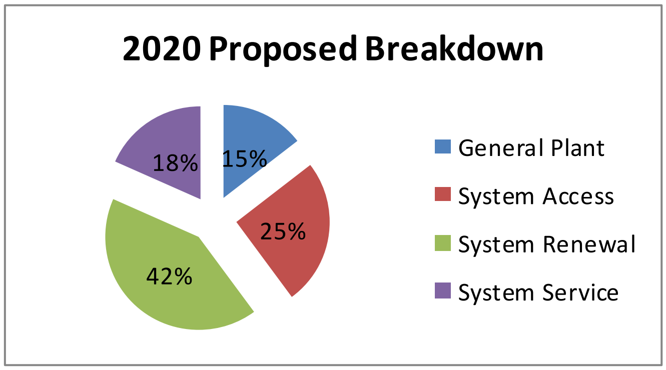


Chart 5.4.4.8: Breakdown of Proposed Expenditures 2020

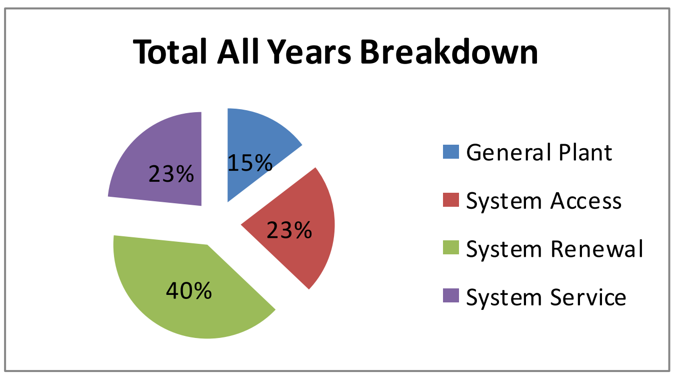


Chart 5.4.4.9: Breakdown of Proposed Expenditures All Years

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)*

5.4.5.2 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.

Overall Plan (2011-2020)

The section provides the justification and supporting information for the level of investments that have been included in the PowerStream's DS Plan. The data, information and analysis that are necessary to support the capital costs within this rate proposal are presented with references to previous detailed sections as applicable. As previously identified in Sections 5.3.3 and 5.4.2 of this DS Plan, the capital expenditures required in this DS Plan are supported by methodologies, measures, and planning processes that are intended to provide value to customers.

Comparative Expenditures by Category

Comparative expenditures by category over the historical period were provided in Exhibit G, Tab 2, Section 5.4.4 on Table 5.4.4.1.

Forecast Impact on System Operating & Maintenance Costs

Refer to Exhibit G, Tab 2, Section 5.3.3, page 27.

a) System Access

System Access investments are mandatory, non-discretionary projects initiated by customers or 3rd parties. These projects include:

i. new connections and subdivisions (including industrial/commercial/institutional (ICI) connections and service layouts);
ii. Road Authority projects that require the relocation of distribution system assets;
iii. metering;
iv. other customer initiated work; and
v. RGEN FIT/microFit.

PowerStream uses the economic evaluation methodology prescribed by the Distribution System Code (DSC) to determine the level, if any, of capital contributions for each project, with such levels incorporated into the annual capital budget. These investments are typically a high priority, cannot be deferred, and must proceed as planned. A summary of the proposed 2015-2020 system access expenditures is shown in Table 5.4.5.1 below.

	2015	2016	2017	2018	2019	2020
System Access	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**
i. New Connections and Subdivisions	13,671	14,718	15,801	16,404	17,037	17,674
ii. Road Authority	6,259	9,702	8,679	8,357	5,719	6,222
iii. Metering	3,887	3,025	3,060	3,720	4,715	6,556
iv. Other Customer Initiated Work	329	787	929	1,080	1,256	1,415
v. RGEN FIT/microFIT (Net Rate Base)	-	-	-	-	-	-
v. RGEN FIT/microFIT (Gross Rate Base)	280	137	110	-	-	-
Total System Access (Rate Base)	24,145	28,232	28,470	29,561	28,726	31,867

Table 5.4.5.1: System Access Proposed Expenditures

i. New Connections and Subdivisions

This is a perpetual capital expenditure comprised of non-discretionary projects initiated by customers or developers, where investment is required to enable customers to connect to PowerStream's distribution system. This program includes customer service requests, such as new and upgraded service connections for residential, commercial and industrial customers.

PowerStream uses the economic evaluation methodology as prescribed by the Distribution System Code (DSC) to determine the amount, if any, of capital contributions for each project, with the net investment required incorporated into the annual capital budget. These investments cannot be deferred and must proceed as planned.

Expenditures related to customer connection project costs are forecasted based on a number of factors which include:

- historical levels of activity and investment;
- known projects in the planning stage;
- a review of economic factors; and
- predicted civil contractor cost adjustments of 3% for labour and materials.

While these factors are the basis for the forecasts, there is a high likelihood that actual expenditures will vary significantly from projections and from year to year. Annual plans are tracked monthly and new forecasts are issued quarterly as new customer connection information becomes available.

The 2016 to 2020 investment requirements for the installation of new service infrastructure, as provided in Table 5.4.5.2, are aligned with the increasing trend in the volume of new customer connections and cost escalations for contractors. Refer to Exhibit H, Tab 3 for a detailed discussion on historical and future customer growth.

System Access	2015 ($ 000)	2016 ($ 000)	2017 ($ 000)	2018 ($ 000)	2019 ($ 000)	2020 ($ 000)
i. New Connections and Subdivisions	13,671	14,718	15,801	16,404	17,037	17,674

Table 5.4.5.2 Proposed Investment for New Connections and Subdivisions

In addition to assessing the historical expenditures of past years, PowerStream also performs assessments of municipal forecasts, the current customer requests project schedule, and potential future projects based upon discussions with customers and developers in the determination of future investment to support customer connections. PowerStream also coordinates its plans as much as possible with the York/Simcoe Regions on planning for customer connections. Ultimately, system access projects are driven by decision points external to PowerStream, and due to factors outside of PowerStream's control, there is a high likelihood for actual expenditures to vary considerably from original projections year to year.

ii. Road Authority Projects

Projects in this category involve the relocation of PowerStream's distribution system assets to support road relocation and road reconstruction projects at the request of the Regions of York, Simcoe County, or the Ministry of Transportation or the local municipalities. The initiation and timing of these projects is outside of PowerStream's control and therefore the timing and value of investment required by PowerStream is subject to change.

Road Authority projects are customer initiated and PowerStream is obligated under the Distribution System Code and its Conditions of Service to perform these projects and incur its share of related expenditures. These investments cannot be deferred by PowerStream and must proceed when and where required by the customer. PowerStream follows the Public Service Works on Highways Act, 1990 and associated regulations governing the recovery of costs related to road reconstruction work by collecting contributed capital for 50% of labour and labour saving devices.

Capital contributions toward the cost of all customer demand projects are collected by PowerStream in accordance with the DSC and the provisions of the Conditions of Service.

The forecast investments for the 2016 to 2020 are provided below in Table 5.4.5.3. Timelines for the execution of these projects are dictated by York Region, Simcoe County, the local municipalities, or the Ministry of Transportation.

PowerStream coordinates its proposed distribution system projects, as much as possible, with these stakeholders in order to maximize efficiencies and minimize disruptions to the public. PowerStream holds regular planning discussions with the Region of York, Simcoe County, the municipalities, and the Ministry of Transportation, and also actively participates in Public Utilities Coordinating Committee (PUCC) meetings in order to better identify the scope and number of road authority projects forecast in future years. Lead times for notification of projects typically range from 6 to 36 months, depending on the scope of the project.

PowerStream's proposed investment expenditures for 2016 is based upon the scope and volume of the road authority driven projects planned for that year. The 2017 to 2020 proposed investment expenditures are based on a trended forecast based on the historical number of projects initiated from 2011 to 2014 with the latest forecasts for 2015 and 2016. The complete 2015 to 2020 investment requirements is shown in Table 5.4.5.3 below.

	2015	2016	2017	2018	2019	2020
System Access	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**
ii. Road Authority	6,259	9,702	8,679	8,357	5,719	6,222

Table 5.4.5.3: Proposed Investment for Road Authority Projects

iii. Metering

Metering investments includes the installation and replacement of PowerStream's retail and wholesale metering assets, in compliance with standards from Measurement Canada and the IESO. The work includes:

- installation of new and replacement metering for residential and multi-unit residential customers;
- installation of interval meters for new industrial/commercial/institutional (ICI) customers;
- installation of interval meters for existing GS>50 customers who do not already have an interval meter;
- installation or replacement of IESO-registered wholesale meters at wholesale delivery points;
- inspection and replacement of defective meters;
- Interval Meter support infrastructure investments (MV90); and
- Smart Meter support infrastructure investments.

The forecast investments for 2016 to 2020 are provided below in Table 5.4.5.4. Proposed meter replacements are to address anticipated meter failures and for the replacement of expired meters in compliance with Measurement Canada regulations.

These investments cannot be deferred by PowerStream and must be completed as planned to meet customer needs and maintain regulatory compliance. Investments in meters are forecasted primarily through the review of the number of meter seal expiry dates, metering requirements to support new connections and conversion of multi-residential buildings from bulk to suite metering, and metering equipment requirements to support the Smart Meter network infrastructure, and also forecasted customer growth.

	2015	2016	2017	2018	2019	2020
System Access	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**
iii. Metering	3,887	3,025	3,060	3,720	4,715	6,556

Table 5.4.5.4: Proposed Investment for Metering 2015-2020

iv. Other Customer Initiated Work

Projects in this category involve the relocation of PowerStream's distribution system assets (poles, anchors, transformers, cables) to support requests from customers, developers and other land owners and agencies. Timelines for the execution of these projects are dictated by customers, developers and other land owners. Lead times for notification of projects typically range from 1 to 12 months, depending on the scope of the project.

PowerStream is obligated under the DSC and its Conditions of Service to perform these projects and incur its share of related expenditures. These investments cannot be deferred by PowerStream and must proceed when and where required by the customer. capital contributions toward the cost of all customer demand projects are collected by PowerStream in accordance with the DSC and the provisions of its Conditions of Service.
PowerStream's proposed investment expenditures for 2016 to 2020 are based on the historical actual expenditures of projects initiated from 2011 to 2014 with latest forecasts for 2014 and 2015. The forecast investments for 2016 to 2020 are provided below in Table 5.4.5.5.

	2015	2016	2017	2018	2019	2020
System Access	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**
iv. Other Customer Initiated Worl	329	787	929	1,080	1,256	1,415

Table 5.4.5.5: Proposed Investment for Other Customer Initiated Work

v. RGEN FIT/microFIT

Projects in this category involved the connection of FIT and microFIT renewable generation to PowerStream's distribution system in accordance with requests from OPA-contracted participants. Timelines for the execution of these projects are dictated by the generator.

PowerStream is obligated under the DSC and its Conditions of Service to connect these projects. These investments cannot be deferred by PowerStream and must proceed when and where required by the customer. Capital contributions toward the cost of all the RGEN connection projects are collected by PowerStream in accordance with the DSC and the provisions of its Conditions of Service.

PowerStream does not propose any *net* expenditure for the years 2015 to 2017 as all FIT and microFIT connections are 100% funded by capital contributions from the customer. As there is some uncertainty if the IESO programs will continue after 2017, PowerStream has elected not to propose any expenditure for this initiative in 2018 or after. The forecast investments (net and gross) for 2016 to 2020 are provided below in Table 5.4.5.6.

System Access	($ 000)	($ 000)	($ 000)	($ 000)	($ 000)	($ 000)
v. RGEN FIT/microFIT (Gross Rate Base)	280	137	11	-	-	-
v. RGEN FIT/microFIT (Net Rate Base)	-	-	-	-	-	-

Table 5.4.5.6: Proposed Investment for RGEN FIT/microFIT

b) System Renewal

System renewal investments are projects and programs directed toward the replacement or rehabilitation of equipment due to being beyond useful life and/or deteriorating condition. These projects are classified as controllable as the initiation and timing of these projects is largely within PowerStream's control.

As described in Exhibit G2, Tab 2, Section 5.4.4 page 6, PowerStream's System Renewal project expenditures have ranged from $11.527 M to $42.388 M during the 2011 to 2015 period. The 2016 forecast of $48.715 M, an increase of $6.327 M over 2015, is intended to provide the necessary funding to maintain the health of the distribution system, in particular for the underground cable and asset replacement programs, overhead lines and asset replacement programs, and rear lot conversion projects. A summary of the proposed 2015-2020 System Renewal expenditures is shown in Table 5.4.5.7 below.

	2015	2016	2017	2018	2019	2020
System Renewal	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**
i. UG Lines - Planned Asset Replacement	20,687	21,601	22,862	23,781	24,666	25,186
ii. Distribution Lines - Emergency/Reactive Replac	8,416	8,636	8,730	8,888	8,925	8,504
iii. Overhead Lines - Planned Asset Replacement	7,698	7,907	9,082	8,558	9,144	9,022
iv. Storm Hardening& Rear Lot Conversion	3,500	7,900	8,000	7,500	6,900	7,200
v. Stations/P&C - Asset Replacement	2,087	2,671	2,827	3,325	3,336	2,493
Total System Renewal	42,388	48,715	51,500	52,052	52,971	52,406

Table 5.4.5.7: Proposed System Renewal Expenditures 2015-2020

i. Underground Lines - Planned Asset Replacement

This category of investments includes various projects and programs for the replacement or rehabilitation of cable, switchgear and pad-mounted transformers that comprise the main components of the underground distribution system. Since the distribution system assets in this category were originally engineered, constructed and connected as a complete system, the majority of the planned replacement of these assets is also optimally and holistically done as a system. For example, the replacement of padmount transformers and switchgears is frequently incorporated into the cable replacement projects to which they are connected. Therefore, the 2015-2020 proposed expenditures for Underground Lines and Assets is shown as a combined budget for cable replacement, padmount transformers replacement, and switchgear replacement. The combined forecast investments for 2016 to 2020 are provided in Table 5.4.5.8.

i) Cable Replacement and Rehabilitation Projects

PowerStream has approximately 8,200 km of underground primary cable length in service, the vast majority of which is direct buried with the balance in duct. A significant percentage of these cables are at, or near, end of life, and are starting to fail with increased frequency.

Refer to Section Exhibit G, Tab 2, 5.3.2, *Overview of Assets Managed*, for the demographics of cables.

There are two methods of cable remediation for addressing the cable aging issue:

- Cable Replacement – replace existing cable with new cable; and
- Cable Injection – extend existing cable service life by injecting a fluid compound into the cable to rehabilitate the insulation.

PowerStream's approach for maintaining the cable population, once they have been identified by age or failure, is summarized below:

a) PowerStream conducts testing to determine the condition of the cable and to rank the order of severity of condition; and
b) PowerStream uses a cable prioritization system to select which cables should be scheduled for replacement and which cables should be scheduled for injection.

While the Cable Replacement option is more expensive than the Cable Injection option with respect to initial capital cost, it does have the advantage of new cable that will be utilized for a longer period of time (50-55 years).

The Cable Injection option is less expensive and is intended to extend the life of cable by 20 years. As the cable gets older, the cable insulation may develop a premature aging process caused by a phenomenon known as "water treeing". Water trees will reduce the breakdown strength of the insulation and eventually lead to cable failure. The Cable Injection process injects silicone chemicals down the strands of the cable. The silicone fluid diffuses out of the strands through the strand shield and into the insulation. The fluid then polymerizes with water (or moisture) and the silicone molecule grows and fills all water trees and voids. This increases the dielectric strength of the cable and thus extends the life of the cable. It should be noted that cable dielectric failure may result from causes other than “water treeing” alone. Some examples include impurity, presence of by-products, contaminants, gas, electric trees, etc. As a result, there are many cases where the cable injection process is not effective.

PowerStream first began cable injection pilot projects in 2011 and, because of the success of the pilot projects, has continued and expanded the program in the years since.

Cable Injection is only viable for a specific demographics of cable. The criteria for selecting cable injection candidates are listed below.

- Pre 1989;
- Not solid core;
- Not strand-filled;
- Concentric neutral not corroded significantly;
- No electrical trees present (cable injection only can repair water trees and not electrical trees); and
- Only a few splices within a cable segment.

Starting in 2012, PowerStream began conducting cable testing (Tan Delta tests) to further assess the condition of cable to:

- Determine which intervention method (replacement vs. injection) is more suitable to a specific location;
- Determine the appropriate quantity and timing of cable intervention (replacement or injection); and
- Validate and prioritize the cable replacement/injection projects.

The Tan Delta test results helped PowerStream determine the severity of cable degradation and to prioritize the specific cables for injection or replacement.

Based on the findings of the Asset Condition Assessment, and a detailed analysis of success and costs of the two remediation techniques, PowerStream proposes to remediate specific underground cables in specific areas with:

- the cable injection program at the rate of 100 km/year until 2036. It is estimated that the Cable Injection program will take at least 22 years to complete all the suitable cable available for rehabilitation; and
- to replace underground cables at a rate of 30 km/year. It is estimated that the Cable Replacement program will continue at the same rate of km replaced per year after 2036, at which time the amounts will increase.

Detailed justification information on the cable replacement and injection projects can be found in the Material Investments section in Appendix A to this DS Plan.

ii) Switchgear Replacement Program

PowerStream has approximately 1825 distribution switchgear units in service. According to the Kinectrics Inc. Report *"Asset Amortization Study for the Ontario Energy Board"*, the useful life of pad-mounted switchgear is 20-45 years with a typical useful life of 30 years.

Refer to Exhibit G, Tab 2, Section 5.3.2, *Overview of Assets Managed*, for the demographics of switchgear.

Refer to Exhibit G, Tab 2, Section 5.3.2, *Overview of Assets Managed*, for the health index for switchgear. Among the switchgear population in PowerStream South, there are approx. 1,000 units that are PMH (air insulated) type. The operational concerns of PMH units in PowerStream South are listed below.

- PMH units are live-front and are an obsolete design. They are not approved for new installations and for planned replacement of existing units in the 27.6 kV system. PowerStream's long-term plan is to eventually phase out all PMH units in the 27.6 kV system and replace them with either SF6 or solid dielectric dead front gear;
- PMH units require regular maintenance (dry-ice cleaning);
- PMH units are rated at 25 kV nominal, but are operated at 27.6 kV. This increases the risk of flash over, especially with the presence of contamination and moisture; and

- Failure rate of PMH units is high. PowerStream has experienced cases of flash over in units that are not old.

It is expected that as the existing distribution switchgear units age and deteriorate with time, inspection and analysis results will show a growing number of switchgear units in poor condition and requiring replacement.

To address the deteriorating switchgear condition concerns, PowerStream proposes to replace 31-36 of the worst units/year. It is expected that the switchgear replacement program will be an on-going program to maintain the integrity of the distribution system.

Detailed justification information on the switchgear replacement projects can be found in the Material Investments section in Appendix A of this DS Plan.

iii) Transformer Replacements (Padmount)

PowerStream has approximately 40,000 underground transformers, both padmount and submersible, in service. According to the Kinectrics Inc. Report *"Asset Amortization Study for the Ontario Energy Board",* the useful life of a padmount transformer is 25-45 years with a typical useful life of 40 years.

PowerStream normally operates its pole tops and single phase residential padmount transformers on a run-to-failure approach (except for those transformers that pose a safety or environmental risk).

In order to reduce the increased costs associated with unplanned three phase transformers failures, in 2013, PowerStream initiated a proactive replacement project. This proactive replacement project replaces the worst pad-mounted and submersible transformers based on the annual inspection program results and historical transformer loading information.

Where necessary, PowerStream also performs remediation work (re-connection and/or an additional transformer) at specific locations of legacy delta/wye distribution transformers in order to ensure compliance with ESA directives.

Refer to Exhibit G, Tab 2, Section 5.3.2, *Overview of Assets Managed*, for the demographics of distribution transformers.

PowerStream experienced 50, 66 and 78 underground transformer failures (including padmount transformer and submersible transformer) in 2011, 2012, and 2013 respectively, an average of 65 failures per year.

PowerStream proposes the replacement of 60 padmount transformers per year, prioritized according to worst condition based on the results of the inspection program and transformer loading analysis. Forecasted expenditures are based on historical average replacement costs.

iv) Mini-Rupter Switches

PowerStream has approximately 433 mini-rupter switches in service. Mini-rupters are described as high-capacity isolating switches found in vaults in commercial/industrial areas. According to the Kinectrics Inc. Report *"Asset Amortization Study for the Ontario Energy Board"*, the useful life of UG vault switches is 20-50 years with a typical useful life of 35 years.

This Project has been implemented to replace end-of-life switch units to maintain system reliability and customer service. On a prioritized basis, each year PowerStream will inspect, review, and select a number of switch units for replacement. The locations and priority are determined based on the results from the Asset Condition Assessment (ACA) process and internal stakeholders.

The existing Mini-Rupter switches design and connection do not provide sufficient access to allow field staff to perform switching and maintenance operations under normal and emergency situations, thus impairing service to affected customers. These switches are open to dirt and contamination and susceptible to flashover affecting system reliability. PowerStream is intending to replace the mini-rupter switches with either a solid dielectric switch, or alternatively a way 6 switch, depending on space and existing configuration limitation.

Mini-Rupter switch failures pose a safety risk to operations staff. The Mini-Rupter switch is located within an enclosed vault room. The Mini-Rupter switch may fail when operations staff is working on the unit or other equipment within the vault. When the Mini-Rupter switch fails, there may be flashover or fire, which may result in personal injury.

PowerStream proposes to replace 15 of the worst units/year. It is expected that the mini-rupter switch replacement program will be an on-going program to maintain the integrity of the distribution system.

Detailed justification information on the mini-rupter switch replacement projects can be found in the Material Investments section in Appendix A of this DS Plan.

The total for all these initiatives related to underground line assets (cable, switchgear, transformers, mini-rupters) is as shown in the following Table 5.4.5.8.

	2015	2016	2017	2018	2019	2020
System Renewal	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**
i. UG Lines - Planned Asset Replacement	20,687	21,601	22,862	23,781	24,666	25,186

Table 5.4.5.8: Proposed UG Lines Expenditures 2015-2020

ii. Distribution Lines – Emergency/Reactive Replacement

Projects in this category involved the immediate replacement of PowerStream's distribution system assets (poles, transformers, switches, switchgear, cable, conductor, insulators, guys, anchors, etc) due to unanticipated failure, storms, motor vehicle accidents, vandalism, etc.

PowerStream's Emergency/Reactive forecasts expenditures for 2016 to 2020 are based on historical spending during the period of 2011 to 2013, and are shown in Table 5.4.5.9 below.

	2015	2016	2017	2018	2019	2020
System Renewal	($ 000)	($ 000)	($ 000)	($ 000)	($ 000)	($ 000)
ii. Distribution Lines - Emergency/Reactive Replace	8,416	8,636	8,730	8,888	8,925	8,504

Table 5.4.5.9: Proposed Distribution Lines – Emergency/Reactive Expenditures

iii. Overhead Lines – Planned Asset Replacement

This category of investments includes projects for the replacement of poles, insulators, and switches that comprise the main components of the overhead distribution system. It also includes discrete voltage conversion projects. Depending on geographical area and distribution system characteristics, the replacement of these individual assets are often combined into the same project, and as such, the proposed capital expenditures for the assets in this category has also been combined into one budget.

i) Pole Replacement Program

PowerStream has over 40,000 wood poles in service. A significant percentage of these poles are at, or near, end of life, and their condition has deteriorated to the point that there is a high probability of failure. According to Kinectrics Inc. Report *"Asset Amortization Study for the Ontario Energy Board*", the useful life of wood poles is 35-75 years with a typical useful life of 45 years. For IFRS depreciation purposes, PowerStream uses 40 years as the useful life for poles.

Refer to Section Exhibit G, Tab 2, 5.3.2, *Overview of Assets Managed*, for the demographics of wood poles.

It is expected that as the existing poles age and deteriorate, inspection and testing results will show an increasing number of poles in poor condition and requiring replacement. Assuming an equal installation age profile of poles through its distribution system, theoretically 2.5% of the poles would require replacement every year. Since the majority of poles in PowerStream's distribution system are of later vintage, PowerStream's experience has shown that only 1% of the pole population are expected to be found in poor condition every year (over the next 5 years). As such,, PowerStream proposes to only replace 400 poles per year to keep up with the aging pole demographics (1% of 40,000 poles = 400 poles).

It is expected that the pole replacement program will be an on-going program to maintain the integrity of the distribution system and to protect public safety.

Detailed justification information for the Pole Replacement program can be found in the Material Investments section in Appendix A of this DS Plan.

ii) Replacement of 44 kV porcelain insulators

PowerStream is experiencing a growing number of power interruptions due to insulator failure. It has been found that the older vintage of 44kV porcelain insulators are prone to tracking and flash over. It is estimated that there are over 1,660 of these insulators in the PowerStream distribution system. PowerStream is proposing to replace all remaining legacy 44 kV porcelain insulators with polymer type insulators over the next four years (415 units per year).

iii) Fault Indicator replacement program

Since PowerStream was the result of mergers of several “predecessor” utilities, there are several different types of fault indicators currently deployed on PowerStream distribution systems. Some areas have fault indicators heavily deployed, while others have limited numbers installed or no fault indicators at all. This program is a combination of adding fault indication to areas where fault indication is absent, as well as replacing older technology fault indicators that are obsolete or prone to malfunction. In addition, second generation fault indicators installed over the past 10-15 years are battery operated and the batteries are reaching end of life, necessitating the change out of the fault indicators or where possible replacement of the batteries. The Fault Indicator Deployment Plan requires the deployment of a standard, modern fault indicator. Levels of spending remain constant at $500,000 per annum from 2015 through 2017, then increases to $635,000 by 2023. Increased expenditures are to account for inflation and also to budget for the costs of communications infrastructure to connect to SCADA fault indicators at strategic locations.

iv)Replacement of end-of-life RTU-controlled automated switches

PowerStream has approximately 340 Remote Terminal Unit (RTU) automated switches in service. According to the Kinectrics Inc. Report *"Asset Amortization Study for the Ontario Energy Board"* the operational useful life of these automated switches is 25 years, with an IFRS useful life of 40 years.

RTU controlled switches (predominantly SCADA-Mates) provide rapid transfer of loads in emergencies, reduce restoration time which improves reliability, provide flexibility to reconfigure the system to avoid feeder and station overloads during summer peak. There are a number of existing overhead RTU-controlled switches that are at or close to end-of-life, and will eventually fail to open or close remotely. Through annual inspection and maintenance programs, PowerStream will identify the units that are in the worst condition and require replacement. PowerStream proposes to replace 5 of these RTU-controlled switches each year for the next 10 years.

v) Voltage Conversion Projects - 8kV and 13.8 kV to 27.6kV

The following voltage conversion projects are included in the Overhead Lines and Assets Planned Replacement program:

- 2015 Elder Mill MS Conversion- Part 2 (3F2);
- 2015/2016 Miller Avenue Markham 27.6kV Conversion;
- 2017 Concord MS Conversion to 27.6 kV - Phase 3;
- 2017 Hwy 27 from Major Mack to Nashville 27.6kV Conversion; and
- 2019 Elder Mill MS Conversion – Part 3.

Detailed justification information for the voltage conversion projects can be found in the Material Investments section of Appendix A to this DS Plan.

PowerStream's total proposed investment expenditures for Overhead Lines - Planned Asset Replacement for 2016 to 2020 is based on the planned replacement or rehabilitation of 400 poles/year, 415 – 44kV porcelain insulators/year, and 5 remote-controlled switches/year. Also, these proposed expenditures include the five voltage conversion projects between 2015 and 2019 as noted above. Historic per unit costs have been used to determine the 2016 to 2020 Test Year investment requirements, which are shown in Table 5.4.5.10 below.

	2015	2016	2017	2018	2019	2020
System Renewal	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**
iii. Overhead Lines - Planned Asset Replacement	7,698	7,907	9,082	8,558	9,144	9,022

Table 5.4.5.10: Proposed Overhead Line Planned Expenditures 2015-2020

iv. Storm Hardening & Rear Lot Conversion

Exhibit G, Tab 2, Section 5.2.3 page 10, refers to a study performed as a result of the December 21st 2013 ice storm. Included in the study report was a series of recommendations. This category covers the capital work that PowerStream must complete to harden (strengthen) the overhead distribution system to withstand the frequency and severity of storms (wind, rain, ice) that have been experienced the last few years and, according to meteorologists, is expected to become more common in the future.

The vast majority of PowerStream's overhead distribution system has been designed and constructed to legacy standards for the typical wind and ice loadings commonly experienced at that time. Over the past 15 years, the increased frequency and severity of extreme weather events has led to improvements to construction standards for all new distribution system construction, however, parts of the existing distribution system needs remedial work to bring it up to the latest standards.

As noted in Exhibit G, Tab 2, Section 5.2.3, PowerStream has a number of pockets of customers (mainly residential) being supplied by rear lot construction. In accordance with the consultant's report, PowerStream will adopt full conversion for rear lots and recommend completion over 15 years. The projects will be prioritized based on age, asset condition, customer needs and reliability.

PowerStream's proposed rear lot conversion investment expenditures for 2016 to 2020 is based on historical expenditures of similar type construction work. The proposed investments are based on estimated construction costs of approximately $12,400 per customer.

Initiatives included in the Storm Hardening program include:

a) *Grade 1/Composite Poles for Strategic Locations:*
PowerStream will continue development of composite pole standards and consider use of composite poles and Grade 1 construction in future construction of poles with 3 or more circuits or critical poles as defined.

b) *Periodic in-line Anchoring :*
PowerStream will review existing lines and determine additional anchoring needs, both in-line anchors and storm-guying. PowerStream plans to reinforce all poles that carry 4 circuits, 1500 poles in all.

c) *Flood Avoidance:*
Relocate all existing flood sensitive equipment (switches, breakers, relays, etc) located in existing transformer stations to be above grade. PowerStream plans to complete this work over four years.

d) *Rear Lot Remediation*:
Convert to full front lot current standard over 15 years.

PowerStream's proposed investment expenditures for 2016 to 2020 is based on combination of available resources and affordability.

The forecasted Storm Hardening and Rear Lot Conversion investments for 2016 to 2020 are provided below in Table 5.4.5.11.

	2015	2016	2017	2018	2019	2020
System Renewal	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**
iv. Storm Hardening & Rear Lot Conversion	3,500	7,900	8,000	7,500	6,900	7,200

Table 5.4.5.11: Proposed Storm Hardening Expenditures 2015-2020

v. Stations/P&C - Asset Replacement

Projects in this category include the planned and unscheduled replacement of assets related to Stations and also Protection and Control (P&C) for transformer stations connected to the provincial transmission system, and distribution substations supplied from inside the distribution system. The assets covered by this program includes transformers, circuit breakers and switchgear, capacitors, reactors, RTUs, relays, and SCADA control systems for the eleven 230kV transformer stations and 54 municipal substations owned by PowerStream.

The level of investment for the planned replacement of specific station related assets are to address anticipated end of life equipment failure and meet the reliability requirements of the IESO Market Rules and Standards.

The level of investment for the unscheduled replacement of station related assets is determined from the historical expenditures during the 2011 to 2013 period. The forecast investments for 2016 to 2020 are provided below in Table 5.4.5.12.

	2015	2016	2017	2018	2019	2020
System Renewal	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**
v. Stations/P&C - Asset Replacement	2,087	2,671	2,827	3,325	3,336	2,493

Table 5.4.5.12: Proposed Stations/P&C Expenditures 2015-2020

c) System Service

PowerStream's forecasted System Service expenditures levels represent the minimum expenditures necessary to support the related initiatives through 2016 to 2020.

System Service investments address capacity, reliability, safety, security and Smart Grid/RGEN initiatives. A summary of the proposed 2015-2020 System Service expenditures is shown in Table 5.4.5.13 below.

System Service	2015 ($ 000)	2016 ($ 000)	2017 ($ 000)	2018 ($ 000)	2019 ($ 000)	2020 ($ 000)
i. Additional Capacity - Stations	14,115	16,175	9,439	12,261	2,629	4,296
ii. Additional Capacity -Lines	9,203	17,769	17,232	11,698	18,182	12,153
iii. Reliability including Dist. Auto.	3,943	3,159	4,183	4,658	4,550	5,161
iv. Station Safety & Security	62	149	149	234	533	341
v. Smart Grid/RGEN - System Relate	1,151	1,070	1,070	1,070	1,070	1,070
Total System Service	28,473	38,322	32,072	29,920	26,963	23,022

Table 5.4.5.13: Summary of System Service Expenditures 2015-2020

Note: The above 2015 Smart Grid/RGEN amounts are Non-Rate base and, as directed by the OEB, will be recorded in OEB deferral account 1534. The above 2016-2020 Smart Grid/RGEN amounts will no longer be recorded in deferral accounts, as prescribed by the OEB Filing Requirements, Chapter 2.

i. Additional Capacity – Stations

This category of investments includes projects for the construction of new, or the expansion of existing transformer stations and municipal substations. Proposed investments under this category for 2016 to 2020 are projects intended to ensure stations (both TSs and MSs) have peak loadings maintained at or below their planning ratings. Since the scope of both of these types of projects are very similar, proposed capital expenditures for the assets in this category has also been combined into one budget.

i) Additional Capacity Station Projects at Transformer Stations

Proposed TS additional capacity investments during 2016 to 2020 are related to expenditures for the completion of the Vaughan VTS#4 transformer station where the first aspects of this project (land purchase and environmental assessment) started in 2014. The in-service date for Vaughan VTS#4 station is scheduled for spring 2017, and the construction of additional new feeder connections for this station is scheduled for 2017-2020. The detailed justification for the Vaughan VTS#4 project was provided in PowerStream's 2014 EDR Application EB-2013-0166.

In addition, PowerStream is proposing expenditures in 2020 related to purchase of land for the new Markham MTS#5.

ii) Additional Capacity Station Projects at Municipal Stations

Proposed investments for Additional Capacity MS projects are intended to maintain the loading of existing municipal stations at or below their computed firm kVA ratings. In addition, the proposed investments are designed to ensure sufficient spare capacity exists such that if there is a loss of one station, the neighbouring two stations can accommodate the lost capacity.

PowerStream has proposed investments for 7 new MSs and Increase Capacity at 3 MSs in 2016 to 2020:

- New 44kV MS – Painswick South (Barrie) – construction 2015, in service 2016;
- New 44kV MS - Mill St. MS#2 (Tottenham) – construction 2016-2018, in service 2019;
- New 44kV MS - Harvie Rd. MS (Barrie) – construction 2020, in service 2021 (land 2016);
- New 44kV MS - Dufferin MS#2 (Alliston) – construction 2016-2018, in service 2019;
- New 44kV MS - Little Lake MS#2 (Barrie) – construction 2015-2017, in service 2018;
- New 44kV MS - Melbourne MS#2 (Bradford) – construction 2016-2018, in service 2019;
- New 44kV MS - Patterson MS#2 (Beeton) – construction 2019-2020, in service 2021;
- Increase Capacity – Aurora MS6 (Aurora) – construction 2016-2017, in service 2018;
- Increase Capacity – Aurora MS4 (Aurora) – construction 2019-2020, in service 2021; and
- Increase Capacity – Letitia MS (Barrie) – construction 2018-2019, in service 2020;

As referenced in Exhibit G, Tab 2, Section 5.3.1, PowerStream undertakes a planning study to review system peaks compared to system capacity, to determine if expansion to the transformation or distribution system is required. Additionally, PowerStream will be investigating alternative capacity solutions under the Regional Planning IRRP process, as noted in Exhibit G, Tab 2, Section 5.2.2. The capacity reviews will be performed to quantify loads and needs, and depending on the results of the alternative supply solutions, the plans stated for additional capacity at municipal stations may be altered.

The forecast investments for 2016 to 2020 are provided below in Table 5.4.5.14.

Detailed information on the Material Investments under this category can be found in Appendix A of this DS Plan.

	2015	2016	2017	2018	2019	2020
System Service	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**
i. Additional Capacity - Stations	14,115	16,175	9,439	12,261	2,629	4,296

Table 5.4.5.14: Proposed Additional Capacity – Stations Expenditures 2015-2020

ii. Additional Capacity – Lines

Proposed investments under this category for 2016 to 2020 are projects intended to maintain feeder peak loading below 400 amps under normal conditions and to comply with calculated feeder egress ratings during normal and contingency conditions. This is required to maintain reliable supply to customers.

The majority of projects under this category support load growth within the various municipalities of PowerStream's service area for servicing new subdivisions, industrial loads, and commercial and institutional developments.

The projects types include:

- additional feeder circuits added to existing pole lines;
- line extensions; and
- the rebuild of existing feeder circuits using higher capacity conductor.

The forecast investments for 2016 to 2020 are provided below in Table 5.4.5.15. Detailed information on the Material Investments under this category can be found in Appendix A of this DS Plan.

System Service	2015 ($ 000)	2016 ($ 000)	2017 ($ 000)	2018 ($ 000)	2019 ($ 000)	2020 ($ 000)
ii. Additional Capacity -Lines	9,203	17,769	17,232	11,698	18,182	12,153

Table 5.4.5.15: Proposed Additional Capacity – Lines Expenditures 2015-2020

iii. Reliability Investments including Distribution Automation

Reliability driven investments are projects proposed to maintain or improve current levels of service to customers. Feeders with deteriorating reliability statistics are targeted for review and remedial action plans are developed to improve reliability.

Reliability investments in 2016 to 2020 are focused on initiatives to improve feeder reliability, and the deployment of distribution automation assets and systems identified in PowerStream's GEA Plan filed in EB-2012-0161.

Improvements to distribution automation is a key component of PowerStream's reliability improvement efforts for the worst performing feeders and poor performing areas of the 13.8kV and 27.6kV distribution system. In general, distribution automation will improve power outage restoration and therefore system reliability. The decision on quantity and location of automation equipment is made on a case-to-case basis and guided by the following three criteria:

- *Economic Consideration*: the cost of a distribution automation project must be less than the benefit of the reliability improvement, calculated using customer interruption frequency and duration;

- *Feeder Loading Consideration*: to facilitate back-up and emergency load transfer, distribution automation equipment must be installed so that the feeder segment loading can be limited to a certain threshold, based on specific feeder configuration; and

- *System Control Consideration*: to facilitate control room operations, distribution automation equipment must be installed based on specific feeder operating conditions.

As part of Distribution Automation, automatic feeder restoration projects are planned for the Vaughan, Richmond Hill and Markham transformer stations each year of the DS Plan. Each project involves the implementation of Automatic Feeder Restoration capabilities on two feeders at two transformer stations over a two year period.

Also, upgrades to the existing transformer and bus differential protections are planned because the existing relays are approaching the end of their expected life. New relays will provide fault recording capabilities which, when the data is analyzed, will allow improvement to relay settings and/or optimize the fuse settings on the distribution feeders.

Other distribution automation initiatives include the installation of SCADA-controlled switches and reclosers, improvements to SCADA infrastructure including communication networks, and distribution feeder fault indicator installation.

The forecasted Reliability investments, including Distribution Automation, for 2016 to 2020 are provided below in Table 5.4.5.16. Detailed information on the Material Investments under this category can be found in Appendix A of this DS Plan.

	2015	2016	2017	2018	2019	2020
System Service	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**
iii. Reliability including Dist. Auto.	3,943	3,159	4,183	4,658	4,550	5,161

Table 5.4.5.16: Proposed Reliability Expenditures 2015-2020

iv. Station Safety and Security

Station Safety and Security investments are required to address projects identified through project prioritization as requiring investment to address safety risks and also risks of equipment damaged from physical and cyber intrusions and the present lack of acceptable levels of equipment monitoring. Justification on a project basis is included in the material project templates provided in Appendix A.

Station video surveillance systems have been added to increase station security as well as monitor equipment operation during switching functions. Fixed infrared cameras have been added to one station to monitor equipment temperatures of outdoor station equipment.

Proposed expenditures in 2016 – 2017 include initiatives to strengthen the security systems of the Operations' network and critical cyber assts. PowerStream recognizes that expenditures are needed to maintain compliance with the North American Electricity Reliability Council's Critical Infrastructure Program (NERC-CIP) for protecting the Operations' Cyber Assets from cyber-attack. The effort will focus on the further segmentation of the network; implementing Electronic Security Perimeters (ESP) within Physical Security Perimeters (PSP).

This proposed initiative will further strengthen the security of critical assets, as no outside third party will access to the physical plant. Critical Operations' data will not be integrated into the "cloud" and remain within the sphere of the Operations' Department.

Other proposed security expenditures under this category in 2016-2020 include station switchyard lighting improvements.

Safety investments under this category for 2016 to 2020 are projects designed to address safety deficiencies or potential environmental risks present in the distribution system.

The safety investments include the following initiatives:

- Oil containments systems for transformer stations; and
- Transformer station switchgear arc flash prevention.

The forecasted Station Safety & Security investments for 2016 to 2020 are provided below in Table 5.4.5.17.

	2015	2016	2017	2018	2019	2020
System Service	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**
iv. Station Safety & Security	62	149	149	234	533	341

Table 5.4.5.17: Proposed Station Safety & Security Expenditures 2015-2020

v. Smart Grid/RGEN Investments

Proposed projects in this category are related to initiatives to support the continuation of PowerStream's Smart Grid Implementation Plan as detailed in PowerStream's GEA Plan submitted in EB-2012-0161 (Exhibit B2, Tab1, Schedule 2). In accordance with OEB guidelines, Smart Grid/RGEN expenditures in Year 2016, and after, are no longer recorded in deferral accounts. Proposed Smart Grid/RGEN investments under the System Service category include programs and expenditures related to:

- Smart Grid energy storage technologies;
- Smart Grid distribution system operations technologies; and
- RGEN projects to facilitate transfer trip communication between renewable generators and the station relays at transformer stations.

The forecast Smart Grid investments for 2016 to 2020 are provided below in Table 5.4.5.18.

	2015	2016	2017	2018	2019	2020
System Service	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**
v. Smart Grid/RGEN - System Related	1,151	1,070	1,070	1,070	1,070	1,070

Table 5.4.5.18: Proposed Smart Grid Expenditures 2015-2020

Note: The above 2015 Smart Grid/RGEN amounts will be through the OEB-approved Smart Grid Deferral Account 1534. Smart Grid/RGEN investments in 2016-2020 will be included as part of the regular rate base capital accounts in accordance with OEB Filing Requirements Chapter 2.

d) General Plant

The proposed investments in General Plant projects are focused on a new Customer Information Systems (CIS), Information Technology (IT) and Information Systems, Communication Systems, Buildings/Facilities, Fleet, Tools, Interest Capitalization and Smart Grid – (non-distribution system related). A summary of all the proposed 2015-2020 General Plant expenditures is shown in Table 5.4.5.19 below.

General Plant	2015 ($ 000)	2016 ($ 000)	2017 ($ 000)	2018 ($ 000)	2019 ($ 000)	2020 ($ 000)
i. Customer Service	11,703	3,991	6,816	2,996	2,996	3,103
ii. IT & Info/Communication Systems	5,302	7,560	7,016	4,587	7,244	8,318
iii. Buildings & Emerging Operations	3,696	655	713	779	899	1,208
iv. Fleet	2,274	2,600	2,161	2,386	2,573	2,424
v. Tools	570	467	473	820	709	711
vi. Interest Capitalization	1,000	1,020	1,040	1,061	1,082	1,104
vii. Smart Grid - Other	1,338	1,338	1,338	1,338	1,338	1,338
Total General Plant	25,882	17,631	19,558	13,967	16,841	18,206

Table 5.4.5.19: Summary of General Plant Expenditures 2015-2020

i. Customer Service

Proposed investments under this category for 2016 to 2020 are projects designed to maintain, enhance or upgrade critical customer information infrastructure and systems. They include:

- CIS replacement – Completion of Phase 1 and Go Live (2015);
- IVR (incoming voice recognition) technology replacement;
- customer centre workforce management;
- fieldworker system changes & equipment replacement;
- customer process and system improvements ;
- customer web portal & mobile applications; and
- remote disconnect meters & load limiters.

The forecast Customer Service expenditures for 2016 to 2020 are provided below in Table 5.4.5.20.

General Plant	2015 ($ 000)	2016 ($ 000)	2017 ($ 000)	2018 ($ 000)	2019 ($ 000)	2020 ($ 000)
i. Customer Service	11,703	3,991	6,816	2,996	2,996	3,103

Table 5.4.5.20: Proposed Customer Service Expenditures 2015-2020

Detailed justification information on the customer service projects can be found in the Material Investments section in Appendix A of this DS Plan.

ii. IT & Info/Communication Systems

This category of investments includes both investments directly initiated by the Information Services Department (IT), and also other investments of Information and Communication Systems projects driven by the business needs of other departments. Since the scopes of both these types of investments are very similar, proposed capital expenditures for the projects and initiatives in this category have also been combined into one budget.

i) Information Services (IT)

Proposed investments under this category for 2016 to 2020 are projects designed to maintain, enhance or upgrade critical information technology infrastructure, systems and applications. They include:

- client hardware & operating systems;
- servers & infrastructure;
- application software;
- the main telecom system;
- customer information systems enhancements; and
- enterprise resource planning (ERP) enhancements.

ii) Information/Communication Systems

Proposed investments under this category for 2016 to 2020 are projects designed to maintain, enhance or upgrade information and communications systems for improving operational efficiencies within the other business units. They include:

- Financial and accounting systems database and software upgrades;
- GIS database and software upgrades and improvements;
- C55 Asset analytics software for capital program optimization & monitoring; and
- Work Force Management initiatives.

The combined total forecast IT & Information/Communication Systems expenditures for 2016 to 2020 are provided below in Table 5.4.5.21.

	2015	2016	2017	2018	2019	2020
General Plant	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**
ii. IT & Info/Communication Systems	5,302	7,560	7,016	4,587	7,244	8,318

Table 5.4.5.21: Proposed IT & Info/Communication Expenditures 2015-2020

Detailed justification information on IT projects can be found in the Material Investments section in Appendix A of this DS Plan.

iii. Buildings and Emerging Operations

As indicated in Exhibit G, Tab 2, Section 5.3.3 page 14, the majority of PowerStream's buildings are of recent construction and are generally in good shape.

PowerStream's Vaughan and Markham facilities are relatively new, so major capital replacement expenditures are not anticipated within this DS Plan. The Barrie (Patterson) operations centre is in relatively good condition but some components are being renovated through 2014-2015 to update the building to current standards, rejuvenate aging mechanical systems and to increase space utilization and efficiency.

Based on regular assessments of building condition, it is apparent that all buildings require various minor investments to maintain in a good state of repair, improve productivity within the work environment, accommodate growth in the workforce and address identified health and safety risks.

Expenditures for the maintenance and operations of PowerStream's buildings are increasing year over year, in part, due to required external repairs, structural improvements required to address shortcomings in existing systems and layouts.

Proposed expenditure for facilities are based on the following categories and components:

- Interior (furniture);
- Exterior (pavement, fencing, lighting, stores yard);
- Mechanical (plumbing);
- Structural (windows, doors, wall partitions);
- HVAC (heating & air conditioning);
- Equipment (major tools, lifts); and
- Other (Emerging Operations).

The forecast Buildings and Emerging Operations investments for 2016 to 2020 are provided below in Table 5.4.5.22.

	2015	2016	2017	2018	2019	2020
General Plant	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**
iii. Buildings & Emerging Operations	3,696	655	713	779	899	1,208

Table 5.4.5.22: Proposed Buildings & Emerging Operations Expenditures 2015-2020

Detailed justification information on facilities projects can be found in the Material Investments section in Appendix A of this DS Plan.

iv. Fleet

Proposed investments under this category for 2016 to 2020 are projects designed to maintain and/or replace vehicles necessary to support the operation and maintenance of the distribution system. PowerStream manages a fleet of over 250 heavy duty and light duty vehicles, trailers, and other mobile equipment.

PowerStream's replacement guideline for fleet assets is as follows:

- *Heavy duty vehicles:* Replaced when the vehicle reaches 250,000 km, or 12000 engine-hours, and shows an upward trend in unscheduled maintenance costs in previous three years.

- *Medium duty vehicles:* Replaced when vehicle reaches 200,000 km and shows an upward trend in unscheduled maintenance costs in previous three years.
- *Cars, utility vehicles, passenger vans:* Replaced when vehicle reaches 200,000 km and shows an upward trend in unscheduled maintenance costs in previous three years.
- *Pickup trucks:* Replaced when vehicle reaches 275,000 km and shows an upward trend in unscheduled maintenance costs in previous three years.

Miscellaneous fleet:

- pole trailers: 20 year replacement
- tension machines: 15 year replacement
- reel trailers: 15 year replacement
- forklifts: 15 year replacement
- traffic signals – technical assessment on condition and estimated repairs.
- loaders - technical assessment on condition and estimated repairs.

The forecast Fleet expenditures for 2016 to 2020 are provided below in Table 5.4.5.23.

General Plant	2015 ($ 000)	2016 ($ 000)	2017 ($ 000)	2018 ($ 000)	2019 ($ 000)	2020 ($ 000)
iv. Fleet	2,274	2,600	2,161	2,386	2,573	2,424

Table 5.4.5.23: Proposed Fleet Expenditures 2015-2020

Detailed justification information fleet projects can be found in the Material Investments section in Appendix A of this DS Plan.

v. Tools

Projects in this category are for the purchase of tools and equipment required for crews to carry out their day-to-day work, maintenance activities, and testing and diagnostic activities.

Expenditures in this category are for purchases of all major Lines tools and equipment that have an individual value greater than $1000 and with a life expectancy of more than one year. Day-to-day line work requires a variety of specialty tools that allow workers to safely and efficiently construct and maintain the distribution system. Examples of required tools and equipment are:

- barriers used in live line operations;
- hoisting equipment;
- temporary grounding devices;
- temporary secondary service jumpers;
- live line rubber cover up;
- live line tools, such as switch sticks;
- tension stringing equipment including replacement ropes, travelers, brackets;
- ladders, test meters, manhole entry systems & gas detectors. Etc;.
- hydraulic presses and crimpers;
- various test equipment;
- traffic control signs, lights, cones, etc.;
- equipment for Locating; and
- PPE (personal protective equipment).

The forecast Tools expenditures for 2016 to 2020 are provided below in Table 5.4.5.24.

	2015	2016	2017	2018	2019	2020
General Plant	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**	**($ 000)**
v. Tools	570	467	473	820	709	711

Table 5.4.5.24: Proposed Tool Expenditures 2015-2020

Detailed justification information on the tools projects can be found in the Material Investments section in Appendix A of this DS Plan.

vi. Interest Capitalization

Interest Capitalization for 2016 to 2020 are IFRS-recognized expenditures to capture interest expense on capital spending that is in the “Work-In-Progress” stage before being energized or deemed used and useful.

The forecast Interest Capitalization expenditures for 2016 to 2020 are provided below in Table 5.4.5.25.

General Plant	2015 ($ 000)	2016 ($ 000)	2017 ($ 000)	2018 ($ 000)	2019 ($ 000)	2020 ($ 000)
vi. Interest Capitalization	1,000	1,020	1,040	1,061	1,082	1,104

Table 5.4.5.25: Proposed Interest Capitalization Expenditures 2015-2020

vii. Smart Grid - Other

Proposed projects in this category are related to initiatives to support PowerStream's Smart Grid Implementation Plan as detailed in PowerStream's GEA Plan submitted in EB-2012-0161. In accordance with OEB Filing Requirements, Smart Grid expenditures in Year 2016, or after, are no longer recorded in deferral account 1534

.

Proposed investments include programs and expenditures unrelated to the distribution system for the purpose of:

- facilitate electric vehicle connections;
- home energy management technologies; and
- data analytics.

The forecast Smart Grid investments for the 2016 to 2020 Test Years are provided below in Table 5.4.5.26.

General Plant	2015 ($ 000)	2016 ($ 000)	2017 ($ 000)	2018 ($ 000)	2019 ($ 000)	2020 ($ 000)
vii. Smart Grid - Other	1,338	1,338	1,338	1,338	1,338	1,338

Table 5.4.5.26: Proposed Smart Grid – Other Expenditures 2015-2020

Note: Smart Grid investments in 2015 will be through the OEB-approved Smart Grid Deferral Account 1534. Smart Grid investments in 2016-2020 will be included as part of the regular rate base capital accounts.

Material Investments

PowerStream has provided all of its material investment templates, which have been designed to address Section 5.4.5.2 of the Filing Requirements, attached to this DS Plan as Appendix A.

A summary of the projects that exceed the materiality threshold can be found in Exhibit G, Tab 2, Section 5.4.1, Table 2 to Table 5.

Appendix A

Project Investment Summaries

Delivered: February 24, 2015

Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	101896	2015	6	Dollars

Project Name

New Commercial Subdivision Development

Major Category	**System Access**	

Project Overview

1. Additional Information	Service Territory	PowerStream South
	Location	PowerStream South Service Area
	Scope	Subdivision - Underground Commercial/Industrial System Developer requests an Offer to Connect (OTC) due to green field development. The OTC provides the estimated cost for a subdivision containing commercial/industrial units. Estimated costs are for infrastruture only and not including transformers for each development. Depending on the output of the economic model, PowerStream will typically contribute 100%.
	Justification	Under section 28 of the Electricity Act, distributors have an obligation to provide connection for new buildings to its distribution system.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	308137
	Job Number	C00405
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Not Applicable.
	Comparative Information on Equivalent Historical Projects (if any)	On an annual basis PowerStream continues to have new customer connections. The value and number of connections vary year to year based on market and new construction demands.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	New commercial/industrial subdivisions require an economic evaluation to determine PowerStream's capital contribution requirements.
	1a. Main Driver	Service Requests. This is a regulatory requirement based on the prescribed economic evaluation methodology.
	1b. Priority and Reasons for Priority	Not Applicable.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Represents capital contributed for investment in new developments.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Factors Affecting Timing/Priority	PowerStream assesses the connection of new customers on an annual basis.
	Factors Relating to Customer Preferences or Input	The Customer has input into the electrical design of the distribution system expansion. The Customer is also responsible for determining the site plans and layout with final approval from the municipality.
	Factors Affecting the Final Cost of the Project	The number of customer connections vary from year to year.
	How Controlled Costs have been Minimized	Construction service is provided by PowerStream and its contractor. PowerStream's contractor was selected through a competitive RFP process which provides best costs and cost certainty. After the Customer has been presented with an OTC, the Customer always has the option to to pursue an alternative bid and uses the services of a qualified contractor for the work that is eligible for alternative bid.
	Identify if Other Planning Objectives are Met by the Project, if so, which ones	Not Applicable.
	Options Considered and Summary of Analysis	Not Applicable.
	Results of Final Economic Evaluation, if applicable	Final economic evaluations are done on a subdivision by subdivision basis.
	System Impacts (Nature, Magnitude and Costs)	Not Applicable.

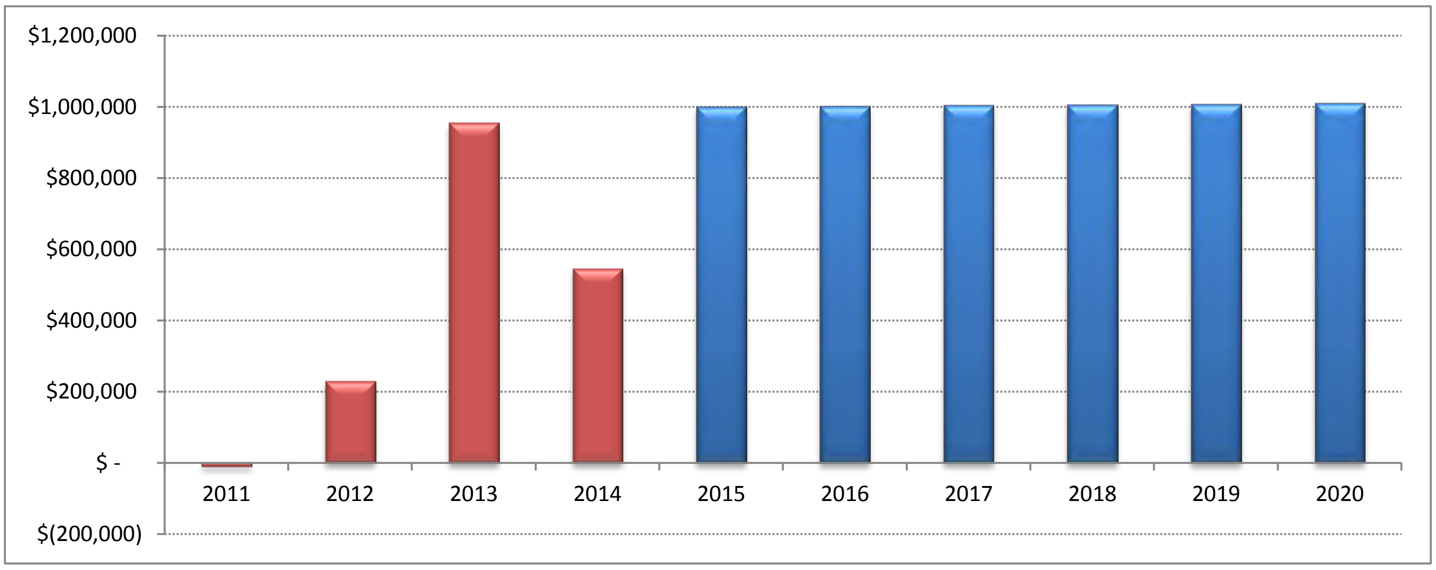
Project Summary Report

Project Code	Report Start Year	Number of Years	Scale
101896	2015	6	Dollars

Project Name

New Commercial Subdivision Development

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ (9,969)	$ 229,226	$ 954,433	$ 546,045	$ 1,000,008	$ 1,001,908	$ 1,003,808	$ 1,005,707	$ 1,007,607	$ 1,009,506



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	101911	2015	6	Dollars
	Project Name: New Commercial Subdivision Development			

Major Category	System Access	

Project Overview

1. Additional Information	Service Territory	PowerStream North
	Location	PowerStream North Service Area
	Scope	Subdivision - Underground Commercial/Industrial System Developer requests an Offer to Connect (OTC) due to green field development. The OTC provides the estimated cost for a subdivision containing commercial/industrial units. Estimated cost for infrastruture only and not including transformers for each development is $600,000. Depending on the output of the economic model, PowerStream will typically contribute 100%.
	Justification	Under section 28 of the Electricity Act, distributors have an obligation to provide connection for new buildings to its distribution system.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	308138
	Job Number	C00425
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Not Applicable.
	Comparative Information on Equivalent Historical Projects (if any)	On an annual basis PowerStream continues to have new customer connections. The value and number of connections vary year to year based on market and new construction demands.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	New commercial/industrial subdivisions require an economic evaluation to determine PowerStream's capital contribution requirements.
	1a. Main Driver	Service Requests. This is a regulatory requirement based on the prescribed economic evaluation methodology.
	1b. Priority and Reasons for Priority	Not Applicable.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Represents capital contributed for investment in new developments.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Factors Affecting Timing/Priority	PowerStream assesses the connection of new customers on an annual basis.
	Factors Relating to Customer Preferences or Input	The Customer has input into the electrical design of the distribution system expansion. The Customer is also responsible for determining the site plans and layout with final approval from the municipality.
	Factors Affecting the Final Cost of the Project	The number of customer connections vary from year to year.
	How Controlled Costs have been Minimized	Construction service is provided by PowerStream and its contractor. PowerStream's contractor was selected through a competitive RFP process which provides best costs and cost certainty. After the Customer has been presented with an OTC, the Customer always has the option to to pursue an alternative bid and uses the services of a qualified contractor for the work that is eligible for alternative bid.
	Identify if Other Planning Objectives are Met by the Project, if so, which ones	Not Applicable.
	Options Considered and Summary of Analysis	Not Applicable.
	Results of Final Economic Evaluation, if applicable	Final economic evaluations are done on subdivision by subdivision basis.
	System Impacts (Nature, Magnitude and Costs)	Not Applicable.

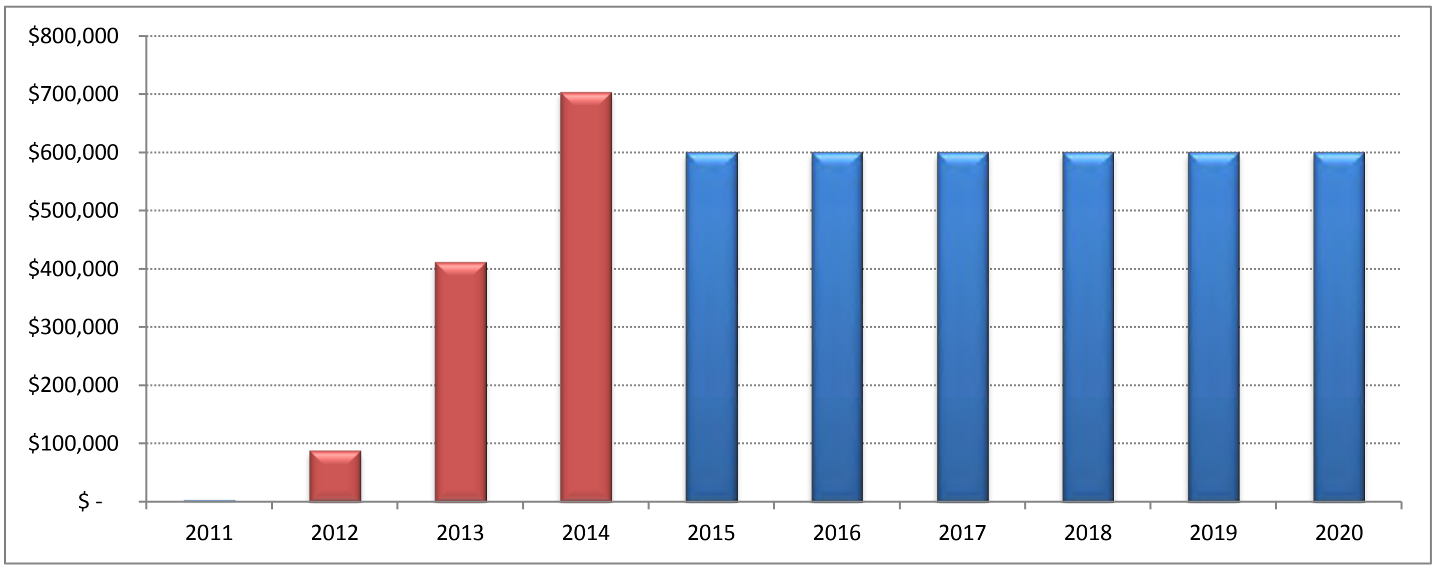
Project Summary Report

Project Code	Report Start Year	Number of Years	Scale
101911	2015	6	Dollars

Project Name

New Commercial Subdivision Development

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ 3,110	$ 87,031	$ 411,217	$ 703,622	$ 600,000	$ 600,000	$ 600,000	$ 600,000	$ 600,000	$ 600,000



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	101887	2015	6	Dollars

Project Name

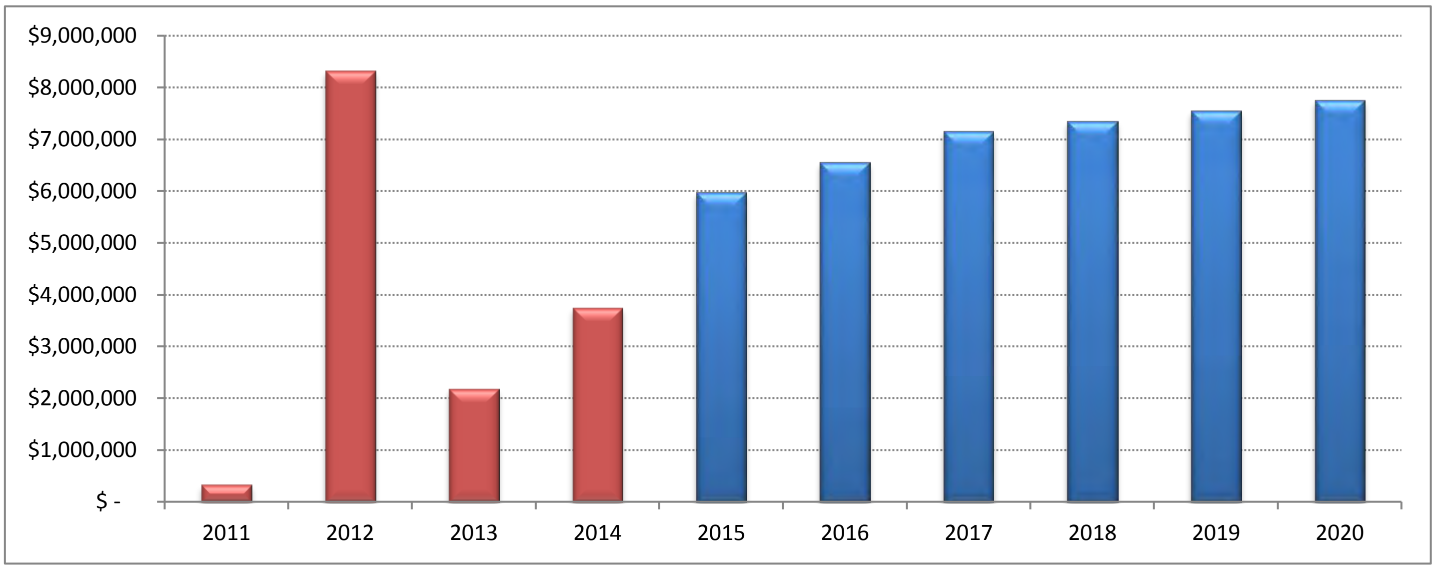
New Residential Subdivision Development

Major Category	**System Access**	
Project Overview		
1. Additional Information	Service Territory	PowerStream South
	Location	PowerStream South Service Area
	Scope	Subdivision - Underground Residential Distibution System Developer requests an Offer to Connect (OTC) due to green field development. The OTC provides the estimated cost for a subdivision containing residential units. Estimated serviced/installed residential lots are as follows: Total number of lots estimated to be installed in 2015 are 3100. Note that the subdivision lot allocation by the city supposed to be normal starting from 2013. Average cost of a serviced lot is $3,502.00. Estimated cost of installed and serviced residential lots (infrastruture only and constructed up to the street line) is as follows: 3100 lots x $3,502.00/lot = $10.85 million PowerStream's average cash contribution for a residential subdivision is 55% up front for "Option A". For "Option B" PowerStream pays 55% to the developer through transfer payment at the time of energization of the residential subdivision. PowerStream contribution has increased due to the removal upstream. There are 1176 hours allocated for the Engineering Administration costs. For easements 300 hours and new service set up 876 hours.
	Justification	Under section 28 of the Electricity Act, distributors have an obligation to provide connection for new buildings to its distribution system.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital Residential Subdivision
	Fiscal Year	2015
	Parent WO#	300757
	Job Number	C00400
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Not Applicable.
	Comparative Information on Equivalent Historical Projects (if any)	On an annual basis PowerStream continues to have new customer connections. The value and number of connections vary year to year based on market and new construction demands.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	New residential subdivisions require an economic evaluation to determine PowerStream's capital contribution requirements.
	1a. Main Driver	Service Requests. This is a regulatory requirement based on the prescribed economic evaluation methodology.
	1b. Priority and Reasons for Priority	Not Applicable.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Represents capital contributed for investment in new developments.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Factors Affecting Timing/Priority	PowerStream assesses the connection of new customers on an annual basis.
	Factors Relating to Customer Preferences or Input	The Customer has input into the electrical design of the distribution system expansion. The Customer is also responsible for determining the site plans and layout with final approval from the municipality.
	Factors Affecting the Final Cost of the Project	The number of customer connections vary from year to year.
	How Controlled Costs have been Minimized	Construction service is provided by PowerStream and its contractor. PowerStream's contractor was selected through a competitive RFP process which provides best costs and cost certainty. After the Customer has been presented with an OTC, the Customer always has the option to to pursue an alternative bid and uses the services of a qualified contractor for the work that is eligible for alternative bid.
	Identify if Other Planning Objectives are Met by the Project, if so, which ones	Not Applicable.
	Options Considered and Summary of Analysis	Not Applicable.

Project Summary Report	Project Code **101887**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name New Residential Subdivision Development			

Results of Final Economic Evaluation, if applicable	Final economic evaluations are done on a subdivision by subdivision basis.
System Impacts (Nature, Magnitude and Costs)	Not Applicable.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ 319,931	$ 8,318,530	$ 2,173,637	$ 3,739,864	$ 5,970,964	$ 6,548,610	$ 7,148,346	$ 7,345,444	$ 7,547,865	$ 7,750,209



Project Summary Report

Project Code	Report Start Year	Number of Years	Scale
101906	2015	6	Dollars

Project Name: New Residential Subdivision Development

Major Category **System Access**

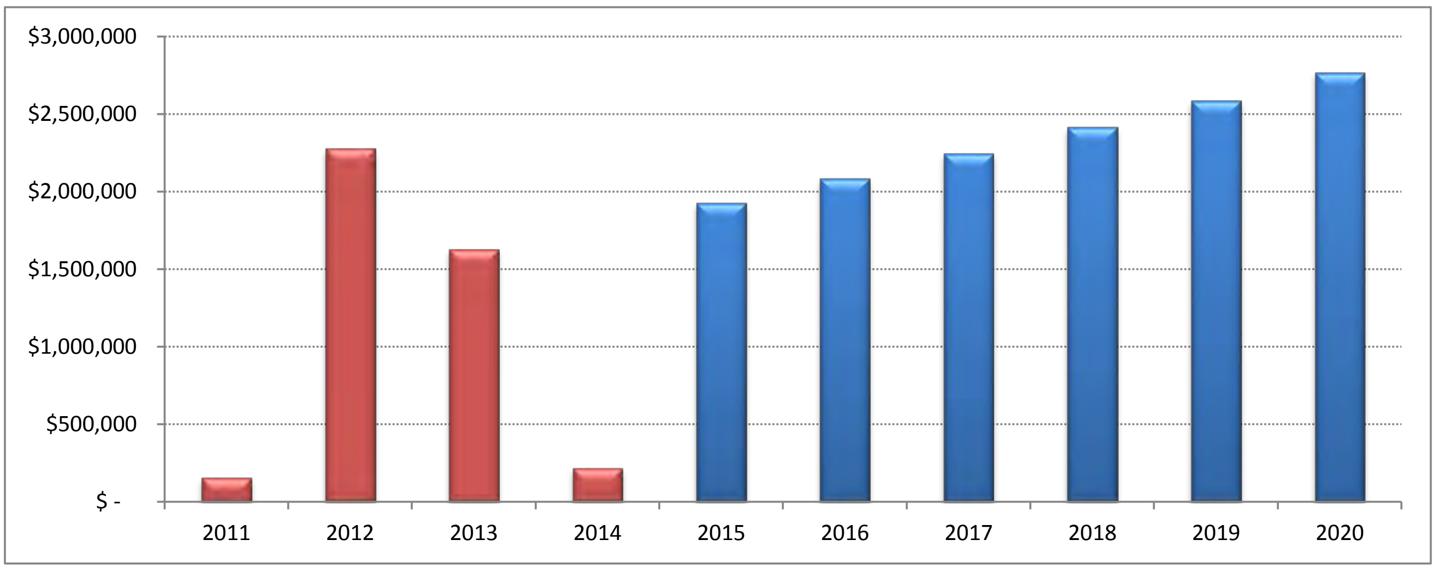
Project Overview

1. Additional Information	Service Territory	PowerStream North
	Location	PowerStream North Service Area
	Scope	Subdivision - Underground Residential Distibution System Developer requests an Offer to Connect (OTC) due to green field development. The OTC provides the estimated cost for a subdivision containing residential units. Estimated serviced/installed residential lots are as follows: Total number of lots estimated to be designed in 2015 are 1300. Total number of lots estimated to be installed in 2015 are 1000. Average cost of a serviced lot is $3,500.00. Estimated cost of installed and serviced residential lots (infrastructure only and constructed up to the street line) is as follows: 1000 lots x $3,500.00/lot = $3.50 million PowerStream's average cash contribution for a residential subdivision is 55% up front for "Option A". For "Option B" PowerStream pays 55% to the developer through transfer payment at the time of energization of the residential subdivision. PowerStream contribution has increased due to the removal upstream. There are 380 hours allocated for the Engineering Administration costs. For easements 95 hours and new service set up 285 hours.
	Justification	Under section 28 of the Electricity Act, distributors have an obligation to provide connection for new buildings to its distribution system.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital Residential Subdivision
	Fiscal Year	2015
	Parent WO#	305033
	Job Number	C00420
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Not Applicable.
	Comparative Information on Equivalent Historical Projects (if any)	On an annual basis PowerStream continues to have new customer connections. The value and number of connections vary year to year based on market and new construction demands.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	New residential subdivisions require an economic evaluation to determine PowerStream's capital contribution requirements.
	1a. Main Driver	Service Requests. This is a regulatory requirement based on the prescribed economic evaluation methodology.
	1b. Priority and Reasons for Priority	Not Applicable.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Represents capital contributed for investment in new developments.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Factors Affecting Timing/Priority	PowerStream assesses the connection of new customers on an annual basis.
	Factors Relating to Customer Preferences or Input	The Customer has input into the electrical design of the distribution system expansion. The Customer is also responsible for determining the site plans and layout with final approval from the municipality.
	Factors Affecting the Final Cost of the Project	The number of customer connections vary from year to year.
	How Controlled Costs have been Minimized	Construction service is provided by PowerStream and its contractor. PowerStream's contractor was selected through a competitive RFP process which provides best costs and cost certainty. After the Customer has been presented with an OTC, the Customer always has the option to to pursue an alternative bid and uses the services of a qualified contractor for the work that is eligible for alternative bid.
	Identify if Other Planning Objectives are Met by the Project, if so, which ones	Not Applicable.
	Options Considered and Summary of Analysis	Not Applicable.

Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	101906	**2015**	**6**	**Dollars**
	Project Name: New Residential Subdivision Development			

Results of Final Economic Evaluation, if applicable	Final economic evaluations are done on a subdivision by subdivision basis.
System Impacts (Nature, Magnitude and Costs)	Not Applicable.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ 153,587	$ 2,275,398	$ 1,625,717	$ 217,038	$ 1,925,000	$ 2,084,499	$ 2,244,000	$ 2,414,500	$ 2,587,200	$ 2,767,185



Project Summary Report	Project Code 101892	Report Start Year 2015	Number of Years 6	Scale Dollars
	Project Name New Subdivision Development - Secondary Service Lateral			

Major Category **System Access**

Project Overview

1. Additional Information	Service Territory	PowerStream South
	Location	PowerStream South Service Area
	Scope	This expenditure pertains to secondary service lateral installation for new subdivisions for OTC's signed in 2015 and prior to 2015. With respect to new subdivision developments, there are requirements to install secondary underground services from the service tails terminated at the street line to the meter base for each lot. This work involves trenching and backfill and supply and installation of the duct, secondary service cable, splices at the street line and termination in the meter base. This work will allow for the connection of the secondary service to the pad-mounted transformer which, in turn provides power to the customer's unit. There are 2 - types of secondary services based on a pre-determined length typically installed within a subdivision. They are 3/0 and/or 250MCM aluminium, 600V rated secondary cables. The secondary service installation breakdown is as follows: 90% - 3/0 and 10% - 250MCM cables. 3300 services (3/0 - 2970 & 250MCM - 330) The total cost to install a 3/0 or 250MCM secondary service is approximately $500.00 (cost includes: contract labour + connection fee + meter+PS inspection) x 3300 services = $1.65 million.
	Justification	Under section 28 of the Electricity Act, distributors have an obligation to provide connection for new buildings to its distribution system.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	300800
	Job Number	C00410
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Not Applicable.
	Comparative Information on Equivalent Historical Projects (if any)	On an annual basis PowerStream continues to have new customer connections. The value and number of connections vary year to year based on market and new construction demands.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	New residential and commercial/industrial subdivisions require an economic evaluation to determine PowerStream's capital contribution requirements.
	1a. Main Driver	Service Requests. This is a regulatory requirement base on the prescribed economic evaluation methodology.
	1b. Priority and Reasons for Priority	Not Applicable.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Represents capital contributed for investment in new developments.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Factors Affecting Timing/Priority	PowerStream assesses the connection of new customers on an annual basis.
	Factors Relating to Customer Preferences or Input	The Customer has input into the electrical design of the distribution system expansion. The Customer is also responsible for determining the site plans and layout with final approval from the municipality.
	Factors Affecting the Final Cost of the Project	The number of customer connections vary from year to year.
	How Controlled Costs have been Minimized	Construction service is provided by PowerStream and its contractor. PowerStream's contractor was selected through a competitive RFP process which provides best costs and cost certainty. After the Customer has been presented with an OTC, the Customer always has the option to to pursue an alternative bid and uses the services of a qualified contractor for the work that is eligible for alternative bid.
	Identify if Other Planning Objectives are Met by the Project, if so, which ones	Not Applicable.

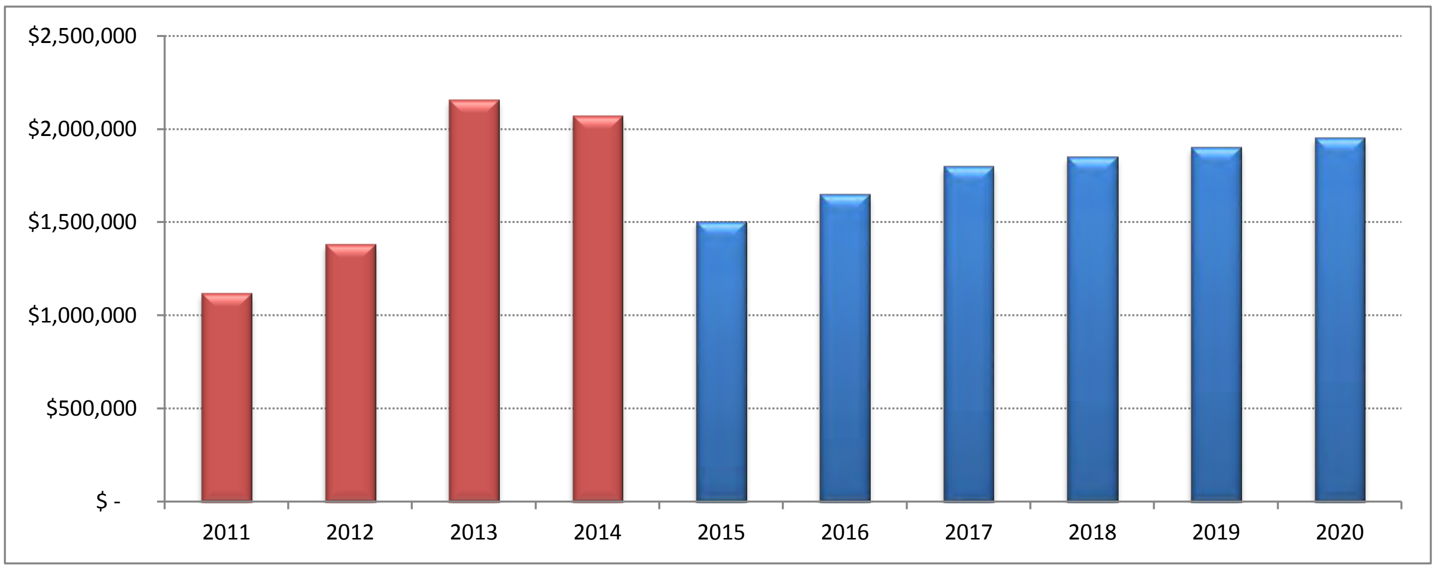
Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	101892	2015	6	Dollars

Project Name

New Subdivision Development - Secondary Service Lateral

Options Considered and Summary of Analysis	Not Applicable.
Results of Final Economic Evaluation, if applicable	Final economic evaluations are done on a subdivision by subdivision basis.
System Impacts (Nature, Magnitude and Costs)	Not Applicable.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ 1,119,100	$ 1,380,902	$ 2,156,481	$ 2,071,136	$ 1,503,989	$ 1,649,281	$ 1,799,275	$ 1,850,799	$ 1,902,270	$ 1,953,761



Project Code	Report Start Year	Number of Years	Scale
101914	2015	6	Dollars

Project Summary Report

Project Name: New Subdivision Development - Secondary Service Lateral

Major Category System Access

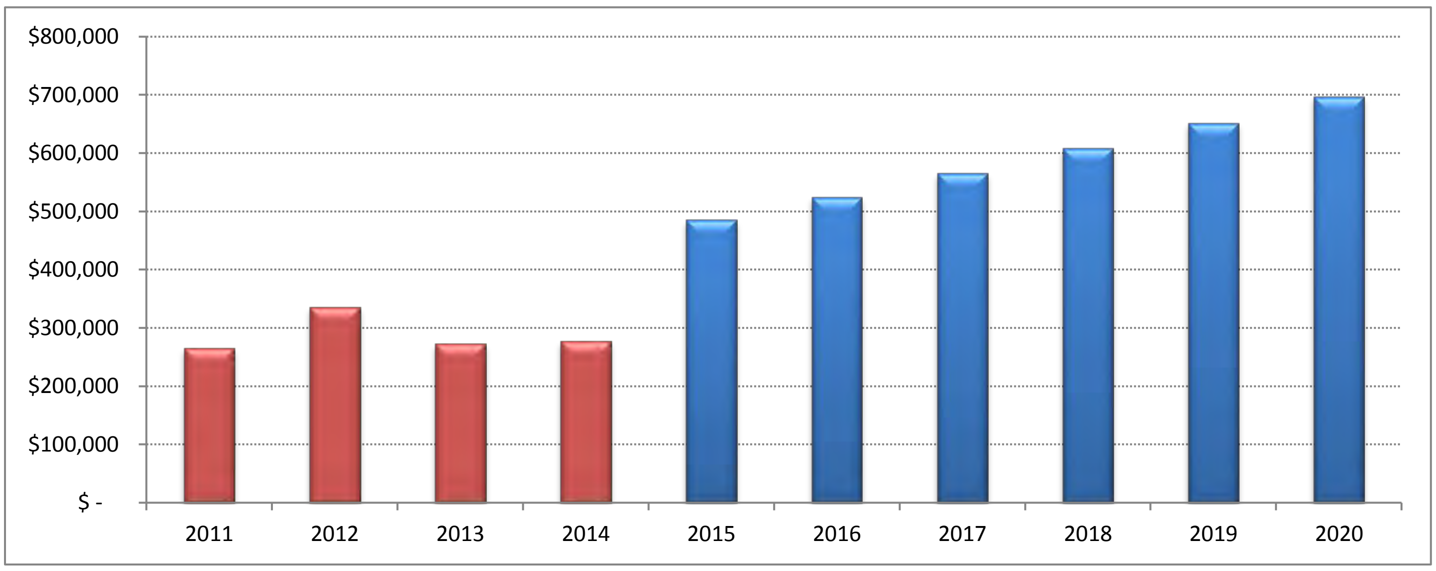
Project Overview

1. Additional Information	Service Territory	PowerStream North
	Location	PowerStream North Service Area
	Scope	This expenditure pertains to secondary service lateral installation for new subdivisions for OTC's signed in 2015 and prior to 2015. With respect to new subdivision developments, there are requirements to install secondary underground services from the service tails terminated at the street line to the meter base for each lot. This work involves trenching and backfill and supply and installation of the duct, secondary service cable, splices at the street line and termination in the meter base. This work will allow for the connection of the secondary service to the pad-mounted transformer which, in turn provides power to the customer's unit. There are 2 - types of secondary services based on a pre-determined length typically installed within a subdivision. They are 3/0 and/or 250MCM aluminium, 600V rated secondary cables. The secondary service installation breakdown is as follows: 90% - 3/0 and 10% - 250MCM cables. 1000 services (3/0 - 900 & 250MCM - 100) The total cost to install a 3/0 or 250MCM secondary service is approximately $485.00 (cost includes: contract labour + connection fee + meter+PS inspection) 1000 services @ $485/service = $485,000.00 Total PS contribution in 2015 for North services is $485,000.00
	Justification	Under section 28 of the Electricity Act, distributors have an obligation to provide connection for new buildings to its distribution system.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	305034
	Job Number	C00430
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Not Applicable.
	Comparative Information on Equivalent Historical Projects (if any)	On an annual basis PowerStream continues to have new customer connections. The value and number of connections vary year to year based on market and new construction demands.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	New residential and commercial/industrial subdivisions require an economic evaluation to determine PowerStream's capital contribution requirements.
	1a. Main Driver	Service Requests. This is a regulatory requirement base on the prescribed economic evaluation methodology.
	1b. Priority and Reasons for Priority	Not Applicable.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Represents capital contributed for investment in new developments.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Factors Affecting Timing/Priority	PowerStream assesses the connection of new customers on an annual basis.
	Factors Relating to Customer Preferences or Input	The Customer has input into the electrical design of the distribution system expansion. The Customer is also responsible for determining the site plans and layout with final approval from the municipality.
	Factors Affecting the Final Cost of the Project	The number of customer connections vary from year to year.
	How Controlled Costs have been Minimized	Construction service is provided by PowerStream and its contractor. PowerStream's contractor was selected through a competitive RFP process which provides best costs and cost certainty. After the Customer has been presented with an OTC, the Customer always has the option to to pursue an alternative bid and uses the services of a qualified contractor for the work that is eligible for alternative bid.
	Identify if Other Planning Objectives are Met by the Project, if so, which ones	Not Applicable.

Project Summary Report	Project Code **101914**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name New Subdivision Development - Secondary Service Lateral			

Options Considered and Summary of Analysis	Not Applicable.
Results of Final Economic Evaluation, if applicable	Final economic evaluations are done on a subdivision by subdivision basis.
System Impacts (Nature, Magnitude and Costs)	Not Applicable.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ 264,641	$ 335,371	$ 272,439	$ 277,081	$ 485,045	$ 524,515	$ 565,540	$ 607,974	$ 651,843	$ 697,193



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	101872	2015	6	Dollars

Project Name

O/H and U/G Residential Service Upgrades

Major Category **System Access**

Project Overview

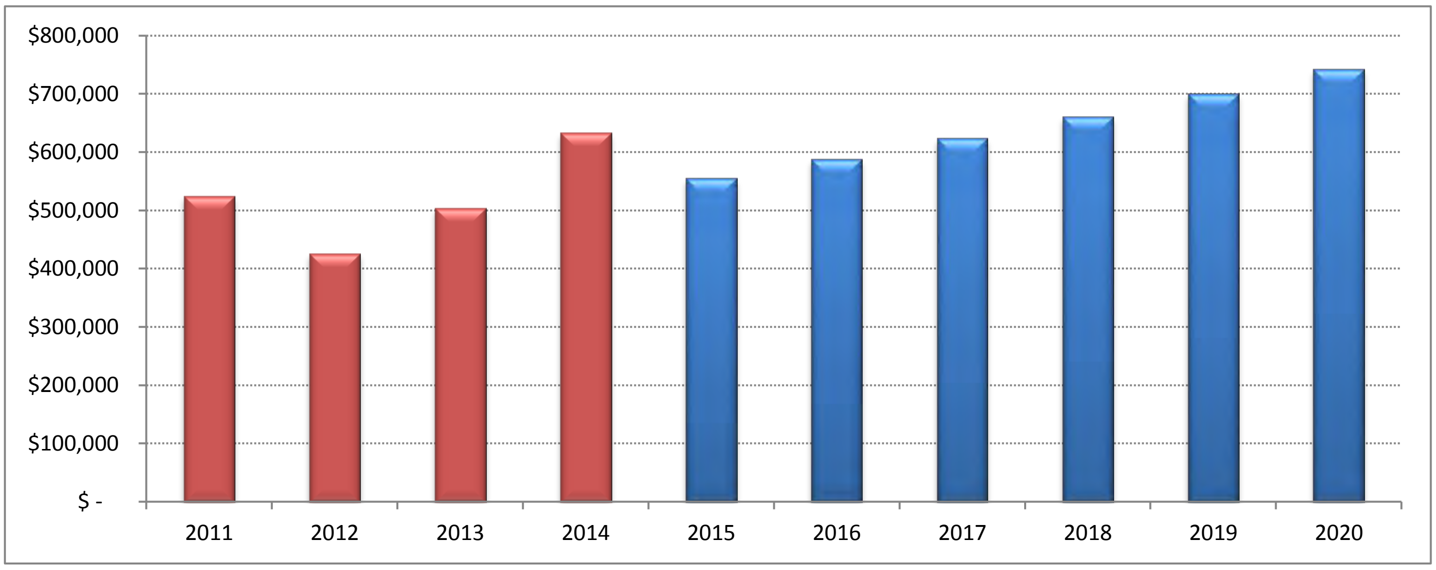
1. Additional Information	Service Territory	PowerStream South
	Location	PowerStream's South Service Area (Vaughan, Markham, Richmond Hill, Aurora)
	Scope	This expenditure is based on customers request for residential service upgrades outside of an Offer to Connect (OTC) residential subdivision. Typically only a disconnect and a reconnect is required to be completed by Line staff. Examples of upgrades are as follows: - Fuses to breaker panel change initiated by the customer. - Over head conductor / under ground cable replacement initiated by PowerStream. - Primary service upgrade i.e. Farm Service The customer contribution is based on the total cost of the new service minus the overhead credits as outlined in the Distribution System Code. The credits are based on the following: 1. Up to 30m of overhead service cable at no charge or equivalent for underground service. 2. Service connections at no charge. 3. For services up to 200amps, transformation is provided. For services above 200amps or services requiring their own transformer, an equivalent transformation credit will be given. The 2015 budget was prepared in March 2014 and based on the following: The projected Service Designs for 2015 is 793 with approx 595 being connected.
	Justification	Under section 28 of the Electricity Act, distributors have an obligation to provide connection for buildings to its distribution system.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital Layouts – O/H – U/G Residential Service Upgrades
	Fiscal Year	2015
	Parent WO#	300798
	Job Number	C00340
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Not Applicable.
	Comparative Information on Equivalent Historical Projects (if any)	Proposed expenditures are based on historical figures of number of connections and costs.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	Not Applicable.
	1a. Main Driver	Service Requests.
	1b. Priority and Reasons for Priority	Not Applicable.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Not Applicable.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Factors Affecting Timing/Priority	Not Applicable.
	Factors Relating to Customer Preferences or Input	The Customer determines the size of the service upgrade they require, such as 200A or 400A. The Customer also determines if they want an existing overhead service to be changed to underground, and has input into the route of the underground service.
	Factors Affecting the Final Cost of the Project	Not Applicable.
	How Controlled Costs have been Minimized	Construction service is provided by PowerStream and its contractor. PowerStream's contractor was selected through a competitive RFP process which provides best costs and cost certainty.
	Identify if Other Planning Objectives are Met by the Project, if so, which ones	Not Applicable.
	Options Considered and Summary of Analysis	Not Applicable.
	Results of Final Economic Evaluation, if applicable	Not Applicable.
	System Impacts (Nature, Magnitude and Costs)	Not Applicable.

Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	101872	2015	6	Dollars

Project Name

O/H and U/G Residential Service Upgrades

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ 524,456	$ 425,449	$ 503,584	$ 633,063	$ 554,580	$ 587,854	$ 623,126	$ 660,514	$ 700,145	$ 742,154

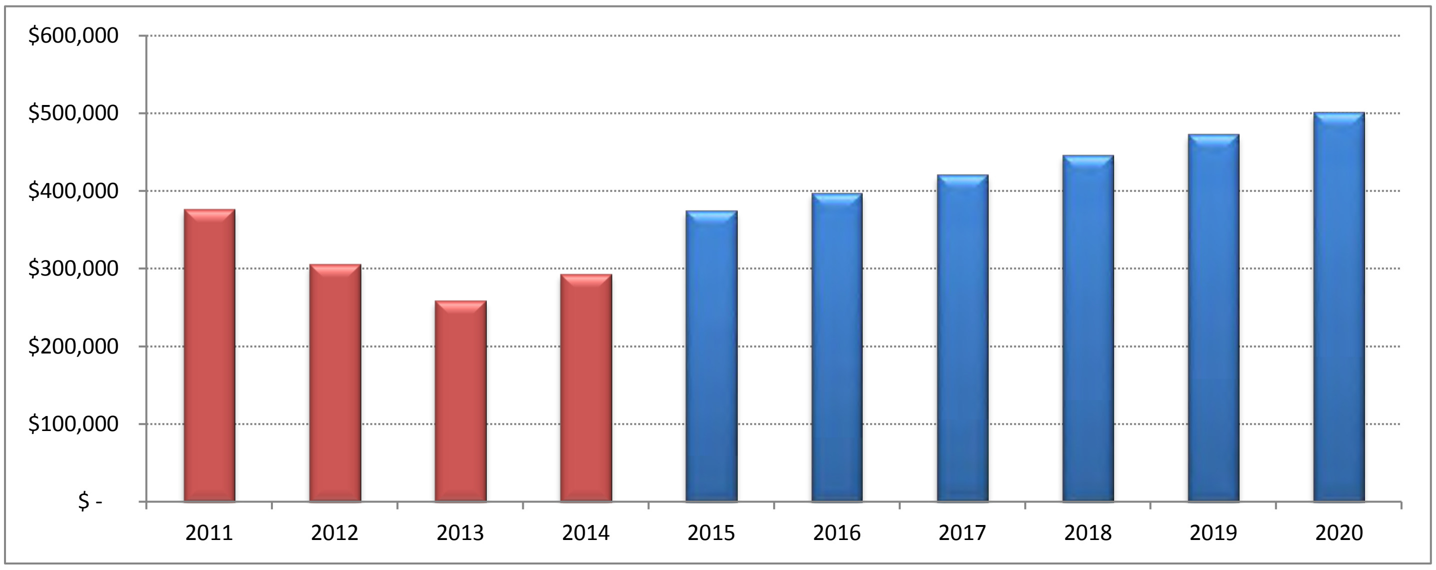


Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	101873	2015	6	Dollars
	Project Name			
	O/H and U/G Residential Service Upgrades			

Major Category	**System Access**	
Project Overview		
1. Additional Information	Service Territory	PowerStream North
	Location	PowerStream's North Service Area(Barrie, Alliston, Beeton, Bradford, Thorton, Penetang., Tottenham)
	Scope	This expenditure is based on customers request for residential service upgrades outside of an Offer to Connect (OTC) residential subdivision. Typically only a disconnect and a reconnect is required to be completed by Line staff Examples of upgrades are as follows: - Fuses to breaker panel change initiated by the customer. - Over head conductor / under ground cable replacement initiated by PowerStream. - Primary service upgrade i.e. Farm Service The customer contribution is based on the total cost of the new service minus the overhead credits as outlined in the Distribution System Code. The credits are based on the following: 1. Up to 30m of overhead service cable at no charge or equivalent for underground service. 2. Service connections at no charge. 3. For services up to 200amps, transformation is provided. For services above 200amps or services requiring their own transformer, an equivalent transformation credit will be given. The 2015 budget was prepared in March 2014 and based on the following: The projected Service Designs for 2015 is 500 services with 375 being connected.
	Justification	
2. General Project Information (OEB)	Contributed Capital	Contributed Capital Layouts – O/H – U/G Residential Service Upgrades
	Fiscal Year	2015
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Not Applicable.
	Comparative Information on Equivalent Historical Projects (if any)	Proposed expenditures are based on historical figures of number of connections and costs.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	Not Applicable.
	1a. Main Driver	Service Requests.
	1b. Priority and Reasons for Priority	Not Applicable.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Not Applicable.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Factors Affecting Timing/Priority	Not Applicable.
	Factors Relating to Customer Preferences or Input	The Customer determines the size of the service upgrade they require, such as 200A or 400A. The Customer also determines if they want an existing overhead service to be changed to underground, and has input into the route of the underground service.
	Factors Affecting the Final Cost of the Project	Not Applicable.
	How Controlled Costs have been Minimized	Construction service is provided by PowerStream and its contractor. PowerStream's contractor was selected through a competitive RFP process which provides best costs and cost certainty.
	Identify if Other Planning Objectives are Met by the Project, if so, which ones	Not Applicable.
	Options Considered and Summary of Analysis	Not Applicable.
	Results of Final Economic Evaluation, if applicable	Not Applicable.
	System Impacts (Nature, Magnitude and Costs)	Not Applicable.

Project Summary Report	Project Code **101873**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name O/H and U/G Residential Service Upgrades			

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ 376,288	$ 305,203	$ 258,596	$ 292,829	$ 374,341	$ 396,802	$ 420,611	$ 445,846	$ 472,597	$ 500,955



Power Stream	Project Code	Report Start Year	Number of Years	Scale
Project Summary Report	**101764**	**2015**	**6**	**Dollars**
	Project Name: Road Authority Expenditure PS North			

Major Category **System Access**

Project Overview

1. Additional Information	Service Territory	PowerStream North
	Location	PowerStream North Service Territory
	Scope	Road authority projects that require relocation of PS's plant. Estimated based on historical Data. Barrie: Whiskey Creek Floodway U/G potential relocations Barrie: Dunlop St. - Eccles to Toronto St. Pole relocations Bradford: Various Road Improvements Penetanguishene: Harriett St - Jeffrey St to Edward St New Tecumseth: Dayfoot - Prospect to Main Thornton: Various road improvement projects Contributed capital estimated at 33% of the gross estimate based on historical cost estimates
	Justification	The City's and local Municipalities requires PowerStream to relocate the distribution system to accomodate road works.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital Road Authority
	Fiscal Year	2015
	Parent WO#	
	Job Number	C00230
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The timing and schedule of the road projects is non-controllable and based on the road projects being advanced by the Municipalities.
	Comparative Information on Equivalent Historical Projects (if any)	The historical spend on PS North Road Authority projects is $2.0M gross, $0.6M contributed and $1.4M net.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	Service Requests. The City's and local Municipalities requires PowerStream to relocate the distribution system to accomodate road works.
	1a. Main Driver	These projects are non-controllable and are a requirement of the Public Service Works on Highways Act R.S.O. 1990, CHAPTER P.49
	1b. Priority and Reasons for Priority	These projects are non-controllable and are a requirement of the Public Service Works on Highways Act R.S.O. 1990, CHAPTER P.49
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	These projects are non-controllable and the scope is defined and determined by the limits and amount of road work / road widening being done by the Municipality.
	2. Safety	The relocation of the distribution system needs to be done in advance of the road work. PS Crews cannot safely work in the same time and space as the Road Crews.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Factors Affecting Timing/Priority	The scope and timing of the projects are driven by the Municipalities. Planned road projects may be advanced or deferred within a calendar year based on various constraints such as budget, or based on political pressures, economic development, traffic flow, etc.
	Factors Relating to Customer Preferences or Input	The scope is defined and determined by the limits and amount of road work / road widening being done by the Municipality.
	Factors Affecting the Final Cost of the Project	The scope is defined and determined by the limits and amount of road work / road widening being done by the Municipality.
	How Controlled Costs have been Minimized	Construction service is provided by PowerStream and its contractor. PowerStream's contractor was selected through a competitive RFP process which provides best costs and cost certainty.
	Identify if Other Planning Objectives are Met by the Project, if so, which ones	Not Applicable.
	Options Considered and Summary of Analysis	Not Applicable.
	Results of Final Economic Evaluation, if applicable	Not Applicable.

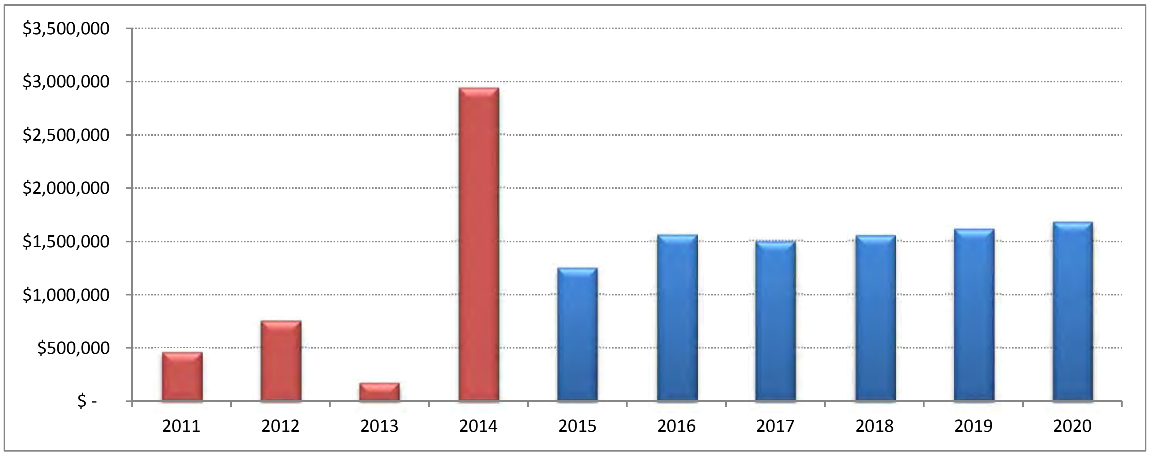
Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	101764	2015	6	Dollars

Project Name

Road Authority Expenditure PS North

System Impacts (Nature, Magnitude and Costs): These projects are non-controllable and the scope is defined and determined by the limits and amount of road work / road widening being done by the Municipality.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ 459,509	$ 757,793	$ 171,112	$ 2,939,959	$ 1,251,353	$ 1,565,594	$ 1,499,841	$ 1,556,975	$ 1,616,522	$ 1,682,548



Project Summary Report

Project Code	Report Start Year	Number of Years	Scale
101762	2015	6	Dollars

Project Name

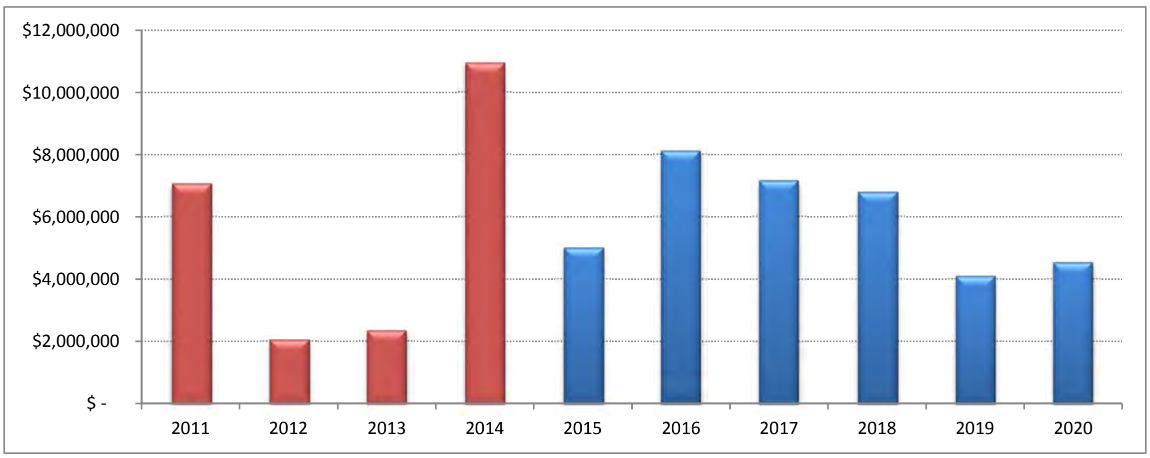
Road Authority Expenditure PS South

Major Category	**System Access**	
Project Overview		
1. Additional Information	Service Territory	PowerStream South
	Location	PowerStream South Service Territory
	Scope	YORK REGION 19th Avenue at Leslie Street Intersection, Richmond HillDonald Cousins Parkway from Major Mack to Hwy 48, Markham, King Road from Yonge Street to Bond Crescent King, Richmond Hill, Langstaff Road from Dufferin St to Keele St, Vaughan, Major Mackenzie from Donald Cousins to 9th Line, Markham No apparent conflicts, St. John's SideRoad from Bayview Ave to Leslie St, Aurora, YRRT Y2.2 Yonge St. - Major Mackenzie Dr to 19th Ave, Richmond Hill, H2 - HWY 7 - Pine Valley to Hwy 400 and Go Tracks to Yonge Highway 7, Vaughan, AURORA Bluegrass Drive Bluegrass Drive, Aurora, Skyview Lane, Aurora, Steeplechase Avenue, Aurora, Woodsend Crescent, Aurora, RICHMOND HILL Portage Avenue from Bathurst east, Richmond Hill, Madison Avenue from Bathurst east, Richmond Hill, Park Crescent from Sunset Beach to Sunset Beach Park, Richmond Hill, Coon`s Road from Humberland to Yonge, Richmond Hill, West Beaver Creek Road from Leslie Street to West Pearce St, Richmond Hill, MARKHAM, Miller Avenue from Birchmont to Kennedy, Markham
	Justification	The Region's and local Municipalities requires PowerStream to relocate the distribution system to accomodate road works.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital Road Authority
	Fiscal Year	2015
	Parent WO#	
	Job Number	C00200
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The timing and schedule of the road projects is non-controllable and based on the road projects being advanced by the Municipalities.
	Comparative Information on Equivalent Historical Projects (if any)	Historically in PS South Territory, the Road Authority spend has been $5M gross, $1.5M contributed, and $3.5M net. The Road Authority budget for the next few years has been increased due to increased road widenings due to by York Region's rapid bus transit projects and increased road projects by York Region.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	The Region's and local Municipalities requires PowerStream to relocate the distribution system to accomodate road works.
	1a. Main Driver	Service Requests. These projects are non-controllable and are a requirement of the Public Service Works on Highways Act R.S.O. 1990, CHAPTER P.49
	1b. Priority and Reasons for Priority	These projects are non-controllable and are a requirement of the Public Service Works on Highways Act R.S.O. 1990, CHAPTER P.49
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	The scope is defined and determined by the limits and amount of road work / road widening being done by the Municipality.
	2. Safety	The relocation of the distribution system needs to be done in advance of the road work. PS Crews cannot safely work in the same time and space as the Road Crews.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Factors Affecting Timing/Priority	The scope and timing of the projects are driven by the Municipalities. Planned road projects may be advanced or deferred within a calendar year based on various constraints such as budget, or based on political pressures, economic development, traffic flow, etc.
	Factors Relating to Customer Preferences or Input	The scope and timing of the projects are driven by the Municipalities. Planned road projects may be advanced or deferred within a calendar year based on various constraints such as budget, or based on political pressures, economic development, traffic flow, etc.
	Factors Affecting the Final Cost of the Project	The scope is defined and determined by the limits and amount of road work / road widening being done by the Municipality.
	How Controlled Costs have been Minimized	Construction service is provided by PowerStream and its contractor. PowerStream's contractor was selected through a competitive RFP process which provides best costs and cost certainty.

	Project Code	Report Start Year	Number of Years	Scale
Project Summary Report	101762	2015	6	Dollars
	Project Name: Road Authority Expenditure PS South			

Identify if Other Planning Objectives are Met by the Project, if so, which ones	Not Applicable.
Options Considered and Summary of Analysis	Not Applicable.
Results of Final Economic Evaluation, if applicable	Not Applicable.
System Impacts (Nature, Magnitude and Costs)	The scope is defined and determined by the limits and amount of road work / road widening being done by the Municipality.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ 7,077,271	$ 2,055,042	$ 2,342,483	$ 10,956,175	$ 5,007,538	$ 8,136,379	$ 7,179,017	$ 6,799,693	$ 4,102,094	$ 4,539,401



Power Stream **Project Summary Report**	Project Code **103637**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name	GS>50 MIST Meter Program Implementation		

Major Category	**System Access**	

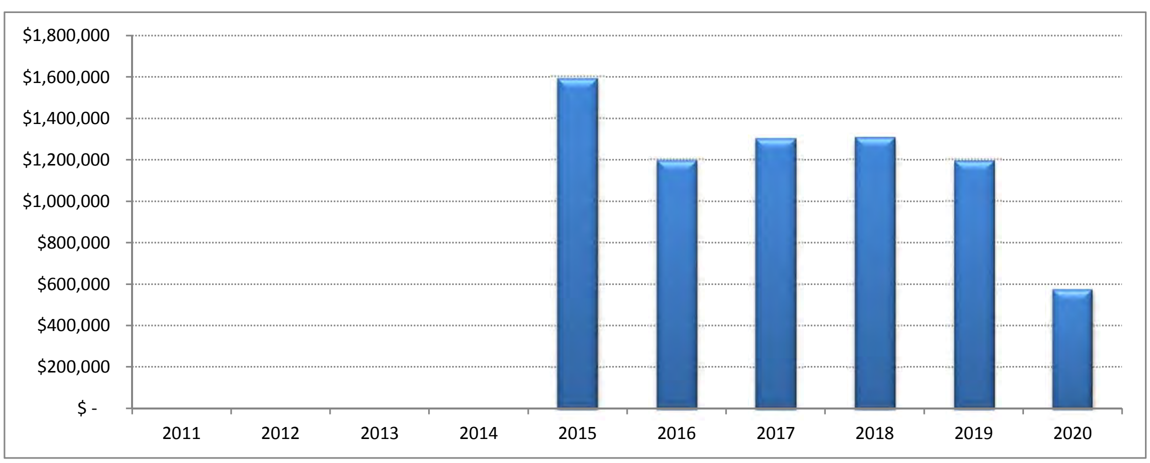
Project Overview

1. Additional Information	Service Territory	PowerStream North and South
	Location	The General Service greater than 50 kW (GS>50) meters are spread-out through the service territory in small to medium size businesses as well as condos, plazas and other commercial centres.
	Scope	The GS>50kW class of customer is in an unique position among electricity consumers, as they are not able to access their data in 15 minute or hourly intervals since the current meter is an electro-mechanical meter which is manually read once a month. The scope of this project is to replace the 4,500 electro-mechanical meters within our system with meters capable of providing that level of granularity, as well implement a communication system to bring the data back to the head-end system, allowing our customers to access their energy data in interval granularity for better energy decisions. The data will be available for download in the Green Button format to allow customers to utilise off-the-shelf software to analyse the data or to easily compare a facility within our service territory to other facilities regardless if outside of our service territory. In the current year, we will be building the communication infrastructure, setup the head-end system and build the customer interface to allow us to implement the end-to-end system. Deployment of the meters will be phased over 5 years, in order to comply with the OEB ruling to have all customers moved over by August 21, 2020. We are actively exploring opportunities to leverage PowerStream's Wi-Max technology to reduce the overall costs of licensing/monthly communication charges.
	Justification	Project is an OEB requirement as per Distribution System Code amendment, pursuant to section 70.2 of
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	No risks have been currently identified, other than the standard project risks which will be actively managed by project management techniques.
	Comparative Information on Equivalent Historical Projects (if any)	Estimated costs are based on historical expenditures of similar meter, communication and data presentment projects.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	The project will require the implementation of three components; - Meters capable of capturing the data - Communication strategy to allow for collection from the meter to the Head-End System - Make the customers' data available in a manner that provides the maximum value to the customer PowerStream will be utilising a layered approach to communication in order to minimize communication costs to our customers, where possible favouring the lower cost option. PowerStream continues to look for opportunities to leverage PowerStream's currently deployed Wi-Max system in order to lower costs. The constraint to fully leverage this low-cost Wi-Max solution is the availability of Measurement Canada approved meters that natively support this communication protocol. Where lower costs options are not supported PowerStream will utilise secure cellular or land lines. PowerStream will be leveraging our Operational Data Store for data collection and data presentment.
	1a. Main Driver	To implement a low cost communication and meter solution that meets the customer needs as defined in the Distribution System Code, while maximizing the data value to the customer.
	1b. Priority and Reasons for Priority	High Priority - as this is a mandated activity under Ontario's Distribution System Code (DSC) which needs to be completed by August 21, 2020
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Project alternatives are limited to the type and technology of the replacement meter. However, there is no alternative that avoids the need to replace the meter. PowerStream continues to engage with Meter Manufacturers to determine timeline for Measurement Canada approval of meters capable of supporting cheaper communication options that don't rely on the need to upgrade the current AMI system to support the additional data load or implement a communication system that requires long term monthly charges.
	2. Safety	No safety drivers identified.
	3. Cyber-Security, Privacy	No Cyber-Security drivers identified

Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	103637	2015	6	Dollars
	Project Name	GS>50 MIST Meter Program Implementation		

	4. Coordination, Interoperability	Although not a driver of this project a secondary benefit will be the ability to utilise these meters as
	5. Economic Development	No direct economic development, although the additional energy data and the additional capability to
	6. Environmental Benefits	No environmental benefits have been identified
5. Category-Specific Requirements for Each Project/Activity (OEB)	Factors Affecting Timing/Priority	Implementation to be completed by August 2020
	Factors Relating to Customer Preferences or Input	Green Button solution - feedback from commercial real estate representatives at meetings hosted by MaRS EDAP expressed the position that large property managers see a lot of value in getting data in a consistent format when they have buildings across multiple utilities they collect and assimilate data monthly (typically manually) for internal benchmarking, energy management and reporting purposes. Getting data in a machine readable and common (Green Button Download My Data) format would do away with a lot of the time and effort involved in accessing energy consumption data for the C&I sector. Delivering GS>50 data in Green Button format allows the LDC to meet that request.
	Factors Affecting the Final Cost of the Project	Factors affecting the Final Cost of the Project include: 1) meter costs 2) re-installation and cross phasing of complex metering configurations 3) higher communication costs associated with reaching inside/subterranean meter locations 4) development of head-end system to capture/store and make data available
	How Controlled Costs have been Minimized	By not tying ourselves to one technology, PowerStream continues to engage with meter/communications vendors to drive down costs.
	Identify if Other Planning Objectives are Met by the Project, if so, which ones	Not Applicable.
	Options Considered and Summary of Analysis	Not Applicable.
	Results of Final Economic Evaluation, if applicable	Not Applicable.
	System Impacts (Nature, Magnitude and Costs)	Not Applicable.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ 1,592,952	$ 1,196,859	$ 1,303,795	$ 1,308,610	$ 1,195,725	$ 574,761



Project Summary Report	Project Code **102175**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Residential Meter "ICON F" Meter Replacement Program			

Major Category	System Access	

Project Overview

1. Additional Information	Service Territory	PowerStream South
	Location	The "ICON F" meter was installed in the City of Markham as part of the first deployment of smart meters. Some "ICON F" meters are scattered throughout the PowerStream South Territory.
	Scope	The "ICON F" Meter refers to the flexnet module firmware version installed in the meter. The scope of replacement of meters for this year is 2000 meters. There are appoximately 136000 "ICON F" meters in PowerStream's distribution system. This project is the 2nd year of a 9 year program, designed to replace meters in conjunction with the depreciation of the meter. This project is limited to single phase smart meters procured and installed in 2007. During the Bell WurldTech security audit it was determined that the "ICON F" meter did not meet all encryption data requirements. The "ICON F" meters are the first generation smart meters installed at PowerStream. The "ICON F" meters are limited in their firmware upgradeability. Most labour is performed by the single phase contractor. Meters will be scrapped and replaced with 3rd generation ICON meters with firmware programming.
	Justification	Customer Security and Privacy is important to PowerStream. The ICON F version of meters have data encryption but the data encryption is not upto current industry standards. During the Bell WurldTech security audit it was determined that the "ICON F" meter did not meet all encryption data requirements. The "ICON F" meters are the first generation smart meters installed at PowerStream. The "ICON F" meters are limited in their firmware upgradeability. Future smart grid deployed projects would be limited in areas that have ICON F meters deployed. The meters must be replaced as an end of life program through the current financial model of depreciation. The ICON F meter replacement program emulates replacement of the meter population based upon the capital smart meter depreciation curve.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Not Applicable.
	Comparative Information on Equivalent Historical Projects (if any)	Estimated costs are based on historical expenditures of similar meter replacement projects.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	The "ICON F" meter was installed in the City of Markham as part of the first deployment of smart meters. Some "ICON F" meters are scattered throughout the PowerStream South Territory. The "ICON F" Meter refers to the flexnet module firmware version installed in the meter. The scope of replacement of meters for this year is 2000 meters. There are appoximately 136000 "ICON F" meters in PowerStream's distribution system. This project is the 2nd year of a 9 year program, designed to replace meters in conjunction with the depreciation of the meter. This project is limited to single phase smart meters procured and installed in 2007. During the Bell WurldTech security audit it was determined that the "ICON F" meter did not meet all encryption data requirements. The "ICON F" meters are the first generation smart meters installed at PowerStream. The "ICON F" meters are limited in their firmware upgradeability. Most labour is performed by the single phase contractor. Meters will be scrapped and replaced with 3rd generation ICON meters with firmware programming.
	1a. Main Driver	Service Requests. This project is limited to single phase smart meters procured and installed in 2007. During the Bell WurldTech security audit it was determined that the "ICON F" meter did not meet all encryption data requirements. The "ICON F" meters are the first generation smart meters installed at PowerStream. The "ICON F" meters are limited in their firmware upgradeability.
	1b. Priority and Reasons for Priority	Not Applicable.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Project alternatives are limited to the type and technology of the replacement meter. However, there is no alternative that avoids the need to replace the meter.
	2. Safety	Not Applicable.

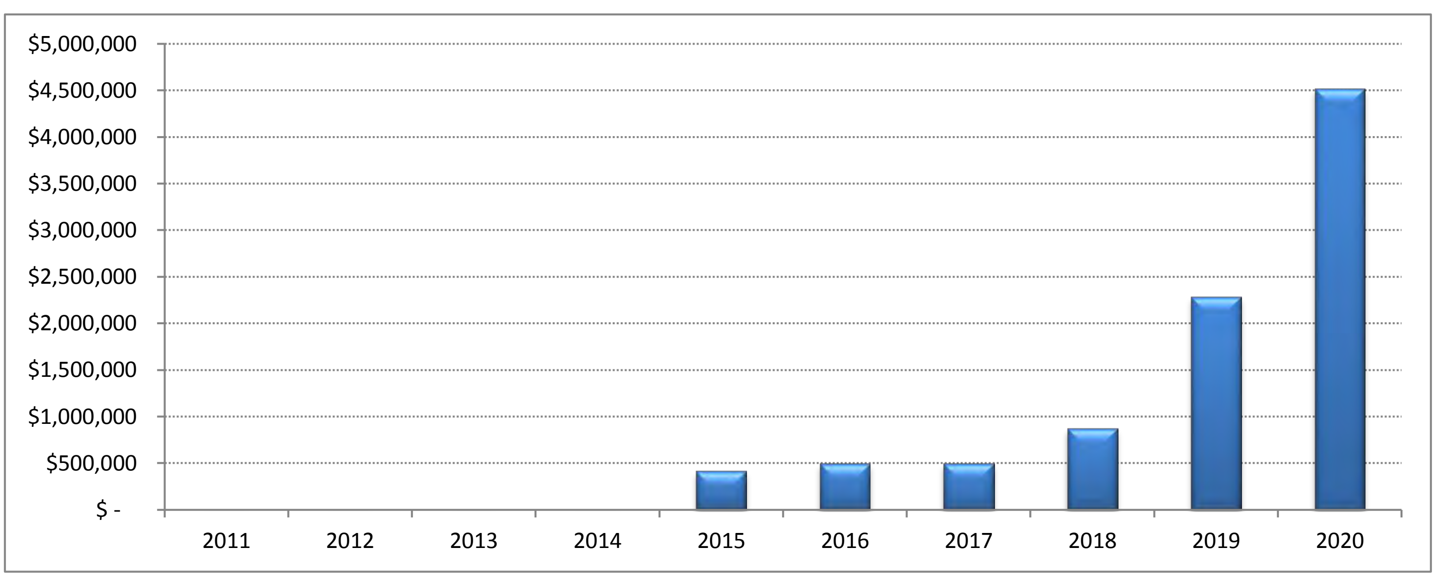
Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	102175	2015	6	Dollars

Project Name

Residential Meter "ICON F" Meter Replacement Program

	3. Cyber-Security, Privacy	Because the "ICON F" meters are first generation smart meters installed in 2007, and data encryption was not a concern at that time, they do not meet the data encryption requirements that have been implemented since that time.
	4. Coordination, Interoperability	Not Applicable
	5. Economic Development	None.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Factors Affecting Timing/Priority	The timing and priority for meter replacement will be determined by seal date, model, and serial numbers of the meters being replaced.
	Factors Relating to Customer Preferences or Input	Not Applicable.
	Factors Affecting the Final Cost of the Project	Factors affecting the Final Cost of the Project include: 1) Meter type 2) Meter features 3) Manufacturer of Meter 4) Ability to negotiate volume discounts from the meter supplier. 5) Cost of meter communication infrastructure require to support communicating with the meters.
	How Controlled Costs have been Minimized	Controllable costs will be minimized through a comprehensive work plan and competitive meter pricing.
	Identify if Other Planning Objectives are Met by the Project, if so, which ones	Not Applicable.
	Options Considered and Summary of Analysis	Not Applicable.
	Results of Final Economic Evaluation, if applicable	Not Applicable.
	System Impacts (Nature, Magnitude and Costs)	Not Applicable.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ 411,051	$ 494,361	$ 494,746	$ 872,435	$ 2,280,384	$ 4,517,454



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	101763	2015	6	Dollars

Project Name

Unforeseen Projects Initiated by the Customer PS North

Major Category	**System Access**	

Project Overview

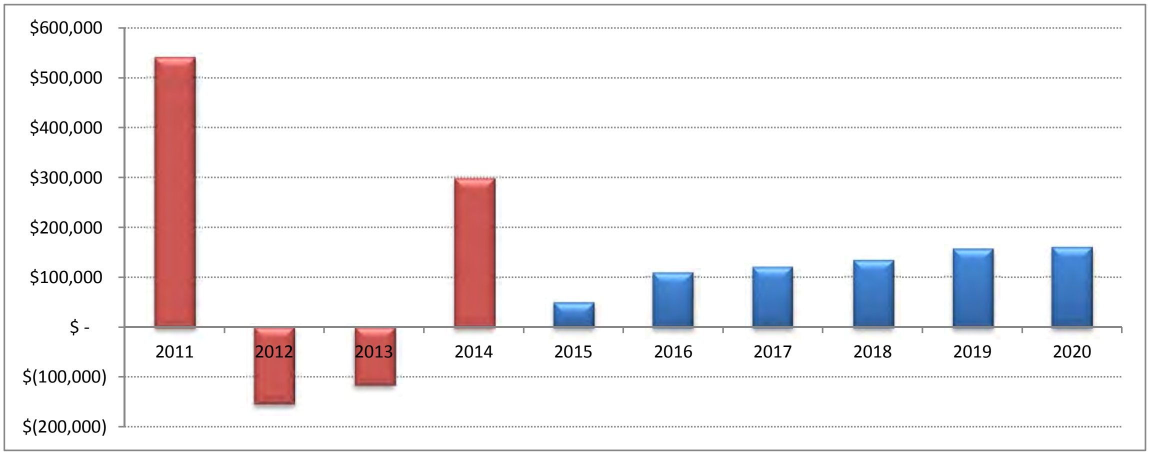
1. Additional Information	Service Territory	PowerStream North
	Location	PowerStream North Service Territory
	Scope	Unforeseen Projects, Typically these projects are line extension to supply power to new and existing customers. The project can be a complete new line build or upgrade from 1 ph to 3ph.
	Justification	These projects are requested by a customer and are Non-Controllable. The 2015 estimate is based on a 10% annual increase. It is expected with the Places to Grow Act and zero set back, we'll encounter more conflicts and requests for u/g and/or o/h relocation.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital Emerging Customer
	Fiscal Year	2015
	Parent WO#	
	Job Number	C00235
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	These projects are non-controllable and are driven by the Customer's schedule.
	Comparative Information on Equivalent Historical Projects (if any)	The level of activity/demand in Customer Relocation Requests can fluctuate from year-to-year.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	Unforeseen Projects, Typically these projects are line extension to supply power to new and existing
	1a. Main Driver	Service Requests. These projects are typically required due to conflicts that the development has such as location of entrances/driveways, clearances to overhead lines, etc.
	1b. Priority and Reasons for Priority	These are non-controllable projects and are driven by Customer demand.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	The EDS needs to be relocated due to a conflict with the Customer's development project.
	2. Safety	The relocation of the EDS may be a result of the need to maintain safety clearances to PowerStream's EDS.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Factors Affecting Timing/Priority	These projects are non-controllable and are driven by the Customer's schedule.
	Factors Relating to Customer Preferences or Input	These projects are typically required due to conflicts that the development has such as location of entrances/driveways, clearances to overhead lines, etc.
	Factors Affecting the Final Cost of the Project	The final costs of the project are dependent on the available space to relocate the EDS. Sometimes, undergrounding of a section of overhead line might be required. This would drive up the cost of the relocation work.
	How Controlled Costs have been Minimized	Construction service is provided by PowerStream and its contractor. PowerStream's contractor was selected through a competitive RFP process which provides best costs and cost certainty.
	Identify if Other Planning Objectives are Met by the Project, if so, which ones	Not Applicable.
	Options Considered and Summary of Analysis	Not Applicable.
	Results of Final Economic Evaluation, if applicable	Not Applicable.
	System Impacts (Nature, Magnitude and Costs)	Not Applicable.

Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	101763	2015	6	Dollars

Project Name

Unforeseen Projects Initiated by the Customer PS North

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ 541,347	$ (153,875)	$ (115,487)	$ 298,828	$ 49,387	$ 109,259	$ 120,900	$ 133,723	$ 156,353	$ 159,969



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	101761	2015	6	Dollars
	Project Name: Unforeseen Projects Initiated by the customer PS South			

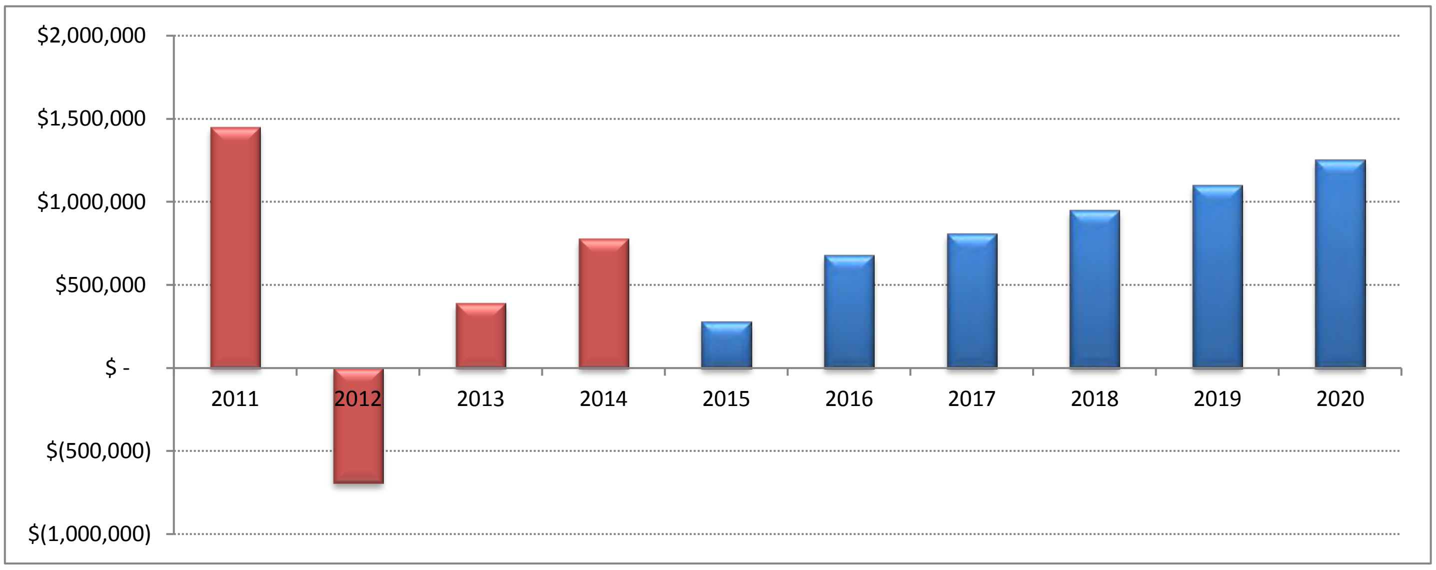
Major Category	System Access	

Project Overview

1. Additional Information	Service Territory	PowerStream South
	Location	PowerStream South Service Territory
	Scope	Unforeseen Projects, Typically these projects are line extension to supply power to new and existing customers. The project can be a complete new line build or upgrade from 1 ph to 3ph.
	Justification	These projects are requested by a customer and are Non-Controllable. The 2015 estimate is based on a 10% annual increase. It is expected with the Places to Grow Act and zero set back, we'll encounter more conflicts and requests for u/g and/or o/h relocation
2. General Project Information (OEB)	Contributed Capital	Contributed Capital Emerging Customer
	Fiscal Year	2015
	Parent WO#	
	Job Number	C00210
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	These projects are non-controllable and are driven by the Customer's schedule.
	Comparative Information on Equivalent Historical Projects (if any)	The level of activity/demand in Customer Relocation Requests can fluctuate from year-to-year.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	Unforeseen Projects, Typically these projects are line extension to supply power to new and existing customers. The project can be a complete new line build or upgrade from 1 ph to 3ph. Or it can require the undergrounding of an overhead line due to proximity of the development (e.g. condo building) to the overhead line.
	1a. Main Driver	Service Requests. These projects are typically required due to conflicts that the development has such as location of entrances/driveways, clearances to overhead lines, etc.
	1b. Priority and Reasons for Priority	These are non-controllable projects and are driven by Customer demand.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	The EDS needs to be relocated due to a conflict with the Customer's development project.
	2. Safety	The relocation of the EDS may be a result of the need to maintain safety clearances to PowerStream's EDS.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Factors Affecting Timing/Priority	These projects are non-controllable and are driven by the Customer's schedule.
	Factors Relating to Customer Preferences or Input	These projects are typically required due to conflicts that the development has such as location of entrances/driveways, clearances to overhead lines, etc.
	Factors Affecting the Final Cost of the Project	The final costs of the project are dependent on the available space to relocate the EDS. Sometimes, undergrounding of a section of overhead line might be required. This would drive up the cost of the relocation work.
	How Controlled Costs have been Minimized	Construction service is provided by PowerStream and its contractor. PowerStream's contractor was selected through a competitive RFP process which provides best costs and cost certainty.
	Identify if Other Planning Objectives are Met by the Project, if so, which ones	Not Applicable.
	Options Considered and Summary of Analysis	Not Applicable.
	Results of Final Economic Evaluation, if applicable	Not Applicable.
	System Impacts (Nature, Magnitude and Costs)	Not Applicable.

Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	101761	2015	6	Dollars
	Project Name: Unforeseen Projects Initiated by the customer PS South			

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ 1,449,123	$ (692,016)	$ 388,781	$ 776,335	$ 279,618	$ 677,544	$ 808,502	$ 946,668	$ 1,099,428	$ 1,254,572



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100835	2015	6	Dollars

Project Name

Cable Injection Program - 2015 to 2020

Major Category **System Renewal**

Project Overview

1. Additional Information

Service Territory: PowerStream North & South

Location: Various locations in PowerStream

Scope: Carry out cable injection to approx. 105-115 km per year of existing in-service underground primary XLPE cable to maintain system reliability and customer service.

Justification:

This project is part of PowerStream's long-term cable remediation program. Cable remediation is carried out to extend the life of end-of-life primary cable to maintain system reliability and customer service. On a prioritized basis, each year PowerStream will review, test and select suitable cable segments for cable injection.

PowerStream has a considerable quantity of underground primary cable in service (approx. 8,220 km of cable). The oldest cables of this cable population are at end-of-life and are failing. Since cable is the main component of the underground electrical distribution system when a cable segment fails, system reliability and customer service are negatively affected. For small-scale outages, PowerStream has the capability to replace or repair the faulted cable segments under reactive emergency response; however, if too many cable failures occur at the same time, PowerStream would not have sufficient resources to manage the large-scale and cascading outages. If this happens, the distribution system integrity will be compromised and reliability will be unacceptable to the customers.

To manage the risk of large-scale cable failures, PowerStream must implement a proactive cable remediation plan. The plan includes continuous work on assessing, prioritizing, and remediating the worst cable segments by a combination of cable injection and cable replacement. It is expected that cable injection will improve the cable insulation and extend the life of the cable by another 20 years. Cable injection cost is lower in comparison to cable replacement cost, but the method is only suitable and cost effective for some cable types and field conditions. PowerStream’s approach to manage the high risk cable population is summarized below:

• Address the cable aging issue by a combination of cable injection and cable replacement on a prioritized basis. The splices will be replaced when the cable is injected.
• Conduct testing to determine the condition of the cable.
• Use the cable prioritization system to select cable replacement and cable injection candidates.
• The cable injection program will stay at a stable level for 22 years, then terminate.
• The cable replacement program will stay at a stable level for 22 years, and then will increase to higher level from year 23 onward.

PowerStream’s 22-year Cable Remediation Plan will address on average 130-140 km of cable per year (approx. 105-115 km injection and 25 km replacement) at a cost of $15.7M per year (2015 dollars). The annual cost will increase by 3% per year to account for general cost increase due to inflation and external cost.

As the cable gets older, the cable insulation may develop a premature aging process caused by a phenomenon known as "water treeing". Water trees will reduce the breakdown strength of the insulation and eventually lead to cable failure. Cable injection process will inject silicone chemicals down the strands of the cable. The silicone fluid will diffuse out of the strands through the strand shield and into the insulation. The fluid then polymerizes with water (or moisture) and the silicone molecule grows and fills all water trees and voids. This increases the dielectric strength of the cable and thus extends the life of the cable. It is expected that cable injection will extend the life of end-of-life cable by 20 years.

According to PowerStream’s 22-year Cable Remediation Plan, we intend to inject on an average of 115 km per year from 2015 – 2036.

22 years is the optimal time period to get the benefit of the injection program for the targeted cable population. If PowerStream shortens the time frame, PowerStream will receive the benefit of improving cable performance faster. However, to do so, PowerStream will have to increase the annual budget. If PowerStream extends the time frame beyond the 22 years, the cable segments may deteriorate to the point that they are no longer suitable candidates for cable injection.

According to PowerStream’s 22-year Cable Remediation Plan, we intend to replace on an average of 25 km per year from 2015 – 2036.. This quantity includes two parts:
• Replacement of “Left-behind” segments from the injection projects (20 km per year).
• Replacement of “Main-stream” segments (5 km per year).

2. General Project Information (OEB)

Contributed Capital: Contributed Capital 0%

Fiscal Year: 2015

Parent WO#

Job Number

Power Stream **Project Summary Report**	Project Code **100835**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Cable Injection Program - 2015 to 2020			

3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Risk: Fluctuation in cost and staff resources (internal and external) to complete high annual volume of work. Risk Management: PowerStream has retained two cable injection service providers working at different work sites throughout the year under multi-year Master Service Agreements. The unit prices are kept constant during the term of the Master Service Agreement. The quality of work and responsiveness for both contractors are kept competitive. Regular progress meetings are held to ensure technical and operational issues are resolved promptly; budget performance is monitored; and projects are on track.
	Comparative Information on Equivalent Historical Projects (if any)	PowerStream has budgeted and completed the same level of cable injection work load in 2014. Therefore the proposed annual budget for 2015 onward is a continuation of the cable injection program at the same level.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	Carry out cable injection to approx. 105-115 km per year on existing in-service underground primary XLPE cable to maintain system reliability and customer service.
	1a. Main Driver	Mitigate Failure Risks. The main driver for this project is system reliability and customer service. This project is part of PowerStream's long-term cable injection program. Cable injection is carried out to extend the life of end-of-life primary cable to maintain system reliability and customer service. On a prioritized basis, each year PowerStream will review, test and select suitable cable segments for cable injection.
	1b. Priority and Reasons for Priority	PowerStream has a very large quantity of underground primary cable in service. A portion of the cable population is at end-of-life and requires rehabilitation in order to maintain system integrity and reliable service to the customers. If not rehabilitated, the cable population will get older and will fail more often to the level that is not manageable by PowerStream and not tolerable by the customers.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	The main alternative is to "do nothing" and allow the cable to fail and be replaced under emergency situations. However this approach is not practical or viable as it will have a negative impact on customer service and system reliability.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:	There were 103, 123, 133 and 113 cable and splice failures in 2011, 2012, 2013 and 2014 respectively. If not rehabilitated, the cable population will get older and will fail more often to the level that is not manageable by PowerStream and not tolerable by the customers. Cable is the main component of the underground electrical distribution system and when a cable segment fails, system reliability and customer service are negatively affected. PowerStream monitors the condition of its primary cables to ensure that they meet minimum requirements for safety and reliability. The asset demographics indicate that annual remediation efforts are required to keep pace with the annual aging and deterioration of cables, and specifically, that the oldest cables of the PowerStream cable population are at end-of-life and are failing. To manage the risk of large-scale primary cable failures, PowerStream has implemented a Cable Remediation Plan. The plan includes continuous work on assessing, prioritizing, and remediating the worst cable segments by a combination of cable injection and cable replacement. PowerStream's approach to manage the high risk cable population is summarized below: • Conduct testing to assess the condition of the cable. • Use a cable prioritization system to select cable segment candidates for replacement or injection. • Designate prioritized cable candidates for cable injection or cable replacement.
	1. Condition of Asset vs. Typical Life Cycle and Performance Record	According to the Kinectrics Report "Asset Amortization Study for the Ontario Energy Board", Typical Useful Life of non-tree retardant XLPE cable is 25 years. Many of PowerStream's existing cable segments are older than 25 years and are expected to fail if not rehabilitated.
	2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure	Approximately 19,779. See calculation of this figure in 3. below.

Project Summary Report

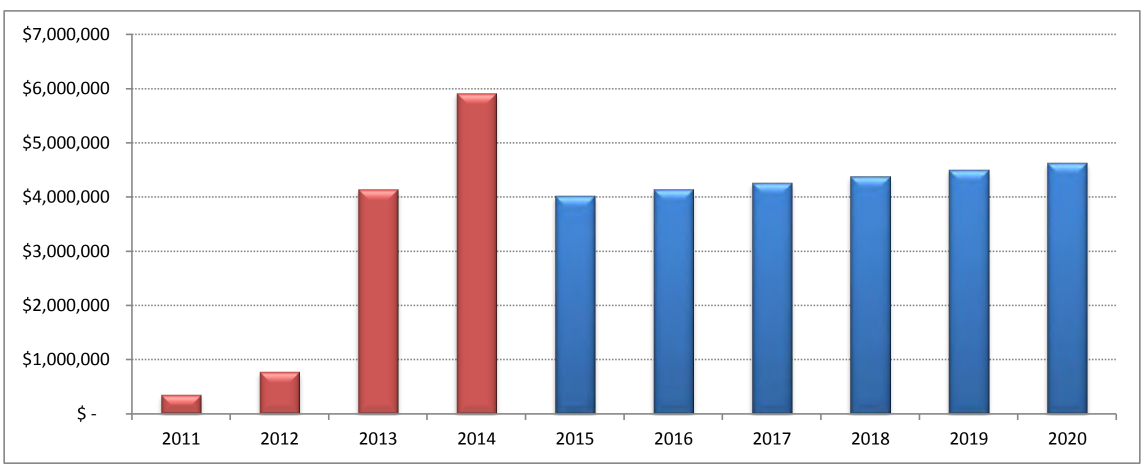
Project Code	Report Start Year	Number of Years	Scale
100835	**2015**	**6**	**Dollars**

Project Name

Cable Injection Program - 2015 to 2020

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)	For 1000 m of cable: • Frequency of Failure is: 0.5 failure per 1000m of cable per year For 115000 m of cable: • Frequency of Failure Rate is: 0.5 x 115000/1000 = 57.5 failures (rounded to 57 failures) per year According to 2012 Control Room data, there were 123 Cable and Splice failures affecting 42,724 customers and 3,577,118 CMI. • Average number of customers affected by 1 failure is: 42,724/123 = 347 customers • Projected number of customers affected by 57 failures is: 347 x 57 = 19,779 customers • Average CMI for 1 failure is: 3,577,118/123 = 29,082 CMI • Projected CMI for 57 failures is: 29,082 x 57 = 1,657,674 CMI
4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)	Cable failures have negative impact to system reliability and customer service. Outages cause inconvenience and financial loss to customers (office closing, production stoppage).
5. Value of Customer Impact	High
Factors Affecting Project Timing, if any	Not Applicable.
Consequences for O&M System Costs Including Implications of Not Implementing	• O&M Cost for emergency cable failure repair = $10,000 per failure • O&M Cost for 57 cable failure repairs = $10,000 x 57 = $570,000.
Reliability and Safety Factors	This project is part of the long-term cable remediation program. The project will help avoid a total of 57 potential cable failures and 1,657,674 potential CMI.
Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits)	The main alternative is to "do nothing" and allow the cable to fail and be replaced under emergency situations. However this approach is not practical or viable as it will have a negative impact on customer service and system reliability.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ 349,694	$ 771,664	$ 4,141,808	$ 5,913,763	$ 4,024,219	$ 4,138,312	$ 4,255,465	$ 4,375,771	$ 4,499,323	$ 4,626,219



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100851	2015	6	Dollars
	Project Name: Cable Replacement Program - 2015 to 2020			

Major Category System Renewal

Project Overview

1. Additional Information

Service Territory: PowerStream North & South

Location: Various locations in PowerStream

Scope: Carry out cable replacement to approx. 25 km per year of existing in-service underground primary XLPE cable to maintain system reliability and customer service.

Justification: This project is part of PowerStream's long-term cable remediation program. Cable remediation is carried out to extend the life of end-of-life primary cable to maintain system reliability and customer service. On a prioritized basis, each year PowerStream will review, test and select suitable cable segments for cable injection.

PowerStream has a considerable quantity of underground primary cable in service (approx. 8,220 km of cable). The oldest cables of this cable population are at end-of-life and are failing. Since cable is the main component of the underground electrical distribution system when a cable segment fails, system reliability and customer service are negatively affected. For small-scale outages, PowerStream has the capability to replace or repair the faulted cable segments under reactive emergency response; however, if too many cable failures occur at the same time, PowerStream would not have sufficient resources to manage the large-scale and cascading outages. If this happens, the distribution system integrity will be compromised and reliability will be unacceptable to the customers.

To manage the risk of large-scale cable failures, PowerStream must implement a proactive cable remediation plan. The plan includes continuous work on assessing, prioritizing, and remediating the worst cable segments by a combination of cable injection and cable replacement. It is expected that cable injection will improve the cable insulation and extend the life of the cable by another 20 years. Cable injection cost is lower in comparison to cable replacement cost, but the method is only suitable and cost effective for some cable types and field conditions. PowerStream’s approach to manage the high risk cable population is summarized below:

• Address the cable aging issue by a combination of cable injection and cable replacement on a prioritized basis. The splices will be replaced when the cable is injected.
• Conduct testing to determine the condition of the cable.
• Use the cable prioritization system to select cable replacement and cable injection candidates.
• The cable injection program will stay at a stable level for 22 years, then terminate.
• The cable replacement program will stay at a stable level for 22 years, and then will increase to higher level from year 23 onward.

PowerStream’s 22-year Cable Remediation Plan will address on average 130-140 km of cable per year (approx. 105-115 km injection and 25 km replacement) at a cost of $15.7M per year (2015 dollars). The annual cost will increase by 3% per year to account for general cost increase due to inflation and external cost.

As the cable gets older, the cable insulation may develop a premature aging process caused by a phenomenon known as "water treeing". Water trees will reduce the breakdown strength of the insulation and eventually lead to cable failure. Cable injection process will inject silicone chemicals down the strands of the cable. The silicone fluid will diffuse out of the strands through the strand shield and into the insulation. The fluid then polymerizes with water (or moisture) and the silicone molecule grows and fills all water trees and voids. This increases the dielectric strenghth of the cable and thus extends the life of the cable. It is expected that cable injection will extend the life of end-of-life cable by 20 years.

According to PowerStream’s 22-year Cable Remediation Plan, PowerStream intends to inject on an average of 115 km per year from 2015 – 2036. The period of 22 years is the optimal time period to get the benefit of the injection program for the targeted cable population. If PowerStream shortens the time frame, PowerStream will receive the benefit of improving cable performance faster. However, to do so, PowerStream will have to increase the annual budget. If PowerStream extends the time frame beyond the 22 years, the cable segments may deteriorate to the point that they are no longer suitable candidates for cable injection.

According to PowerStream’s 22-year Cable Remediation Plan, PowerStream intends to replace on an average of 25 km per year from 2015 – 2036.. This quantity includes two parts:
• Replacement of “Left-behind” segments from the injection projects (20 km per year).
• Replacement of “Main-stream” segments (5 km per year).

2. General Project Information (OEB)

Contributed Capital: Contributed Capital 0%

Fiscal Year: 2015

Parent WO#

Job Number

Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100851	2015	6	Dollars
	Project Name: Cable Replacement Program - 2015 to 2020			

3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Risk: Fluctuation in cost and staff resource (internal and external) to complete high annual volume of work. Risk Management: PowerStream has retained an external contractor working at different work sites throughout the year under a multi-year EPC (Engineering Procurement Construction) Master Service Agreement. Regular progress meetings are held to ensure technical and operational issues are resolved promptly; budget performance is monitored; and projects are on track.
	Comparative Information on Equivalent Historical Projects (if any)	PowerStream has budgeted and completed the same level of cable replacement work load in 2014. Therefore the proposed annual budget for 2015 onward is a continuation of the cable replacement program at the same level.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	Carry out cable replacement to approx. 25 km per year of existing in-service underground primary XLPE cable to maintain system reliability and customer service.
	1a. Main Driver	Mitigate Failure Risk. The main driver for this project is system reliability and customer service. This project is part of PowerStream's long-term cable replacement program to replace end-of-life primary cable to maintain system reliability and customer service. On a prioritized basis, each year PowerStream will review, test and select suitable cable segments for cable replacement.
	1b. Priority and Reasons for Priority	PowerStream has a very large quantity of underground primary cable in service. A portion of the cable population is at end-of-life and requires rehabilitation in order to maintain system integrity and reliable service to the customers. If not rehabilitated, the cable population will get older and will fail more often to the level that is not manageable by PowerStream and not tolerable by the customers.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	An alternative is to do nothing and allow the cable to fail and be replaced under emergency situations. However this approach is not recommended because it will have a negative impact on customer service and system reliability.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:	There were 103, 123, 133 and 113 cable and splice failures in 2011, 2012, 2013 and 2014 respectively. If not rehabilitated, the cable population will get older and will fail more often to the level that is not manageable by PowerStream and not tolerable by the customers. Cable is the main component of the underground electrical distribution system and when a cable segment fails, system reliability and customer service are negatively affected. PowerStream monitors the condition of its primary cables to ensure that they meet minimum requirements for safety and reliability. The asset demographics indicate that annual remediation efforts are required to keep pace with the annual aging and deterioration of cables, and specifically, that the oldest cables of the PowerStream cable population are at end-of-life and are failing. To manage the risk of large-scale primary cable failures, PowerStream has implemented a Cable Remediation Plan. The plan includes continuous work on assessing, prioritizing, and remediating the worst cable segments by a combination of cable injection and cable replacement. PowerStream’s approach to manage the high risk cable population is summarized below: • Conduct testing to assess the condition of the cable. • Use a cable prioritization system to select cable segment candidates for replacement or injection. • Designate prioritized cable candidates for cable injection or cable replacement.
	1. Condition of Asset vs. Typical Life Cycle and Performance Record	According to the Kinectrics Report "Asset Amortization Study for the Ontario Energy Board", Typical Useful Life of non-tree retardant XLPE cable is 25 years. Many of PowerStream's existing cable segments are older than 25 years and are expected to fail if not rehabilitated.
	2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure	Approximately 4,511. For the calculation of this figure, please refer to 3. below.

Project Summary Report

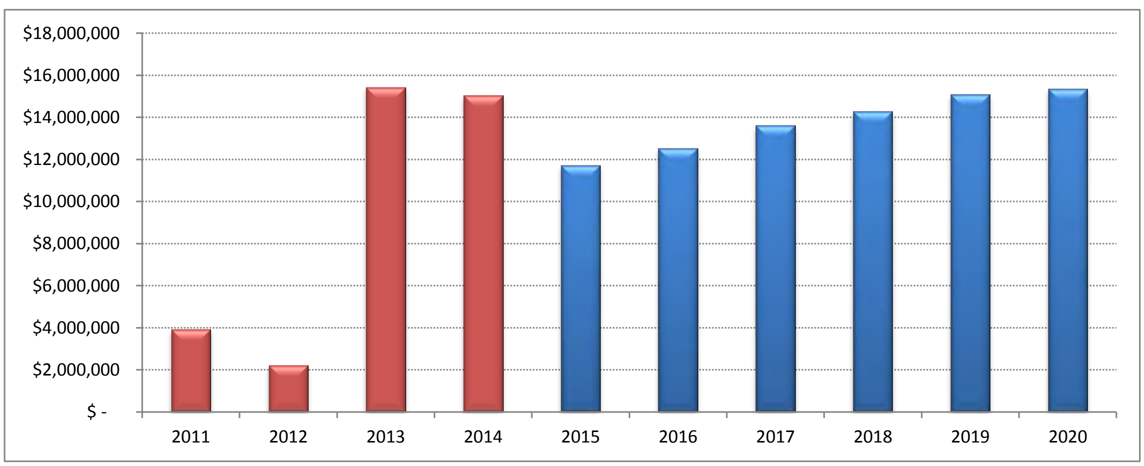
Project Code	Report Start Year	Number of Years	Scale
100851	2015	6	Dollars

Project Name

Cable Replacement Program - 2015 to 2020

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)	For 1000 m of cable: • Frequency of Failure is: 0.5 failure per 1000m of cable per year For 25000 m of cable: • Frequency of Failure Rate is: 0.5 x 25000/1000 = 12.5 failures (rounded to 13 failures) per year According to 2012 Control Room data, there were 123 Cable and Splice failures affecting 42,724 customers and 3,577,118 CMI • Average number of customers affected by 1 failure is: 42,724/123 = 347 customers • Projected number of customers affected by 24 failures is: 347 x 13 = 4,511 customers • Average CMI for 1 failure is: 3,577,118/123 = 29,082 CMI • Projected CMI for 13 failures is: 29,082 x 13 = 378,006 CMI
4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)	Cable failures have negative impact to system reliability and customer service. Outages cause inconvenience and financial loss to customers (office closing, production stoppage).
5. Value of Customer Impact	High
Factors Affecting Project Timing, if any	Not Applicable.
Consequences for O&M System Costs Including Implications of Not Implementing	• O&M Cost for emergency cable failure repair = $10,000 per failure • O&M Cost for 13 cable failure repairs = $10,000 x 13 = $130,000.
Reliability and Safety Factors	This project is part of the long-term cable rehabilitation program. The project will help avoid a total of 13 potential cable failures and 378,006 potential CMI.
Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits)	The main alternative is to "do nothing" and allow the cable to fail and be replaced under emergency situations. However this approach is not practical or viable as it will have a negative impact on customer service and system reliability.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$3,917,735	$ 2,219,486	$ 15,417,075	$ 15,036,321	$ 11,718,862	$ 12,538,684	$ 13,607,273	$ 14,288,297	$ 15,085,861	$ 15,340,181



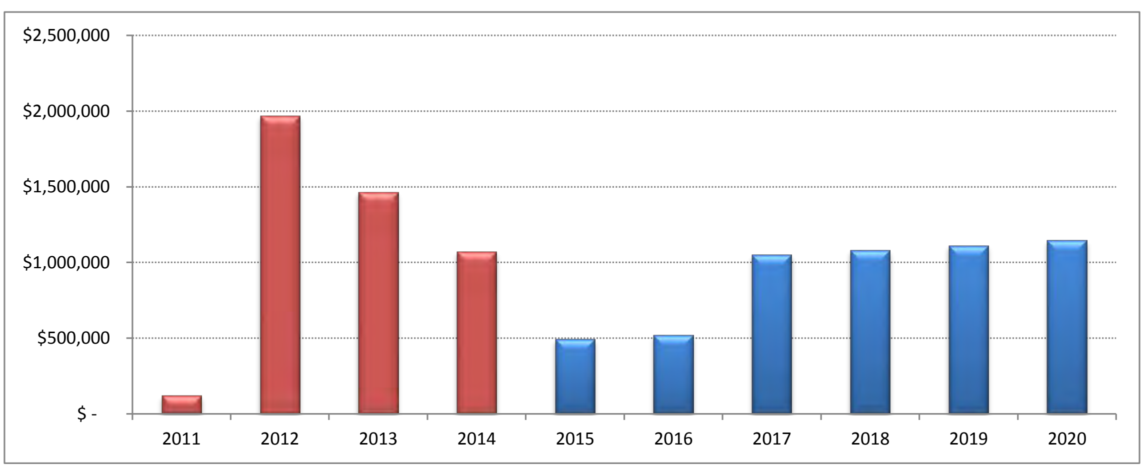
Project Summary Report	Project Code **100890**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Emerging Cable Replacement Projects			

Major Category	**System Renewal**	
Project Overview		
1. Additional Information	Service Territory	PowerStream North & South
	Location	Various Location in PowerStream North and South
	Scope	Perform Cable replacement on various location. The projects submitted under this category will be evaluated by planning in conjunction with System Operation, Lines and Customer Services. The funds allocated are sufficent to replace 2 km of primary cable in industrial subdvision (3 phase) or 4km of cable in residential subdvision.
	Justification	PowerStream has approx. 7,836 km of underground primary cable length, the vast majority of which is direct buried and the rest is in duct. Currently we have a planned Cable replacement projects for North and South which target a particular subdivision based on age/outage information and are submitted during the budget cycle. However due to condition of the cables and outages; some section/area will have to be addressed as they emerge. In 2014 the cable and splices are the leading cause of CMI (Customer Minutes of Interruption) in the Defective Equipment category and contributed to over 3M CMI's. As the cable system get older we expect that the failures will increase and some of this residential or industrial sub divisions will have to be addressed in emergency as opposed to planned replacement. Typically these projects require a very fast response due to criticality of the account or condition of the cable (end of life cable which is beyond repair). The projects submitted under this category will be evaluated by planning in conjunction with System Operation, Lines and Customer Services.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Municipal approvals can impact completion dates however, most projects are started in the first half of the year and completed by years end. Cable faults occuring in the last half of the year are typically planned for the following budget year.
	Comparative Information on Equivalent Historical Projects (if any)	The full 'Emerging Cable Replacement' budget was spent in previous budget years.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	The Emerging Cable Replacement budget is used to Perform Cable replacements at various locations throughout the year. Projects submitted under this category will be evaluated by planning in conjunction with System Operation, Lines and Customer Services. The funds allocated are sufficent to address relatively minor industrial and residential cable failures that occur during the budget year.
	1a. Main Driver	Mitigate Failure Risks. The main driver for this project is reliability and customer service. PowerStreams aging cable is replaced following a strategic plan managed by the Cable Replacement Program. The Emerging Cable Replacement Project is intended to address immediate cable failures within the budgeted year that occur without warning.
	1b. Priority and Reasons for Priority	These projects are required as often the cable is very end of life or is beyond repair.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Cable failures addressed under the Emerging Cable program are aged cable that would normally have been replaced under the planned program, but fail prior to expectation.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:	PowerStream performs cable testing on aged cable in order to plan and prioritize cable replacement needs. This Cable Replacement program is intended to address the cables which are end of life and beyond repair. The consequences include power outages, unhappy customers, and unplanned replacement activity and costs. Key accounts in industrial areas often make the repair timing critical.

Project Summary Report	Project Code **100890**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Emerging Cable Replacement Projects			

1. Condition of Asset vs. Typical Life Cycle and Performance Record	The life cycle of direct buried cable is typically 25 years. All cable replacements captured under the Emerging Cable portfolio are approaching end of life. The emerging cable replacements address end of life cable that fails prior to planned replacement.
2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure	100 (typically)
3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)	Outage durations for cable failures are of significant length due to repair time. In most cases, operations is able to find switching methods to restore power to affected customers. However, switching diversity is lost, and there is risk that some customers may not be restored until the faulted cable is replaced. When the cable is not replaced, rate of failure will likely accelerate resulting in increased customer outages which will have a negative impact to system reliability and customer service. Based on the estimate of 2 failures per year, there would be 3,600 CMI (Customer Minutes of Interruption) in a industrial loop or 21,600 CMI per residential loop. For industrial location: CMI (Customer Minutes of Interruption): The CMI is estimated as follows: CMI = (10 customers x 3 hours) x 60 minutes x 2 failures/year = 3600 per half loop for industrial location. For residential location: CMI per subdivision = 60 customers x 3 hours x 60 minutes x 2 failures/year = 21,600 CMI per half loop.
4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)	The majority of Emerging Cable Faults are occuring in industrial parks. Typically these projects require a very fast response due to criticality of the account or condition of the cable (end of life cable which is beyond repair).
5. Value of Customer Impact	High
Factors Affecting Project Timing, if any	The Emerging Cable Replacement project is intended to be an ongoing yearly project.
Consequences for O&M System Costs Including Implications of Not Implementing	Not Applicable.
Reliability and Safety Factors	The Emerging Cable Replacement project was developed to support PowerStream's reliability performance and maintain a positive customer experience.
Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits)	Cable replacement cost under the emerging budget are the same as if they were planned replacements. The emerging fund gives flexibility to address issues as they occur.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ 119,989	$ 1,968,435	$ 1,463,874	$ 1,070,775	$ 491,687	$ 520,801	$ 1,050,756	$ 1,081,576	$ 1,113,287	$ 1,145,915



Power Stream	Project Code	Report Start Year	Number of Years	Scale
	102870	2015	6	Dollars

Project Summary Report

Project Name

Submersible Transformer Replacement - 2015-2016 - North

Major Category	System Renewal	

Project Overview

1. Additional Information	Service Territory	PowerStream North
	Location	Various locations in the PowerStream North
	Scope	For 2015 budget year, it is proposed to replace 12 submersible transformers with padmount transformers. The 12 submersible transformers are located in the "Cundles Road E. South" area in Barrie(South of Cundles Road E.). The associated cables will also be replaced.
	Justification	In 2010 Lines North identified 57 submersible transformer locations to be retrofitted to meet a new operations switching procedure. The existing submersible transformers included in this proposal do not provide sufficient access to allow field staff to perform switching and maintenance operations under normal and emergency situations, thus reducing customer service and reliability level to the affected customers. The transformers are obsolete and no longer purchased by PowerStream. These submersible transformers, referred to by the operations staff as "Rocketships" or "Streetlight Pole Transformers", were installed at the bottom of street lighting poles. These "Rocketship" units are of very old vintage, dating back to 1967 and are at end-of-life. They are obsolete, no longer manufactured, and spare parts are non-existent. Operations staff have raised many concerns with continued operation of this supply system which are summarized under the following 9 items: 1. The transformer units are connected using non-load break equipment which means they cannot be connected or disconnected while energized. As a result, portions of the circuit must be isolated when work is required on any part of the primary system, resulting in approx. 18 hours of interruption when an unplanned event occurs. 2. The isolation can affect several transformers pending the circuit configuration and may disrupt up to 100 customers at a time. 3. Trouble response work becomes very complicated because of the fusing design. The fuse is connected to a non-conductive fiberglass support system held in place with metal bolts to a metal structure. Faults have occurred passing through the bolts to the grounded equipment. This path cannot be seen from any opening, and is impossible to confirm without dismantling the unit. 4. Failures such as described in item 3 above have resulted in the fuse housing being by-passed and the terminations being bolted together in order to restore the circuit. 5. Replacement parts are not available. 6. The physical size of the units restricts any use of live line techniques and requires a "hands on" approach which requires isolation. This would typically involve disconnection, potential testing and grounding. 7. The vault that contains the transformer is undersized. There is only 8 cm (3 inch) between the vault wall and the transformer. As a result, cable movement is next to impossible and work on connections is very limited. The lack of clearance within the unit also prevents access to the potential test points and approved grounding equipment is not available. 8. The primary cable installed between these units is non-jacketed cable. At many locations, the concentric neutral wires have corroded significantly or are non-existent. This is a concern for line staff who rely on system neutral to be able to effectively ground their work zone. 9. Secondary cable is comprised of many tee taps which several services may be connected to. As a result, in the event of a "burn-off", several services can be out of power. For the above reasons, the submersible transformers should be replaced. The issues were discussed in the PowerStream Reliability Committee meeting of July 7, 2010. The Reliability Committee have agreed that the units should be replaced and requested System Planning to include the replacement work in the
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	308145
	Job Number	C00715
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Risk: Fluctuation in cost and staff resource (internal and external) to complete high annual volume of work. Risk Management: PowerStream has budgeted and completed the same level of work with submersible transformer replacement for the past four years. Therefore the proposed work for 2015 is a continuation of the submersible transformer replacement program. Some of the tasks to manage the risk are: meetings amongst all involved parties to go over the project details, schedule, logistics, and resource requirements; regular progress meetings to ensure technical and operational issues are resolved promptly; budget performance is monitored; and projects are on track.
	Comparative Information on Equivalent Historical Projects (if any)	This project is the continuation of PowerStream submersible transformer replacement program. PowerStream has budgeted and completed the same level of work with submersible transformer replacement for the past four years. Therefore the proposed work for 2015 is a continuation of the submersible transformer replacement program. This is the last batch of the identified high risk submersible transformers that require replacement.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0

Project Summary Report	Project Code **102870**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name [Submersible Transformer Replacement - 2015-2016 - North]			

4. Evaluation Criteria (OEB)

Project Summary

For 2015 budget year, it is proposed to replace 12 submersible transformers with pad mount transformers.
The 12 submersible transformers are located in the "Cundles Road E. South" area in Barrie (South of Cundles Road E.). The associated cables will also be replaced.
The exact schedule and logistics will be determined by Lines, System Control, Capital Design, and System Planning to achieve co-ordination of work and to minimize customer disruption.

1a. Main Driver

Mitigate Failure Risks. The main driver for this project is system reliability and customer service.
This project is the last batch of PowerStream's long-term submersible transformer replacement program to replace end-of-life submersible transformers to maintain system reliability and customer service.

1b. Priority and Reasons for Priority

This is the last batch of the identified high risk submersible transformers that require replacement in order to maintain system integrity and reliable service to the customers. If not replaced, the transformers may fail. In addition, the transformers need to be replaced to reduce the safety risk of personal injury if transformer failures occur.

In 2010 Lines North identified 57 submersible transformer locations to be retrofitted to meet a new operations switching procedure.
The existing submersible transformers included in this proposal do not provide sufficient access to allow field staff to perform switching and maintenance operations under normal and emergency situations, thus reducing customer service and reliability level to the affected customers.
The transformers are obsolete and no longer purchased by PowerStream. These submersible transformers, referred to by the operations staff as "Rocketships" or "Streetlight Pole Transformers", were installed at the bottom of street lighting poles. These "Rocketship" units are of very old vintage, dating back to 1967 and are at end-of-life. They are obsolete, no longer are manufactured, and spare parts non-existent.

Operations staff has raised many concerns with continued operation of this supply system which are summarized under the following 9 items:
1. The transformer units are connected using non-load break equipment which means they cannot be connected or disconnected while energized. As a result, portions of the circuit must be isolated when work is required on any part of the primary system, resulting in approx. 18 hours of interruption when an unplanned event occurs.
2. The isolation can affect several transformers pending the circuit configuration and may disrupt up to 100 customers at a time.
3. Trouble response work becomes very complicated because of the fusing design. The fuse is connected to a non-conductive fiberglass support system held in place with metal bolts to a metal structure. Faults have occurred passing through the bolts to the grounded equipment. This path cannot be seen from any opening, and is impossible to confirm without dismantling the unit.
4. Failures such as described in item 3 above have resulted in the fuse housing being by-passed and the terminations being bolted together in order to restore the circuit.
5. Replacement parts are not available.
6. The physical size of the units restricts any use of live line techniques and requires a "hands on" approach which requires isolation. This would typically involve disconnection, potential testing and

1c. Qualitative and Quantitative Analysis of Project and Project Alternatives

As described above.

2. Safety

Submersible transformer failures pose safety risk to staff and the public. The transformers are located in areas that are accessible to the public. The transformers may fail when staff are working on the unit or when the public in close proximity of the unit. When the transformer fails, there may be flashover, fire, or rupture of the transformer tank, which may result in personal injury.

3. Cyber-Security, Privacy

Not Applicable.

4. Coordination, Interoperability

Not Applicable.

5. Economic Development

Not Applicable.

6. Environmental Benefits

Because transformer contains oil, transformer failures may cause rupture of the transformer tank, resulting in oil being spilled onto the ground. By replacing end-of-life transformers with new units, the risk of oil contamination can be eliminated.

Project Summary Report	Project Code **102870**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Submersible Transformer Replacement - 2015-2016 - North			

5. Category-Specific Requirements for Each Project/Activity (OEB)	Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:	Transformers are used to step down the primary voltage to a lower secondary voltage that supplies customers. A number of submersible transformers are installed at the bottom of street light poles. These are old and unique installations that include a submersible transformer in a small congested ground access pit, open air fusing in a metalclad streetlight fixture and fixed primary connections. They are obsolete, no longer manufactured and spare parts are non-existent. The fixed primary connection does not allow for switching resulting in considerable outage disruptions to customers whenever work is required to be performed on the units or in the general vicinity. In 2010 Lines North identified 57 submersible transformer locations to be retrofitted to meet a new operations switching procedure. The existing submersible transformers included in this proposal do not provide sufficient access to allow field staff to perform switching and maintenance operations under normal and emergency situations, thus reducing customer service and reliability level to the affected customers. The transformers are obsolete and no longer purchased by PowerStream. These submersible transformers, referred to by the operations staff as "Rocketships" or "Streetlight Pole Transformers", were installed at the bottom of street lighting poles. These "Rocketship" units are of very old vintage, dating back to 1967 and are at end-of-life. They are obsolete, no longer are manufactured, and spare parts non-existent. Operations staff has raised many concerns with continued operation of this supply system which are summarized under the following 9 items: 1. The transformer units are connected using non-load break equipment which means they cannot be connected or disconnected while energized. As a result, portions of the circuit must be isolated when work is required on any part of the primary system, resulting in approx. 18 hours of interruption when an unplanned event occurs. 2. The isolation can affect several transformers pending the circuit configuration and may disrupt up to 100 customers at a time. 3. Trouble response work becomes very complicated because of the fusing design. The fuse is connected to a non-conductive fiberglass support system held in place with metal bolts to a metal structure. Faults have occurred passing through the bolts to the grounded equipment. This path cannot be seen from any
	1. Condition of Asset vs. Typical Life Cycle and Performance Record	As described above.
	2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure	Approximately 87. For the calculation of this figure, please refer to 3. below.
	3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)	For 1 transformer: • Frequency of Failure is: 0.2 failure per year (1 in 5 years) For 12 transformers: • Frequency of Failure is: 0.2 failure x 12 = 2.4 failures According to 2012 Control Room data, there were 4 Submersible Transformer failures affecting 144 customers and 33,434 CMI. • Average number of customers affected by 1 failure is: 144/4 = 36 customers • Projected number of customers affected by 2.4 failures is: 36 x 2.4 = 87 customers • Average CMI for 1 failure is: 33,434/4 = 8,359 CMI • Projected CMI for 2.4 failures is: 8,359 x 2.4 = 20,060 CMI
	4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)	Transformer failures have negative impact to system reliability and customer service. Outages cause inconvenience and financial loss to customers. In addition, there is a safety risk to staff and the public (persanal injury) if people are in close proximity of the transformer at the time of failure.
	5. Value of Customer Impact	High
	Factors Affecting Project Timing, if any	Not Applicable.
	Consequences for O&M System Costs Including Implications of Not Implementing	• O&M Cost for 1 emergency transformer failure replacement = $12,000 per failure • O&M Cost for 2.4 emergency transformer failure replacement = $12,000 x 2.4 = $28,800
	Reliability and Safety Factors	This project is the last batch the submersible transformer replacement program. The project will help avoid a total of 2.4 potential transformer failures and 20,060 potential CMI. The project will also help reduce some safety risk (potential personal injury) that may result due to transformer failures.

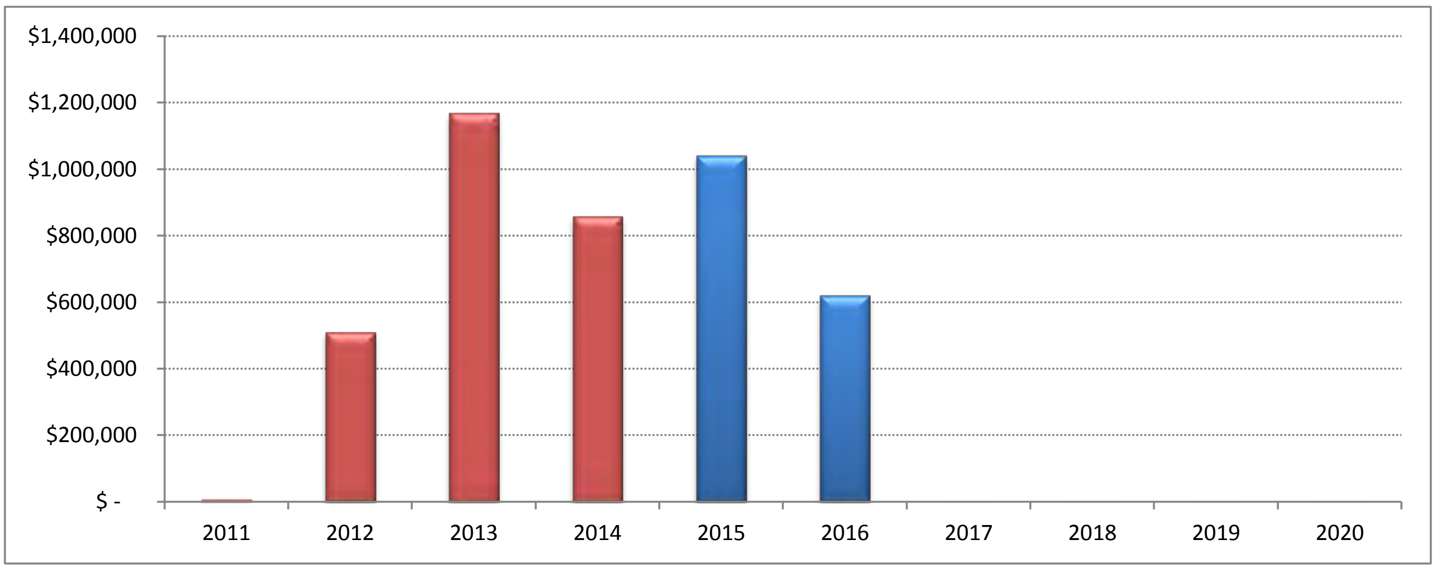
Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	102870	2015	6	Dollars

Project Name

Submersible Transformer Replacement - 2015-2016 - North

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits)	This project is the last batch the submersible transformer replacement program. The project will help avoid a total of 2.4 potential transformer failures and 20,060 potential CMI. The project will also help reduce some safety risk (potential personal injury) that may result due to transformer failures.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ 6,451	$ 508,952	$ 1,168,202	$ 856,776	$ 1,040,300	$ 620,000	$ -	$ -	$ -	$ -



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100859	2015	6	Dollars

Project Name

Switchgear Replacement Program - 2015 to 2020

Major Category **System Renewal**

Project Overview

1. Additional Information	Service Territory	PowerStream North & South
	Location	Various locations in PowerStream
	Scope	It is proposed to replace 36 units in 2015. The installation will include associated U/G terminations, fault indicators, and locks. The exact locations will be jointly determined by Lines, System Control, Capital Design, and System Planning.
	Justification	This project is part of PowerStream's long-term distribution switchgear replacement program. Switchgear replacement is carried out to replace end-of-life switchgear units to maintain system reliability and customer service. On a prioritized basis, each year PowerStream will inspect, review, and select a number of switchgear units for replacement. The locations and priority are determined based on the results from the Asset Condition Assessment (ACA) process, and discussion and feedback among Lines, System Control, Capital Design, and System Planning. Background: The distribution switchgear units are critical component of PowerStream distribution system. As these units get older and their functionality and reliability deteriorate, they should be replaced to maintain system reliability and customer service. The ACA model and methodology, which were developed by Kinectrics Inc., have been used by many electric utilities to identify and prioritize asset replacement, and have been submitted to the Ontario Energy Board (OEB) in many rate submissions by those companies. The ACA model and methodology are generally considered by the electricity industry and the OEB as acceptable tools and process that a company can use to justify and prioritize the replacement of old electric distribution assets. An extract of the ACA Technical Report on Distribution Switchgear at Powerstream is attached. This document described the methodology to take into consideration the following information to calculate the health index and the effect of distribution switchgear failures. - Condition Parameters (e.g. Age, Infrared Record, Field Inspection) - Condition Factors - Parameter Weighting Factors - Failure Probability - Failure Effect
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Risk: Fluctuation in cost and staff resources (internal and external) to complete high annual volume of work. Risk Management: PowerStream has budgeted and is completing the same level of switchgear replacement work load in 2014. Therefore the proposed annual budget for 2015 onward is a continuation of the switchgear replacement program at the same level (no increase in quantity). Some of the tasks to manage the risk are: meetings amongst all involved parties to go over the project details, schedule, logistics, and resource requirements; regular progress meetings to ensure technical and operational issues are resolved promptly; budget performance is monitored; and projects are on track.
	Comparative Information on Equivalent Historical Projects (if any)	This project is the continuation of PowerStream's long-term switchgear replacement program. Each year PowerStream conducts field inspections and uses those results to prioritize and select suitable candidates for replacement.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	Replace 36 switchgear units. The installation will include associated U/G terminations, fault indicators, and locks. The exact locations, schedule, and logistics will be jointly determined by Lines, System Control, Capital Design, and System Planning to achieve co-ordination of work and to minimize customer disruption.
	1a. Main Driver	Obsolescence. The main driver for this project is system reliability and customer service. This project is part of PowerStream's long-term switchgear replacement program to replace end-of-life switchgear units to maintain system reliability and customer service. On a prioritized basis, each year PowerStream will inspect, review, and select suitable switchgear units for replacement.
	1b. Priority and Reasons for Priority	PowerStream has a very large quantity of switchgear units in service. A portion of the switchgear population is at end-of-life and requires replacement in order to maintain system integrity and reliable service to the customers. If not replaced, the switchgear population will get older and will fail more often to the level that is not manageable by PowerStream and not tolerable by the customers. In addition, the switchgear units need to be replaced to reduce the safety risk of personal injury if switchgear failures do occur.

	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Please refer to explanation above.
	2. Safety	Switchgear failures pose safety risk to staff and the public. The switchgear may fail when staff are working on the unit or when the public is in close proximity to the unit. When the switchgear unit fails, there may be flashover or rupture of the enclosure, which may result in personal injury.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	In the case of oil-filled switchgear units, switchgear failures may cause rupture, resulting in oil being spilled onto the ground. Because the oil-filled units are replaced with non-oil units, the environmental risk is eliminated.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:	Padmounted switchgear units are used in distribution cable feeder loops supplying residential subdivisions and commercial/industrial customers. Switchgear units are utilized to isolate/control other equipment, and to reconfigure the distribution cable feeder loops for maintenance, restoration or other operating requirements. Each year, PowerStream inspects padmount switchgear according to the inspection requirements established by the OEB Distribution System Code and ESA Regulation 22/04. Replacement “candidates” are selected based on a combination of inspection results (physical condition) and a calculated asset health index. The following factors are used to calculate the switchgear asset health index: • Equipment age • Structural integrity • Presence of “hotspots” • Condition of mechanical mechanism • Condition of bus insulation Switchgear units that have been classified to have a “poor” health index condition are proposed to be replaced There were 30, 24, and 28 switchgear failures in 2011, 2012, and 2013 respectively. If not replaced, the switchgear population will get older and will fail more often to the level that is not manageable by PowerStream and not tolerable by the customers. On a prioritized basis, each year PowerStream will inspect, review, and select suitable switchgear units for replacement.
	1. Condition of Asset vs. Typical Life Cycle and Performance Record	According to the Kinectrics Report "Asset Amortization Study for the Ontario Energy Board", Typical Useful Life of switchgear is 30 years. Many units of PowerStream's existing switchgear population are older than 30 years and are expected to fail more if not replaced. The majority of the switchgear will be replaced with industry standard SF6 insulated switchgear units. SF6 switchgear units are sealed units and all internal live parts are encapsulated. The inherent design of SF6 switchgear enables these units to be relatively free from contamination and moisture issues, as compared to the switchgear they are replacing. SF6 switchgear are “dead front” units which means that the cables are connected to the switchgear through insulated connectors thus eliminating exposure of any live component to dirt and moisture. SF6 switchgear require minimal maintenance as all the compartments are sealed.
	2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure	Approximately 17982. For the calculation of this figure, please refer to 3. below.
	3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)	For 1 switchgear unit: • Frequency of Failure is: 0.5 failure per year (1 in 2 years) For 36 switchgear units: • Frequency of Failure is: 0.5 failure x 36 = 18 failures According to 2012 Control Room data, there were 24 Switchgear failures affecting 23,968 customers and 934,458 CMI • Average number of customers affected by 1 failure is: 23,968/24 = 999 customers • Projected number of customers affected by 18 failures is: 999 x 18 = 17,982 customers • Average CMI for 1 failure is: 934,458/24 = 38,936 CMI • Projected CMI for 18 failures is: 38,936 x 18 = 700,848 CMI
	4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)	Switchgear failures have negative impact to system reliability and customer service. Outages cause inconvenience and financial loss to customers (office closing, production stoppage).
	5. Value of Customer Impact	High

Project Code	Report Start Year	Number of Years	Scale
100859	2015	6	Dollars

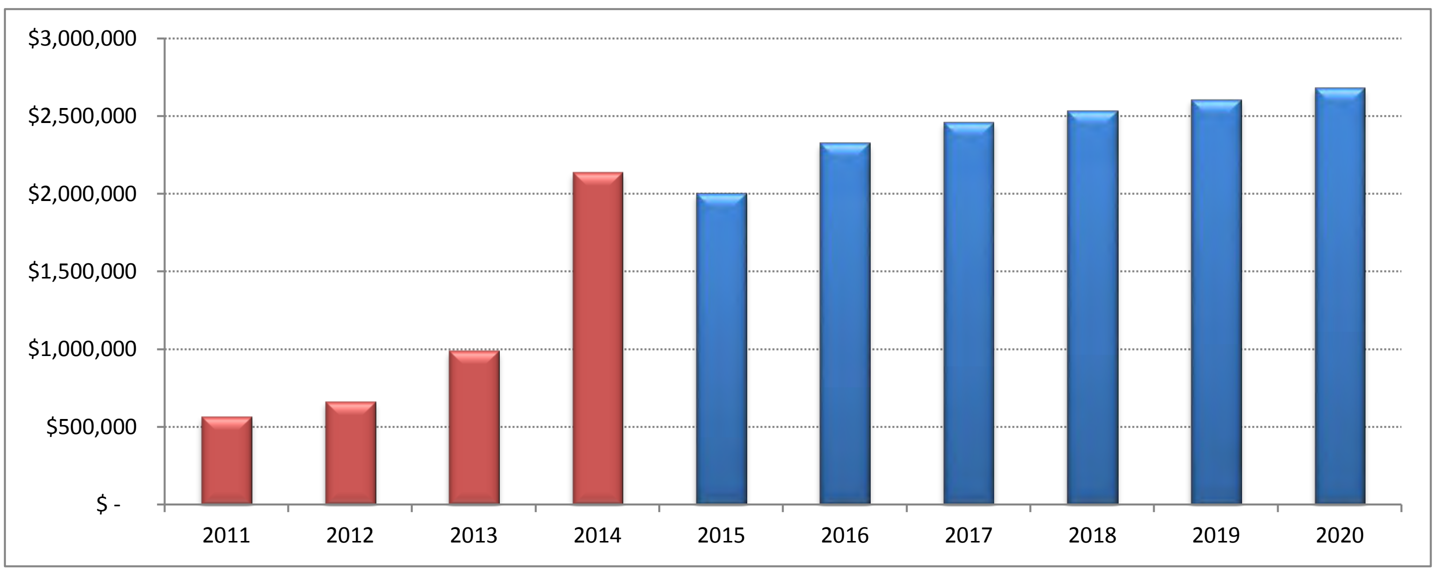
Project Summary Report

Project Name

Switchgear Replacement Program - 2015 to 2020

Factors Affecting Project Timing, if any	Not Applicable.
Consequences for O&M System Costs Including Implications of Not Implementing	• O&M Cost for 1 emergency switchgear failure replacement = $98,800 per failure • O&M Cost for 18 emergency switchgear failure replacement = $98800 x 18 = $1,778,400
Reliability and Safety Factors	This project is part of the long-term switchgear replacement program. The project will help avoid a total of 18 switchgear failures and 700,848 potential CMI. The project will also help reduce some safety risk (potential personal injury) that may result due to switchgear failures.
Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits)	This project is part of the long-term switchgear replacement program. The project will help avoid a total of 18 switchgear failures and 700,848 potential CMI. The project will also help reduce some safety risk (potential personal injury) that may result due to switchgear failures.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ 566,295	$ 662,337	$ 990,400	$ 2,138,988	$ 2,003,445	$ 2,327,404	$ 2,462,129	$ 2,533,373	$ 2,606,624	$ 2,681,945



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	101800	2015	6	Dollars

Project Name

Storm damage - Replacement of distribution equipment due to storm.

Major Category **System Renewal**

Project Overview

1. Additional Information	Service Territory	PowerStream South
	Location	PowerStream South - (Vaughan, Markham, Richmond Hill, Aurora)
	Scope	Expenditures in this category are for the emergency replacement of major line distribution assets, such as poles, transformers, conductors, and switches, that are damaged during storm activity. PowerStream's distribution system can be impacted by significant weather events involving wind, snow, ice, sleet, hail, lightning, or any combination thereof. Such weather events can cause significant damage to the distribution system, and damaged or failed components are replaced promptly. The budget for this category is based primarily on historical trends over the past few years.
	Justification	Major storms can cause significant damage to distribution systems, resulting in power outages and disruption to optimal system operation, and can also create safety hazards for utility personnel and the general public. In such events, therefore, failed distribution equipment is promptly replaced to remove any safety hazards, restore power to customers, and return the system to its normal operating configuration.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Not Applicable.
	Comparative Information on Equivalent Historical Projects (if any)	For actual historical information for Powerstream South - Please see chart and graph below.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	Expenditures in this category are for the emergency replacement of major line distribution assets, such as poles, transformers, conductors, and switches, that are damaged during storm activity. PowerStream's distribution system can be impacted by significant weather events involving wind, snow, ice, sleet, hail, lightning, or any combination thereof. Such weather events can cause significant damage to the distribution system, and damaged or failed components are replaced promptly. The budget for this category is based primarily on historical trends over the past few years.
	1a. Main Driver	Safety. Damage due to storms that exceed the rated design capacity of the equipment.
	1b. Priority and Reasons for Priority	Not Applicable.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Not Applicable.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:	As the Asset(s) pertaining to this Project have already failed or been damaged by the storms, this Project is the resulting follow-up to return distribution assets to safe operating condition and restore electrical service.
	1. Condition of Asset vs. Typical Life Cycle and Performance Record	Not Applicable.
	2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure	0
	3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)	Not Applicable.
	4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)	Not Applicable.

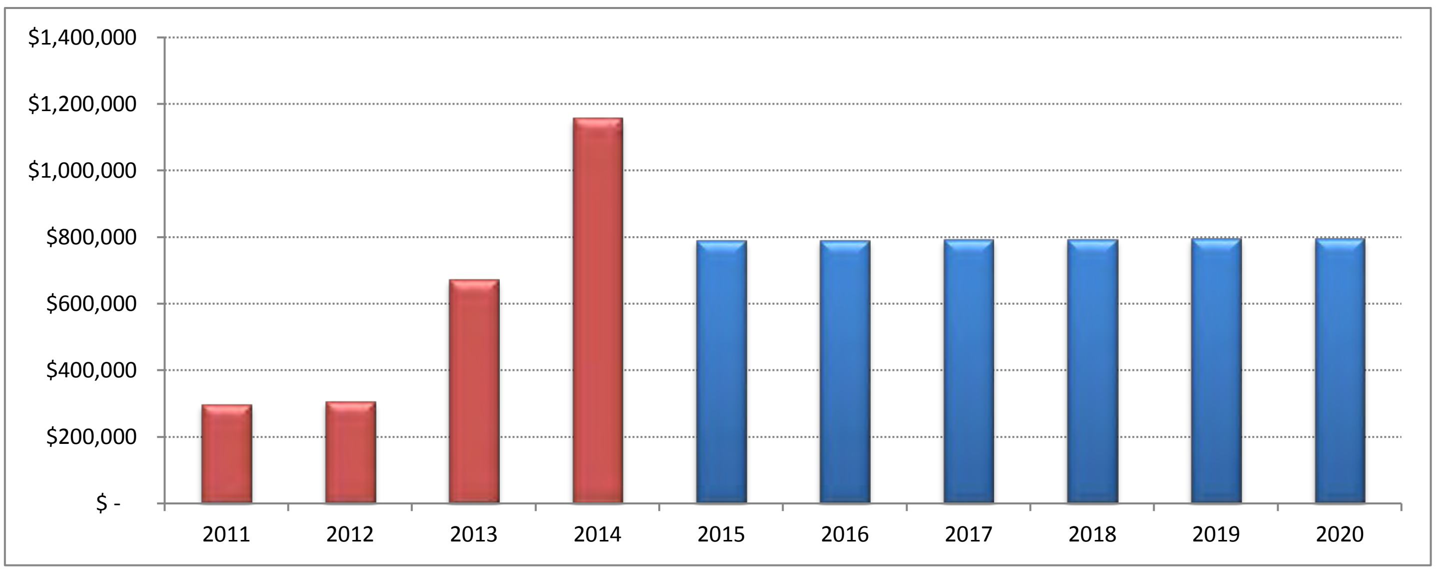
	Project Code	Report Start Year	Number of Years	Scale
Project Summary Report	**101800**	**2015**	**6**	**Dollars**

Project Name

Storm damage - Replacement of distribution equipment due to storm.

5. Value of Customer Impact	Low
Factors Affecting Project Timing, if any	Not Applicable.
Consequences for O&M System Costs Including Implications of Not Implementing	Not Applicable.
Reliability and Safety Factors	Not Applicable.
Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits)	Assets and Equipment replaced under this Project are always "like for like" renewal.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ 297,226	$ 306,122	$ 671,963	$ 1,158,364	$ 789,848	$ 790,569	$ 793,430	$ 793,082	$ 795,943	$ 796,130



	Project Code	Report Start Year	Number of Years	Scale
PowerStream	101860	2015	6	Dollars

Project Summary Report

Project Name: Storm damage - Replacement of distribution equipment due to storm.

Major Category	System Renewal	

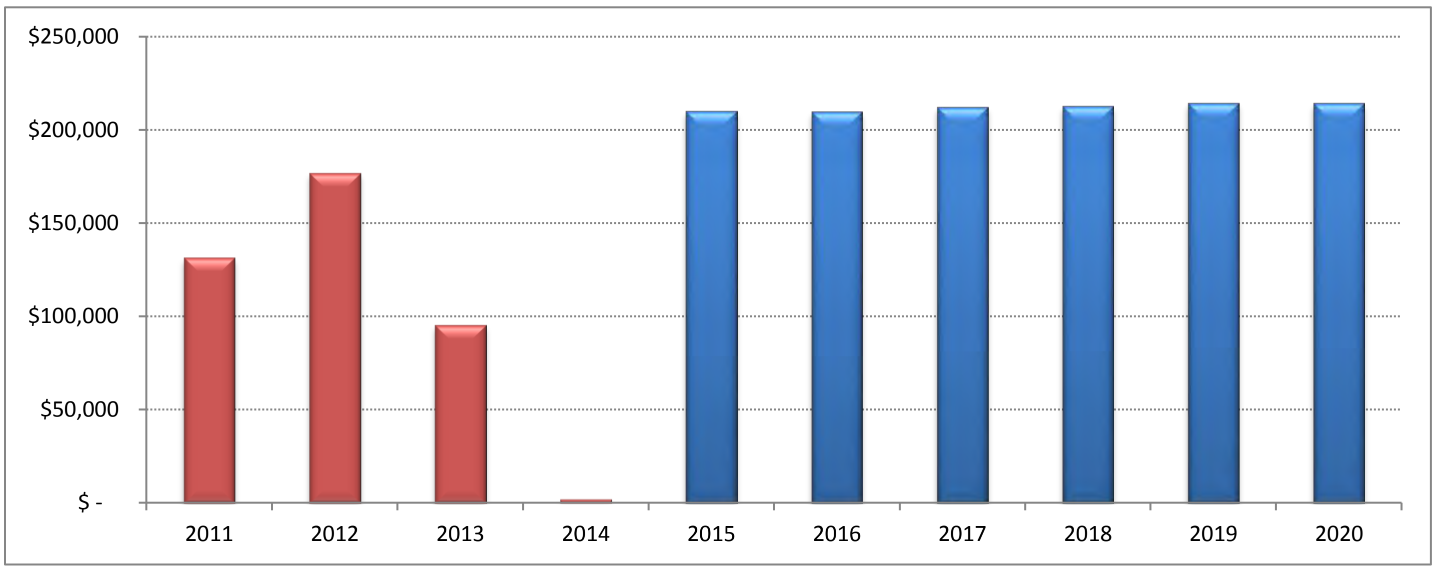
Project Overview

1. Additional Information	Service Territory	PowerStream North
	Location	PowerStream North
	Scope	Expenditures in this category are for the emergency replacement of major line distribution assets, such as poles, transformers, conductors, and switches, that are damaged during storm activity. PowerStream's distribution system can be impacted by significant weather events involving wind, snow, ice, sleet, hail, lightning, or any combination thereof. Such weather events can cause significant damage to the distribution system, and damaged or failed components are replaced promptly. The budget for this category is based primarily on historical trends over the past few years.
	Justification	Major storms can cause significant damage to distribution systems, resulting in power outages and disruption to optimal system operation, and can also create safety hazards for utility personnel and the general public. In such events, therefore, failed distribution equipment is promptly replaced to remove any safety hazards, restore power to customers, and return the system to its normal operating configuration.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Not Applicable.
	Comparative Information on Equivalent Historical Projects (if any)	For actual historical information for Powerstream North - Please see chart and graph below.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	Expenditures in this category are for the emergency replacement of major line distribution assets, such as
	1a. Main Driver	Safety. Damage due to storms that exceed the rated design capacity of the equipment.
	1b. Priority and Reasons for Priority	Not Applicable.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Not Applicable.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:	As the Asset(s) pertaining to this Project have already failed or been damaged by the storms, this Project is the resulting follow-up to return distribution assets to safe operating condition and restore electrical service.
	1. Condition of Asset vs. Typical Life Cycle and Performance Record	Not Applicable.
	2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure	0
	3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)	Not Applicable.
	4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)	Not Applicable.
	5. Value of Customer Impact	Low
	Factors Affecting Project Timing, if any	Not Applicable.
	Consequences for O&M System Costs Including Implications of Not Implementing	Not Applicable.

Project Summary Report	Project Code **101860**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Storm damage - Replacement of distribution equipment due to storm.			

Reliability and Safety Factors	Not Applicable.
Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits)	Assets and Equipment replaced under this Project are always "like for like" renewal.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ 131,192	$ 176,789	$ 95,186	$ 1,686	$ 209,937	$ 209,663	$ 212,173	$ 212,542	$ 214,409	$ 214,029



Project Summary Report	Project Code **101808**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Switchgears - Unscheduled Replacement of Failed Distribution Equipment			

Major Category **System Renewal**

Project Overview

1. Additional Information	Service Territory	PowerStream South
	Location	PowerStream South - (Vaughan, Markham, Richmond Hill, Aurora)
	Scope	This expenditure covers the cost of emergency replacement of failed switchgear units on the distribution system. Switchgear units are key components on a distribution system, providing points where feeders can be sectionalised or tied together. They can also contain a combination of fuses or breakers that protect underground cables that serve customer locations. These switchgear units facilitate load transfers, isolation for planned or emergency work, and switching operations to restore power during outage situations. Failed switching units are removed from the distribution system and are replaced with serviceable equipment in order to restore power to customers and return the system to its normal operating configuration. This budget is based primarily on historical trends over the past few years.
	Justification	A failure of switchgear equipment has an adverse impact on reliability, since these failures result in customer outages and mainline feeders can also be affected. Because switchgear units provide strategic switching locations, a switchgear failure has an adverse impact on system operation. Therefore, it is imperative for a failed unit to be replaced immediately to restore power to customers and also to restore the system to its normal operating state.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The condition of associated equipment (cables, terminations, etc) and on-site conditions may present risks to safety and speedy equipment replacement. Crews analyse and deal with hazards on a case-by-case basis while replacing equipment and restoring power to customers as quickly as possible.
	Comparative Information on Equivalent Historical Projects (if any)	Several switchgear units are replaced each year on an emergency basis, and the historic costs are the basis for the future planned expenditures.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	Failed switchgear typically results in customer outages. The failed equipment is repalced promptly with a new asset to restore power to customers.
	1a. Main Driver	Safety. Outage restoration.
	1b. Priority and Reasons for Priority	Replacement of failed equipment is a top priority in order to restore power to affected customers, restore the system to its normal operating configuration, and mitigate any potential safety risks.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Not replacing the failed switchgear promptly would leave customers without power and the system would be in an abnomal operating state. This alternative is not acceptable.
	2. Safety	Failed switchgear could present potential safety risks, which are mitigated as part of the restoration and replacement.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not replacing failed switchgear could have an adverse impact on economic development, as business customers could be without power due to the failure.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:	Not Applicable.
	1. Condition of Asset vs. Typical Life Cycle and Performance Record	Not Applicable.
	2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure	200

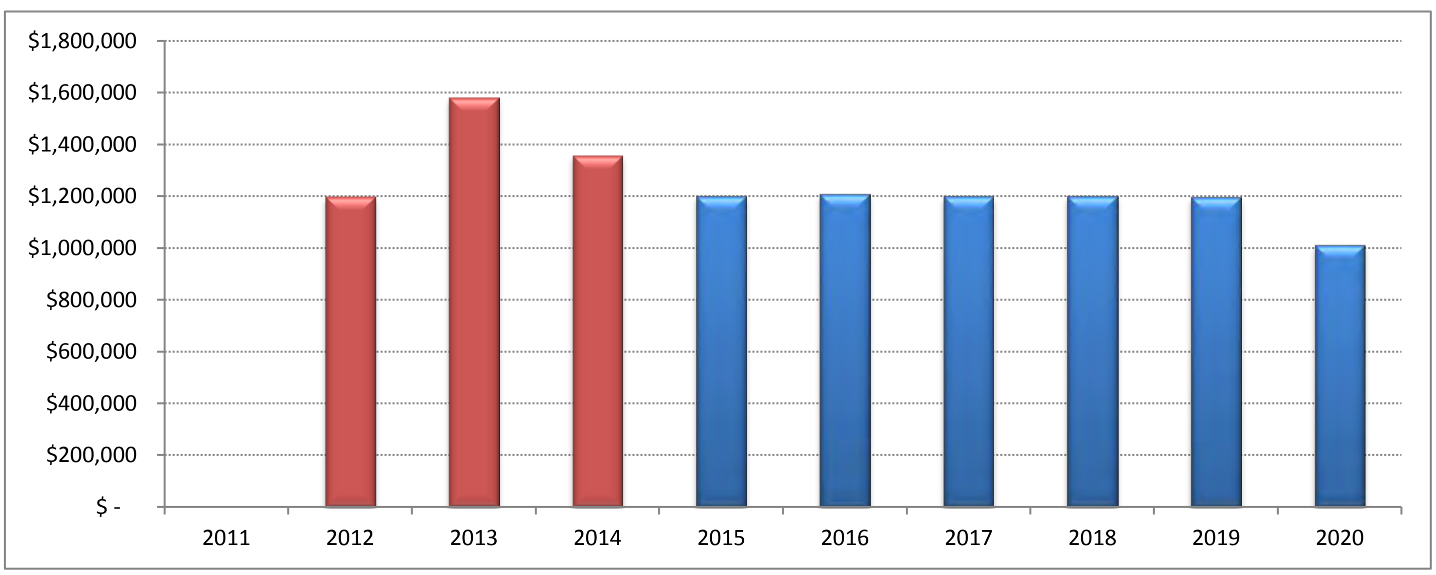
	Project Code	Report Start Year	Number of Years	Scale
Project Summary Report	**101808**	**2015**	**6**	**Dollars**

Project Name

Switchgears - Unscheduled Replacement of Failed Distribution Equipment

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)	Several switchgear failures occur per annum, and replacement and restoration can take several hours. Rsk of failure is higher with equipment of older vintage. These units are targeted for replacement under the proactive Switchgear Replacement Program.
4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)	Replacing failed switchgear would likely not have a significant positive impact on customer satisfaction, but not replacing the equipment promptly would have a deleterious impact on customer satisfaction.
5. Value of Customer Impact	High
Factors Affecting Project Timing, if any	Equipment is replaced immediately.
Consequences for O&M System Costs Including Implications of Not Implementing	Not Applicable.
Reliability and Safety Factors	Not replacing equipment would have an adverse impact on reliability and present potential safety risks.
Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits)	Not Applicable.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ 1,197,589	$ 1,580,286	$ 1,356,945	$ 1,200,422	$ 1,206,682	$ 1,200,101	$ 1,200,476	$ 1,195,500	$ 1,010,718



	Project Code	Report Start Year	Number of Years	Scale
PowerStream	101848	2015	6	Dollars

Project Summary Report

Project Name

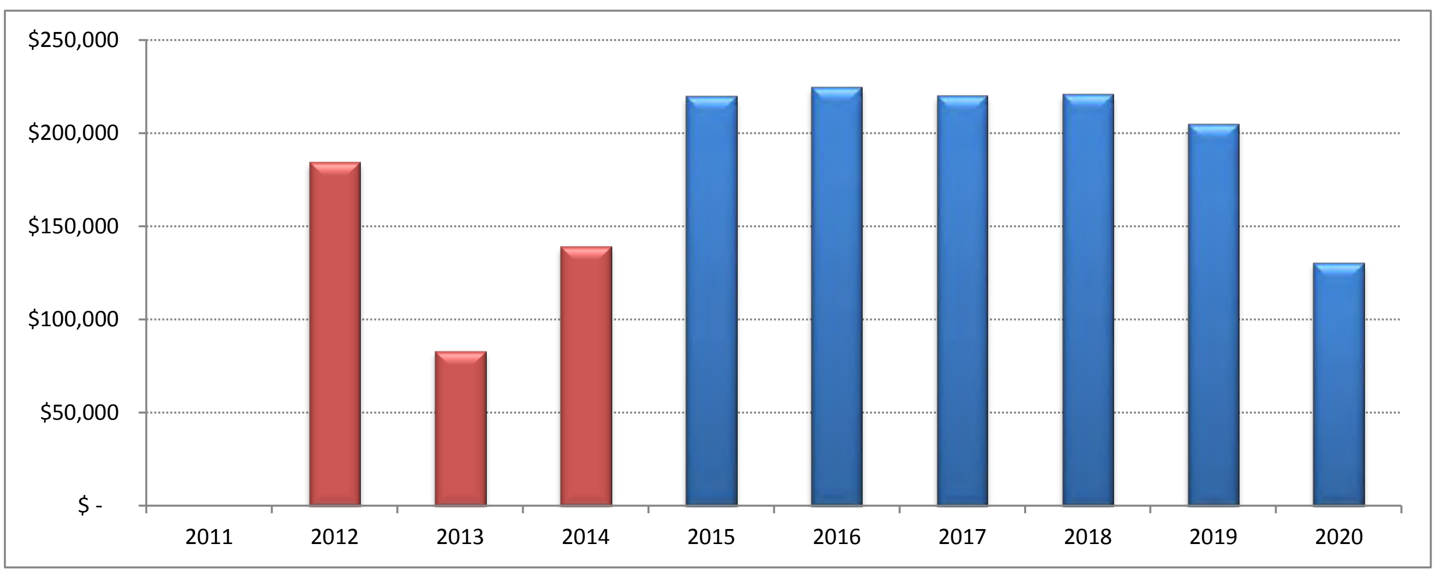
Switchgears - Unscheduled Replacement of Failed Distribution Equipment

Major Category	**System Renewal**	
Project Overview		
1. Additional Information	Service Territory	PowerStream North
	Location	PowerStream North
	Scope	This expenditure covers the cost of emergency replacement of failed switchgear units on the distribution system. Switchgear units are key components on a distribution system, providing points where feeders can be sectionalised or tied together. They can also contain a combination of fuses or breakers that protect underground cables that serve customer locations. These switchgear units facilitate load transfers, isolation for planned or emergency work, and switching operations to restore power during outage situations. Failed switching units are removed from the distribution system and are replaced with serviceable equipment in order to restore power to customers and return the system to its normal operating configuration. This budget is based primarily on historical trends over the past few years.
	Justification	A failure of switchgear equipment has an adverse impact on reliability, since these failures result in customer outages and mainline feeders can also be affected. Because switchgear units provide strategic switching locations, a switchgear failure has an adverse impact on system operation. Therefore, it is imperative for a failed unit to be replaced immediately to restore power to customers and also to restore the system to its normal operating state.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The condition of associated equipment (cables, terminations, etc) and on-site conditions may present risks to safety and speedy equipment replacement. Crews analyse and deal with hazards on a case-by-case basis while replacing equipment and restoring power to customers as quickly as possible.
	Comparative Information on Equivalent Historical Projects (if any)	Several switchgear units are replaced each year on an emergency basis, and the historic costs are the basis for the future planned expenditures.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	Failed switchgear typically results in customer outages. The failed equipment is repalced promptly with a
	1a. Main Driver	Safety. Outage restoration.
	1b. Priority and Reasons for Priority	Replacement of failed equipment is a top priority in order to restore power to affected customers, restore the system to its normal operating configuration, and mitigate any potential safety risks.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Not replacing the failed switchgear promptly would leave customers without power and the system would be in an abnomal operating state. This alternative is not acceptable.
	2. Safety	Failed switchgear could present potential safety risks, which are mitigated as part of the restoration and
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not replacing failed switchgear could have an adverse impact on economic development, as business customers could be without power due to the failure.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:	Not Applicable.
	1. Condition of Asset vs. Typical Life Cycle and Performance Record	Not Applicable.
	2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure	200
	3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)	Several switchgear failures occur per annum, and replacement and restoration can take several hours. Rsk of failure is higher with equipment of older vintage. These units are targeted for replacement under the proactive Switchgear Replacement Program.

Power Stream **Project Summary Report**	Project Code **101848**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Switchgears - Unscheduled Replacement of Failed Distribution Equipment			

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)	Replacing failed switchgear would likely not have a significant positive impact on customer satisfaction, but not replacing the equipment promptly would have a deleterious impact on customer satisfaction.
5. Value of Customer Impact	High
Factors Affecting Project Timing, if any	Equipment is replaced immediately.
Consequences for O&M System Costs Including Implications of Not Implementing	Not Applicable.
Reliability and Safety Factors	Not replacing equipment would have an adverse impact on reliability and present potential safety risks.
Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits)	Not Applicable.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ 184,272	$ 82,718	$ 139,028	$ 219,726	$ 224,702	$ 220,047	$ 220,742	$ 204,944	$ 130,140



Power Stream **Project Summary Report**	Project Code **101824**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Unscheduled Replacement of Failed Equipment - Poles, etc			

Major Category	**System Renewal**	

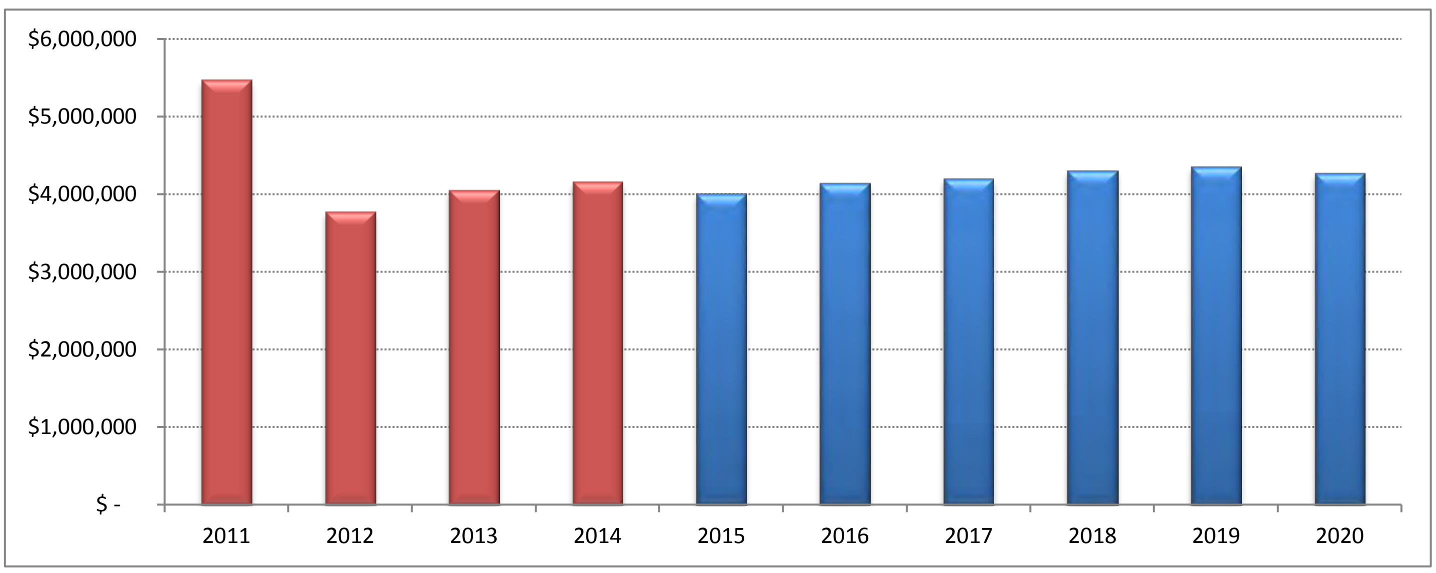
Project Overview

1. Additional Information	Service Territory	PowerStream South
	Location	PowerStream South - (Vaughan, Markham, Richmond Hill, Aurora)
	Scope	The emergency replacement of poles, conductors, devices and transformers generally occur when these components fail. In some cases, particularly with poles, terminations, connectors, and transformers, the equipment is replaced on an emergency basis if they are found to be in a state where failure is imminent. These conditions are usually identified during regular inspections, during “drive-bys” by field crews, or by calls from members of the public. Inspections can take the form of planned line patrols or infra-red thermographic scanning, which reveals “hot spots” due to deterioration of live components. In cases where equipment has deteriorated to the point where failure is imminent, there are potential threats to personnel and public safety and system reliability. Therefore, such equipment is also promptly replaced. The budget for this category is largely based on historical trends over the past several years.
	Justification	Failure of these components typically results in outages to customers, but also have an adverse impact on the safety and integrity of the distribution system. Therefore, such failed equipment is replaced immediately to restore power to customers, remove any safety hazards, and restore the system to its normal operating configuration.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The condition of equipment and on-site factors may present risks to safety and speedy equipment replacement. Crews analyse and deal with hazards on a case-by-case basis while replacing equipment and restoring power to customers as quickly as possible.
	Comparative Information on Equivalent Historical Projects (if any)	Historical number of events and associated costs are the basis for estimating future planned expenditures.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	Failed equipment (poles, conductors, transformers, and accessories) is replaced with new assets.
	1a. Main Driver	Safety. Failed equipment typically results in customer outages. The failed equipment is repalced promptly with a new asset to restore power to customers.
	1b. Priority and Reasons for Priority	Replacement of failed equipment is a top priority in order to restore power to affected customers, restore the system to its normal operating configuration, and eliminate any potential safety risks.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	There are no viable alternatives to the prompt replacement of failed equipment.
	2. Safety	Safety could be adversely impacted by not promptly undertaking the replacement of failed assets.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:	Not Applicable.
	1. Condition of Asset vs. Typical Life Cycle and Performance Record	Not Applicable.
	2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure	1000 (typically)
	3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)	Varies

	Project Code	Report Start Year	Number of Years	Scale
Project Summary Report	**101824**	**2015**	**6**	**Dollars**
	Project Name: Unscheduled Replacement of Failed Equipment - Poles, etc			

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)	Customer satisfaction would be adversely impacted if power was not restored promptly following equipment failure.
5. Value of Customer Impact	High
Factors Affecting Project Timing, if any	Failed equipment is replaced promptly.
Consequences for O&M System Costs Including Implications of Not Implementing	Not Applicable.
Reliability and Safety Factors	Not replacing equipment immediately would adversely impact reliability and potentially create safety hazards.
Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits)	Not Applicable.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ 5,472,537	$ 3,771,533	$ 4,051,060	$ 4,157,571	$ 4,004,267	$ 4,136,745	$ 4,195,526	$ 4,298,340	$ 4,349,171	$ 4,266,252



Project Summary Report	Project Code **101844**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Unscheduled Replacement of Failed Distribution Equip - Poles, Etc.			

Major Category **System Renewal**

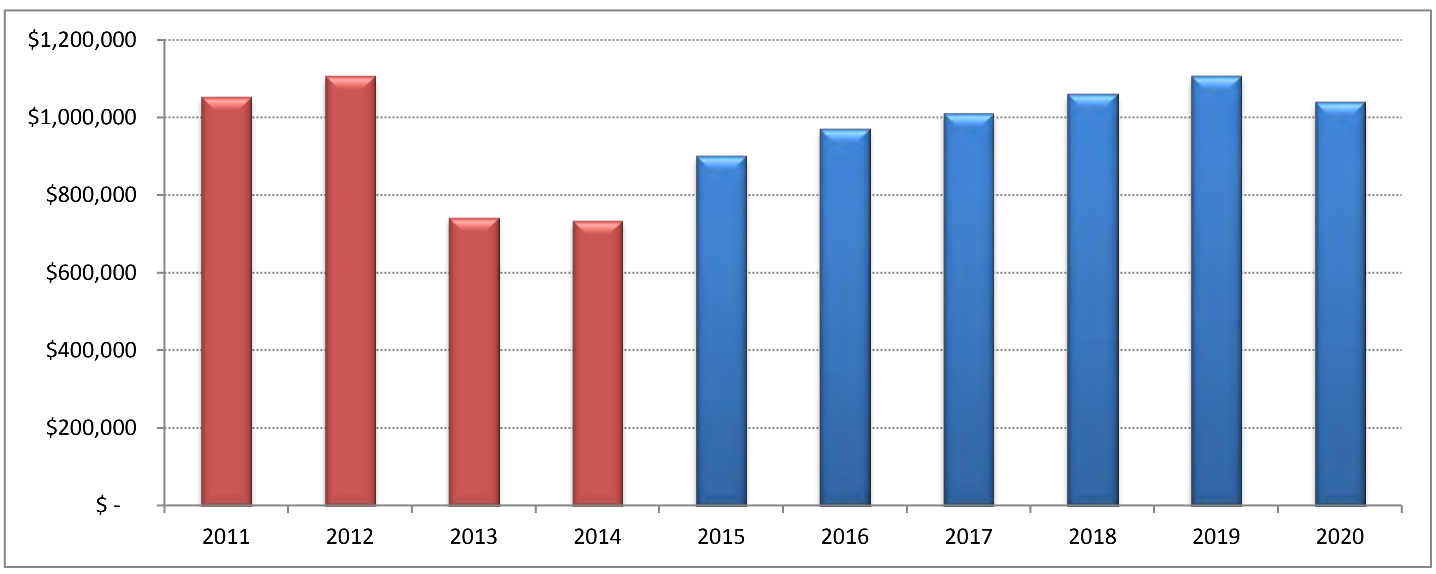
Project Overview

1. Additional Information	Service Territory	PowerStream North
	Location	PowerStream North
	Scope	The emergency replacement of poles, conductors, devices and transformers generally occur when these components fail. In some cases, particularly with poles, terminations, connectors, and transformers, the equipment is replaced on an emergency basis if they are found to be in a state where failure is imminent. These conditions are usually identified during regular inspections, during “drive-bys” by field crews, or by calls from members of the public. Inspections can take the form of planned line patrols or infra-red thermographic scanning, which reveals “hot spots” due to deterioration of live components. In cases where equipment has deteriorated to the point where failure is imminent, there are potential threats to personnel and public safety and system reliability. Therefore, such equipment is also promptly replaced.
	Justification	Failure of these components typically results in outages to customers, but also have an adverse impact on the safety and integrity of the distribution system. Therefore, such failed equipment is replaced immediately to restore power to customers, remove any safety hazards, and restore the system to its normal operating configuration.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The condition of equipment and on-site factors may present risks to safety and speedy equipment replacement. Crews analyse and deal with hazards on a case-by-case basis while replacing equipment and restoring power to customers as quickly as possible.
	Comparative Information on Equivalent Historical Projects (if any)	Historical number of events and associated costs are the basis for estimating future planned expenditures.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	Failed equipment (poles, conductors, transformers, and accessories) is replaced with new assets.
	1a. Main Driver	Safety. Failed equipment typically results in customer outages. The failed equipment is repalced promptly with a new asset to restore power to customers.
	1b. Priority and Reasons for Priority	Replacement of failed equipment is a top priority in order to restore power to affected customers, restore the system to its normal operating configuration, and eliminate any potential safety risks.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	There are no viable alternatives to the prompt replacement of failed equipment.
	2. Safety	Safety could be adversely impacted by not promptly undertaking the replacement of failed assets.
	3. Cyber-Security, Privacy	Not Applicable
	4. Coordination, Interoperability	Not Applicable
	5. Economic Development	Not Applicable
	6. Environmental Benefits	Not Applicable
5. Category-Specific Requirements for Each Project/Activity (OEB)	Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:	As described below.
	1. Condition of Asset vs. Typical Life Cycle and Performance Record	The assets to be replaced under this program are in a failed state.
	2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure	1000 (typically)
	3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)	Customer impacts vary depending on the type of asset that has failed, location within the distribution system, location geographically, and the load interrupted at the time of failure.

Project Summary Report	Project Code **101844**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Unscheduled Replacement of Failed Distribution Equip - Poles, Etc.			

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)	Customer satisfaction would be adversely impacted if power was not restored promptly following equipment failure.
5. Value of Customer Impact	High
Factors Affecting Project Timing, if any	The programme itself is an on-going programme with no defined start and end time. The timing of equipment failing is typically random, but influenced by loading, weather conditions, and other external factors
Consequences for O&M System Costs Including Implications of Not Implementing	As this programme is for the purposes of replacing overhead distribution system assets that have already failed, the resulting consequences are more directly related to capital than OM&A.
Reliability and Safety Factors	Not Applicable
Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits)	Failed overhead distribution system assets replaced under this programme are "like for like".

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ 1,052,550	$ 1,107,423	$ 740,413	$ 732,786	$ 900,090	$ 970,290	$ 1,010,630	$ 1,059,941	$ 1,106,183	$ 1,039,734



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100867	2015	6	Dollars

Project Name

Pole Replacement Program - 2015 to 2020

Major Category	System Renewal	
Project Overview		
1. Additional Information	Service Territory	PowerStream North & South
	Location	Various locations in PowerStream
	Scope	Remediate 400 poles, including approx. 370 pole replacements and approx. 30 pole reinforcements.
	Justification	Poles are critical component of the distribution system as many pieces of equipment are attached to them (conductors, transformers, switches, street lights, telecommunication attachments, etc.). As a pole's physical condition and structural strength deteriorate, the pole may become inadequate for its intended function, and should be replaced to maintain the integrity of the distribution system, and to protect public safety. The pole testing program has revealed that a number of poles need to be replaced. One of the criteria used for replacement is "percent remaining strength" as per CSA Standard C22.3 No. 1-10. Clause 8.3.1.3 of CSA Standard C22.3 No. 1-10 states that "when the strength of a wood pole structure has deteriorated to 60% of the required design capacity, the structure shall be reinforced or replaced". Every year, on a prioritized basis, a number of poles are proposed for replacement or reinforcement due to the pole conditions and remaining strength. The pole remediation will have positive impact on PowerStream's goals to maintain public & staff safety, system reliability, and to meet OEB & CSA requirements. PowerStream will select the annual pole replacement and reinforcement candidates from the following two categories: Category 1: Poles that have less than 60% remaining strength which are needed to be addressed to meet the requirement of CSA Standard C22.3 No. 1-10 Clause 8.3.1.3. Category 2: Poles that have more than 60% remaining strength but exhibit worsening conditions such as rot, decay, splitting, insect infestation, bending and leaning, and present a high probability of failure which pose a safety risk to employees and public. In 2014 PowerStream completed a pilot project on pole reinforcement. Pole reinforcement cost is only 25-30% of replacement cost. The reinforcement method is cost effective and suitable for a certain situations such as poles with butt decay, crack at ground level, carpenter ants, poles that will be removed in near future due to road widening. Proposed Remediation Plan: It is expected that as the existing poles age and deteriorate, on a rolling basis, inspection and testing results will show a number of poles in poor condition and requiring replacement or reinforcement. To address the pole condition concern, it is recommended to remediate 400 poles per year, including approx. 370 replacement poles and approx. 30 reinforcement poles. It is expected that the pole remediation program will be an on-going program to maintain the integrity of the distribution system and to protect public safety.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Risk: Fluctuation in cost and staff resource (internal and external) to complete high annual volume of work. Risk Management: In 2013 & 2014 PowerStream budgeted, and completed the same level of pole replacement each year. Therefore the proposed annual budget for 2015 onward is a continuation of the pole remediation program at the same level. Some of the tasks to manage the risk are: meetings amongst all involved parties to go over the project details, schedule, logistics, and resource requirements; regular progress meetings to ensure technical and operational issues are resolved promptly; budget performance is monitored; and projects are on track.
	Comparative Information on Equivalent Historical Projects (if any)	This project is the continuation of PowerStream long-term pole remediation program. In 2013 & 2014 PowerStream budgeted, and completed the same level of pole replacement each year. Each year PowerStream conduct field inspection and use the inspection result to prioritize and select suitable candidates for replacement or reinforcement.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	For 2015 it is proposed to remediate 400 poles, including approx. 370 pole replacement and approx. 30 pole reinforcement. The exact locations, schedule, and logistics will be jointly determined by Lines, System Control, Capital Design, and System Planning to achieve co-ordination of work and to minimize customer disruption.

Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100867	2015	6	Dollars

Project Name

Pole Replacement Program - 2015 to 2020

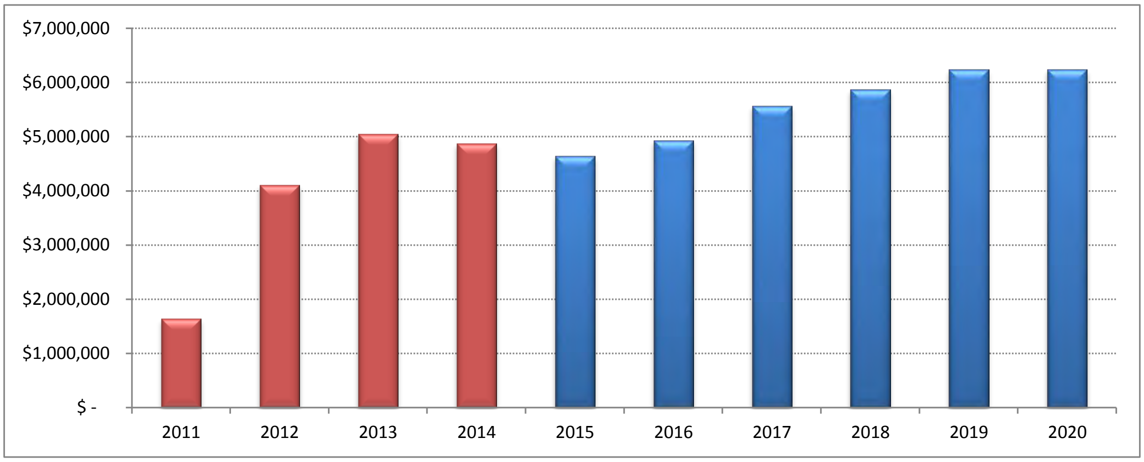
1a. Main Driver	Mandated Compliance. The main driver for this project is compliance and safety. This project is part of PowerStream's long-term pole remediation program to replace and reinforce end-of-life poles to maintain the integrity and safety of the distribution system. On a prioritized basis, each year PowerStream will inspect, review, and select suitable poles for replacement or reinforcement.
1b. Priority and Reasons for Priority	PowerStream has a very large quantity of wood poles in service. A portion of the pole population is at end-of-life and requires replacement or reinforcement in order to maintain system integrity and safety to the public. The risk of pole failure arising from pole condition (as distinct from other factors such as vehicle impacts) rises directly as pole condition deteriorates. While a pole that is in poor condition may be capable of sustaining its load under normal operating conditions, the presence of any abnormal factors such as snow, ice and wind loads, or external impact, acting individually or in combination, may cause instantaneous loads which exceed the ability of the pole to sustain. Pole design and specifications normally provide for a substantial margin of load bearing capacity over actual or peak loads; as a pole deteriorates, this margin shrinks and eventually disappears. Because poles are physically interconnected by conductors, the risk of pole failure is also influenced by the condition of neighbouring poles. A series of poles in good condition may be capable of withstanding a substantial impact to one pole (for example, due to a vehicle collision) because neighbouring poles have sufficient load bearing capacity to support the damaged or severed pole and maintain energized equipment at a safe distance above the ground. However, as the condition of interconnected poles deteriorates, the reserve load bearing capacity of the poles diminishes, and the same vehicle impact (for example) could produce instantaneous loads which create a domino effect and cause the failure of several interconnected poles at the same time. The consequences of pole failure primarily affect safety (for the public and workers) as well as reliability. As such, safe clearances and limits of approach are defined and must be maintained. A key function of the pole system is to suspend equipment operating at high voltages at a safe height above the ground and clear of any potential approach or contact by people, vehicles, or other objects, in addition to simply supporting the equipment. Total pole failure (i.e., the complete loss of structural integrity and function) creates unacceptable risks to the public and utility workers. In addition, since many poles are adjacent to roadways, a collapse into the roadway can result in vehicle damage. In addition to immediate risks to safety, total pole failure also presents potentially severe and prolonged reliability impacts. Even under ideal environmental conditions, the loss of one or more poles and the associated feeders can interrupt power to hundreds or thousands of customers for several hours before temporary repairs can be effected, any may cause further outages when permanent repairs are made.
1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Please refer to above for details.
2. Safety	Pole failures pose safety risk to staff and the public. The pole may fail when staff are working on the pole or when the public in close proximity of the unit. When the pole falls, there may be other equipment (e.g. overhead transformer or overhead switch) that will also fall.
3. Cyber-Security, Privacy	Not Applicable.
4. Coordination, Interoperability	Not Applicable.
5. Economic Development	Not Applicable.
6. Environmental Benefits	In the case that there are transformers on the pole, a pole falling down may also cause the transformers to fall down on to the street below, resulting in transformer tank rupturing, and oil being spilled onto the ground.

	Project Code	Report Start Year	Number of Years	Scale
Power Stream	100867	2015	6	Dollars
Project Summary Report	Project Name: Pole Replacement Program - 2015 to 2020			

5. Category-Specific Requirements for Each Project/Activity (OEB)	Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:	Through an annual inspection and testing program, PowerStream monitors the condition of its poles to ensure that they meet minimum requirements for safety and reliability. Among other factors, PowerStream is guided in its pole assessment process by Clause 8.3.1.3 of Canadian Standards Association ("CSA") Standard C22.3 No. 1-10, which states that: "when the strength of a wood pole structure has deteriorated to 60% of the required design capacity, the structure shall be reinforced or replaced". Other considerations include pole condition information such as rot, decay, splitting, insect infestation, bending, and leaning. PowerStream believes that the replacement of poles exhibiting poor condition is non-discretionary in view of compliance with the CSA code, as well as considerations for safety of the public and for workers operating in, on, or around the poles and their associated equipment. The pole replacement and reinforcement candidates are selected based on the combination of the following two categories: Category 1: Poles that have less than 60% remaining strength which are needed to be addressed to meet the requirement of CSA Standard Clause 8.3.1.3. Category 2: Poles that have more than 60% remaining strength but exhibit worsening conditions such as rot, decay, splitting, insect infestation, bending, and leaning and present a high probability of failure which presents a safety risk to employees and public.
	1. Condition of Asset vs. Typical Life Cycle and Performance Record	According to the Kinectrics Report "Asset Amortization Study for the Ontario Energy Board", Typical Useful Life of wood poles is 45 years. There are poles in PowerStream's existing pole population which are older than 45 years and are expected to fail if not replaced or reinforced. It should be noted that age is only one of the many factors affecting the physical condition of wood poles. There are cases where relatively young poles have deteriorated physical condition due to factors such as: insect infestation, fungus, rot, cracking, leaning, bending.
	2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure	Approximately 2000. For details on the calculation, please refer to 3. below.
	3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)	For 1 pole: • Frequency of Failure is: 0.05 failure per year (1 in 20 years) For 400 poles: • Frequency of Failure is: 0.05 failure x 400 = 20 failures. • Estimated average number of customers affected by 1 failure is = 100 customers • Estimated projected number of customers affected by 20 failures is: 100 x 20 = 2,000 customers Duration of interruption = 3 hours per interruption CMI for 1 pole failure = 100 customers x 3 hour x 60 min = 18,000 CMI CMI for 20 pole failures = 18,000 CMI x 20 = 360,000 CMI
	4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)	Pole failures have negative impact to system reliability and customer service. Outages cause inconvenience and financial loss to customers (office closing, production stoppage).
	5. Value of Customer Impact	High
	Factors Affecting Project Timing, if any	Not Applicable.
	Consequences for O&M System Costs Including Implications of Not Implementing	• O&M Cost for 1 emergency pole failure replacement = $20,000 per failure • O&M Cost for 20 emergency pole failure replacement = $20,000 x 20 = $400,000
	Reliability and Safety Factors	This project is part of the long-term pole remediation program. The project will help avoid a total of 20 pole failures and 360,000 potential CMI. The project will also help reduce some safety risk (potential personal injury) that may result due to pole failures.
	Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits)	This Project is configured to be the lowest cost soultion to replace or reinforce only those poles in poorest conditions. The main alternative would be the "do nothing" option, and only to replace poles reactively after they fail. However, due to the issues as discussed above, the "do nothing" alternative is not a viable option.

Project Summary Report	Project Code 100867	Report Start Year 2015	Number of Years 6	Scale Dollars
	Project Name Pole Replacement Program - 2015 to 2020			

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$1,638,822	$ 4,111,507	$ 5,045,992	$ 4,872,277	$ 4,645,383	$ 4,933,143	$ 5,570,700	$ 5,870,246	$ 6,241,483	$ 6,244,377



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	101355	2015	6	Dollars
	Project Name	Unforeseen Projects Initiated by PowerStream		

Major Category	**System Renewal**	
Project Overview		
1. Additional Information	Service Territory	PowerStream North & South
	Location	PowerStream North and South Service Territory
	Scope	Unforeseen Projects: These projects address asset replacement or system upgrade to maintain the safety,integrity and reliability of the system.
	Justification	In past 2011 the Emerging project South budget was $777,248 and North budget was $616,065. However, the 2012 budget was reduced to $590,206 (South) and $368,953 (north) as an Emerging Cable replacement project was added to the project portfolio. It is recommended to increase the budget for Unforeseen Projects to $1,200,000. Total Emerging portfolio is recommended to be budgeted 60% South and 40% North. The requirements of the funds will increase as the infrastructure is aging and more assets are being identified through the annual inspection and maintenance program that require immediate replacement. The project will address the following projects: *Overhead system upgrade projects. *Assets (transformer,Poles, Cables, Switchgear, Elbow) identified by Inspection and Maintenance program as immediate replacement candidates to maintain the system intergity and reliability. *Overloaded transformer which exceed the IEEE overloading guidelines
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Experience has shown that each year brings several unforeseen concerns that need immediate attention.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	This project budget is intended to cover Unforeseen Projects: These projects address asset replacement or system upgrade to maintain the safety,integrity and reliability of the system.
	1a. Main Driver	Safety. The main driver for the project is safety and to maintain system intergrity and reliability. Annual inspection results for assets such as poles, switchgear, transformers, etc. allow Engineering to strategize and make appropriate remediation plans for aging infrastructure. However, each year concerns are identified that need immediate attention and this project is intended to fund these changes.
	1b. Priority and Reasons for Priority	This project is prioritized as an ongoing yearly project to address immediate concerns as they happen.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	This project is the method PowerStream uses to financially address unforeseen events that impact the quality of the distribution system. The project gives engineering the ability to provide appropriate action to legitimate concerns as they develop. The alternative is to do nothing in the current fiscal year and budget any action for a future year. This alternative is not acceptable as inspection programs are finding assets that need to be replaced ASAP and suficient funds need to be available to enable these replacements. A third option is to provide less funds in the Unforeseen budget however, experience has shown that a smaller 'Unforseen' budget is less efective and increases risk by forcing immediate asset replacement into future years.
	2. Safety	Unforeseen projects include those that need to address safety concerns.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:	As described below.
	1. Condition of Asset vs. Typical Life Cycle and Performance Record	As the specific details of the work to be performed under this Project is unknown until such a time as it is required, the asset condition is not available.

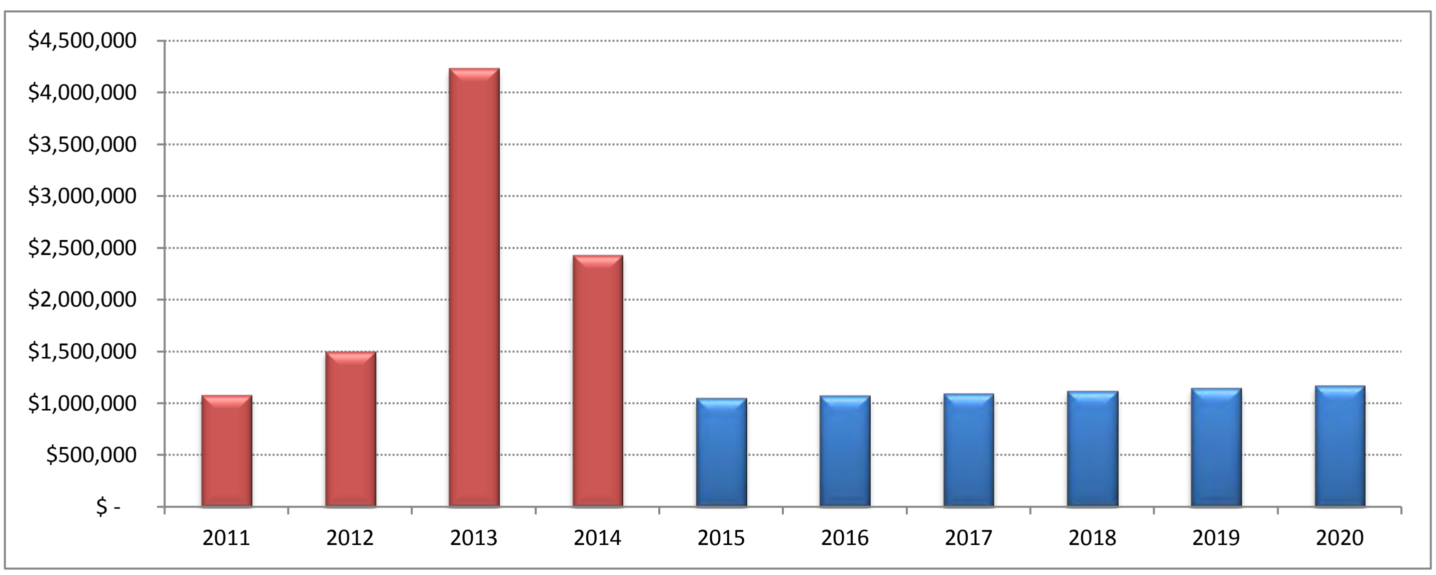
Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	101355	2015	6	Dollars

Project Name

Unforeseen Projects Initiated by PowerStream

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure	0
3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)	As the specific details of the work to be performed under this Project is unknown until such a time as it is required, the Quantitative Customer Impacts is not available.
4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)	As the specific details of the work to be performed under this Project is unknown until such a time as it is required, the Qualitative Customer Impacts is not available.
5. Value of Customer Impact	Medium
Factors Affecting Project Timing, if any	As the specific details of the work to be performed under this Project is unknown until such a time as it is required, the Factor affecting Project Timing is not available.
Consequences for O&M System Costs Including Implications of Not Implementing	Not Applicable.
Reliability and Safety Factors	Not Applicable.
Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits)	In general, the programme "Unforeseen Projects Initiated by PowerStream" under the System Renewal category will be "like for like".

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ 1,076,240	$ 1,499,516	$ 4,232,576	$ 2,429,637	$ 1,046,472	$ 1,070,527	$ 1,093,812	$ 1,117,360	$ 1,141,172	$ 1,165,266



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	103659	2015	6	Dollars

Project Name

Storm Hardening & Rear Lot Supply

Major Category	System Renewal	
Project Overview		
1. Additional Information	Service Territory	PowerStream North & South
	Location	Various locations in PowerStream
	Scope	Complete the work for the Storm Hardening Program in which various components of the distribution system are changed out, reinforced, and relocated to enable the distribution system to withstand storms better in the future. The work program includes: 1. Conversion of rear lot overhead supply system to front lot underground supply system. 2. Periodic storm guying and in-line guying and anchoring for pole lines that have 4 circuits on them. 3. Relocation of flood sensitive equipment in Stations from below grade to above grade or to safer height. These include battery, battery charger, inverter, feeder switch, capacitor, AC and DC distribution panel, ATS, HVAC, UPS, and equipment storage.
	Justification	This project is part of the long-term program to implement the recommendations from the Storm Hardening Report. During the December 2013 ice storm in Ontario, PowerStream experienced many prolonged outages due to the various factors, including the heavy weight of the ice on various distribution components and on trees in close proximity of the distribution system. Subsequent to the ice storm event, PowerStream has retained CIMA to review the distribution system and produce the Ice Storm Hardening Report with recommendations to make the distribution system stronger and withstand the storm better in the future. The Ice Storm Hardening Report was discussed among various departments within PowerStream. Some of the recommendations from the report were adopted for implementation. The proposed capital work programs are: 1. Conversion of rear lot overhead supply system to front lot underground supply system. 2. Periodic storm guying and in-line guying and anchoring for pole lines that have 4 circuits on them. 3. Relocation of flood sensitive equipment in Stations from below grade to above grade or to safer height. These include battery, battery charger, feeder switch, capacitor, AC and DC distribution panel, ATS, HVAC, UPS, and equipment storage. Background: On the weekend of December 21-22, 2013, a significant freezing rain storm moved through Southern Ontario. Ice accumulation resulted in downed branches, trees and power lines, which resulted in over 500,000 customers losing power in Ontario. This included, at its peak, over 92,000 customers in PowerStream’s service territory, predominantly in Aurora, Markham, Richmond Hill and Vaughan. The vast majority of customers within PowerStream’s territory were restored within 24 hours of the completion of the storm, and full restoration in PowerStream’s service territory was realized on December 30, 2013. The freezing rain produced significant damage to the tree canopy in PowerStream’s service territory. It was this damage to the tree canopy that then caused significant damage to the overhead primary and secondary distribution system. The failed trees came down on the power lines causing outages. There were limited pole or transformer failures and those that occurred were generally the result of the weight of the failed tree canopy and not the ice itself. In addition to the type of failures that occurred, the failures were widespread such that backup feeders that PowerStream normally relies on to provide quick restoration of power were unavailable as failures equally occurred in the backup feeders. A significant number of the failures also occurred in the single phase or secondary lines for which there is no backup and direct restoration was required to re-establish power to the customer. PowerStream wanted to consider ways to to effectively “harden” the distribution system against ice storms of this nature and storms in general. These may include changes to the distribution design standards, upgrade of old systems to present day standards (i.e. rear yard services) and vegetation management practices. PowerStream has retained a consulting firm, CIMA, to review PowerStream’s distribution system with respect to the capability to withstand severe ice storm in the future. CIMA has completed the review and submitted the Ice Storm Hardening Report. Extensive discussions among various departments in PowerStream resulted in a prioritzed work programs that were proposed for implementation. These work programs were proposed to be implemented over a number of years to manage the risk of asset failures.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2016
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Risk: Fluctuation in cost and staff resource (internal and external) to complete high annual volume of work.

Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	103659	2015	6	Dollars
	Project Name: Storm Hardening & Rear Lot Supply			

	Comparative Information on Equivalent Historical Projects (if any)	PowerStream has completed similar rear lot project, pole line replacement and reinforcement project, and station equipment project.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	Complete the work for the Storm Hardening Program in which various components of the distribution system are changed out, reinforced, and relocated to enable the distribution system to withstand ice storm better in the future. The work program includes: 1. Conversion of rear lot overhead supply system to front lot underground supply system. 2. Periodic storm guying and in-line guying and anchoring for pole lines that have 4 circuits on them. 3. Relocation of flood sensitive equipment in Stations from below grade to above grade or to safer height. These include battery, battery charger, inverter, feeder switch, capacitor, AC and DC distribution panel, ATS, HVAC, UPS, and equipment storage.
	1a. Main Driver	Mitigate Failure Risks. To maintain safety, system reliability and customer service.
	1b. Priority and Reasons for Priority	1. PowerStream has many pockets of rear lot overhead supply locations that are ageing and deteriorating. The rear lot supply system poses many safety, reliability and customer service concerns that must be addressed. 2. PowerStream has many pole lines that carry 4 circuits on them. These pole lines are conserdered high risk because if these poles collapse under storm, many customers will encounter power outage, and public safety will be at risk. Strengthening these poles will reduce the risk. 3. All seven of PowerStream's transformer stations that have indoor type switchgear have equipment in the basement of the switchgear buildings. It is imperative that the battery banks, battery chargers, inverters and distribution panels are not exposed to water. These components are crucial to the operation of the station. Should a flood occur in the basement, submersed equipment could maloperate causing damage to the equipment and possibly create prolonged outages. There is also a significant electric shock hazard when electrical equipment is subjected to water leading to an unsafe working environment. For these reasons, all non-watertight equipment in the basements should be relocated to the main floor level or, at the very least, elevated to safer levels in the basement.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	This project will reduce safety risk to customers and PowerStream staff, and maintain reliability and customer service in the the event of major storm. An alternative is to do nothing and allow the system to fail under major storm and be replaced under emergency. However this approach is not recommended because it will have a negative impact on safety, system reliability, and customer service.
	2. Safety	The existing distribution lines and poles in rear lots is more susceptible to breaking and falling during storms, posing serious public safety concerns.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.

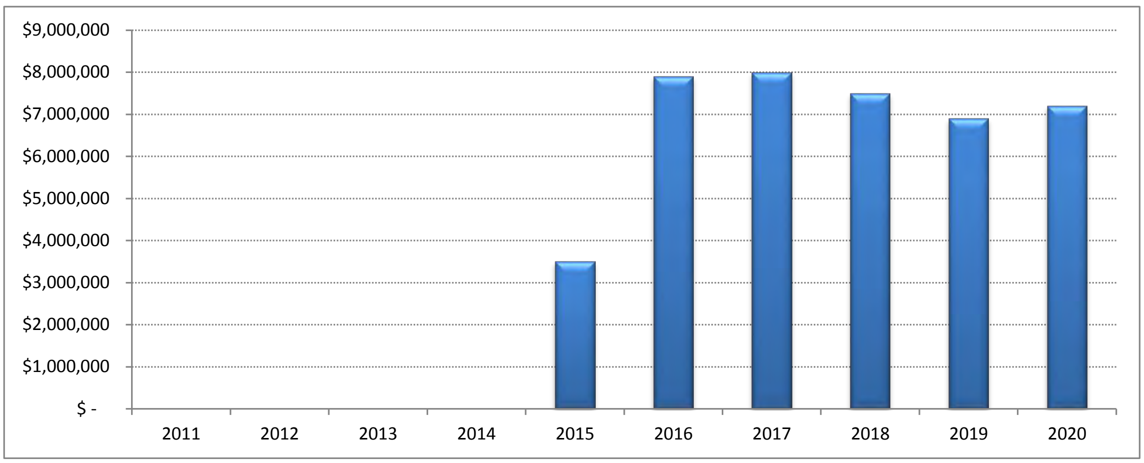
	Project Code	Report Start Year	Number of Years	Scale
Project Summary Report	103659	2015	6	Dollars
	Project Name: Storm Hardening & Rear Lot Supply			

5. Category-Specific Requirements for Each Project/Activity (OEB)	Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:	Long outage restoration time due to difficult accessibility for PowerStream crews: In comparison to front lot customers, rear lot customers have to wait longer for the crews to restore power during an outage. The crews have to gain access to the back yard to identify, locate, isolate, and repair/replace equipment. In heavily vegetated areas, the crews must also clear or trim the vegetation before they can access the equipment. If the replacement of major equipment (e.g. pole, transformer) is necessary, the outage time will extend because the crews need specialized equipment (e.g. large crane) to reach over customer houses to the rear lot. More frequent outages due to vegetation, animal contact, and lack of access for PowerStream crews: When a rear lot supply was first constructed, the area was likely clear of obstruction. Over time, however, trees/ bushes have grown near the electrical equipment, and may make contact with the power line. The growth of vegetation also increases the risk of animals contact with electrical equipment. PowerStream has many pole lines that carry 4 circuits on them. These pole lines are considered high risk because if these poles collapse under storm, many customers will encounter power outage, and public safety will be at risk. All seven of PowerStream's transformer stations that have indoor type switchgear have equipment in the basement of the switchgear buildings. It is imperative that the battery banks, battery chargers, inverters and distribution panels are not exposed to water. These components are crucial to the operation of the station. Should a flood occur in the basement, submersed equipment could maloperate causing damage to the equipment and possibly create prolonged outages. There is also a significant electric shock hazard when electrical equipment is subjected to water leading to an unsafe working environment.
	1. Condition of Asset vs. Typical Life Cycle and Performance Record	1. Rear lot distribution lines were installed a long time ago (some areas were installed in 1948 - 1970 time frame). It is extremely difficult to gain access to the backyard to maintain, repair, and restore power. As a result there are prolong outages to customers. This is especially more difficult in the event of ice storm. 2. 4-circuit pole lines are critical part of the distribution system because they carry more circuits than does a typical pole line (e.g. 3 circuits, 2 circuits. 1 circuit). If the pole collapse, 4 feeders be out of service and more customers will encounter power outage. 3. Flood sensitive equipment currently located below grade at stations may be damaged in the event of flooding in station basement and cause power outage. The high risk equipment are: battery, battery charger, inverter, feeder switch, capacitor bank, AC distribution panel, DC distibution panel, UPS (Uninetrrupted Power Supply),UPS panel, ATS (Automatic Transfer Switch), HVAC (Heating Venting Air Conditioning),and equipment storage.
	2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure	Approximately 1000. For details on the calculation of this figure, please refer to 3. below.
	3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)	• Frequency of Failure is: 0.5 failure per year • Estimated number of customers affected by 1 failure is: 2,000 customers • Estimated number of customers affected by 0.5 failure is: 2,000 x 0.5 = 1,000 customers • Duration of interruption is: 4 hours per interruption. • CMI per 1 failure is: 2000 x 4 hour x 60 min = 480,000 CMI • CMI per 0.5 failure is: 480,000 x 0.5 = 240,000 CMI
	4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)	Power outages cause inconvenience and financial loss to customers (office closing, production stoppage). Poles and lines failure poses safety hazards to the public.
	5. Value of Customer Impact	High
	Factors Affecting Project Timing, if any	Not Applicable.
	Consequences for O&M System Costs Including Implications of Not Implementing	• O&M Cost for 1 failure = $100,000 per failure • O&M Cost for 0.5 failure = $100,000 x 0.5 = $50,000.
	Reliability and Safety Factors	This project is part of the long-term Storm Hardening Program. The project will help avoid a total of 0.5 potential failure and 240,000 potential CMI. In addition, this project also reduce safety hazards associated with pole lines collapsing and flooded equipment under major storm.

	Project Code	Report Start Year	Number of Years	Scale
Project Summary Report	**103659**	**2015**	**6**	**Dollars**
	Project Name: Storm Hardening & Rear Lot Supply			

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits)	Alternatives include "do nothing" and only replace distribution system plant reactively when it fails. However there is the risk of some pole lines failing and large scale equipment to fail and hence this approach is not viable because it will have a negative impact on safety, customer service, and system reliability.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ 3,499,998	$ 7,900,017	$ 7,999,752	$ 7,499,834	$ 6,900,540	$ 7,200,072



Power Stream	Project Code	Report Start Year	Number of Years	Scale
Project Summary Report	**101012**	**2015**	**6**	**Dollars**
	Project Name: Planned Circuit Breaker Replacement Markham TS#1&2 & Lazenby TS#1			

Major Category **System Renewal**

Project Overview

1. Additional Information	Service Territory	PowerStream South
	Location	Markham TS#2, Markham TS#1 & Lazenby TS#1
	Scope	Replacement of the following 27.6 kV feeder circuit breakers: - J Bus 27.6kV feeder breakers 24M1, 24M3, 24M7 at Markham TS2 (2015) - The four Y Bus 27.6kV feeder breakers at Markham TS1 (2015) - All twelve Richmond Hill (Lazenby) TS1 feeder breakers (2018 & 2019)
	Justification	The circuit breakers at all of these stations are considered "obsolete" in that they are no longer built or supported by the manufacturer. Spare parts are not commercially available but can be recovered through the cannibalization of stock that we have on hand. Due to operational concerns, System Planning, Station Sustainment and Station Design & Standards have jointly developed the attached plan to replace the obsolete circuit breakers at PowerStream's transformer stations and municipal stations for the next 8 years. The plan is subject to annual re-assessment of the equipment.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Replacement equipment has a long lead time and there is a risk on delayed delivery. This risk will be mitigated by standardizing replacement equipment and by placing orders early. Outage availability is another risk. This risk will be mitigated by booking the outages well in advance.
	Comparative Information on Equivalent Historical Projects (if any)	This project is a continuation of the Station Circuit Breaker Replacement Program begun in 2009. The following replacements have been undertaken: - Markham TS#2 M5 OX 36 breaker in 2003 - Markham TS#1 OX 36 feeder breakers on B bus in 2010 - Markham TS#2 OX 36 feeder breakers on Q bus in 2014 - Vaughan TS#1 all ABB HKSA breakers in 2009-2010 - Vaughan TS#2 ABB HKSA breakers in 2011-2012
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	The existing 27.6 kV circuit breakers at the following locations have been identified in the Asset Condition Assessment (ACA) Model as requiring replacement due to obsolescence and historical failures. - M1, M3 and M7 OC 36 breakers on Markham TS#2 J bus - Four OX 36 feeder breakers on Markham TS#1 Y bus - All ABB HKSA feeder breakers on Richmond Hill (Lazenby) TS#1 A and B buses
	1a. Main Driver	Obsolescence. The main driver for this project is to maintain system reliaibiity and resolve obsolescence issues. Existing breakers are obsolete in that these types of breaker are no longer manufactured and spare parts are no longer commercially available.
	1b. Priority and Reasons for Priority	Priority is high because this equipment is considered obsolete, has a history of premature failure and has the potential to affect a large number of customers in the event of a failure.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Do nothing alternative is not acceptable due to the severity of failure of these breakers. Failure of the existing equipment would warrant emergency replacement resulting in non-budgeted funding requirements and could result in lengthy customer interruptions. Replacement of failed equipment is expected to be more costly than proactive replacement. Impact on customers can be minimized with proactive replacement.
	2. Safety	The replacement equipment will mitigate the potential safety concerns if one of the existing breakers failured violently.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Replacing the breakers reduces the risk that SF6 gases could be vented into the atmosphere.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:	HKSA and OX 36 breakers are considered obsolete and have a history of premature failure. Spare parts are no longer commercially available.

Project Code	Report Start Year	Number of Years	Scale
101012	2015	6	Dollars

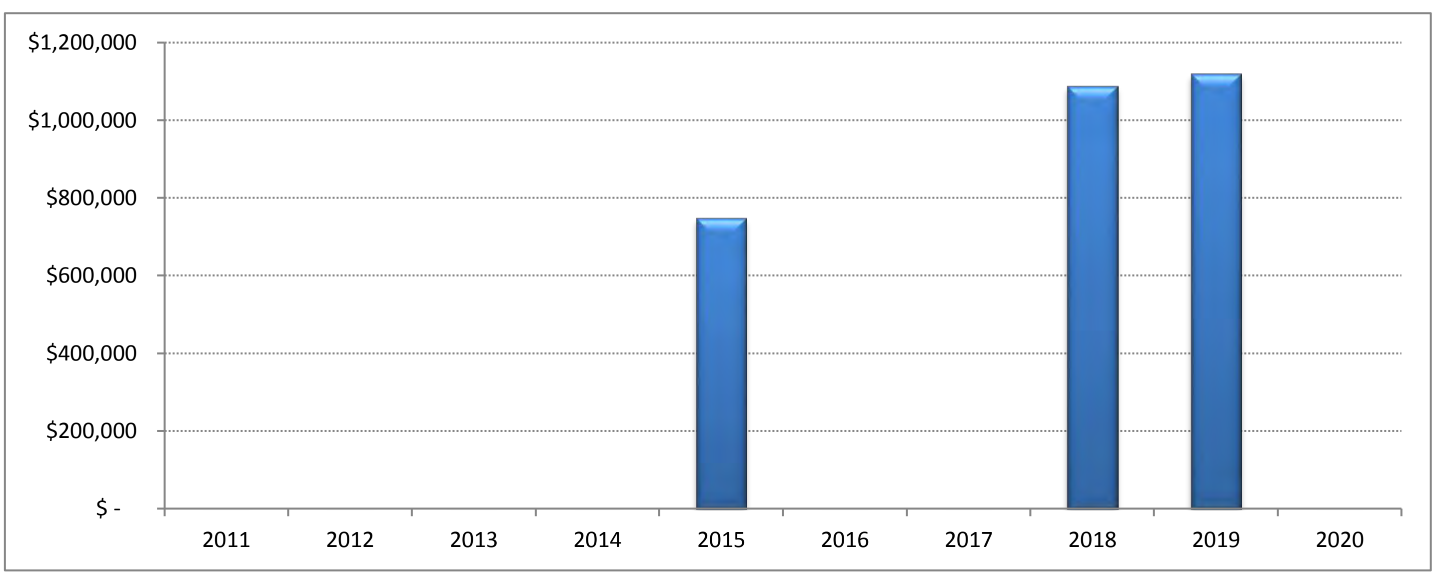
Project Summary Report

Project Name

Planned Circuit Breaker Replacement Markham TS#1&2 & Lazenby TS#1

1. Condition of Asset vs. Typical Life Cycle and Performance Record	At the proposed time of replacement, these circuit breakers will be between 23 and 33 years old, whereas the typical life expectancy of a breaker is 35 years or more. However, GEC OX 36 and ABB HKSA circuit breakers are considered obsolete and have a history of premature failure.
2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure	Approximately 4000
3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)	Frequency of failure is estimated to be 0.1 per breaker per year and is based on typical industry statistics for breakers of this type and condition.
4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)	Failure of one of these circuit breakers could have a wide-spead impact to the supply of electricity to nearby residential, commercial and industrial customers.
5. Value of Customer Impact	High
Factors Affecting Project Timing, if any	Several circuit breaker, switchgear and other replacement projects are scheduled over the next five years. Although all are considered to be of high or very high priority, priorities may shift.
Consequences for O&M System Costs Including Implications of Not Implementing	If the breakers are replaced, maintenance costs will be reduced and parts will be readily available and perhaps not have to be custom made. Failure of the existing equipment would warrant emergency replacement resulting in non-budgeted funding requirements and could result in lengthy customer interruptions. Replacement of failed equipment is expected to be more costly than proactive replacement. Replacement of these breakers will result in standardization and consequently, reduced requirements for spare equipment.
Reliability and Safety Factors	Replacement breakers will be more reliable and pose reduced risk to personnel.
Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits)	From a configuration perspective, this is a like-for-like replacement but the replacement equipment will require reduced maintenance and parts will be readily available.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ 747,766	$ -	$ -	$ 1,087,788	$ 1,119,281	$ -



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	102730	2015	6	Dollars
	Project Name: Station Switchgear Replacement (ACA) 8th Line MS323			

Major Category System Renewal

Project Overview

1. Additional Information	Service Territory	PowerStream North
	Location	Bradford
	Scope	Replacement of 15kV switchgear at 8th Line MS323. The existing line-up is to be replaced with a new metal-clad 15kV switchgear line-up with arc resistant construction that meets PowerStream's standard.
	Justification	The circuit breakers are considered "obsolete" in that they are no longer built or supported by the manufacturer. Spare parts are not commercially available but can be recovered through the cannibalization of stock that we have on hand. Due to operational concerns, System Planning, Station Sustainment and Station Design & Standards have jointly developed the attached plan to replace the obsolete circuit breakers at PowerStream's transformer stations and municipal stations for the next 8 years. The plan is subject to annual assessment of the equipment. Priorities may change.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2017
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Equipment has a long lead time. This risk will be mitigated by ordering the equipment in 2017 for installation in 2018.
	Comparative Information on Equivalent Historical Projects (if any)	Replacements similar to this proposed replacement have been executed a number of times in recent years. Standard materials are used and field crews have the required experience.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	The existing SF6 switchgear has been identified in the Asset Condition Assessment (ACA) Model as requiring replacement due to obsolescence, very poor condition and historical failures. The existing line-up is to be replaced with a new metal-clad 15kV switchgear line-up with arc resistant construction that meets PowerStream's standard and will be housed in a new building.
	1a. Main Driver	Obsolescence. Existing assets are considered obsolete and reaching end of life and are considered a reliability risk.
	1b. Priority and Reasons for Priority	Priority is very high due to the very poor condition of this equipment and the potential to affect a large number of customers in the event of a failure. A failure could result in complete loss of supply from the station requiring load transfer to another station. Such a transfer could be very challenging and take several hours and may result in overloading other facilities.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Failure of the existing equipment would warrant emergency replacement resulting in non-budgeted funding requirements and could result in lengthy customer interruptions. Replacement of failed equipment is expected to be more costly than proactive replacement. Impact on customers can be minimized with proactive replacement.
	2. Safety	Existing switchgear does not meet current safety criteria. An explosive failure of the existing switchgear could seriously injure personnel in the proximity. The proposed new metal-clad 15kV switchgear line-up with arc resistant construction meets PowerStream's standard.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	With the replacement of existing switchgear, the risk of leaks of SF6 gas into the environment will be reduced.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:	From a configuration perspective, this is a like-for-like replacement, however, the proposed replacement equipment is technologically enhanced as compared with the existing equipment. The new equipment is designed to require less maintenance and meets current safety standards.
	1. Condition of Asset vs. Typical Life Cycle and Performance Record	At the time of replacement, the existing switchgear will be nearly 30 years old. Existing switchgear has a history of performance issues and is considered to be in very poor condition.
	2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure	Approximately 2000

Project Code	Report Start Year	Number of Years	Scale
102730	**2015**	**6**	**Dollars**

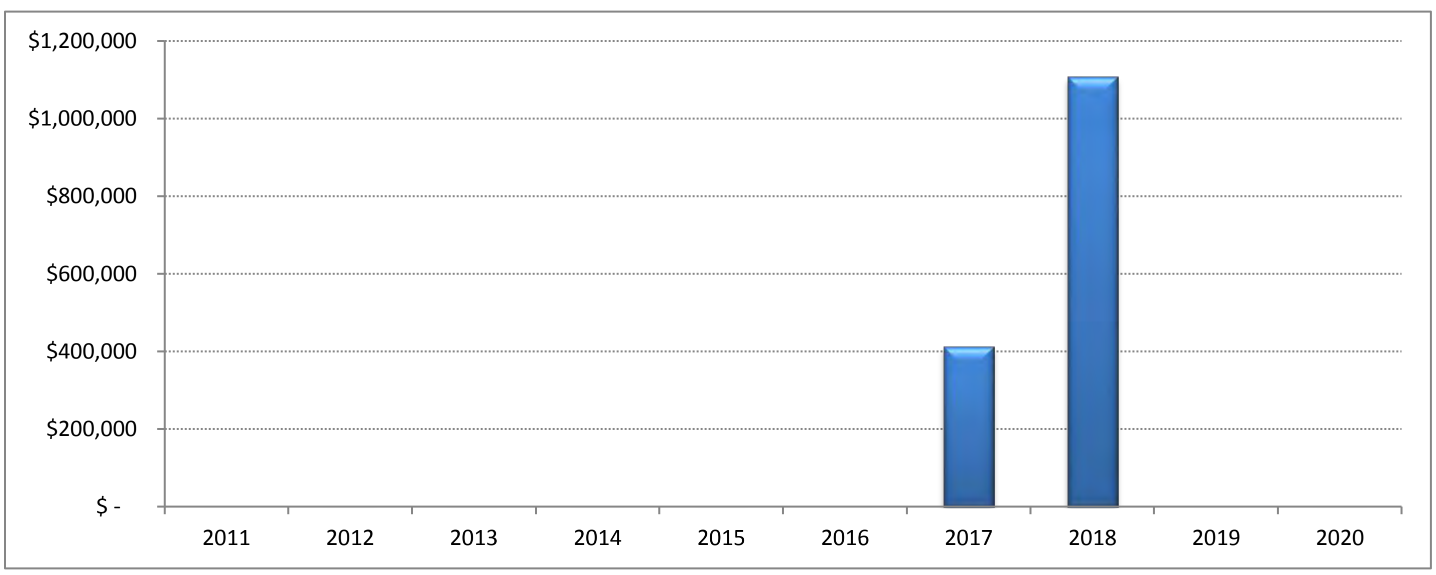
Project Summary Report

Project Name

Station Switchgear Replacement (ACA) 8th Line MS323

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)	Frequency of failure is estimated to be 0.1 per breaker per year and is based on typical industry statistics for breakers of this type and condition. A supply interruption due to a feeder breaker failure would typically be in the order of 2 hours. Failure of the transformer breaker could result in a much longer outage duration.
4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)	Failure of this equipment would negatively impact the electricity supply to many residential, commercial and industrial customers in the area.
5. Value of Customer Impact	High
Factors Affecting Project Timing, if any	Eight similar switchgear replacement projects are scheduled over the next five years. Although all are considered to be of high or very high priority, priorities among these projects may shift.
Consequences for O&M System Costs Including Implications of Not Implementing	Existing switchgear has higher maintenance costs than the proposed replacement equipment. Failure of the existing equipment would warrant emergency replacement resulting in non-budgeted funding requirements and could result in lengthy customer interruptions. Replacement of failed equipment is expected to be more costly than proactive replacement.
Reliability and Safety Factors	The proposed replacement equipment is more reliable and safer due to arc resistant construction.
Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits)	From a configuration perspective, this is a like-for-like replacement but the replacement equipment is more technologically advanced, requiring reduced maintenance and has improved safety features.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ 412,339	$ 1,106,666	$ -	$ -



Power Stream Project Summary Report	Project Code 102732	Report Start Year 2015	Number of Years 6	Scale Dollars
	Project Name: Station Switchgear Replacement (ACA) Patterson MS336			

Major Category System Renewal

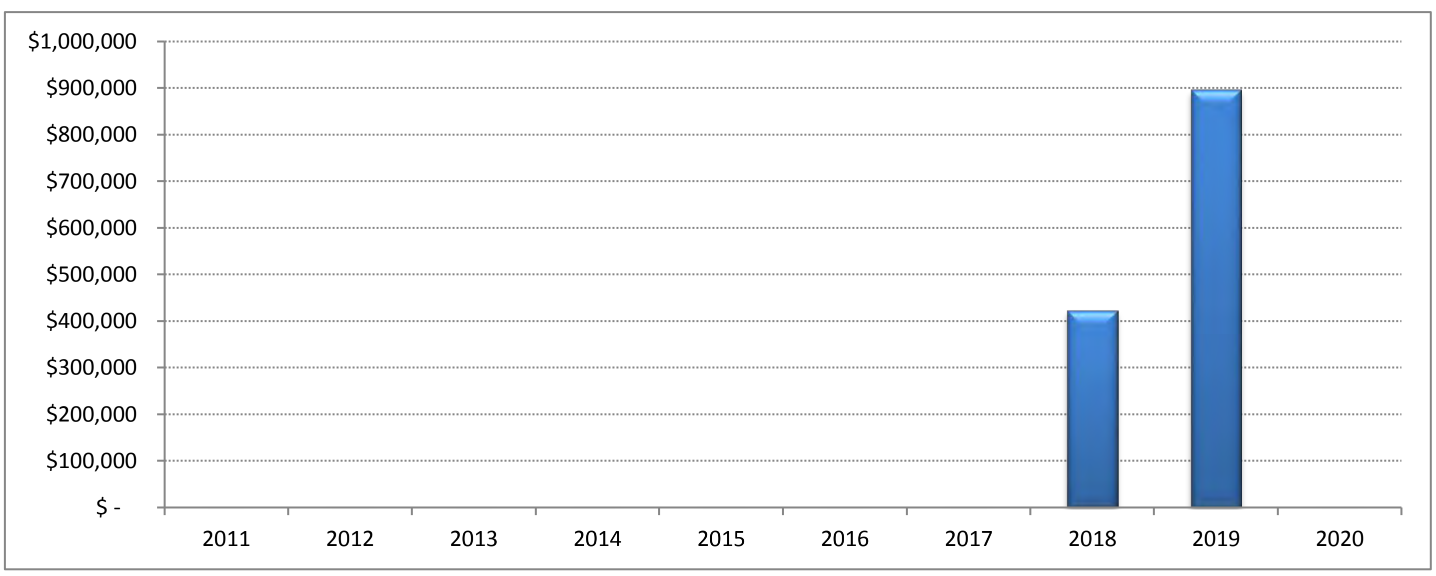
Project Overview

1. Additional Information	Service Territory	PowerStream North
	Location	Alliston
	Scope	Replacement of 15kV switchgear at Patterson MS336. The existing line-up is to be replaced with a new metal-clad 15kV switchgear line-up with arc resistant construction that meets PowerStream's standard.
	Justification	The circuit breakers are considered "obsolete" in that they are no longer built or supported by the manufacturer. Spare parts are not commercially available but can be recovered through the cannibalization of stock that we have on hand. Due to operational concerns, System Planning, Station Sustainment and Station Design & Standards have jointly developed the attached plan to replace the obsolete circuit breakers at PowerStream's transformer stations and municipal stations for the next 8 years. The plan is subject to annual re-assessment of the equipment.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2018
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Equipment has a long lead time. This risk will be mitigated by ordering the equipment in 2018 for installation in 2019.
	Comparative Information on Equivalent Historical Projects (if any)	Replacements similar to this proposed work have been executed a number of times in recent years. Standard materials are used and field crews have the required experience.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	The existing SF6 switchgear has been identified in the Asset Condition Assessment (ACA) Model as requiring replacement due to obsolescence, poor condition and historical failures. The existing line-up is to be replaced with a new metal-clad 15kV switchgear line-up with arc resistant construction that meets PowerStream's standard and will be housed in a new building.
	1a. Main Driver	Obsolesence. Existing assets are considered obsolete and reaching end of life and are considered a reliability risk.
	1b. Priority and Reasons for Priority	Priority is very high due to the poor condition of the existing equipment and the potential to affect a large number of customers in the event of a failure. A failure could result in complete loss of supply from the station requiring load transfer to another station. Such a transfer could be very challenging and take several hours and may result in overloading other facilities.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Failure of the existing equipment would warrant emergency replacement resulting in non-budgeted funding requirements and could result in lengthy customer interruptions. Replacement of failed equipment is expected to be more costly than proactive replacement. Impact on customers can be minimized with proactive replacement.
	2. Safety	Existing switchgear does not meet current safety criteria. The replacement equipment will mitigate the potential safety concerns if one of the existing breakers failured violently. The proposed new metal-clad 15kV switchgear line-up with arc resistant construction meets PowerStream's standards.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	With the replacement of existing switchgear, the risk of leaks of SF6 gas into the environment will be reduced.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:	From a configuration perspective, this is a like-for-like replacement, however, the proposed replacement equipment is technologically enhanced as compared with the existing equipment. The new equipment is designed to require less maintenance and meets current safety standards.
	1. Condition of Asset vs. Typical Life Cycle and Performance Record	At the time of replacement, the existing switchgear will be nearly 30 years old. Existing switchgear has a history of performance issues and is considered to be in poor condition.
	2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure	Approximately 1500

Project Summary Report	Project Code **102732**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Station Switchgear Replacement (ACA) Patterson MS336			

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)	Frequency of failure is estimated to be 0.1 per breaker per year and is based on typical industry statistics for breakers of this type and condition. A supply interruption due to a feeder breaker failure would typically be in the order of 2 hours until load transfers could be made.
4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)	Failure of this equipment would negatively impact the supply of electricity to many residential, commercial and industrial customers.
5. Value of Customer Impact	High
Factors Affecting Project Timing, if any	Eight similar switchgear replacement projects are scheduled over the next five years. Although all are considered to be of high or very high priority, priorities among these projects may shift.
Consequences for O&M System Costs Including Implications of Not Implementing	Existing switchgear has higher maintenance costs than the proposed replacement equipment. Failure of the existing equipment would warrant emergency replacement resulting in non-budgeted funding requirements and could result in lengthy customer interruptions. Replacement of failed equipment is expected to be more costly than proactive replacement.
Reliability and Safety Factors	The proposed replacement equipment is more reliable and safer due to arc resistant construction.
Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits)	From a configuration perspective, this is a like-for-like replacement but the replacement equipment is more technologically advanced, requiring reduced maintenance and has improved safety features.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 421,896	$ 895,805	$ -



Project Summary Report	Project Code **100462**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Letitia MS (MS413)- Increase Capacity from 5MVA to 10MVA			

Major Category **System Service**

Project Overview

1. Additional Information	Service Territory	PowerStream North
	Location	Barrie
	Scope	The project entails design and construction needed to increase the capacity at Letitia MS413 in Barrie from 5MVA to 10MVA and add one 4.16 kV feeder. The upgraded substation will include a 10 MVA 44/4.16kV transformer, four 4.16kV vacuum circuit breakers and feeders. The substation is to be in-service by summer 2019. The project includes engineering design, purchase of station equipment, approvals, substation construction, equipment installation, and commissioning.
	Justification	The proposed new substation is required to provide capacity relief to Letitia MS413. The 2013 summer peak load on MS413 was 112% of the ONAN rating. The contingency maximum station load of 7.6MVA may be exceeded in the near future in the event of an adjacent station load transfer under contingency conditions.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2018
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The greatest risk to completion is procuring the required station equipment to ensure it is available for installation and commissioning prior to the 2019 summer peak.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	The project entails design and construction needed to increase the capacity at Letitia MS413 in Barrie from 5MVA to 10MVA and add one 4.16 kV feeder. The upgraded substation will include a 10 MVA 44/4.16kV transformer, four 4.16kV vacuum circuit breakers and feeders. The substation is to be in-service by summer 2019. The project includes engineering design, purchase of station equipment, approvals, substation construction, equipment installation, and commissioning.
	1a. Main Driver	Support Capacity Delivery. The main driver of the project is to provide capacity relief to Letitia MS413. The 2013 summer peak load on MS413 was 112% of the ONAN rating. The contingency maximum station load of 7.6MVA may be exceeded in the near future in the event of an adjacent station load transfer under contingency conditions.
	1b. Priority and Reasons for Priority	The poject is high priority. The 2013 summer peak load on MS413 was 112% of the ONAN rating and contingency transfer capacity will become limited in the near future.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	The substation upgrade would improve the reliability of service to existing customers through the addition of a fourth feeder and provide a station capacity increase to accommodate future growth. The resulting increase in station capacity would also allow contingency transfers from any adjacent out-of-service stations without exceeding the contingency maximum station load. A possible alternative to the single 10MVA 44/4.16kV station transformer configuration would be to implement a 2x5MVA 44/4.16kV configuration. The 2x5MVA alternative provides redundancy at the station; however, initial cost estimates are 1.5 times greater than the cost of a single 10MVA station. The additional cost is difficult to justify given the available transfer capability to adjacent stations in the event of a transformer outage at the upgraded station and the use of 10MVA transformers at all other substations in the area. The remaining 'do-nothing' alternative is not via because the 2013 summer peak load on MS413 was 112% of the ONAN rating and contingency transfer capacity will become limited in the near future.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.

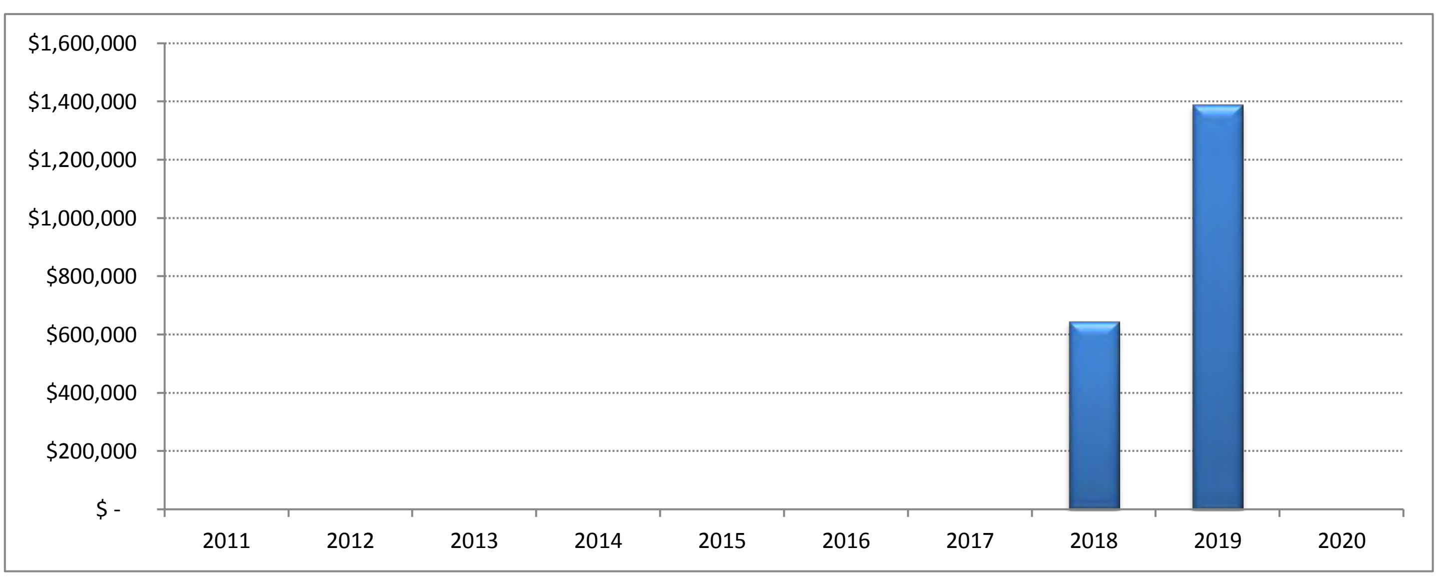
Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100462	2015	6	Dollars

Project Name

Letitia MS (MS413)- Increase Capacity from 5MVA to 10MVA

Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
Identify any reliability , efficiency, safety or coordination benefits	The substation upgrade would improve the reliability of service to existing customers through the addition of a fourth feeder and provide a station capacity increase to accommodate future growth. The resulting increase in station capacity would also allow contingency transfers from any adjacent out-of-service stations without exceeding the contingency maximum station load.
Factors Affecting Timing/Priority	Procuring the required station equipment to ensure it is available for installation and commissioning prior to the 2019 summer peak may affect the timing of the substation construction.
Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The substation upgrade would improve the reliability of service to existing customers through the addition of a fourth feeder and provide a station capacity increase to accommodate future growth. The resulting increase in station capacity would also allow contingency transfers from any adjacent out-of-service stations without exceeding the contingency maximum station load. A possible alternative to the single 10MVA 44/4.16kV station transformer configuration would be to implement a 2x5MVA 44/4.16kV configuration. The 2x5MVA alternative provides redundancy at the station; however, initial cost estimates are 1.5 times greater than the cost of a single 10MVA station. The additional cost is difficult to justify given the available transfer capability to adjacent stations in the event of a transformer outage at the upgraded station and the use of 10MVA transformers at all other substations in the area. The remaining 'do-nothing' alternative is not viable because the 2013 summer peak load on MS413 was 112% of the ONAN rating and contingency transfer capacity will become limited in the near future.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 644,864	$ 1,389,927	$ -



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100043	2015	6	Dollars

Project Name

Painswick South MS: New 44-13.8kV, 20 MVA, 4-Feeder Substation

Major Category	System Service	

Project Overview

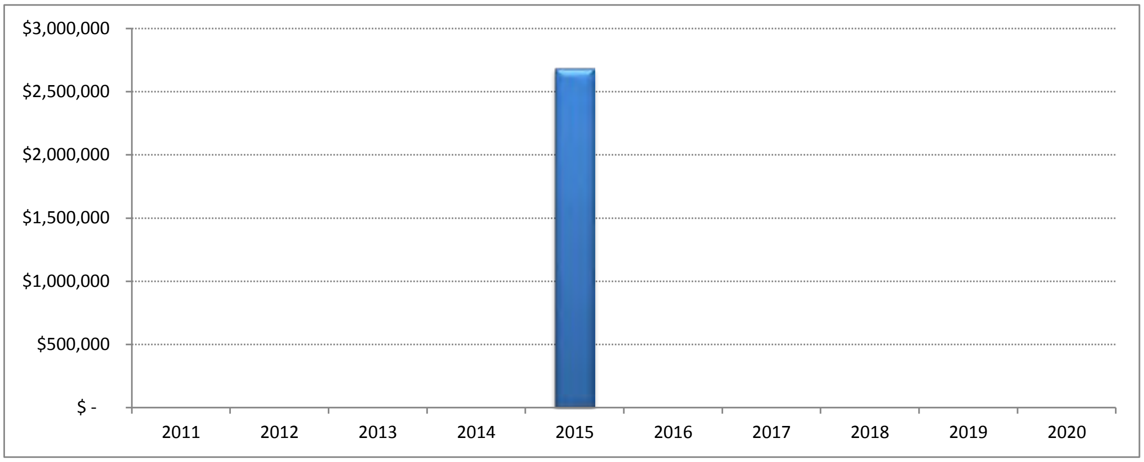
1. Additional Information	Service Territory	PowerStream North
	Location	Yonge Street and Mapleview Drive area in Barrie.
	Scope	The project entails the design and construction of a new 44/13.8kV, 20MVA, 4 feeder substation in the vicinity of Yonge Street and Mapleview Drive in Barrie. The project includes engineering design, purchase of station equipment, approvals, substation construction, equipment installation, and commissioning.
	Justification	The proposed substation is required to provide capacity relief to Big Bay Point MS304 and Huronia MS307. The 2013 summer peak load on MS304 was 104% of the ONAN rating, while MS307 will exceed its ONAN rating in 2015. Capacity relief is required for MS304 in 2016, since the station will exceed its maximum normal load rating at that time. The proposed station is also required to establish a "triad" back-up model. Currently load transfers are possible between MS304 and MS307, with limited transfers available with Park Place MS308. In the event of a transformer failure at MS304 and the subsequent transfer of 50% load to each adjacent station, the new loading at MS307 and MS308 would exceed the contingency maximum load by 2017.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	311302
	Job Number	C00851
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	There is a potential risk of delay when attaining the necessary approvals for the new substation. There is also risk associated with potential delays in equipment delivery and unforeseen complications in construction and installation.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	The project entails the design and construction of a new 44/13.8kV, 20MVA, 4 feeder substation in the vicinity of Yonge Street and Mapleview Drive in Barrie. The project includes engineering design, purchase of station equipment, approvals, substation construction, equipment installation, and commissioning.
	1a. Main Driver	Support Capacity Delivery. The main driver of the project is to provide capacity relief to Big Bay Point MS304 and Huronia MS307. The 2013 summer peak load on MS304 was 104% of the ONAN rating, while MS307 will exceed its ONAN rating in 2015. Capacity relief is required for MS304 in 2016, since the station will exceed its maximum normal load rating at that time. An additional driver is to establish a station back-up under contingency conditions using the "Triad" model. Under the current conditions, load transfers are possible between MS304 and MS307, with limited transfers available with Park Place MS308. In the event of a transformer failure at MS304 and the subsequent transfer of 50% load to each adjacent station, the new loading at MS307 and MS308 would exceed the contingency maximum load by 2017.
	1b. Priority and Reasons for Priority	Very high priority is given to the new station because the 2013 summer peak has already exceeded the MS304 ONAN rating and contingency transfers among existing adjacent stations cannot be accommodated beyond 2017. Investments have already been made to purchase, clear, and prepare the proposed substation land for the start of construction.

Project Summary Report	Project Code **100043**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Painswick South MS: New 44-13.8kV, 20 MVA, 4-Feeder Substation			

	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	The new substation would improve the reliability of service to existing customers and future developments. The resulting triad contingency back-up configuration would provide enough capacity to transfer an out-of-service station load across the other existing stations. The 'do-nothing' alternative is not viable because the 2013 summer peak load on MS304 was 104% of the ONAN rating, while MS307 will exceed its ONAN rating in 2015. Capacity relief is required for MS304 in 2016, since the station will exceed its maximum normal load rating at that time. The do-nothing alternative would not allow the accommodation of future load growth in the area or provide adequate capacity for load transfers in contingency conditions. The alternative to expand the Huronia MS307 site was considered, however, it was rejected because the station has an older medal clad outdoor switchgear manufactured in 1978. Due to the age of the MS307 breakers, replacement parts are obsolete. There is no building at this site and the property foot print is not large enough to build a structure to support the clearances required for a larger 20MVA station. Limited load transfers between MS304, MS307, and MS308 can take place until 2015 while exceeding the ONAN rating at MS304 and MS307. Beyond this, there are no other viable and economic alternatives and relief will be required before the summer of 2016.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	The new substation will provide reliability benefits by providing the required capacity for existing and future developments in the area and providing the required back-up capability during contingency conditions through the triad configuration.
	Factors Affecting Timing/Priority	Factors that could affect the timing of construction and commissioning include potential delays in equipment procurement and delivery, as well as unforeseen complications in station construction and installation.
	Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The new substation would improve the reliability of service to existing customers and future developments. The resulting triad contingency back-up configuration would provide enough capacity to transfer an out-of-service station load across the other existing stations. The 'do-nothing' alternative is not viable because the 2013 summer peak load on MS304 was 104% of the ONAN rating, while MS307 will exceed its ONAN rating in 2015. Capacity relief is required for MS304 in 2016, since the station will exceed its maximum normal load rating at that time. The do-nothing alternative would not allow the accommodation of future load growth in the area or provide adequate capacity for load transfers in contingency conditions. The alternative to expand the Huronia MS307 site was considered, however, it was rejected because the station has an older medal clad outdoor switchgear manufactured in 1978. Due to the age of the MS307 breakers, replacement parts are obsolete. There is no building at this site and the property foot print is not large enough to build a structure to support the clearances required for a larger 20MVA station. Limited load transfers between MS304, MS307, and MS308 can take place until 2015 while exceeding the ONAN rating at MS304 and MS307. Beyond this, there are no other viable and economic alternatives and relief will be required before the summer of 2016.

Project Summary Report	Project Code 100043	Report Start Year 2015	Number of Years 6	Scale Dollars
	Project Name Painswick South MS: New 44-13.8kV, 20 MVA, 4-Feeder Substation			

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ 2,690,054	$ -	$ -	$ -	$ -	$ -



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	102412	2015	6	Dollars

Project Name

Patterson MS#2 - New 44-13.8kV, 2x5 MVA, 2-feeders MS

Major Category **System Service**

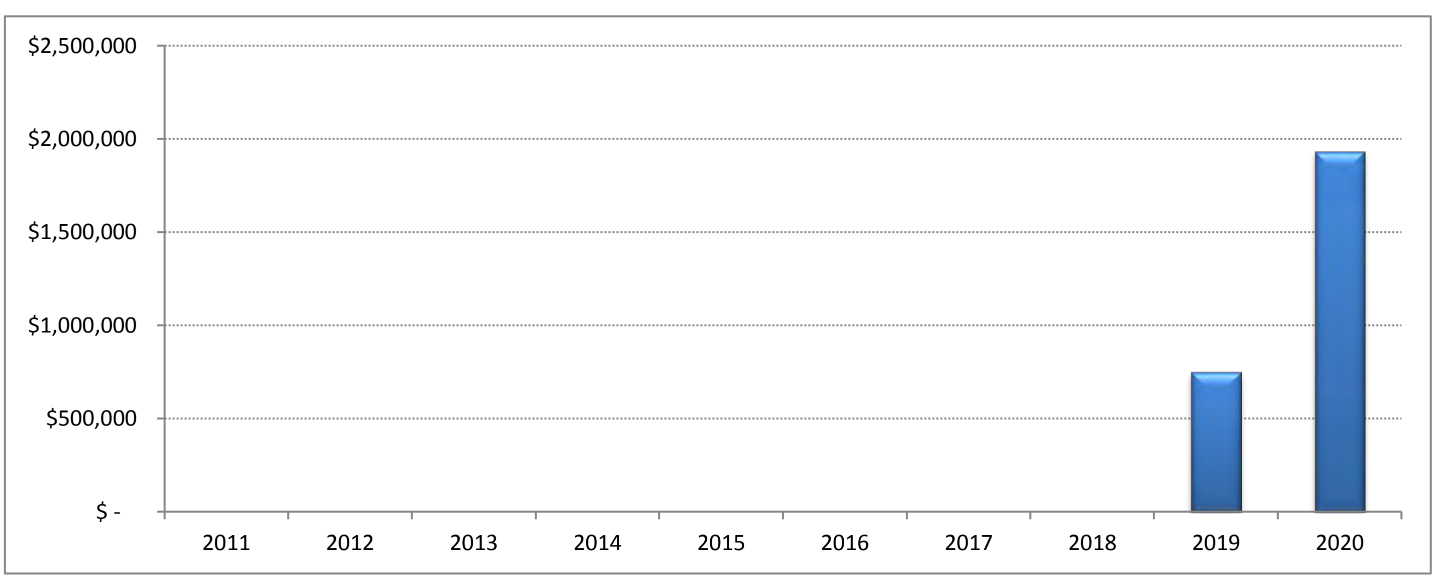
Project Overview

1. Additional Information	Service Territory	PowerStream North
	Location	Beeton
	Scope	The project entails the purchase of a station site in the vicinity of Dayfoot Street and Highland Road in Beeton, suitable for constructing a new 2x5MVA, 44-13.8kV, 2-feeder municipal substation to be in-service by summer 2022. The project includes engineering design, purchase of station equipment, approvals, substation construction, equipment installation, and commissioning.
	Justification	The proposed new substation is required to provide back-up under contingency conditions. Currently there is only one substation located in Beeton; Patterson MS336. The entire Beeton 13.8kV network is supplied from the single MS336. Upon loss of Patterson MS there are no possible contingency transfers to other substations. The new 2x5MVA Patterson MS#2 would provide redundancy in the form of two separate transformers at the substation, which would allow transfer capability in case of loss of one of the station transformers or loss of MS336. In addition, the proposed new substation is required to provide capacity for the new Sorbara (600 home) residential development to be built over the next five years. This additional 1.5MVA of residential load will cause the existing Patterson MS336 to exceed its ONAN rating in the summer of 2021.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2019
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The greatest risk to completion is securing the required land in the vicinity of Dayfoot Street and Highland Road in Beeton. The area surrounding the proposed site is being developed by the Sorbara, Alliance, and Rayville residential subdivisions and there is a risk that the property cost will rise and/or the preferred site will not be available which will mean additional line (44kV and 13.8kV) costs will be incurred.
	Comparative Information on Equivalent Historical Projects (if any)	Painswick South MS, a new 44/13.8kV 20MVA, 4-feeder substation in Barrie, is currently under construction pending completion in 2016. There was difficulty locating and securing available land for the substation, resulting in the purchase and demolition of two residential homes in order to secure a property. The project highlighted the importance of identifying and purchasing property as early as possible to ensure it is available when a new substation is required.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	The project entails the purchase of a station site in the vicinity of Dayfoot Street and Highland Road in Beeton, suitable for constructing a new 2x5MVA, 44-13.8kV, 2-feeder municipal substation to be in-service by summer 2022. The project includes engineering design, purchase of station equipment, approvals, substation construction, equipment installation, and commissioning.
	1a. Main Driver	Support Capacity Delivery. The main driver of the project is to provide back-up under contingency conditions. Currently there is only one substation located in Beeton; Patterson MS336. The entire Beeton 13.8kV network is supplied from the single MS336. Upon loss of Patterson MS there are no possible contingency transfers to other substations. The new 2x5MVA Patterson MS#2 would provide redundancy in the form of two separate transformers at the substation, which would allow transfer capability in case of loss of one of the station transformers or loss of MS336. An additional drivers is to provide capacity for the new Sorbara (600 home) residential development to be built over the next five years. This additional 1.5MVA of residential load will cause the existing Patterson MS336 to exceed its ONAN rating in the summer of 2021.
	1b. Priority and Reasons for Priority	The project is high priority. Currently there is only one substation located in Beeton; Patterson MS336. The entire Beeton 13.8kV network is supplied from the single MS336. Upon loss of Patterson MS there are no possible contingency transfers to other substations. In addition, the vicinity of the proposed station site is being developed by the Sorbara, Alliance, and Rayville residential subdivisions and there is a risk that the property cost will rise and/or the preferred site will not be available which will mean additional line (44kV and 13.8kV) costs will be incurred.

Project Summary Report	Project Code **102412**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Patterson MS#2 - New 44-13.8kV, 2x5 MVA, 2-feeders MS			

	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	The new substation would improve the reliability of service to the Beeton area by providing back-up under contingency conditions. The new 2x5MVA Patterson MS#2 would provide redundancy in the form of two separate transformers at the substation, which would allow transfer capability in case of loss of one of the station transformers or loss of MS336. The 'do-nothing' alternative is not viable because there is currently no back-up substation in Beeton under contingency conditions. The proposed 2x5MVA substation configuration was selected over the alternative 1x10MVA configuration because the dual transformer design allows transfer capability in case of loss of one of the station transformers and also establishes a triad configuration relative to other station transformers.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	The new substation will provide reliability benefits by providing a backup under contingency conditions.
	Factors Affecting Timing/Priority	The availability of land for sale in the vicinity of Dayfoot Street and Highland Road will affect the timing of the substation construction.
	Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The new substation would improve the reliability of service to the Beeton area by providing back-up under contingency conditions. The new 2x5MVA Patterson MS#2 would provide redundancy in the form of two separate transformers at the substation, which would allow transfer capability in case of loss of one of the station transformers or loss of MS336. The 'do-nothing' alternative is not viable because there is currently no back-up substation in Beeton under contingency conditions. The proposed 2x5MVA substation configuration was selected over the alternative 1x10MVA configuration because the dual transformer design allows transfer capability in case of loss of one of the station transformers and also establishes a triad configuration relative to other station transformers.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 749,000	$ 1,931,978



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	101569	2015	6	Dollars
	Project Name	New MS, Dufferin South MS#2 - Alliston		

Major Category System Service

Project Overview

1. Additional Information	Service Territory	PowerStream North
	Location	Dufferin St and Industrial Pkwy area, Alliston
	Scope	The project entails the purchase of a station site in the vicinity of Dufferin St and Industrial Pkwy in Alliston, and constructing a new 2x10MVA, 44/13.8 kV, 4 feeder municipal substation to be in-service by summer 2019. The project includes engineering design, purchase of station equipment, approvals, substation construction, equipment installation, and commissioning.
	Justification	The proposed new Dufferin South MS#2 substation is required to provide capacity relief to 14th Line MS (MS331-T1/T2). With a proposed 6MVA Walton ICI development, as well as a 3.5MVA Tall Tree residential development being completed within the next four to six years, 14th Line MS (MS331) is expected to exceed its ONAN rating in the summer of 2016/2017. The contingency maximum load for MS331-T2 is 20.2MVA, while the contingency maximum load for the nearby MS330 for any potential transfers is only 15.1MVA. As of 2016, if one of the substations experiences an outage the backup transfer station will exceed the contingency maximum rating. The new 2x10MVA Dufferin South MS#2 would provide a triad configuration that would allow the load from either MS331-T2 or MS330 to be divided between the new Dufferin South MS#2 and the remaining station during contingency conditions. The Dufferin South MS#2 land purchase will have to take place in 2016 due to the limited availability of land in the area and the requirement for the new substation to be in-service no later than summer 2019.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2016
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The greatest risk to completion is securing the required land in the vicinity of Dufferin Street and Industrial Parkway in Alliston. The area surrounding the proposed site is part of the Walton ICI development and there is a risk that the property cost will rise and/or the preferred site will not be available which will mean additional line (44kV and 13.8kV) costs will be incurred.
	Comparative Information on Equivalent Historical Projects (if any)	Painswick South MS, a new 44/13.8kV 20MVA, 4-feeder substation in Barrie, is currently under construction pending completion in 2016. There was difficulty locating and securing available land for the substation, resulting in the purchase and demolition of two residential homes in order to secure a property. The project highlighted the importance of identifying and purchasing property as early as possible to ensure it is available when a new substation is required.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	The project entails the purchase of a station site in the vicinity of Dufferin St and Industrial Pkwy in Alliston, and constructing a new 2x10MVA, 44/13.8 kV, 4 feeder municipal substation to be in-service no later than summer 2019. The project includes engineering design, purchase of station equipment, approvals, substation construction, equipment installation, and commissioning.
	1a. Main Driver	Support Capacity Delivery. The main driver of the project is to provide capacity relief to 14th Line MS (MS331-T1/T2). With a proposed 6MVA Walton ICI development, as well as a 3.5MVA Tall Tree residential development being completed within the next four to six years, 14th Line MS (MS331) is expected to exceed its ONAN rating in the summer of 2016/2017. An additional project driver is contingency capacity. The contingency maximum load for MS331-T2 is 20.2MVA, while the contingency maximum load for the nearby MS330 for any potential transfers is only 15.1MVA. As of 2016, if one of the substations experiences an outage the backup transfer station will exceed the contingency maximum rating. The new 2x10MVA Dufferin South MS#2 would provide a triad configuration that would allow the load from either MS331-T2 or MS330 to be divided between the new Dufferin South MS#2 and the remaining station during contingency conditions.

Project Summary Report	Project Code **101569**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name New MS, Dufferin South MS#2 - Alliston			

	1b. Priority and Reasons for Priority	The area surrounding the proposed site is part of the Walton ICI development and there is a risk that the property cost will rise and/or the preferred site will not be available which will mean additional line (44kV and 13.8kV) costs will be incurred. In addition, exceeding the contingency maximum load at MS330 and MS331-T1 beyond 2016 during contingency transfers should be addressed promptly.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	The new substation would improve the reliability of service to existing customers, the future 6MVA Walton ICI development, and the 1,400 home Tall Tree residential development. In addition, the resulting triad contingency back-up configuration would provide enough capacity to transfer an out-of-service station load across the other existing stations. The 'do-nothing' alternative provides limited load transfers to take place between MS331 to MS330 but additional transfers beyond 2017 are not recommended since relief will be required before the summer of 2019 to accommodate the proposed Walton and Tall Tree developments. In addition, the do-nothing alternative would not accommodate contingency transfers between MS331 and MS330 beyond 2016 due to the exceeded contingency maximum load and the lack of other 13.8kV substations in the vicinity. The area surrounding the proposed site is being developed by Walton and there is a risk that the property cost will rise and/or the preferred site will not be available which will mean additional line (44kV and 13.8kV) costs will be incurred.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	The new substation will offer reliability benefits by providing the required capacity for a proposed 6MVA Walton ICI development, as well as a 3.5MVA Tall Tree residential development. In addition, the substation will provide the required back-up capability during contingency conditions through the triad configuration.
	Factors Affecting Timing/Priority	The availability of land for sale in the vicinity of Dufferin St and Industrial Pkwy in Alliston will affect the timing of the substation construction.
	Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The new substation would improve the reliability of service to existing customers, the future 6MVA Walton ICI development, and the 1,400 home Tall Tree residential development. In addition, the resulting triad contingency back-up configuration would provide enough capacity to transfer an out-of-service station load across the other existing stations. The 'do-nothing' alternative provides limited load transfers to take place between MS331 to MS330 but additional transfers beyond 2017 are not recommended since relief will be required before the summer of 2019 to accommodate the proposed Walton and Tall Tree developments. In addition, the do-nothing alternative would not accommodate contingency transfers between MS331 and MS330 beyond 2016 due to the exceeded contingency maximum load and the lack of other 13.8kV substations in the vicinity. The area surrounding the proposed site is being developed by Walton and there is a risk that the property cost will rise and/or the preferred site will not be available which will mean additional line (44kV and 13.8kV) costs will be incurred.

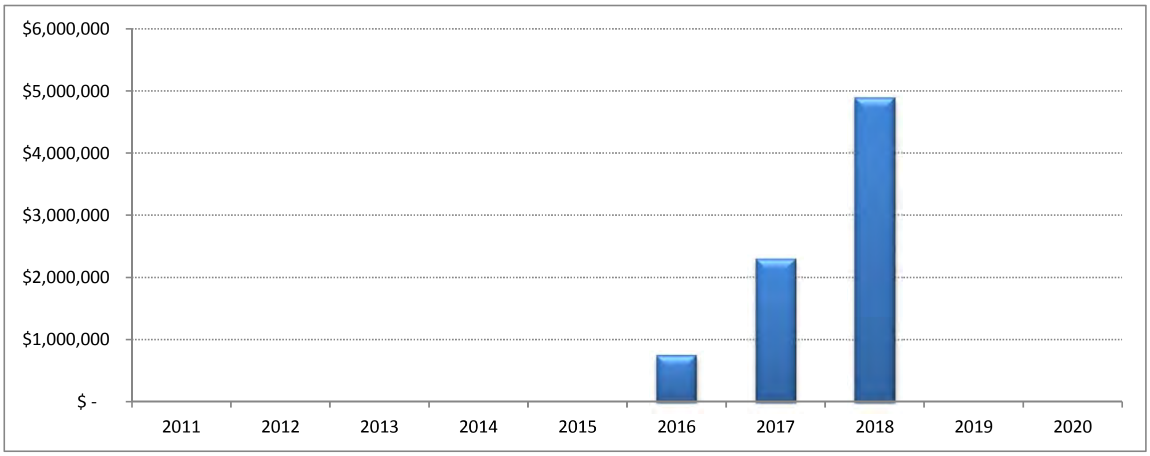
Project Code	Report Start Year	Number of Years	Scale
101569	**2015**	**6**	**Dollars**

Project Summary Report

Project Name

New MS, Dufferin South MS#2 - Alliston

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ 749,000	$ 2,299,074	$ 4,899,189	$ -	$ -



Power Stream **Project Summary Report**	Project Code **101542**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name New MS, Harvie Rd. MS - Barrie			

Major Category **System Service**

Project Overview

1. Additional Information	Service Territory	PowerStream North
	Location	Harvie Rd and Veterans Drive, Barrie
	Scope	The project entails the purchase of a station site in the vicinity of Harvie Road and Veterans Drive in Barrie, and constructing a new 44/13.8kV, 20MVA, 4 feeder municipal substation to be in-service by summer 2020. The project includes engineering design, purchase of station equipment, approvals, substation construction, equipment installation, and commissioning.
	Justification	The proposed new Substation is required to provide capacity relief to Holly MS (MS305) and Ferndale S. MS (MS303). The 2013 summer peak load on MS305 & MS303, was 102% and 95% of the ONAN rating, respectively. Capacity relief for MS305 & MS303 is required in 2016 and 2019, respectively. Contingency backup between MS303 & MS305 exceeded the contingency maximum load of 33.5MVA at each station by 132% during the 2013 summer peak. The limited transfer of 50% MS305 load during contingency conditions results in the contingency maximum load being exceeded at MS303 & MS308 in 2015 and 2018, respectively. The Harvie land purchase has been deferred in previous years due to budget constraints, but the limited availability of land in the area and the requirement for Harvie MS to be in-service by summer 2020 dictates that the land needs to be purchased in 2016.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2016/2020
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The greatest risk to completion is securing the required land in the vicinity of Harvie Road and Veterans Drive in Barrie. The area surrounding the proposed site is fast being developed and there is a risk that the property cost will rise and/or the preferred site will not be available which will mean additional line (44kV and 13.8kV) costs will be incurred.
	Comparative Information on Equivalent Historical Projects (if any)	Painswick South MS, a new 44/13.8kV 20MVA, 4-feeder substation in Barrie, is currently under construction pending completion in 2016. There was difficulty locating and securing available land for the substation, resulting in the purchase and demolition of two residential homes in order to secure a property. The project highlighted the importance of identifying and purchasing property as early as possible to ensure it is available when a new substation is required.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	The project entails the purchase of a station site in the vicinity of Harvie Road and Veterans Drive in Barrie, and constructing a new 44/13.8kV, 20MVA, 4 feeder municipal substation to be in-service by summer 2020. The project includes engineering design, purchase of station equipment, approvals, substation construction, equipment installation, and commissioning.
	1a. Main Driver	Support Capacity Delivery. The main driver of the project is to provide capacity relief to Holly (MS305) and Ferndale (MS303) which experienced a 2013 summer peak load of 102% and 95% of their ONAN rating, respectively. Capacity relief for MS305 & MS303 is required in 2016 and 2019, respectively. An additional driver is to establish a station back-up under contingency conditions using the "Triad" model. Under the current conditions, the loss of a station transformer during the summer peak period would not allow all station load to be supplied by the adjacent stations. Contingency backup between MS303 & MS305 exceeded the contingency maximum load of 33.5MVA at each station by 132% during the 2013 summer peak. The limited transfer of 50% MS305 load during contingency conditions results in the contingency maximum load being exceeded at MS303 & MS308 in 2015 and 2018, respectively.
	1b. Priority and Reasons for Priority	The vicinity of the proposed station site is fast being developed and therefore there is a risk that the property cost will rise and/or the preferred site will not be available which will mean additional line (44kV and 13.8kV) costs will be incurred. In addition, exceeding the contingency maximum load at MS303, MS305, and MS308 beyond 2015 during contingency transfers should be addressed promptly.

Project Code	Report Start Year	Number of Years	Scale
101542	2015	6	Dollars

Project Summary Report

Project Name

New MS, Harvie Rd. MS - Barrie

	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	The new substation would improve the reliability of service to existing customers and future developments. The resulting Triad contingency back-up configuration would provide enough capacity to transfer an out-of-service station load across the other existing stations. The 'do-nothing' alternative is not recommended because Holly (MS305) and Ferndale (MS303) have already experienced a 2013 summer peak load of 102% and 95% of their ONAN rating, respectively, and capacity relief for MS305 & MS303 is required in 2016 and 2019, respectively. The do-nothing alternative would not allow the accommodation of future load growth in the area or provide adequate capacity for load transfers in contingency conditions. In addition, the area surrounding the proposed site is fast being developed and there is a risk that the property cost will rise and/or the preferred site will not be available which will mean additional line (44kV and 13.8kV) costs will be incurred.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	The new substation will provide reliability benefits by providing the required capacity for the proposed future developments in the area and providing the required back-up capability during contingency conditions through the Triad configuration.
	Factors Affecting Timing/Priority	The availability of land for sale in the vicinity of Harvie Road and Veterans Drive will affect the timing of the substation construction.
	Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The new substation would improve the reliability of service to existing customers and future developments. The resulting Triad contingency back-up configuration would provide enough capacity to transfer an out-of-service station load across the other existing stations. The 'do-nothing' alternative is not recommended because Holly (MS305) and Ferndale (MS303) have already experienced a 2013 summer peak load of 102% and 95% of their ONAN rating, respectively, and capacity relief for MS305 & MS303 is required in 2016 and 2019, respectively. The do-nothing alternative would not allow the accommodation of future load growth in the area or provide adequate capacity for load transfers in contingency conditions. In addition, the area surrounding the proposed site is fast being developed and there is a risk that the property cost will rise and/or the preferred site will not be available which will mean additional line (44kV and 13.8kV) costs will be incurred.

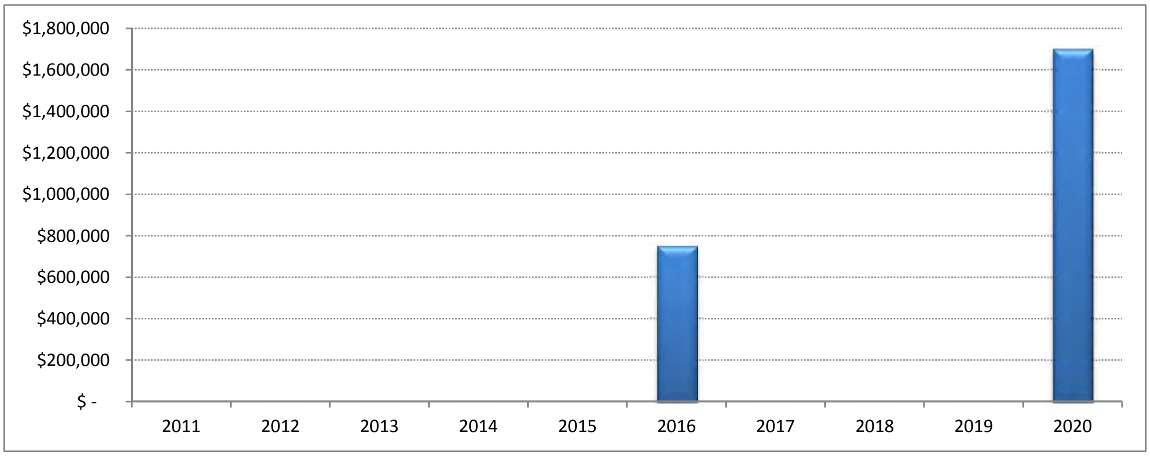
Project Summary Report

Project Code	Report Start Year	Number of Years	Scale
101542	2015	6	Dollars

Project Name

New MS, Harvie Rd. MS - Barrie

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ 749,000	$ -	$ -	$ -	$ 1,700,333



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	101584	2015	6	Dollars

Project Name

New MS, Little Lake MS#2 - Barrie

Major Category	**System Service**	

Project Overview

1. Additional Information	Service Territory	PowerStream North
	Location	St. Vincent St and Livingstone St E area, Barrie
	Scope	The project entails the purchase of a station site in the vicinity of St. Vincent Street and Livingstone Street East in Barrie, and constructing a new 44/13.8kV, 20MVA, 4 feeder municipal substation to be in-service no later than summer 2018. The project includes engineering design, purchase of station equipment, approvals, substation construction, equipment installation, and commissioning.
	Justification	The proposed new Substation is required to provide capacity relief to Little Lake MS (MS306). With the proposed Cundles and Little Lake commercial developments totalling 8.8MVA over the next five years, Little Lake MS (MS306) is expected to exceed its ONAN rating in the summer of 2016 and exceed its maximum normal load in 2017. North Barrie is composed of primarily 4.16kV substations, with only two existing 13.8kV stations; Little Lake MS (MS306) and Anne North MS (MS301). The contingency maximum load for either of the 20MVA substations in Barrie north is 39.9MVA. The individual loading for each existing substation (MS301 & MS306) does not exceed the maximum; however, if one of the substations experiences an outage the backup transfer station will exceed the maximum rating of 39.9MVA during the 2017 summer peak. The new 20MVA Little Lake MS#2 would provide a triad configuration that would allow the load from either MS301 or MS306 to be divided between Little Lake MS#2 and the remaining station during contingency conditions, thereby not exceeding the contingency maximum load of 39.9MVA. The Little Lake MS#2 land purchase will have to take place in 2015 due to the limited availability of land in the area and the requirement for Little Lake MS#2 to be in-service no later than summer 2018.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The greatest risk to completion is securing the required land in the vicinity of St. Vincent Street and Livingstone Street East in Barrie. The area surrounding the proposed site is fast being developed and there is a risk that the property cost will rise and/or the preferred site will not be available which will mean additional line (44kV and 13.8kV) costs will be incurred.
	Comparative Information on Equivalent Historical Projects (if any)	Painswick South MS, a new 44/13.8kV 20MVA, 4-feeder substation in Barrie, is currently under construction pending completion in 2016. There was difficulty locating and securing available land for the substation, resulting in the purchase and demolition of two residential homes in order to secure a property. The project highlighted the importance of identifying and purchasing property as early as possible to ensure it is available when a new substation is required.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	The project entails the purchase of a station site in the vicinity of St. Vincent Street and Livingstone Street East in Barrie, and constructing a new 44/13.8kV, 20MVA, 4 feeder municipal substation to be in-service no later than summer 2018. The project includes engineering design, purchase of station equipment, approvals, substation construction, equipment installation, and commissioning.

Power Stream **Project Summary Report**	Project Code **101584**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name New MS, Little Lake MS#2 - Barrie			

	1a. Main Driver	Support Capacity Delivery. The main driver of the project is to provide capacity relief to Little Lake MS (MS306). With the proposed Cundles and Little Lake commercial developments totalling 8.8MVA over the next five years, Little Lake MS (MS306) is expected to exceed its ONAN rating in the summer of 2016 and exceed its maximum normal load in 2017. An additional driver is to establish a station back-up under contingency conditions using the "Triad" model. North Barrie is composed of primarily 4.16kV substations, with only two existing 13.8kV stations; Little Lake MS (MS306) and Anne North MS (MS301). The contingency maximum load for either of the 20MVA substations in Barrie north is 39.9MVA. The individual loading for each existing substation (MS301 & MS306) does not exceed the maximum; however, if one of the substations experiences an outage the backup transfer station will exceed the maximum rating of 39.9MVA during the 2017 summer peak. The new 20MVA Little Lake MS#2 would provide a triad configuration that would allow the load from either MS301 or MS306 to be divided between Little Lake MS#2 and the remaining station during contingency conditions, thereby not exceeding the contingency maximum load of 39.9MVA.
	1b. Priority and Reasons for Priority	The vicinity of the proposed station site is fast being developed and therefore there is a risk that the property cost will rise and/or the preferred site will not be available which will mean additional line (44kV and 13.8kV) costs will be incurred. In addition, exceeding the contingency maximum load at MS306 and MS301 beyond 2017 during contingency transfers should be addressed promptly.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	The new substation would improve the reliability of service to existing customers and future developments. The resulting Triad contingency back-up configuration would provide enough capacity to transfer an out-of-service station load across the other existing stations. The 'do-nothing' alternative provides limited load transfers to take place between MS306 to MS301 in 2015, but additional transfers beyond 2016 are not recommended since relief will be required before the summer of 2018 to accommodate the proposed Cundles and Little Lake commercial developments. In addition, the do-nothing alternative would not accommodate contingency transfers between stations in Barrie North beyond 2017 due to the exceeded contingency maximum load and the lack of other 13.8kV substations in the vicinity. The area surrounding the proposed site is fast being developed and there is a risk that the property cost will rise and/or the preferred site will not be available which will mean additional line (44kV and 13.8kV) costs will be incurred.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	The new substation will provide reliability benefits by providing the required capacity for the proposed future developments in the area and providing the required back-up capability during contingency conditions through the Triad configuration.
	Factors Affecting Timing/Priority	The availability of land for sale in the vicinity of St. Vincent Street and Livingstone Street East will affect the timing of the substation construction.

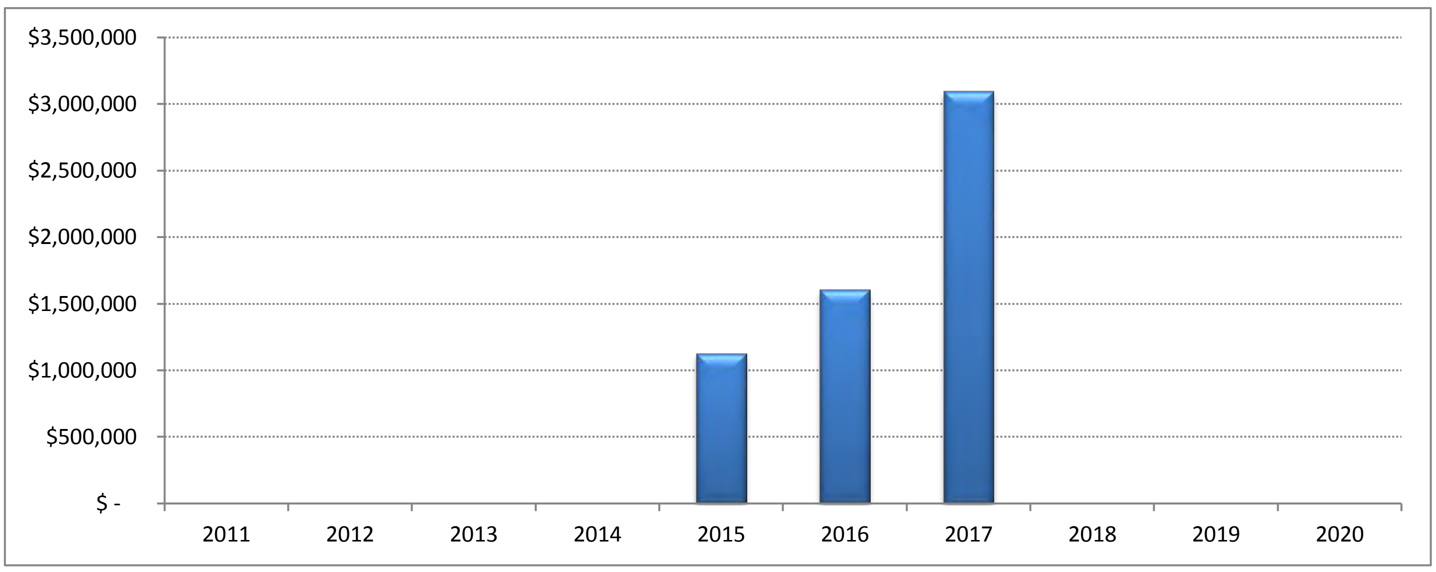
Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	101584	2015	6	Dollars
	Project Name: New MS, Little Lake MS#2 - Barrie			

Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)

The new substation would improve the reliability of service to existing customers and future developments. The resulting Triad contingency back-up configuration would provide enough capacity to transfer an out-of-service station load across the other existing stations.

The 'do-nothing' alternative provides limited load transfers to take place between MS306 to MS301 in 2015, but additional transfers beyond 2016 are not recommended since relief will be required before the summer of 2018 to accommodate the proposed Cundles and Little Lake commercial developments. In addition, the do-nothing alternative would not accommodate contingency transfers between stations in Barrie North beyond 2017 due to the exceeded contingency maximum load and the lack of other 13.8kV substations in the vicinity. The area surrounding the proposed site is fast being developed and there is a risk that the property cost will rise and/or the preferred site will not be available which will mean additional line (44kV and 13.8kV) costs will be incurred.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ 1,125,311	$ 1,603,656	$ 3,095,457	$ -	$ -	$ -



Power Stream — Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	102455	**2015**	**6**	**Dollars**
	Project Name: New MS, Melbourne MS#2 - Bradford			

Major Category	**System Service**	

Project Overview

1. Additional Information	Service Territory	PowerStream North
	Location	Holland Street West and Melbourne Drive area - Bradford
	Scope	The project entails the purchase of a station site in the vicinity of Holland Street West and Melbourne Drive in Bradford, and constructing a new 44/13.8kV, 20MVA, 4 feeder municipal substation to be in-service by summer 2019. The project includes engineering design, purchase of station equipment, approvals, substation construction, equipment installation, and commissioning.
	Justification	The proposed new substation is required to provide capacity relief to Melbourne (MS322), John (MS321), and Reagans (MS324). Currently there is a 500 home residential development east of Middletown Road under construction, as well as a proposed industrial & commercial development (FNB) north of 8th Line. The 2013 summer peak load on MS322 was 98% of the ONAN rating, with the contingency maximum station load of 18MVA being exceeded in 2016 in the event of an adjacent station load transfer from either MS321 or MS324 with the forecasted load growth from current and proposed developments. Under contingency conditions when MS322 load is equally divided among the adjacent MS324 and MS321 the contingency maximum load at either station will be exceeded in 2019. It should be noted that the existing Melbourne MS322 is located on leased land and the new substation would result in either the purchase of the leased land from the Township or locating the new station on purchased land in the vicinity.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2016
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The greatest risk to completion is securing the required land in the vicinity of Holland Street West and Melbourne Drive in Bradford. The area surrounding the proposed site is fast being developed and there is a risk that the property cost will rise and/or the preferred site will not be available which will mean additional line (44kV and 13.8kV) costs will be incurred. At this time, the Town of Bradford has expressed interest in selling the leased Melbourne MS land to PowerStream in 2016.
	Comparative Information on Equivalent Historical Projects (if any)	Painswick South MS, a new 44/13.8kV 20MVA, 4-feeder substation in Barrie, is currently under construction pending completion in 2016. There was difficulty locating and securing available land for the substation, resulting in the purchase and demolition of two residential homes in order to secure a property. The project highlighted the importance of identifying and purchasing property as early as possible to ensure it is available when a new substation is required. At this time, the Town of Bradford has expressed interest in selling the leased Melbourne MS land to PowerStream in 2016.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	The project entails the purchase of a station site in the vicinity of Holland Street West and Melbourne Drive in Bradford, and constructing a new 44/13.8kV, 20MVA, 4 feeder municipal substation to be in-service no later than summer 2019. The project includes engineering design, purchase of station equipment, approvals, substation construction, equipment installation, and commissioning.
	1a. Main Driver	Support Capacity Delivery. The main driver of the project is to provide capacity relief to Melbourne (MS322), John (MS321), and Reagans (MS324). Currently there is a 500 home residential development east of Middletown Road under construction, as well as a proposed industrial & commercial development (FNB) north of 8th Line. The 2013 summer peak load on MS322 was 98% of the ONAN rating, with the contingency maximum station load of 18MVA being exceeded in 2016 in the event of an adjacent station load transfer from either MS321 or MS324 with the forecasted load growth from current and proposed developments. Under contingency conditions when MS322 load is equally divided among the adjacent MS324 and MS321 the contingency maximum load at either station will be exceeded in 2019.
	1b. Priority and Reasons for Priority	The vicinity of the proposed station site is fast being developed and therefore there is a risk that the property cost will rise and/or the preferred site will not be available which will mean additional line (44kV and 13.8kV) costs will be incurred. In addition, exceeding the contingency maximum load at MS322 beyond 2019 during contingency transfers should be addressed promptly.

Power Stream **Project Summary Report**	Project Code **102455**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name New MS, Melbourne MS#2 - Bradford			

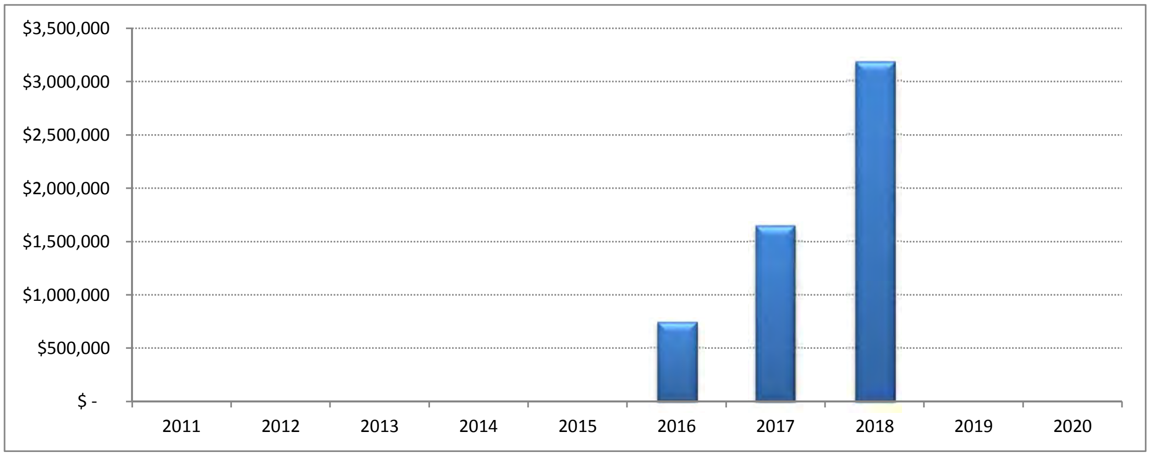
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	The new station would improve the reliability of service to existing customers and provide capacity for future residential, industrial, and commercial developments. The resulting increase in station capacity would also allow contingency transfers from any adjacent out-of-service stations without exceeding the contingency maximum station load. A possible alternative to the single 20MVA 44/13.8kV station transformer configuration would be to implement a 2x10MVA 44/13.8kV configuration. The 2x10MVA alternative provides redundancy at the station; however, initial cost estimates are 1.5 times greater than the cost of a single 20MVA station, with no additional feeders. The additional cost is difficult to justify given the available transfer capability to adjacent stations in the event of a transformer outage at the proposed station. The remaining 'do-nothing' alternative is not recommended because the 2013 summer peak load on MS322 was 98% of the ONAN rating, with the contingency maximum station load of 18MVA being exceeded in 2016 in the event of an adjacent station load transfer from either MS321 or MS324 with the forecasted load growth from current and proposed developments. Under contingency conditions when MS322 load is equally divided among the adjacent MS324 and MS321 the contingency maximum load at either station will be exceeded in 2019. In addition, the area surrounding the proposed site is fast being developed and there is a risk that the property cost will rise and/or the preferred site will not be available which will mean additional line (44kV and 13.8kV) costs will be incurred.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	The new substation will provide reliability benefits by providing the required capacity for the proposed future developments in the area and providing the required back-up capacity at the substation during contingency conditions.
	Factors Affecting Timing/Priority	The availability of land for sale in the vicinity of Holland Street West and Melbourne Drive will affect the timing of the substation construction.
	Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The new station would improve the reliability of service to existing customers and provide capacity for future residential, industrial, and commercial developments. The resulting increase in station capacity would also allow contingency transfers from any adjacent out-of-service stations without exceeding the contingency maximum station load. A possible alternative to the single 20MVA 44/13.8kV station transformer configuration would be to implement a 2x10MVA 44/13.8kV configuration. The 2x10MVA alternative provides redundancy at the station; however, initial cost estimates are 1.5 times greater than the cost of a single 20MVA station, with no additional feeders. The additional cost is difficult to justify given the available transfer capability to adjacent stations in the event of a transformer outage at the proposed station. The remaining 'do-nothing' alternative is not recommended because the 2013 summer peak load on MS322 was 98% of the ONAN rating, with the contingency maximum station load of 18MVA being exceeded in 2016 in the event of an adjacent station load transfer from either MS321 or MS324 with the forecasted load growth from current and proposed developments. Under contingency conditions when MS322 load is equally divided among the adjacent MS324 and MS321 the contingency maximum load at either station will be exceeded in 2019. In addition, the area surrounding the proposed site is fast being developed and there is a risk that the property cost will rise and/or the preferred site will not be available which will mean additional line (44kV and 13.8kV) costs will be incurred.

Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	102455	2015	6	Dollars

Project Name

New MS, Melbourne MS#2 - Bradford

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ 749,000	$ 1,651,393	$ 3,187,430	$ -	$ -



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	101068	2015	6	Dollars

Project Name

New MS, Mill Street MS#2 - Tottenham

Major Category **System Service**

Project Overview

1. Additional Information	Service Territory	PowerStream North
	Location	Mill St E and McCurdy Dr area, Tottenham
	Scope	The project entails the purchase of a station site and construction of the station, in the vicinity of Mill Street East and McCurdy Drive in Tottenham, suitable for constructing a new 2x5MVA, 44-8.32 kV, 3-feeder municipal substation to be in-service no later than summer 2019. The new Mill Street MS#2 is to replace the existing Mill St. MS (MS835), which is currently located on leased land. The project includes engineering design, purchase of station equipment, approvals, substation construction, equipment installation, and commissioning.
	Justification	The proposed new substation is required to provide capacity for the new Ballymore (450 home), Nordstar (500 home), and LRG (335 home) residential developments to be built over the next five years in the Mill Street and Queen Street area of Tottenham. This additional 3.2MVA of residential load will cause Mill St. MS835 to exceed its ONAN rating in the summer of 2018. In addition, there are only two substation located in Tottenham. If Nolan MS834 were to experience an outage, the backup transfer to Mill St MS835 would exceed its contingency maximum load rating of 9.1MVA in 2016. The new 2x5MVA Mill St MS#2 would provide redundancy in the form of two separate transformers at the substation, which would allow transfer capability in case of loss of one of the station transformers or surrounding substations. It should be noted that the existing Mill St MS835 is located on leased land and the new substation would eliminate the need to maintain the leased land.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2016
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The greatest risk to completion is securing the required land in the vicinity of Mill Street East and McCurdy Drive in Tottenham. The area surrounding the proposed site is being developed by the Ballymore and Nordstar residential subdivisions and there is a risk that the property cost will rise and/or the preferred site will not be available which will mean additional line (44kV and 8.32kV) costs will be incurred.
	Comparative Information on Equivalent Historical Projects (if any)	Painswick South MS, a new 44/13.8kV 20MVA, 4-feeder substation in Barrie, is currently under construction pending completion in 2016. There was difficulty locating and securing available land for the substation, resulting in the purchase and demolition of two residential homes in order to secure a property. The project highlighted the importance of identifying and purchasing property as early as possible to ensure it is available when a new substation is required.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	The project entails the purchase of a station site in the vicinity of Mill Street East and McCurdy Drive in Tottenham, and constructing a new 2x5MVA, 44-8.32 kV, 3-feeder municipal substation to be in-service by summer 2019. The new Mill Street MS#2 is to replace the existing Mill St. MS (MS835), which is currently located on leased land. The project includes engineering design, purchase of station equipment, approvals, substation construction, equipment installation, and commissioning.
	1a. Main Driver	Support Capacity Delivery. The main driver of the project is to provide capacity for the new Ballymore (450 home), Nordstar (500 home), and LRG (335 home) residential developments to be built over the next five years in the Mill Street and Queen Street area of Tottenham. This additional 3.2MVA of residential load will cause Mill St. MS835 to exceed its ONAN rating in the summer of 2018. An additional driver is to establish a back-up under contingency conditions. Currently there are only two substation located in Tottenham. If Nolan MS834 were to experience an outage, the backup transfer to Mill St MS835 would exceed its contingency maximum load rating of 9.1MVA in 2016. The new 2x5MVA Mill St MS#2 would provide redundancy in the form of two separate transformers at the substation, which would allow transfer capability in case of loss of one of the station transformers or surrounding substations. It should be noted that the existing Mill St MS835 is located on leased land and the new substation would eliminate the need to maintain the leased land.

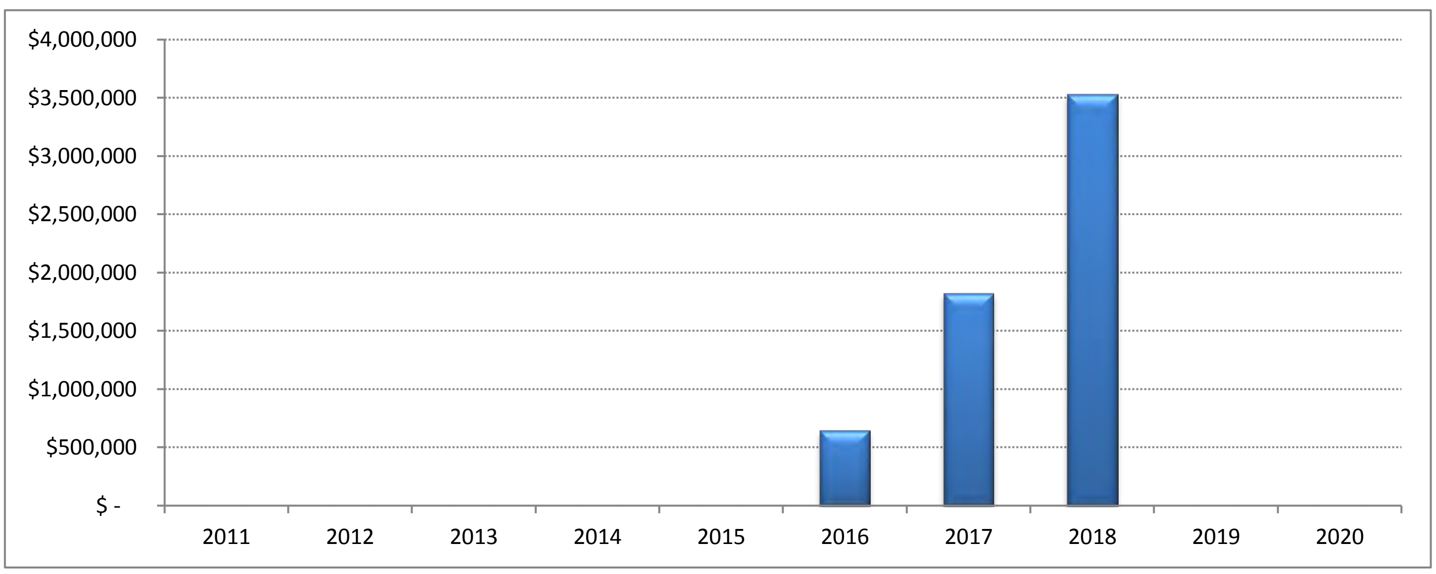
	Project Code	Report Start Year	Number of Years	Scale
Power Stream	101068	2015	6	Dollars
Project Summary Report	Project Name: New MS, Mill Street MS#2 - Tottenham			

	1b. Priority and Reasons for Priority	The vicinity of the proposed station site is being developed by the Ballymore and Nordstar residential subdivisions and there is a risk that the property cost will rise and/or the preferred site will not be available which will mean additional line (44kV and 8.32kV) costs will be incurred. In addition, contingency transfers from Nolan MS834 are not possible beyond 2016 without exceeding the contingency maximum load of MS835 and should be addressed promptly.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	The new substation would improve the reliability of service to existing customers and 1,300 new homes in the Ballymore, Nordstar, and LRG residential developments. The resulting increase in contingency maximum load and redundant transformer configuration at the new substation would provide adequate capacity for any contingency transfers from Nolan MS834. The 'do-nothing' alternative provides limited load transfers to take place between MS835 and MS834 of approximately 100A, but additional relief will be required before the summer of 2019 to accommodate the remainder of the proposed Ballymore, Nordstar, and LRG residential development loads. In addition, the do-nothing alternative would not accommodate contingency transfers between Nolan MS834 and MS835 beyond 2016 due to the exceeded contingency maximum load and the lack of other 8.32kV substations in the vicinity. The area surrounding the proposed site is being developed and there is a risk that the property cost will rise and/or the preferred site will not be available which will mean additional line (44kV and 8.32kV) costs will be incurred.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	The new substation will provide reliability benefits by providing the required capacity for the proposed Ballymore, Nordstar and LRG residential developments in the area and providing the required back-up contingency maximum load capability for the substations in Tottenham.
	Factors Affecting Timing/Priority	The availability of land for sale in the vicinity of Mill Street East and McCurdy Drive will affect the timing of the substation construction. The final completion dates for the Ballymore, Nordstar, and LRG residential developments will also affect the timing for the required station capacity.

Project Summary Report	Project Code 101068	Report Start Year 2015	Number of Years 6	Scale Dollars
	Project Name New MS, Mill Street MS#2 - Tottenham			

Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The new substation would improve the reliability of service to existing customers and 1,300 new homes in the Ballymore, Nordstar, and LRG residential developments. The resulting increase in contingency maximum load at the new substation would provide adequate capacity for any contingency transfers from Nolan MS834. The 'do-nothing' alternative provides limited load transfers to take place between MS835 and MS834 of approximately 100A, but additional relief will be required before the summer of 2019 to accommodate the remainder of the proposed Ballymore, Nordstar, and LRG residential development loads. In addition, the do-nothing alternative would not accommodate contingency transfers between Nolan MS834 and MS835 beyond 2016 due to the exceeded contingency maximum load and the lack of other 8.32kV substations in the vicinity. The area surrounding the proposed site is being developed and there is a risk that the property cost will rise and/or the preferred site will not be available which will mean additional line (44kV and 8.32kV) costs will be incurred. The 'do-nothing' alternative provides limited load transfers to take place between MS835 and MS834 of approximately 100A, but additional relief will be required before the summer of 2019 to accommodate the remainder of the proposed Ballymore, Nordstar, and LRG residential development loads. In addition, the do-nothing alternative would not accommodate contingency transfers between Nolan MS834 and MS835 beyond 2016 due to the exceeded contingency maximum load and the lack of other 8.32kV substations in the vicinity. The area surrounding the proposed site is being developed and there is a risk that the property cost will rise and/or the preferred site will not be available which will mean additional line (44kV and 8.32kV) costs will be incurred.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ 642,000	$ 1,821,953	$ 3,529,079	$ -	$ -



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100420	2015	6	Dollars

Project Name

Vaughan TS #4 - Build Station

Major Category	**System Service**	

Project Overview

1. Additional Information	Service Territory	PowerStream South
	Location	North-west corner of Kipling & Kirby, Vaughan
	Scope	Construction of VTS#4
	Justification	In order to meet the forecast capacity deficiency in the summer of 2017, additional transformation and feeder capacity must be commissioned in the spring of 2017. Accordingly, options which require extensive transmission facilities and corresponding right-of-way acquisition must be developed as soon as possible. It is desirable to site a new station adjacent to existing rights-of-way in the study area or locate a new station at an existing site. The construction of a TS could take up to two years.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	311304
	Job Number	C00850
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Approvals by authorities, electrical equipment deliveries and unforeseen conditions are all factors that can disrupt the project schedule. A consultant will be contracted to aide in maintaining the project schedule and resolving issues that may arise through during the project.
	Comparative Information on Equivalent Historical Projects (if any)	The proposed project will be PowerStream's twelveth 230-28kV transformer station project. The proposed transformer station design will be based on the Markham TS#4 project that was completed in 2010.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	This budget represents the risk, value and cost to construct a new transformer station named Vaughan TS4 to meet load growth through additional transformation and feeder capacity.
	1a. Main Driver	Support Capacity Delivery. VTS#4 Needs Assessment Report has studied various options and concluded that a new TS is required in Vaughan to meet the load growth. Accordingly, options which require extensive transmission facilities and corresponding right-of-way acquisition, must be developed as soon as possible.
	1b. Priority and Reasons for Priority	PowerStream performed a 2011-2020 load forecast in 2010, based on growth projections from municipalities. According to the load forecast, additional transformation and feeder capacity must be commissioned in the spring of 2017 in order to meet the forecast capacity deficiency in the summer of 2017.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	The existing transformer stations and feeders will experience over loading as the load grows. This will restrict the operational flexibility of transferring load between feeders and stations in case of problems on the distribution system. PowerStream is obligated to provide the load required. We run the increased risks of longer service disruptions given the status quo. If adequate backup facilities are not available during contingency conditions there is a strong probability that not all of the load could be picked up. Knowingly running equipment beyond establish guidelines does not represent good utility practice.
	2. Safety	New equipment will be installed following PowerStream's standard design for new stations based on recent transformer station projects. PowerStream maintnenace groups will be familiar with the station design and equipment selected reducing the chance of error.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	The control system will use industry standard, substation style controller products that use cmmunication protocols that are standard in the utility industry. At a later date these can be integrated into an automated restoration scheme.
	5. Economic Development	The new VTS4 will provide move capacity in north Vaughan. This is expected to be attractive for business development.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	If the TS is not built at all, there is a risk of not being able to meet new customer needs as well as increase the risk of the duration of outages to existing customers. System reliability would likely decrease by way of an increase in SAIDI. Customers both new and existing would be less than satisfied.

Project Code	Report Start Year	Number of Years	Scale
100420	2015	6	Dollars

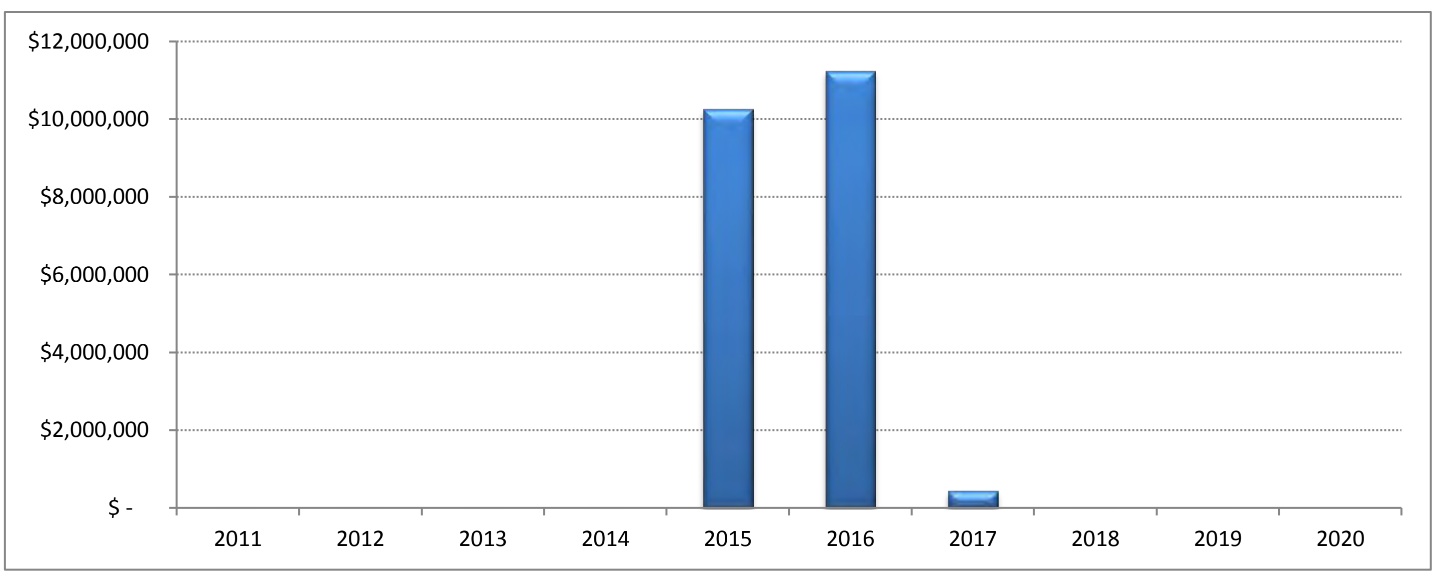
Project Name

Project Summary Report

Vaughan TS #4 - Build Station

Regional Electricity Infrastructure Requirements which affect Project, if applicable	If the TS is not built at all, existing stations and feeders will become overloaded and could result in premature equipment failures and reduce life of existing assets. PowerStream may not be able to supply new customers. Running feeders beyond there normal rating (i.e. 400 Amps) will increase system losses since line losses are proportional to the square of the current (I2R).
Description of Incorporation of Advanced Technology, if applicable	Transformer health monitoring equipmnet will play an important role in preserving the life of the transformers. The new feeder relays can be integrated into a automated feeder integration scheme in the future.
Identify any reliability , efficiency, safety or coordination benefits	Newer electrical equipment is more reliable due to enhanced materials, new monitoring equipment, and proven design. Arc resistant switchgear reduces the potential for injury due to flashovers.
Factors Affecting Timing/Priority	Approvals by authorities and equipment delivery lead times can be factors that could cause delays in the project schedule.
Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	A new transformer station is one of PowerStream's single largest investments. The construction will ensure regulatory compliance is achieved in terms of serving our customers. It will allow PowerStream to continue to operate it system in a safe and effective manner. It shows Good Service reliability will increase once the new station is in service. It will allow for more feeder ties and backup options. System Capacity will increase an addition 170 MVA. This will ensure additional load growth and customers can be served.Utility Practice in terms of asset utilization and load security. It will enable PowerStream to meet transformer station and feeder loading guide lines.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ 10,249,162	$ 11,226,183	$ 422,915	$ -	$ -	$ -



Project Summary Report	Project Code 100963	Report Start Year 2015	Number of Years 6	Scale Dollars
	Project Name New 2x44kV circuits (23M22 & 23M23) from Midhurst TS2 to Essa Rd/Mapleview Dr			

Major Category **System Service**

Project Overview

1. Additional Information	Service Territory	PowerStream North
	Location	Springwater Township and Barrie
	Scope	The project entails the design and construction of approximately 17km's of 2x44kV circuits from Midhurst TS2 to Essa Road and Mapleview Drive in three segments. The first segment (Phase 1 - design 2013, construct 2015) will encompass the area from Midhurst TS2, west along Carson Road, south along Anne Street, and west along Sunnidale Road to Dobson Road. The second segment (Phase 2 - design 2014, construct 2016) will be south from the intersection of Sunnidale Road and Dobson Road to the intersection of Dunlop Street West and Highway 27. The final segment (Phase 3 - design 2015, construct 2017) will be south from Highway 27 and Dunlop Street West to the intersection of Essa Road and Mapleview Drive. The two new feeders are to be in-service by summer 2018. The project includes engineering design, approvals, construction, and commissioning.
	Justification	The new feeders are required to provide capacity relief to the Barrie south area, bounded by Highway 27 to the west, Welham Road to the east, Big Bay Point Road and Harvie Road to the north and Salem/Lockhart Road to the south. The Barrie south area is currently supplied by the 23M5, 13M5, 13M6 and 13M1 feeders. There are four large data centers currently located in the Barrie south area; Data Center #1 is currently contracted for 10MVA with expansion plans to reach 20MVA over the next 8-10 years, Data Center #2 is currently contracted for 5.5MVA with provisions to go to 11MVA at any time, Data Center #3 is currently contracted for 5MVA with expansion plans to reach 20MVA over the next 8-10 years, and Data Center #4 is currently contracted for 2MVA with plans to reach 10MVA within the next 5 years. Three of the data centers have made capital contributions for back-up feeder supply and have executed Operating Agreements with PowerStream for dual supply. This means that under contingency conditions, i.e., loss of their normal supply, the back-up feeder must be able to supply the full facility load. Based on the contingency condition requirements feeder 13M1 and 13M5 summer peak loading will exceed 400A in 2014, with feeder 13M5 exceeding the 600A thermal limit in 2017 and 13M1 exceeding 600A in 2020. Feeders 23M5 and 13M6 will exceed 400A in 2015 and 2016, respectively, while 600A will be exceeded in 2020 and 2022, respectively. The new feeders will ensure that future load growth in the Barrie south area can be supplied, as well as ensuring that the contractual agreements with the data centers is satisfied under contingency conditions. In addition to the capacity requirement, PowerStream has a contractual obligation with Hydro One to utilize the full capacity (166MVA) of Midhurst TS#2. If this capacity is not utilized, PowerStream will need to pay Hydro One for any stranded capacity under the terms of the Midhurst expansion CCRA.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The greatest risk to completion is securing the required approvals from the city in the allotted timeframe. The ramping up of the scheduled customer load at each of the data centers will also impact the timing of the project. Coordinating work with Hydro One for Phase 1 outside of the Barrie service territory may also pose potential scheduling risks.
	Comparative Information on Equivalent Historical Projects (if any)	Some past projects for new circuits have taken 6-8 months to obtain the necessary approvals before proceeding with construction.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	The project entails the design and construction of approximately 17km's of 2x44kV circuits from Midhurst TS2 to Essa Road and Mapleview Drive in three segments. The first segment (Phase 1 - design 2013, construct 2015) will encompass the area from Midhurst TS2, west along Carson Road, south along Anne Street, and west along Sunnidale Road to Dobson Road. The second segment (Phase 2 - design 2014, construct 2016) will be south from the intersection of Sunnidale Road and Dobson Road to the intersection of Dunlop Street West and Highway 27. The final segment (Phase 3 - design 2015, construct 2017) will be south from Highway 27 and Dunlop Street West to the intersection of Essa Road and Mapleview Drive. The two new feeders are to be in-service by summer 2018. The project includes engineering design, approvals, construction, and commissioning.

Project Summary Report	Project Code 100963	Report Start Year 2015	Number of Years 6	Scale Dollars
	Project Name New 2x44kV circuits (23M22 & 23M23) from Midhurst TS2 to Essa Rd/Mapleview Dr			

	1a. Main Driver	Support Capacity Delivery. The main driver of the project is to provide capacity delivery to the Barrie south area. Barrie south is currently supplied by the 23M5, 13M5, 13M6 and 13M1 feeders. There are four large data centers currently located in the Barrie south area; Data Center #1 is currently contracted for 10MVA with expansion plans to reach 20MVA over the next 8-10 years, Data Center #2 is currently contracted for 5.5MVA with provisions to go to 11MVA at any time, Data Center #3 is currently contracted for 5MVA with expansion plans to reach 20MVA over the next 8-10 years, and Data Center #4 is currently contracted for 2MVA with plans to reach 10MVA within the next 5 years. Three of the data centers have made capital contributions for back-up feeder supply and have executed Operating Agreements with PowerStream for dual supply. This means that under contingency conditions, i.e., loss of their normal supply, the back-up feeder must be able to supply the full facility load. Based on the contingency condition requirements feeder 13M1 and 13M5 summer peak loading will exceed 400A in 2014, with feeder 13M5 exceeding the 600A thermal limit in 2017 and 13M1 exceeding 600A in 2020. Feeders 23M5 and 13M6 will exceed 400A in 2015 and 2016, respectively, while 600A will be exceeded in 2020 and 2022, respectively. The new feeders will ensure that future load growth in the Barrie south area can be supplied, as well as ensuring that the contractual agreements with the data centers is satisfied under contingency conditions. An additional driver is to maximize the usage of capacity at Midhurst TS#2. PowerStream has a contractual obligation with Hydro One to utilize the full capacity (166MVA) of Midhurst TS#2. If this capacity is not utilized, PowerStream will need to pay Hydro One for any stranded capacity under the terms of the Midhurst expansion CCRA.
	1b. Priority and Reasons for Priority	The two new feeders are high priority since thermal limits will be exceeded in the Barrie south area beyond 2017 under contingency conditions. The contractual obligations for dual supply further support the urgency to secure additional capacity in Barrie south.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	The two circuits would add approximately 50MVA of capacity to the Barrie south area, thereby providing capacity relief to the existing feeders for future growth and ensure that PowerStream meets its dual supply contractual obligations during contingency conditions. The feeders would also help utilize the full capacity of Midhurst TS#2 to reduce the stranded capacity under the CCRA. In addition, the new feeders would result in cost savings realized from line loss reductions resulting in approximately $63,000 annually. The do-nothing alternative is not recommended since PowerStream will be at a risk of not being able to meet the contractual agreements to supply the data centers under contingency conditions beyond 2017. In addition, the status-quo will have limited adjacent feeder transfers upon loss of any Barrie south feeder given the dual supply data center requirement, resulting in a higher risk of lengthy outages to customers in the area. The alternative to cross Kempfelt Bay utilizing submarine cables from Midhurst TS to Essa/Mapleview is not economically viable, with initial cost estimates exceeding $26 million. Constructing a new transformer station in Barrie was covered in the 2010 Hydro One led South Simcoe study. The alternative encompasses the construction of 15km of 230kV transmission line from Essa TS to Barrie south along an existing transmission corridor and the construction of a new 75/125 MVA station. The initial cost estimates for the proposed alternative was $140 million.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	The new feeders will produce reliability benefits by providing more 44kV circuits to the Barrie south area, thereby increasing transfer options which increases reliability to customers. The new feeders will also help reduce line losses in the area.
	Factors Affecting Timing/Priority	Securing the required approvals from the city in the allotted timeframe and coordinating work with Hydro One for Phase 1 outside of the Barrie service territory may affect the timing of the feeder construction.

Power Stream **Project Summary Report**	Project Code **100963**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name New 2x44kV circuits (23M22 & 23M23) from Midhurst TS2 to Essa Rd/Mapleview Dr			

Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)

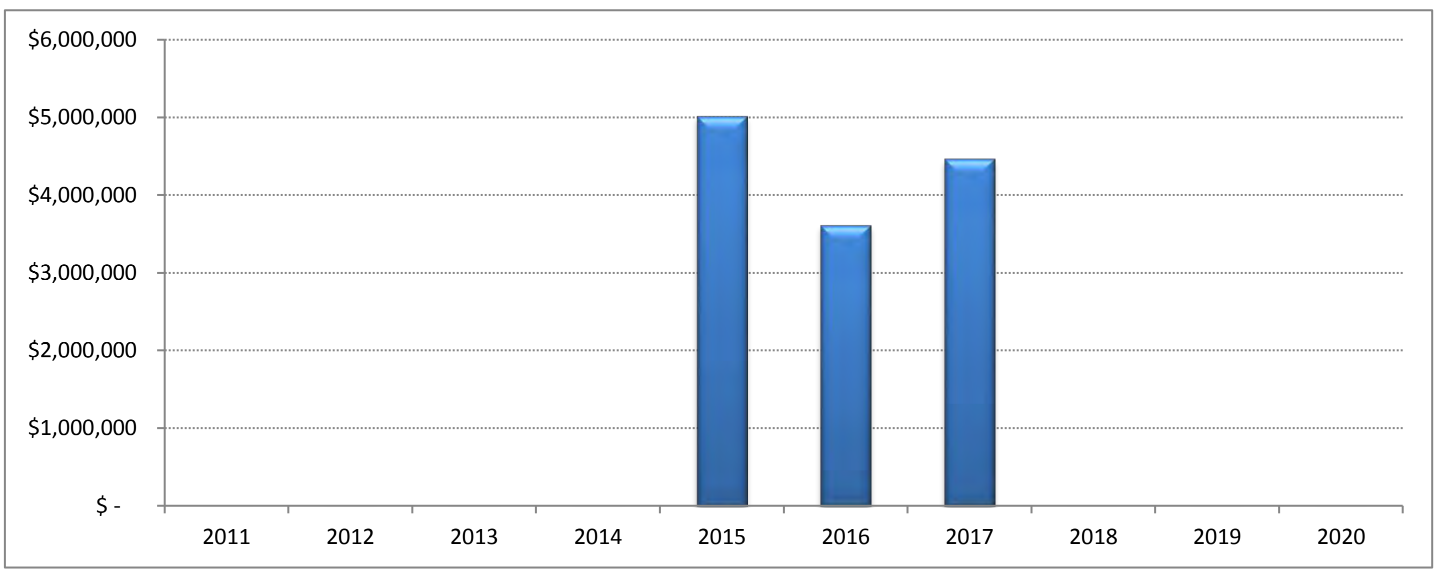
The two circuits would add approximately 50MVA of capacity to the Barrie south area, thereby providing capacity relief to the existing feeders for future growth and ensure that PowerStream meets its dual supply contractual obligations during contingency conditions. The feeders would also help utilize the full capacity of Midhurst TS#2 to reduce the stranded capacity under the CCRA. In addition, the new feeders would result in cost savings realized from line loss reductions resulting in approximately $63,000 annually.

The do-nothing alternative is not recommended since PowerStream will be at a risk of not being able to meet the contractual agreements to supply the data centers under contingency conditions beyond 2017. In addition, the status-quo will have limited adjacent feeder transfers upon loss of any Barrie south feeder given the dual supply data center requirement, resulting in a higher risk of lengthy outages to customers in the area.

The alternative to cross Kempfelt Bay utilizing submarine cables from Midhurst TS to Essa/Mapleview is not economically viable, with initial cost estimates exceeding $26 million.

Constructing a new transformer station in Barrie was covered in the 2010 Hydro One led South Simcoe study. The alternative encompasses the construction of 15km of 230kV transmission line from Essa TS to Barrie south along an existing transmission corridor and the construction of a new 75/125 MVA station. The initial cost estimates for the proposed alternative was $140 million.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ 5,011,705	$ 3,606,692	$ 4,460,060	$ -	$ -	$ -



Project Code	Report Start Year	Number of Years	Scale
100912	2015	6	Dollars

Project Summary Report

Project Name

Add one 27.6 kV Cct on Steeles Ave From Jane St to Keele St by Rebuilding Existing 2 cct Pole line into 4 ccts

Major Category **System Service**

Project Overview

1. Additional Information	Service Territory	PowerStream South
	Location	On Steeles Ave from Jane St to Keele St in Vaughan
	Scope	This project is to rebuild the existing 2 ccts pole line on Steeles Ave from Jane St to Keele St into 4 ccts and extend feeder 21M2 from Jane St to Keele St along Steeles Ave. One additional cct will be installed on the pole line as load grows.
	Justification	Vaughan Official Plan Amendment (OPA) 620 applies to approximately 43 hectares (106 acres) of land located within the southern portion of the City of Vaughan (see key map). It is located on the north side of Steeles Avenue between Keele and Jane Streets directly north of York University in the City of Toronto. The plan is centred on a proposed station site of the Spadina Subway extension. See the attachment for more details. The planned function of this Secondary Plan is to create a vibrant live-work community consisting of mixed use higher density buildings in a compact pedestrian-friendly urban form. The Plan is expected to accommodate 5,500 residential units for a potential population of 11,000 persons and 83,000 sq.m. of office/commercial space generating approximately 4,000 employees. The proposed land uses, densities and built form will be in response to, and supportive of, the higher order transit infrastructure plans, including the Spadina Subway extension, a commuter parking lot and a bus terminal. The Plan also acknowledges and complements the development potential and academic function of York University to the south. The peak demand for OPA 620 is estimated to be 12 MW. Considering the peak demand from TTC subway station is 8MW, a new feeder is required for this area. This project will extend 21M2 from Jane St to Keele St to increase 10 MVA supply capacity to TTC subway station and new development in the Steeles & Keele St area. This project will also increase supply reliability to TTC subway station and new development in the Steeles & Keele St area by adding a new feeder 21M2 from VTS2. The existing feeders are from VTS1 and Finch TS.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2019
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The risk is to get approval from the City of Toronto in time. Capital design will start the design of the project in advance and should get the approvals in place in time. Another risk is the load ramping up schedule after the subway is in service. Planning will monitor the load growth in Steeles and Keele St area. Project schedule will be adjusted accordingly.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	This project is to rebuild the existing 2 ccts pole line on Steeles Ave from Jane St to Keele St into 4 ccts. Feeder 21M2 will be extended to Keele St and Steeles Ave area.
	1a. Main Driver	The main driver for this project is to support the capacity delivery in the Keele St and Steeles Ave area after the new subway is in service.
	1b. Priority and Reasons for Priority	High. The subway will be in service in 2015 and a few new commercial projects are under design in the Steeles/Keele St area.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	This project will extend one feeder (future two) into the area and increase capacity by 40 MVA. This project will also significantly improve power supply diversity to the customers in the area.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.

Power Stream	Project Code	Report Start Year	Number of Years	Scale
	100912	2015	6	Dollars

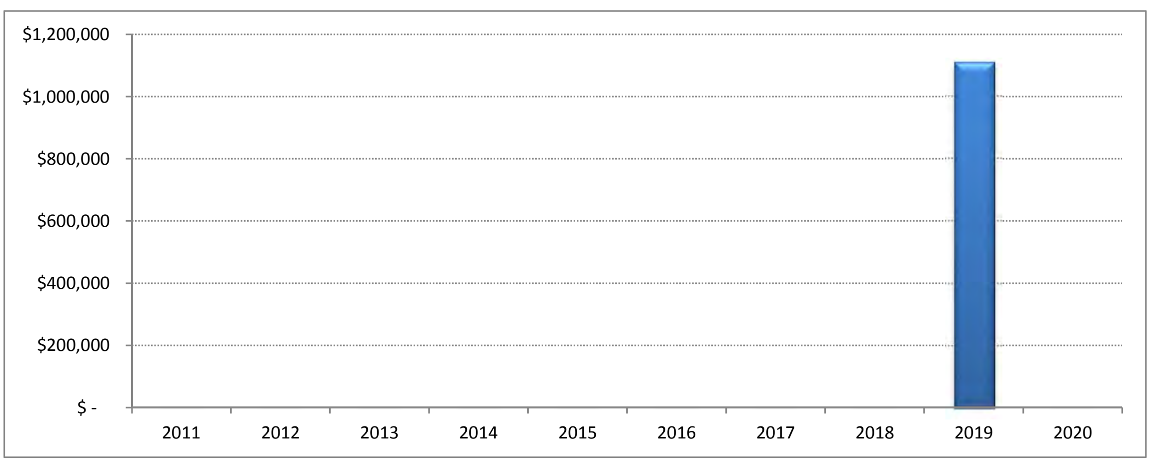
Project Summary Report

Project Name

Add one 27.6 kV Cct on Steeles Ave From Jane St to Keele St by Rebuilding Existing 2 cct Pole line into 4 ccts

	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	Not Applicable.
	Factors Affecting Timing/Priority	The load ramping up schedule will affect the timing and priority of this project.
	Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	This project will extend one feeder (future two) into the area and increase capacity by 40 MVA. The alternatives is the status quo, i.e., do nothing, (i.e., not build project as proposed), but to supply load growth from existing facilities. The area in OPA 620 is supplied by feeder 55M11 & 55M12 from Finch TS as well as 20M8 from VTS1. The peaks of the existing feeders were: 55M11 200A 55M12 300A 20M8 360A The above feeders don't have sufficient capacity to supply new development in the OPA 620 area. New feeders are required as the development progresses. Status Quo will jeopardize PowerStream's obligation to supply new customers along Steeles Ave. The impact severity and timing will depend on the schedule of the OPA 620 development. If load grows as projected, the "do nothing" option may not have sufficient capacity for future load growth.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,110,310	$ -



Project Summary Report	Project Code 101487	Report Start Year 2015	Number of Years 6	Scale Dollars
	Project Name Add one Additional 27.6 kV Cct on Major Mack and 9th Line			

Major Category **System Service**

Project Overview

1. Additional Information	Service Territory	PowerStream South
	Location	on Major Mack Dr from 9th Line to the west in Markham. on 9th Line from Major Mack to the south in Markham.
	Scope	This project is to: -add one 27.6kV cct on Major Mack from CNR to 9th Line, approx 1.3 km. -add one cct on 9th Line from Bur Oak Ave to Major Mack Dr -install load interrupter switch at intersection as per PowerStream's standard.
	Justification	This project is to establish ties between two ccts on Major Mack and 9th Line. A radial feeder is defined as a circuit or a portion of a circuit that feeds a customer(s) with no normal connection to any other supply. This is typical of long rural lines with isolated load areas. There are no pure radial feeders in PowerStream. All of PowerStream's feeders have normal open ties with other feeders. Most customers can be supplied from different directions (paths) by changing normal open points. However, in some areas, there is only one path between any customer and the source of supply. There are two ccts on Major Mack Dr east of Hwy 48, but only one cct goes all the way to 9th Line. The second cct stops half way and is a radial supply. There are two ccts on 9th Line north of 16th Ave, but only one cct goes all the way to Major Mack Dr. The second cct stops half way and is a radial supply.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2020
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The risk is to get approval from the City of Markham in time. Capital design will start the design of the project in advance and should get the approvals in place in time.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	This project is to: -add one 27.6kV cct on Major Mack from CNR to 9th Line, approx 1.3 km. -add one cct on 9th Line from Bur Oak Ave to Major Mack Dr -install LIS' at intersection as per PowerStream's standard.
	1a. Main Driver	Reliability.
	1b. Priority and Reasons for Priority	Insufficient and lack of back-up connections between feeders in this area.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	This project will create one additional tie between ccts on 9th Line and Major Mack Dr.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.

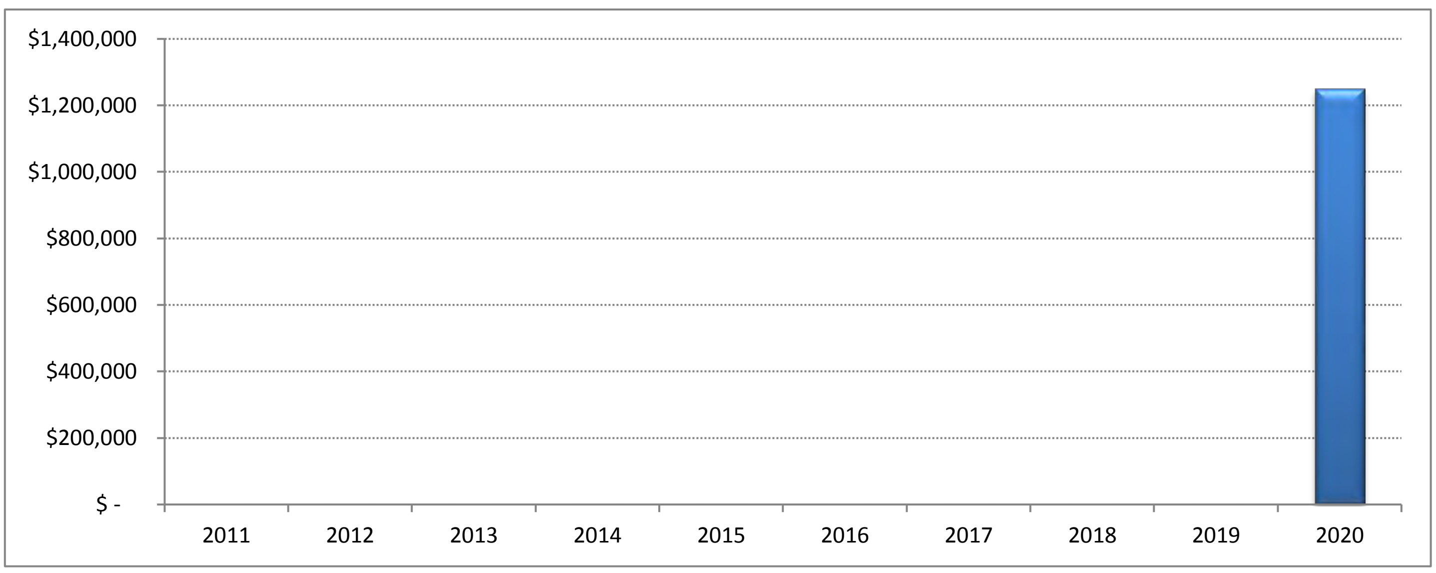
Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	101487	2015	6	Dollars

Project Name

Add one Additional 27.6 kV Cct on Major Mack and 9th Line

Identify any reliability , efficiency, safety or coordination benefits	This project will establish a new tie between ccts on Major Mack and 9th Line.
Factors Affecting Timing/Priority	Reliability performance of the existing feeders will affect the timing and priority.
Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The alternative is status quo, i.e.,do nothing, (i.e., not build project as proposed), but to supply load growth from existing facilities. It will impact PowerStream distribution system in two following aspects: Customers on Major Mack Dr between Hwy 48 and 9th Line are on a radial supply. Customers on radial supplies will experience longer outages when components of the radial feeder fail since there are no alternate paths to supply the affected customers. The longer the radial feeder and the more customers, the more severe the impact will be. The status quo option currently does not meet PowerStream's "Open Grid Network" philosophy for this area. Existing and future urbanization in the area necessitates the need for additional feeders and grid reconfiguration in this area.Do nothing will result in two ccts tied with one cct and it will limit the backup capacity between feeders.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,248,939



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	101480	2015	6	Dollars

Project Name

Build double ccts 27.6kV pole line on 19th Ave between Leslie St and Bayview Ave

Major Category **System Service**

Project Overview

1. Additional Information	Service Territory	PowerStream South
	Location	On 19th Ave between Leslie St and Bayview Ave in Richmond Hill
	Scope	Install 2 ccts 27.6kV pole line on 19th Ave from Leslie St to Bayview Ave
	Justification	To supply new development in Leslie North that is bounded by Elgin Mills Rd, Leslie St, 19th Ave and Bayview Ave) The Leslie North development may accommodate approximately 6,250 housing units with a population of approximately 19,300 people and employment of approximately 3,200 jobs. See the attachment for more details. As per Hemson report, each retail or commercial job needs 300 square feet floor space, and assuming 5W/sq.ft, each job accounts for 1.5kW. Based on 2.5kW per unit and 1.5 kW per job, the total demand would be 20 MW. There presently is no feeder on 19th Ave so a new pole line is required. The progress of the Leslie North development impact the loading of the feeders. There is no feeder on 19th Ave between Leslie St and Bayview Ave. As long as the development starts in 2017, these feeders would be required since there is no feeder on 19th Ave now. PowerStream has an obligation to provide adequate electricity supply to service loads within its service territory, and to properly plan to provide service for anticipated future loads.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2017
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The risk is to get approval from the Town of Richmond Hill in time. Capital design will start the design of the project in 2016 and should get the approvals in place in 2016. The other risk the 19th widening work schedule may impact the pole line construction. PowerStream will work with the town to coordinate the schedule.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	This project is to build 2 ccts pole line on 19th Ave from Leslie St to Bayview Ave.
	1a. Main Driver	Support Capacity Delivery. The primary driver for this Investment is to support capacity delivery for the new development in the Leslie North Area. The Leslie North devement may accommodate approximately 6250 housing units with a population of approximately 19,300 people and employment of approximately 3200 jobs. As per Hemson report, each no-retail commercial job needs 300 square feet floor space, and assuming 5W/sq.ft, then each requires 1.5kW. Based on 2.5kW per unit and 1.5 kW per job the total demand would be 20 MW. There is no feeder on 19th Ave, so new pole line is required.
	1b. Priority and Reasons for Priority	High. The development of properties in this area started in 2014. Without new feeders, the ability to supply new loads will be significantly constrained.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	A new pole line is required to supply the new development. Please refer to analysis provided below.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.

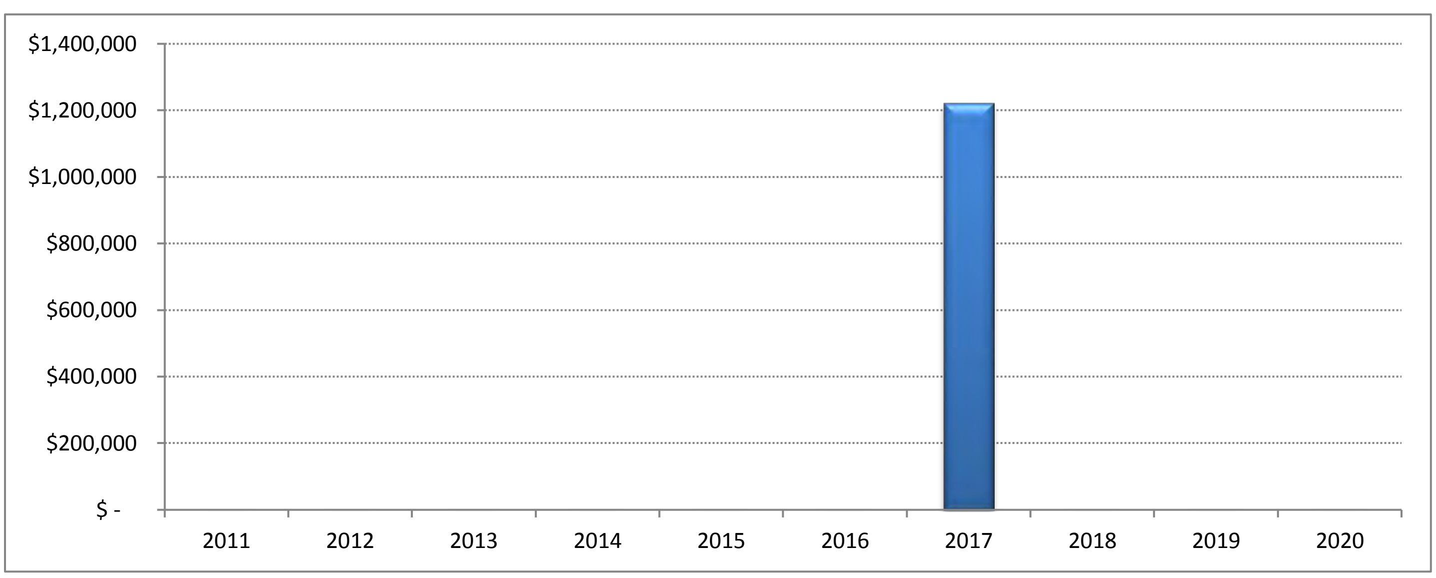
Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	101480	2015	6	Dollars

Project Name

Build double ccts 27.6kV pole line on 19th Ave between Leslie St and Bayview Ave

5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	This project will improve reliability for customers in the area.
	Factors Affecting Timing/Priority	The progress of the Leslie North development impact the loading of the feeders. As long as the development starts in 2017, these feeders would be required since there is no feeder on 19th Ave now.
	Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The alternative is to "do nothing", (i.e., not build project as proposed), but to supply load growth from existing facilities. It will impact PowerStream distribution system in two following aspects: Reliability Presently, there is no pole line on 19th Ave between Leslie St and Bayview Ave. There is one feeder on Leslie St between Elgin Mills Ed and 19th Ave, but it is a radial supply without this project. Any pole failure on Leslie St between Elgin Mills Ed and 19th will cause prolonged outages to customers in the Leslie North development area. Capacity There is no pole line on 19th Ave between Leslie St and Bayview Ave. The peak demand for this Leslie North development is estimated to be 20MW when fully built out, but no time line is available at this time. Two 27.6kV feeders are required to supply the new load because the existing feeders supply other load south of this development too. These customers will be supplied from circuits surrounding the development, but there is no feeder on 19th Ave to supply new loads in the Leslie North development Area. "Do nothing" will jeopardize PowerStream's obligation to supply new customers along 19th Ave. The impact severity and timing will depend on the schedule of the Leslie North development.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,221,747	$ -	$ -	$ -



Power Stream **Project Summary Report**	Project Code **102372**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Install 2x13.8kV ccts Pole Line on Leslie St from Wellington St to St.John's Sdrd			

Major Category **System Service**

Project Overview

1. Additional Information	Service Territory	PowerStream South
	Location	Leslie St from Wellington St to St.John's Sdrd in Aurora, approx 1.5 km. This project will depend on YR Leslie St widening project
	Scope	At the south end of the Leslie St (north of Wellington St), there are two existing pole lines. The pole line on the east side has two 44kV ccts and two 27.6kV ccts. The one on the west side has one 13.8kV cct. York Region is going to widening Leslie St from Wellington St to St.Johns Sdrd to 4 lanes and the existing pole lines will be relocated. The scope of work is to install two pole lines: one on the east side with two 44kV ccts and two 27.6kV ccts, one on the west side with two 13.8kV ccts.
	Justification	The development is idenfied in the Aurora Secondary plan as area 2C and the projected load growth will need one additional 13.8kV cct. It was initially planned to installed two 13.8kV ccts, but not implemented due to anticipated future road widening work. The 2C Planning Area is located at the northeast quadrant of the Town of Aurora. The 2C lands are bounded by the Town of Newmarket on the north, Highway 404 on the east, just north of Wellington Street on the south and Marsh Creek on the west. The 2C Planning Area consists of approximately 445 hectares (1,080 acres) and represents the last Greenfield development opportunity within the Town of Aurora. Lands in the 2C Secondary Plan Area are intended to accommodate approximately 8,000 residents in approx 3000 units and between 5,200 and 6,400 employment opportunities over the next 20 years.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2016
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The risk is to get approval from York Region in time. Capital design will start the design of the project in 2015 and should get the approvals in place in 2015. The other risk is the coordination with the Leslie St widening project. The project will be deferred if York Region defers the road widening work.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	At the south end of the Leslie St (north of Wellington St), there are two existing pole lines. The pole line on the east side has two 44kV ccts and three 27.6kV ccts. The one on the west side has one 13.8kV cct. York Region is going to widening Leslie St from Wellington St to St.Johns Sdrd to 4 lanes and the existing pole lines will be relocated. The scope of work is to install two pole lines: one on the east side with two 44kV ccts and two 27.6kV ccts, one on the west side with two 13.8kV ccts.
	1a. Main Driver	Support Capacity Delivery. The main driver for the project is to support the capacity delivery in Aurora. The lands in the 2C Secondary Plan Area are intended to accommodate approximately 8,000 residents in approx 3,100 units and between 5,200 and 6,400 employment opportunities over the next 20 years. The residential units will be on the west side of Leslie St and will be supplied by 13.8kV feeders.The commercial development will be on the east side of Leslie St and will supplied by 27.6kV feeders from Aurora MS7 & MS8. 2C land is currently supplied by a 13.8kV feeder 5F2. It had a peak of 250A in 2013 and does not sufficient capactity to supply future growth in 2C.

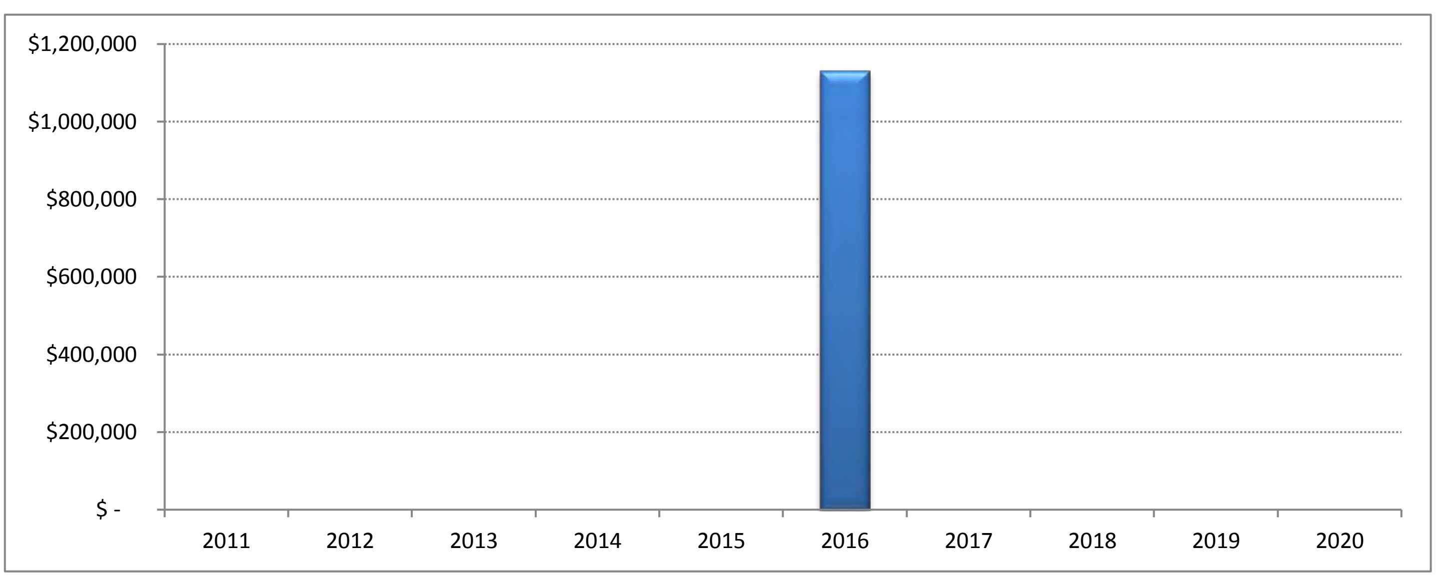
Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	102372	2015	6	Dollars

Project Name

Install 2x13.8kV ccts Pole Line on Leslie St from Wellington St to St.John's Sdrd

	1b. Priority and Reasons for Priority	High. The construction in 2C land has started and many residential units will be connected in the years to come. The existing 13.8kV feeders don't have sufficient capacity to supply the new load. York Region is going to widening Leslie St in 2016 and all pole lines will be relocated. It is good opportunity to rebuild the existing 1 cct 13.8kV pole line into 2 ccts on the west side of Leslie St to reduce cost and traffic impact in the future.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	This project will allow one 13.8kV feeder to rerouted to supply 2C land and increase supply capacity by 300A or 7000 KW. This project will also create a alternate supply path for exsiting customers on Wellington. It will reduce outage impact in case of pole failures on Bayview Ave.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	This project will add one 13.8kV feeder to supply 2C land. It will increase reliability.
	Factors Affecting Timing/Priority	York Region's Leslie St widening project schedule will impact the timing of the project. The progress of 2C land development will impact the loading of the 13.8kV feeders.
	Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The alternative to this proposed project is to "do nothing". However, that alternative is not considered viable as the existing feeder can not supply the expected new load.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ 1,131,418	$ -	$ -	$ -	$ -



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100904	2015	6	Dollars

Project Name

Install Double Cct Pole Line on Major Mackenzie - Hwy 27 to Huntington Rd

Major Category	**System Service**	

Project Overview

1. Additional Information	Service Territory	PowerStream South
	Location	From Hwy 27 to Huntington Rd This project will depend on York Region road widening work
	Scope	To install double 27.6kV ccts pole line To install LIS at intersections To connect the new ccts to the existing ccts on Hwy 27, and Huntington Rd
	Justification	To supply new development on Major Mack between Hwy 27 and Huntington Rd. It includes following major future load growth areas in Vaughan are summarized below: Kleindor Development Kleindor development is part of OPA160 initiated in 2001 and has a planned population of approximately 3,000 people, and 1,000 residential dwelling units. The Kleindor development area that is located on the north side of Major Mackenzie Drive, east side or CP railway and west of Regional Road 27. The estimated load is approx. 2.5 MW. Nashville Heights Development Vaughan's Official Plan Amendment No. 699 (OPA 699provides land use designations and policies to guide growth in Block 61 West within the Kleinburg-Nashville Community. The Amendment area is approximately 185 hectares (457 acres) in size and is bounded on the west by Huntington Road, on the east by the CP rail line, on the south by Major Mackenzie Drive and on the north by lots fronting Nashville Road. OPA 699 has a planned population of approximately 8,000 people, 2,625 residential dwelling units and approximately 700 jobs. Based on 2.7kW per unit and 1.5 kW per job, the total demand would be 8 MW. West Vaughan Employment Area The West Vaughan Employment Area Secondary Plan sets out detailed policies to create a large economic opportunity for York Region. With over 500 hectares of employment designated lands, this area will continue to allow the City of Vaughan to attract a wide range of businesses requiring large tracks of land with excellent Regional road and provincial highway access. The Secondary Plan is planned to accommodate approximately 20,120 employees. There are 1,400 acres of vacant land on both sides of Major Mackenzie Drive that has been zoned as employment land. The potential load from these lands will be significant. The peak demand for this development is estimated to be 50MW to 80 MW when fully built out, but no time line is available at this time. Four 27.6kV feeders are required to supply the new load. York Region is going to widen Major Mackenzie Drive from Hwy 27 to Huntington Rd, and further west to Hwy 50 in 2015 and 2019. There is opportunity for PowerStream to rebuild the existing single phase 4.8 kV cct to double 27.6kV ccts in conjunction with the pole line relocation project.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2018
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The risk is to get approval from the City of Vaughan and York Region in time. York Region is going to rebuild Major Mack Dr in 2017. The pole line construction schedule will depend on road widening schedule. Capital design will work closely with the Region and City to coordinate the project.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	This project is to build two 27.6kV ccts to supply new customers on Major Major Dr and existing customers.
	1a. Main Driver	Support Capacity Delivery. There is one single phase 4.8kV cct on Major Mack Dr between Huntington and the railway track. There is 1/0 radial 27.6kV supply for a new subdivision between the railway track and Hwy 27. The existing feeders don't have sufficient capacity to supply future growth in the area. York Region is to widening the road, and the existing 4.8kV needs to be relocated and it is good opportunity to rebuild the pole line to ultimate requirement.

Power Stream **Project Summary Report**	Project Code **100904**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Install Double Cct Pole Line on Major Mackenzie - Hwy 27 to Huntington Rd			

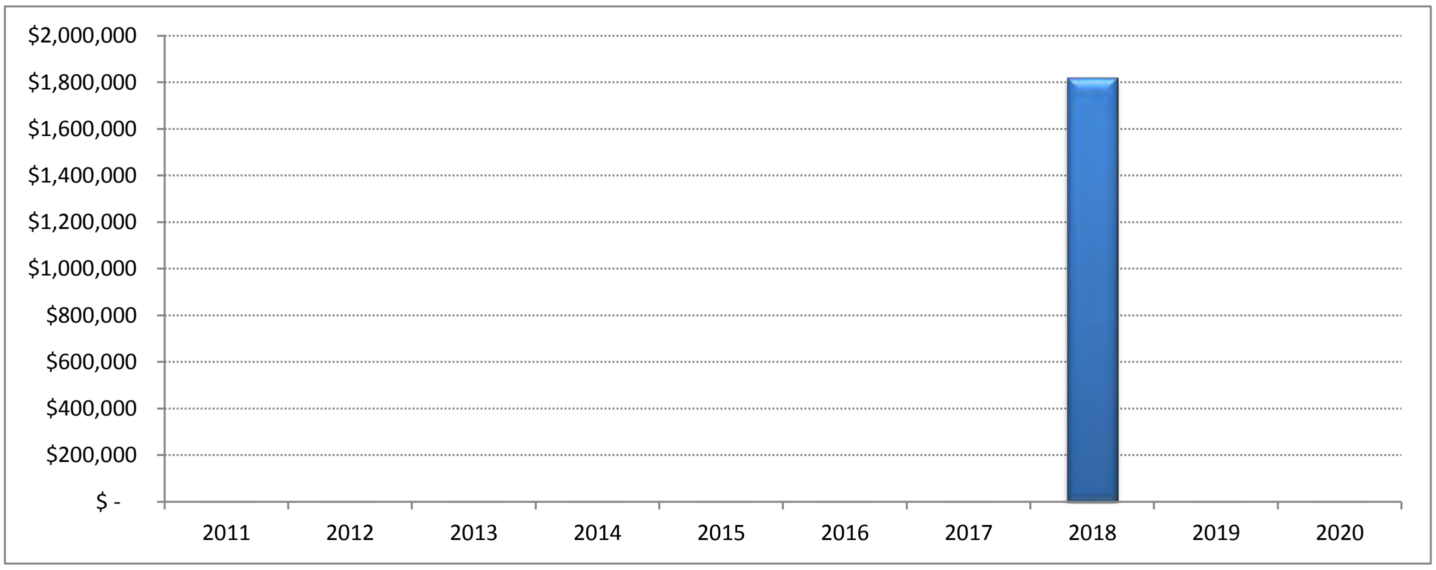
	1b. Priority and Reasons for Priority	The vacant land on both sides of Major Mack Dr are being developed and more and more customers are expected in the coming years. Existing pole line has to be relocated due to road widening work. Building 2 ccts in conjuction with the road widening project will reduce the cost and traffic impact.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	This project will add two 27.6kV ccts to the area and provide 40 MVA capacity for future growth. It will also establist ties between feeders on Hwy 27 and feeders on Huntington Rd. It will also increase power supply reliability in the west part of Vaughan.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	It will also establist ties between feeders on Hwy 27 and feeders on Huntington Rd. It will also increase power supply reliability in the west part of Vaughan.
	Factors Affecting Timing/Priority	The new pole line will be built as per Major Mack Dr road widening design. Therefore, it will be affected by the road widening schedule.
	Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The alternative is to "do nothing" and to supply load growth from existing facilities. It will impact PowerStream distribution system in two following aspects: Reliability There is one single phase 4.8kV cct on Major Mack Dr between Huntington and Hwy 27. PowerStream has adopted "Open Grid Network" planning philosophy, i.e., loop supply with normal open points. The Kleindor development is supplied from Hwy 27 through a radial underground cable, meaning that any pole failure on the cable will cause large scale and prolonged outages to the customers. The Nashville Heights development is supplied from Huntington Rd through a radial underground cable, meaning that any pole failure on the cable or pole line on Huntington Rd will cause large scale and prolonged outages to the customers. Capacity There is one single phase 4.8kV cct on Major Mack Dr between Huntington and Hwy 27. It does not have the capacity to supply Kleindor development, Nashville Heights development and Vaughan West. The alternative will jeopardize PowerStream's obligation to supply new customers in Kleindor and Nashville Heights developments. The impact severity and timing will depend on the schedule of the Kleindor and Nashville Heights development.

Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100904	2015	6	Dollars

Project Name

Install Double Cct Pole Line on Major Mackenzie - Hwy 27 to Huntington Rd

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,819,608	$ -	$ -



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100237	2015	6	Dollars

Project Name
Install Double Ccts 27.6 kV Pole Line on 16th Ave from 9th Line to Reesor Road

Major Category	System Service	

Project Overview

1. Additional Information	Service Territory	PowerStream South
	Location	16th Avenue from 9th Line to Reesor Road - 2km
	Scope	The existing feeders on 16th Ave is a non-standard 3/0 three phase feeder. This project is install double ccts 27.6kV pole line on 16th Ave to to add one 27.6kV cct on 16th Ave from 9th Line to Reesor Rd to increase supply capacity and reliability to Markham East development of Cornell and Box Grove areas; one of the fastest growing areas in PowerStream's service territory.
	Justification	The existing conductor size of the cct on 16th Ave and Reesor is 3/0 AL and does not have enough capacity to supply the new development and provide backup capacity when needed. This project will provide 40 MVA supply capacity to Markham east and address the loading issue of Cornell and Box Grove both in the short and long term. This project will form 27.6kV feeder loops in Cornell area and also reduce the risk of customer outages that might arise as a result of radial feeders in that area. The Cornell Community is bounded by north of 16th Ave to the north, Reesor Road to the east, south of Hwy 7 to the south, and 9th Line to the west. It will accommodate approximately 8,500 dwelling units with approximately 26,000 people. The total load is estimated to be 46 MW when it is fully built out.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2019
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The risk is to get approval from the City of Markham in time. Capital design will start the design of the project in 2018 and should get the approvals in place in 2018.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	This project is install double ccts 27.6kV pole line on 16th Ave to to add one 27.6kV cct on 16th Ave from 9th Line to Reesor Rd to increase supply capacity and reliability to Markham East development of Cornell and Box Grove areas; one of the fastest growing areas in PowerStream's service territory.
	1a. Main Driver	Support Capacity Delivery. The main driver for this project is to support the capacity delivery in the Cornell and Box Grove area. This project is to form a loop supply arrangement for the Cornell development. It also allow feeder 24M3/24M6 to back up feeder 24M4/24M5. This project (Extend two 27.6kV circuits 24M4/24M5 on 16th Ave from 9th Line to Reesor Rd) is an interim step of the ultimate supply plan for the Cornell area and Box Grove areas.
	1b. Priority and Reasons for Priority	High. Installing two additional 27.6kV circuits on 16th Ave will: 1. Addresses the reliability issue of Cornell and Box Grove both in the short and long term. 2. Provide alternate supply route for Cornell development to increase reliability. 3. Consistent with the original Markham TS4 feeder integration plan and business case. 4. It also addresses the reliability issue of 24M4/24M5 which supply Markham Stouffville Hospital.

Power Stream Project Summary Report	Project Code **100237**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Install Double Ccts 27.6 kV Pole Line on 16th Ave from 9th Line to Reesor Road			

	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	The alternative to this project is to "do nothing", but still supply load growth from existing facilities. It will impact PowerStream distribution system in two following aspects: 16th Ave is the northern boundary of Cornell development. There is an existing three phase feeder on 16th Ave (24M7). Feeder 24M7 supplies loads on east of 9th Line between Hwy 7 and Steeles Ave, and load on Reesor Rd between Steeles Ave and Major Mack Dr. The peak of 24M7 was 346A in 2013. The conductor size on 16th Ave and Reesor is 3/0 AL and does not have enough capacity to supply the new development and provide backup capacity when needed. **Reliability** PowerStream has adopted "Open Grid Network" planning philosophy, i.e., loop supply with normal open points. All existing supplies to Cornell and Box Grove are radial from 9th Line, meaning that any pole failure on 9th Line will cause large scale and prolonged outages to the customers. It has been planned to form a 27.6kV loop around Cornell and Box Grove via 9th Line, 14th Ave, Hwy 7, Reesor Rd and 16th Ave. **Capacity** 16th Ave is the northern boundary of Cornell development. There is an existing three phase feeder on 16th Ave (24M7). Feeder 24M7 supplies loads on east of 9th Line between Hwy 7 and Steeles Ave, and load on Reesor Rd between Steeles Ave and Major Mack Dr. The peak of 24M7 was 346A in 2013. The conductor size on 16th Ave and Reesor is 3/0 AL and does not have enough capacity to supply the new development and provide backup capacity when needed. The status quo option currently does not meet PowerStream's "Open Grid Network" philosophy for this area. Existing and future urbanization as well as the hospital expansion in Cornell area necessitates the need for additional feeders and grid reconfiguration in this area.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	The main benefit is to increase supply reliability to Cornell area.
	Factors Affecting Timing/Priority	A number of residential and commercial projects are under construction now in Cornell area. New customers and load are expected in the years to come.
	Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The Project Benefits include: 1. Addresses the reliability issue of Cornell and Box Grove. 2. Provide alternate supply route for Cornell development 3. Consistent with the original Markham TS4 feeder integration plan and business case. The "do nothing" alternative discussed above is not viable for the following reasons: a) Does not meet short term and long term supply needs of the Cornell and Box Grove developments and open grid network philosophy. b) Customers will be at risk of lengthier outages if loop supply is not in place.

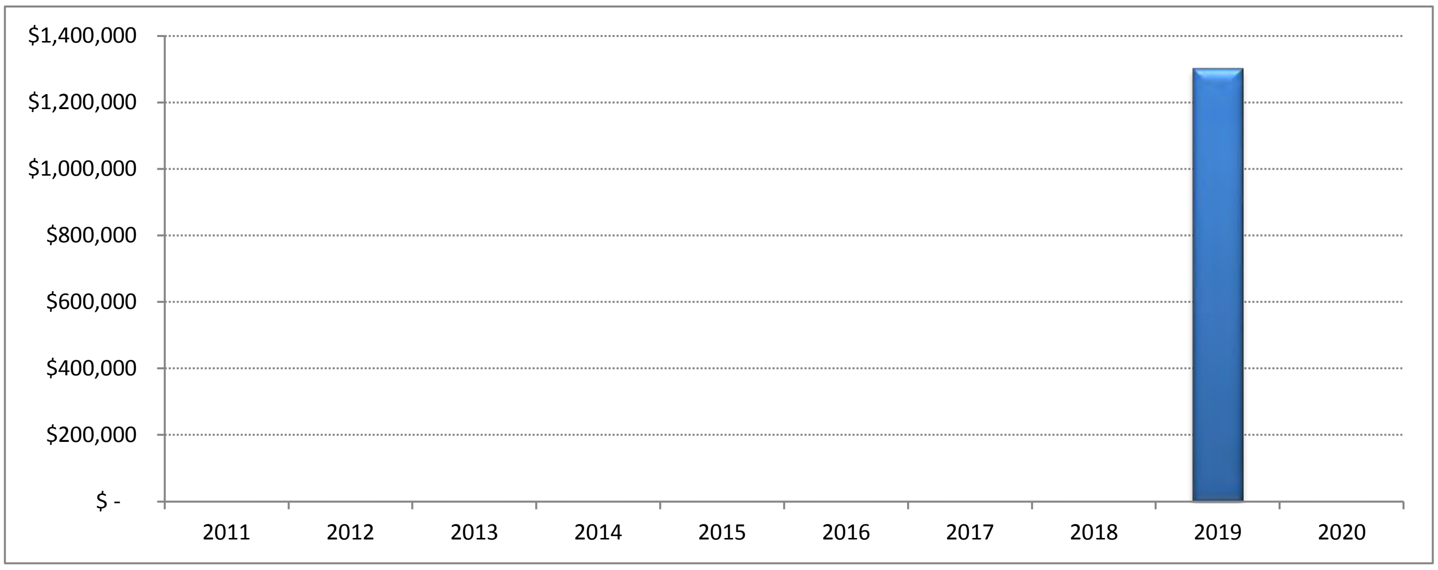
Project Code	Report Start Year	Number of Years	Scale
100237	2015	6	Dollars

Project Summary Report

Project Name

Install Double Ccts 27.6 kV Pole Line on 16th Ave from 9th Line to Reesor Road

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,302,301	$ -



Power Stream **Project Summary Report**	Project Code **103651**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Install one 44kV cct on Mapleview Drive West - Essa to Veterans			

Major Category	System Service	

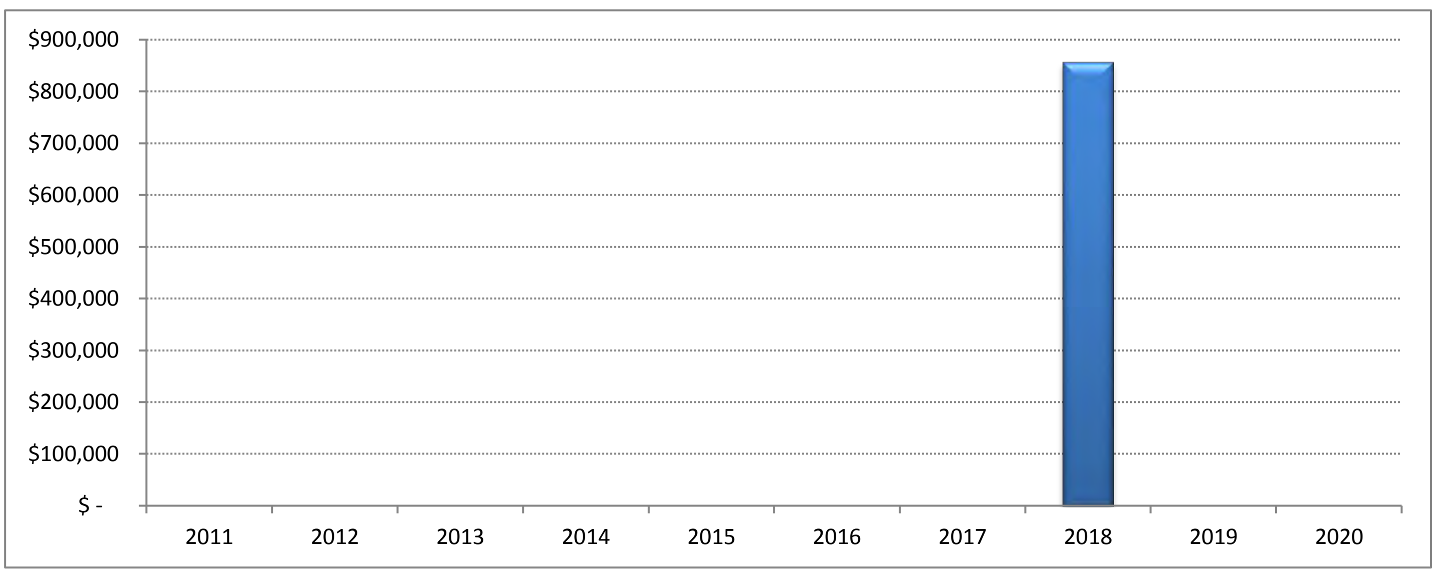
Project Overview

1. Additional Information	Service Territory	PowerStream North
	Location	On Mapleview Drive West east of Essa Road to Veterans Drive
	Scope	To add one additional 44kV circuit to existing 1x44kV & 2x13.8kV pole line along Mapleview Drive. To install switch as required to sectionalize the feeder.
	Justification	The Barrie South-West area is bounded by Highway 27 to the west, Highway 400 to the east, Harvie Road to the north and Salem Road to the south. The Barrie South-West area is currently supplied by the 23M5 and 13M5 feeders, which each experienced loading of 341A and 354A during the 2013 peak, respectively. There are two large data centers currently located in the Barrie South-West area; Data Center #1 is currently contracted for 10MVA with expansion plans to reach 20MVA over the next 8-10 years, while Data Center #2 is currently contracted for 5.5MVA with provisions to go to 11MVA at any time. Based on the contingency condition requirements and considering the anticipated load growth at each facility, feeder 23M5 summer peak loading will exceed 400A in 2015 and exceed the 600A thermal limit in 2020 during a contingency load transfer, while feeder 13M5 will exceed 400A in 2014 and exceed 600A in 2017. Currently the section of Mapleview Drive between Essa Road to Veterans Drive has a single 44kV feeder (23M5). The Essa/Mapleview area will have a new 44kV feeder (23M26) supplying Holly MS in Q2 of 2015 and two additional 44kV feeders (23M22 & 23M27) to be in-service by 2018. These three new 44kV feeders will increase capacity to the Barrie South-West area in response to the data center load growth, however, only the single 23M5 spans the section from Essa Road to Veterans Drive, thereby limiting contingency capacity and transfer options to a single 44kV feeder. In addition a loss of the single 23M5 feeder along Mapleview adjacent feeders in the Barrie South-West area will not be able to pick-up the lost feeder load and therefore reliability in the Barrie South-West area will be negatively impacted.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2018
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The greatest risk to completion is securing the required approvals from the city in the allotted timeframe.
	Comparative Information on Equivalent Historical Projects (if any)	Some past projects for new circuits have taken 6-8 months to obtain the necessary approvals before proceeding with construction.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	To add one additional 44kV circuit to existing 1x44kV & 2x13.8kV pole line along Mapleview Drive. To install switch as required to sectionalize the feeder.
	1a. Main Driver	Support Capacity Delivery. The main driver of the project is to extend the additional capacity provided by the three new 44kV feeders in the Essa/Mapleview area to the load growth at Veterans/Mapleview. The section of Mapleview Drive West between Essa Road to Veterans Drive currently has a single 44kV feeder.
	1b. Priority and Reasons for Priority	The project is high priority since the additional capacity offered by the three new 44kV feeders could be utilized to support future load growth.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	The additional 44kV circuit would add approximately 30MVA of additional capacity to the Veteran/Mapleview area. The feeder would also help establish a back-up feeder to maintain a dual supply at the data center load during contingency conditions. The 'do-nothing' alternative is not recommended because the additional capacity provided by one of the three new 44kV feeders in the Essa/Mapleview area will be unable to supply load growth in the Veterans/Mapleview area.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.

Power Stream **Project Summary Report**	Project Code **103651**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Install one 44kV cct on Mapleview Drive West - Essa to Veterans			

5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	The new feeder will produce reliability benefits by providing more 44kV circuits to the Veterans/Mapleview area, thereby increasing transfer options which increases reliability to customers.
	Factors Affecting Timing/Priority	Securing the required approvals from the city in the allotted timeframe may affect the timing of the feeder construction.
	Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The additional 44kV circuit would add approximately 30MVA of additional capacity to the Veteran/Mapleview area. The feeder would also help establish a back-up feeder to maintain a dual supply at the data center load during contingency conditions. The 'do-nothing' alternative is not recommended because the additional capacity provided by one of the three new 44kV feeders in the Essa/Mapleview area will be unable to supply load growth in the Veterans/Mapleview area.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 855,914	$ -	$ -



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	103633	2015	6	Dollars
	Project Name: Install Two 27.6kV Ccts on 16th Ave from Hwy 404 to Woodbine Ave			

Major Category System Service

Project Overview

1. Additional Information	Service Territory	PowerStream South
	Location	On 16th Ave from Hwy 404 to Woodbine Ave in Markham
	Scope	This project has been designed under WO#311308, but deferred from 2014 to 2016 due to delay in the closure of Buttonville Airport. This project is to install two additional 27.6kV ccts on 16th Ave from Hwy 404 to Woodbine Ave by rebuilding the existing pole line into a 4 ccts pole line or installing a new 2 ccts pole line on 16th Ave where permitted.
	Justification	The objective of this project is to re-route two 27.6kV feeders from Markham to Richmond Hill as part of MTS4 feeder integration plan. This project is to provide additional 40 MVA capacity to Richmond Hill and it will off load Richmond Hill RH-TS1 and RH-TS2 that exceeded their LTRs in 2012. The major future developments in Richmond Hill will be the Beaver Creek Business Park, Headford Business Park, Barker Business Park and Leslie North. According to Town of Richmond Hill's "Vacant Employment Land Inventory - Fall 2011", there are approx. 209 hectares of vacant employment land in these three business parks that are bounded by Hwy 404/Leslie St/Elgin Mills Rd/16th Ave. The total estimated new load is approx. 50MW, so two to three new feeders are required for the proposed development. The total land area of Leslie North is approx. 620 hectares. Approx 5,000 residential units have been proposed, so one new feeder is required. In total, three to four feeders are required to supply these developments in Richmond Hill. These developments are close to Richmond Hill TS1 and TS2, but TS1 and TS2 have been loaded to their summer LTRs. The load is expected to increase by 7MW every year in Richmond Hill. Richmond Hill is supplied by Richmond Hill TS1, TS2 and Buttonville TS. Richmond Hill TS1 and TS2 have been at their LTR's since 2009. The peak in July 2012 was 165 MW on Richmond Hill TS1, 120MW on Richmond Hill TS2. They exceeded their LTRs by 12MW and 20 MW respectively. Richmond Hill TS1 and TS2 do not have extra capacity to supply new loads anticipated in the developments. The load is expected to increase by 7MW every year in Richmond Hill. Buttonville TS is at its LTR in 2012, but 40MW's of load has been transferred to MTS4 after four feeders on Rodick Rd are put in service in May 2013. As a result of new feeders from MTS4, the peak of Buttonville TS will decrease to 120 MW in 2013 and will be below its 10 day Limited Time Rating (LTR) of 153 MW. The freed up capacity can be used to supply new loads in Richmond Hill and Markham. This project is going to save 20,000 CMI. The risk of deferring one year would be $40,000 for CMI based on $2 per CMI and $110,000 for project cost due to inflation. The total cost is $150,000.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2016
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The risk is to get approval from the City of Markham, York Region, Transport Canada as well MTO in time.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	Install Two Additional 27.6kV Ccts on 16th Ave from Hwy 404 to Woodbine Ave in 2016.
	1a. Main Driver	Support Capacity Delivery. The main driver for this project is to support capacity delivery in Richmond Hill.
	1b. Priority and Reasons for Priority	Very High. This project has been approved in 2014's ICM and deferred to 2016 due to issue with Buttonville Airport closure schedule and MTO's Hwy 404 widening schedule.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	This project is needed to provide 40 MVA of load capacity from Buttonville TS to the Richmond Hill area.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.

Project Summary Report

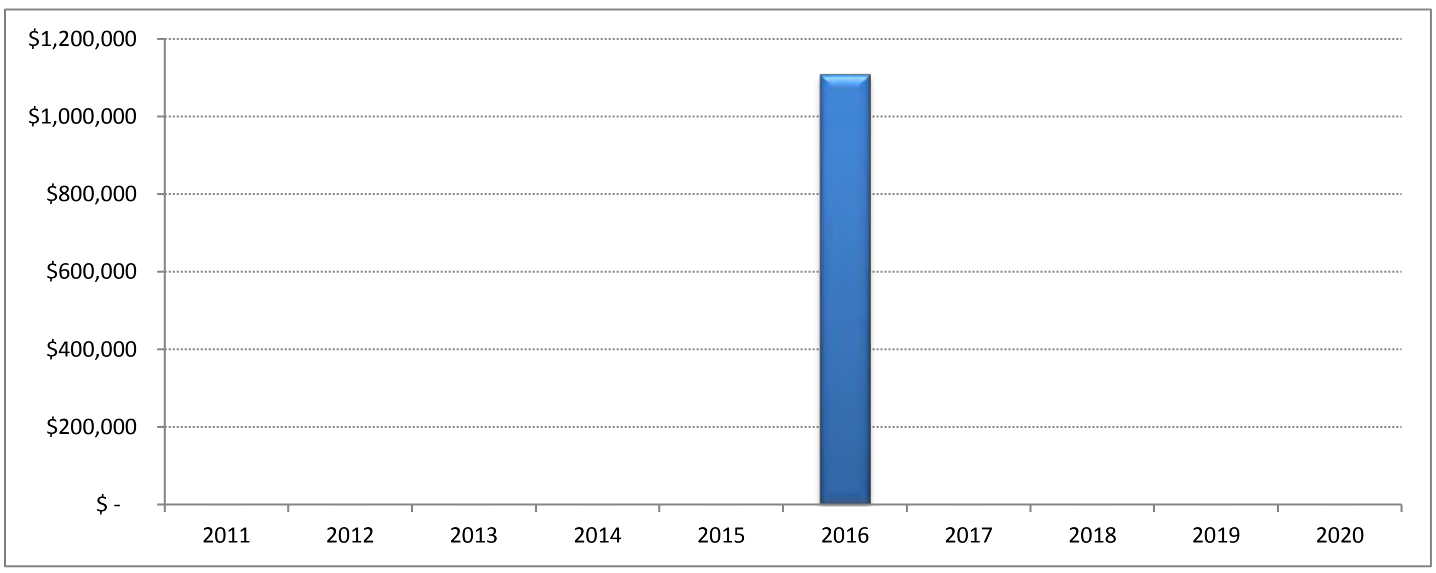
Project Code	Report Start Year	Number of Years	Scale
103633	2015	6	Dollars

Project Name

Install Two 27.6kV Ccts on 16th Ave from Hwy 404 to Woodbine Ave

Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
Identify any reliability , efficiency, safety or coordination benefits	This project will provide 40 MVA capacity from Buttonville TS to the Richmond Hill area. It will also increase supply reliability.
Factors Affecting Timing/Priority	Buttonville Airport is expected to close in Oct 2015. The closing date will affect the project schedule.
Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	This project is needed to provide 40 MVA capacity from Buttonville TS to the Richmond Hill area. It will also increase supply reliability. This is the least cost alternative. The "do nothing" alternative is not viable as it does nothing to provide the required load capacity.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ 1,108,593	$ -	$ -	$ -	$ -



Power Stream	Project Code	Report Start Year	Number of Years	Scale
Project Summary Report	**100924**	**2015**	**6**	**Dollars**
	Project Name: Install two additional 27.6 kV ccts on Hwy 7 from Jane St to Weston Rd			

Major Category **System Service**

Project Overview

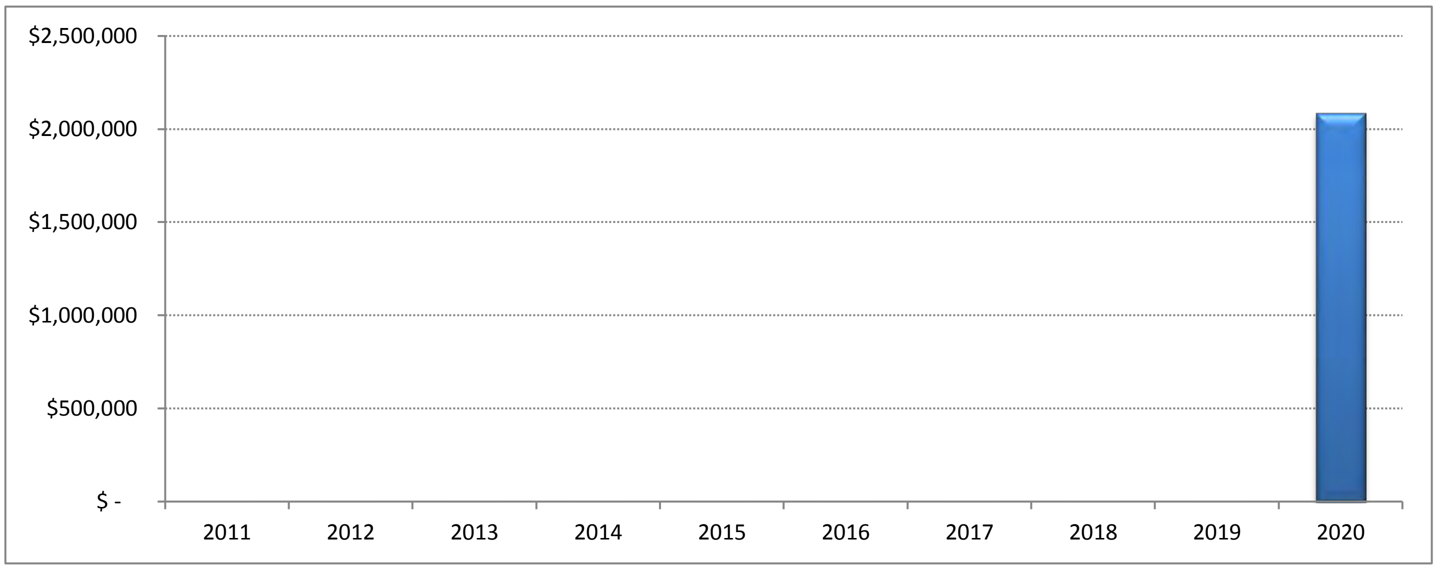
1. Additional Information	Service Territory	PowerStream South
	Location	on Hwy 7 from Jane St to Weston Rd in Vaughan - 2km
	Scope	This project is to reroute two 27.6kV feeders (21M3 & 21M4) to supply new load in Vaughan Metro Center (VMC). This will be achieved by rebuilding the existing pole line on Hwy 7 between Weston Rd and Jane St from 2 ccts into 4 ccts, or installing a new 2 ccts pole line on the opposite side of the exsting pole line, or installing 2 cct in underground ductbank, or combination of above options. It will be determined in the design stage and coordinate with York Region's Hwy 7 widening work and the City of Vaughan's urban design plan.
	Justification	The project objectives are to re-route two 21M3& 21M4 27.6kV ccts from Weston Rd/Hwy 7 east to Jane St/Hwy 7 area, and to install switches or switchgear where required. This is required to supply the Vaughan Metro Center development that is estimated to have a peak demand of 100 MW when fully built out. As of 2013, there are four feeders supplying area: 21M5, 21M11, 20M19, 20M20. The peak demands of these feeders were: 21M5 401A 21M11 280A 20M19 361A 20M20 433A The above feeders were close or exceeded PowerStream's feeder loading guide line of 400A. To meet the load growth in VMC, more feeders are required in VMC area. As per VTS4 feeder integration plan, two feeders from VTS4 will off load existing feeder 21M3 and 21M4 from VTS2 so that they can be used to supply new growth in VMC area (40MVA). In additional, two other feeders 20M17 and 20M18 will be off loaded and supply VMC too (40 MVA).
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2020
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The risk is to get approval from the City of Vaughan and York Region in time. Capital design will start the design of the project and should get the approvals in place in advance.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	The project objectives will be achieved by rebuilding the existing pole line on Hwy 7 between Weston Rd and Jane St from 2 ccts into 4 ccts, or installing a new 2 ccts pole line on the opposite side of the exsting pole line, or installing 2 cct in underground duct bank, or combination of above options. It will be determined in the design stage and coordinate with York Region's Hwy 7 widening work and the City of Vaughan's urban design plan.

Project Summary Report	Project Code **100924**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Install two additional 27.6 kV ccts on Hwy 7 from Jane St to Weston Rd			

	1a. Main Driver	Support Capacity Delivery. The main driver for this project is to support the capacity delivery in VMC area. The development of the VMC that may add 100 MW when fully built out. As per the consultant's master plan, the north west corner of VMC (Smart Center) will have 65MW load and require four 27.6kV feeders. As of 2013, there are four feeders supplying area: 21M5, 21M11, 20M19, 20M20. The peak demands of these feeders were: 21M5 401A 21M11 280A 20M19 361A 20M20 433A The above feeders were close to, or exceeded, PowerStream's feeder loading guide line of 400A. To meet the load growth in VMC, more feeders are required in VMC area. As per VTS4 feeder integration plan, two feeders from VTS4 will off load existing feeder 21M3 and 21M4 from VTS2 so that they can be used to supply new growth in VMC area (40MVA). In additional, two other feeders 20M17 and 20M18 will be off loaded and supply VMC too (40 MVA).
	1b. Priority and Reasons for Priority	Very high. The development of VMC is underway. New capacity is required as the development progresses.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	This project is needed to add 40 MVA supply capacity for the new development in VMC area. All other alternatives explored for supplying 40 MVA to the required area were determined to be more costly.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	This project will increase supply capacity to VMC by 40 MVA. It will also increase supply reliability too.
	Factors Affecting Timing/Priority	VMC development ramping up schedule will impact the timing and priority.
	Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	This project will extend two feeders into the VMC area to increase load capacity by 40 MVA. No other option was determined to be economically viable. The "do nothing" alternative will not allow PowerStream to supply the new load growth.

Project Summary Report	Project Code **100924**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Install two additional 27.6 kV ccts on Hwy 7 from Jane St to Weston Rd			

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,084,275



Project Summary Report	Project Code **102546**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Installation of two new circuits on Leslie Street - 19th Ave to Stouffville Sideroad			

Major Category **System Service**

Project Overview

1. Additional Information	Service Territory	PowerStream South
	Location	On Leslie Street from 19th Ave to Stouffville Sideroad in Richmond Hill.
	Scope	Build 2 ccts pole line on Leslie St from 19th Ave to Stouffville Sideroad. Install switches as per PowerStream's design standard.
	Justification	This project is to provide capacity for development along Leslie St (Leslie North and West Gormley) and to provide backup to 12M6 to increase supply reliability to Richmond Hill north. The Leslie North development may accommodate approximately 6250 housing units with a population of approximately 19,300 people and employment of approximately 3200 jobs. West Gormley will have approx 1,500 residential units and small commercial units. The estimated load is 6 MW. Two 27.6kV feeders are required for these developments. Based on 2.5kW per unit and 1.5 kW per job, the total demand would be 20 MW. There is no feeder on 19th Ave so new pole line is required.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2020
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The risk is to get approval from the Town of Richmond Hill in time. Capital design will start the design of the project and should get the approvals in place in advance.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	Install two new circuits on Leslie Street from 19th Ave to Stouffville Sideroad in Richmond Hill.
	1a. Main Driver	Support Capacity Delivery. The main driver for this project is to support the capacity delivery in Leslie North and West Gormley. The Leslie North development may accommodate approximately 6250 housing units with a population of approximately 19,300 people and employment of approximately 3200 jobs. Based on 2.5kW per unit and 1.5 kW per job, the total demand would be 20 MW. There is no feeder on 19th Ave so new pole line is required. West Gormley will have approx 1,500 residential units and small commercial units. The estimated load is 6 MW. Two 27.6kV feeders are required for these developments.
	1b. Priority and Reasons for Priority	High. The infrastructure development for this area started in 2014.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	The existing pole line on Leslie St is a single phase 16kV cct. New pole line is required to supply the new development.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	This project will increase reliability for customers on Stouffville Sideroad and Leslie St.
	Factors Affecting Timing/Priority	The progress of the Leslie North and Gormley developments impact the loading of the feeders.
	Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	This project is needed, since there is only one single phase cct on Leslie St that cannot supply future three phase loads and cannot provide backup needs between ccts on 19th Ave and ccts on Stouffville Sideroad. The "do nothing" alternative is not viable as it cannot provide supply capacity for the future developments.

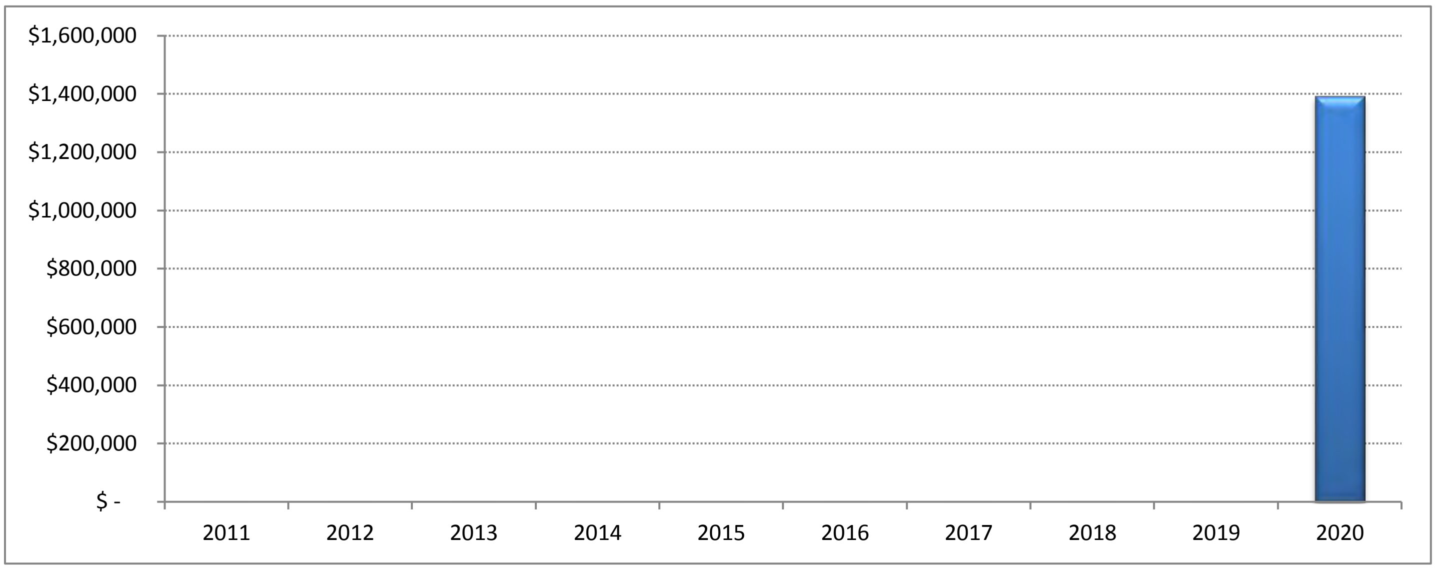
Project Summary Report

Project Code	Report Start Year	Number of Years	Scale
102546	2015	6	Dollars

Project Name

Installation of two new circuits on Leslie Street - 19th Ave to Stouffville Sideroad

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,392,644



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100337	2015	6	Dollars
	Project Name: Markham TS #4 Feeder Egress Part 3			

Major Category	**System Service**	

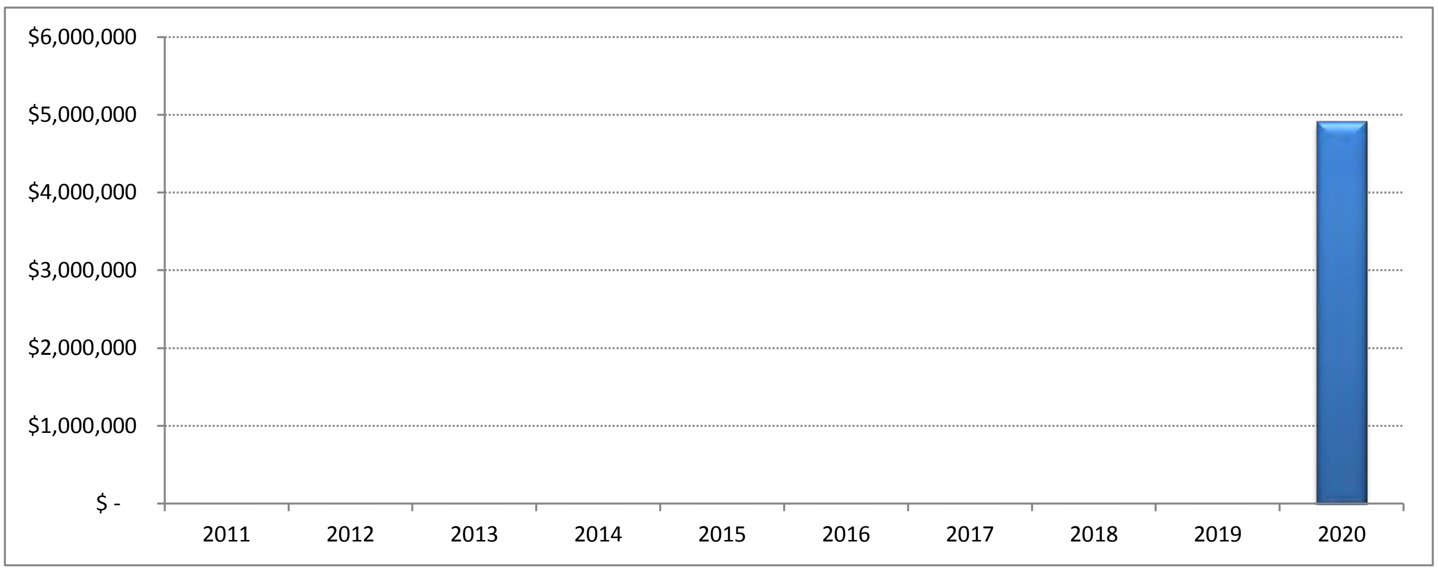
Project Overview

1. Additional Information	Service Territory	PowerStream South
	Location	On Rodick Rd from Markham TS#4 to 14th Ave in Markham, approx. 1.5km.
	Scope	This project is Markham TS #4 Feeder Integration Plan's Part 3, to install 4 feeders from MTS4 to 14th Ave via Rodick Rd. The feeders will be underground from MTS4 to Rodick, and crossing Hwy 407 via ducts in the bridge to Miller Ave, appox 0.8 km. They will be overhead installation from Miller Ave to 14th Ave, approx 0.7 km.
	Justification	This project is going to add 80 MVA capacity to the distribution system to increase supply capacity to Steelcase area, and Warden Ave/14th Ave area. This project will also provide supply capacity from different transmission line so it will also increase supply reliability. There will be intensification in the south end of Markham. Additional supply capacity is required for the new growth. There are many data centers in the Warden/14th Av area, mostly supplied by MTS1. Data centers demand high supply diversity, i.e., feeders from different buses, different transformer stations and even different transmission lines. MTS4 is supplied from a different 230kV transmission line than the 230kV transmission line supplying MTS1. New feeders from MTS4 will provide transmission line diversity to the area and satisfy customer's needs.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2020
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The risk is to get approval from the City of Markham and MTO in time. Capital design will start the design of the project in advance and should get the approvals in place in time.
	Comparative Information on Equivalent Historical Projects (if any)	There are two similar feeder egress projects from MTS4: -Four feeders from MTS4 to Woodbine Ave via Yorktech Blvd via underground ductbank. -Four feeders from MTS4 to Hwy 7 via Rodick Rd via underground ductbank.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	This is Markham TS #4 Feeder Integration Plan's Part 3. This project is to install four 27.6kV feeders from MTS4 along Rodick Rd to 14th Ave. These feeders will be connected to existing feeders on 14th Ave and Miller Ave.
	1a. Main Driver	Support Capacity Delivery. The main driver for this project is to support the capacity delivery in the Markham area and to improve reliability. There are many data center customers on 14th Ave between Hwy 404 and Kennedy Rd. Many of them require higher than average reliability and supplies from two different transformer stations. These four new feeders will add MTS4 into the supply mix and satisfy customers' needs.
	1b. Priority and Reasons for Priority	High. One data center at 371 Gough Rd has been in service in 2014. The initial load is 2 MW and ultimate will be 7 MW by 2018. One data center at 4175-14th Ave will be in service in 2015. The initial load will be 5MW and ultimate will be 10 MW by 2020.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	This project will extend four feeders into the area and increase capacity by 80 MVA. There is no other practical way to supply the new load.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.

Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100337	2015	6	Dollars
	Project Name: Markham TS #4 Feeder Egress Part 3			

Identify any reliability , efficiency, safety or coordination benefits	This project will also provide supply reliability to existing customers on 14th Ave/Woodbine Ave, and 14th Ave/Warden Ave area.
Factors Affecting Timing/Priority	Customers load ramping up schedule will impact the timing and priority.
Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	This project is needed to extend four feeders into the area, and increase load capacity by 80 MVA. Other alternatives have been explored and determined to be more costly. The "do nothing" alternative is not viable as it will not allow PowerStream to supply the new load growth.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,910,872



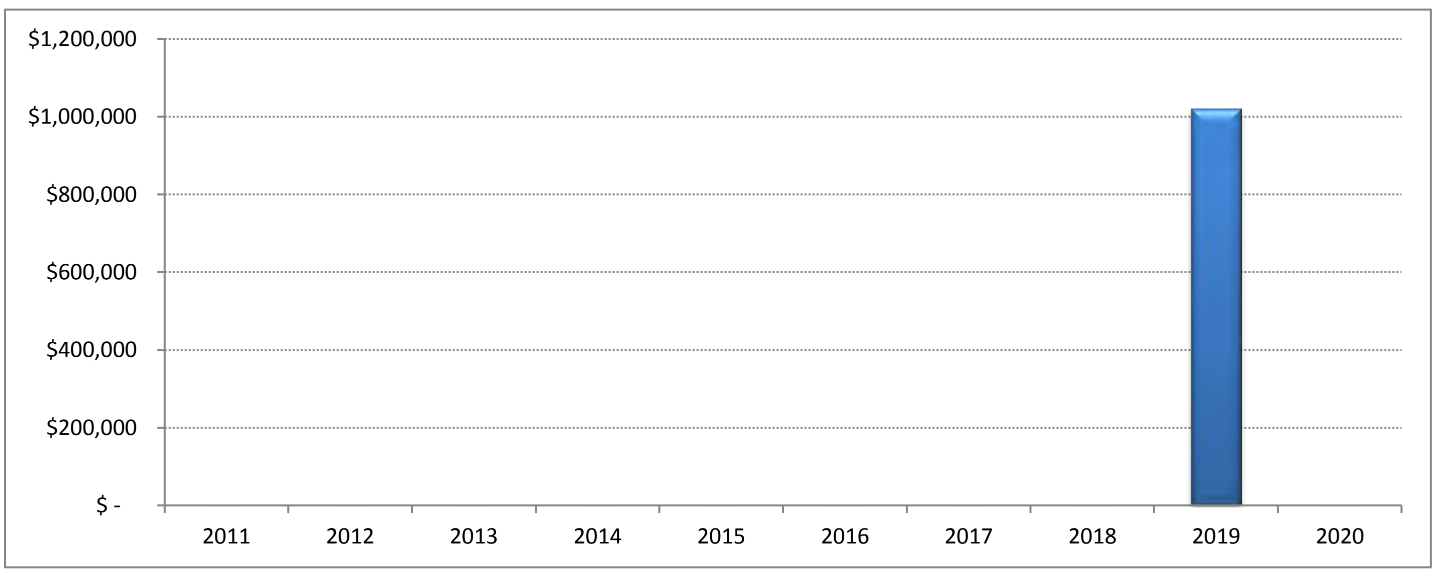
Project Summary Report	Project Code 102545	Report Start Year 2015	Number of Years 6	Scale Dollars
	Project Name New 27.6kV Pole Line on 19th Ave from Leslie to Woodbine Ave			

Major Category	System Service	
Project Overview		
1. Additional Information	Service Territory	PowerStream South
	Location	On 19th Ave from Leslie St to Woodbine Ave.
	Scope	Build 2 ccts pole line between Leslie St and Woodbine Ave. Install switches as per PowerStream's design standard.
	Justification	This project is to •increase power supply reliability for Markham and Richmond Hill, •increase supply capacity to future development in Markham north & Richmond Hill, and •increase operational flexibility in Markham and Richmond Hill. Future Development- Markham Town of Markham’s Official Plan Amendment No. 113 (OPA 113) has been approved by the Region of York (ROPA46). The lands subject to ROPA 46 and OPA 113 comprise approximately 180 hectares (450 acres). The proposed land uses of OPA 113 are primarily Industrial. Honda Canada has built new head office the OPA 113 area in Markham. Honda will initially relocate 500 employees to the new site that is being built on a 19-hectare parcel of land facing Highway 404, just north of Elgin Mills Rd. The complex is to be supplied by 2x1000 kVA and 1x750 kVA transformers. The preliminary load estimate is 30 MW when the land is fully developed and two 27.6 kV feeders are required for this development. Future Development- Richmond Hill The North Leslie Secondary Plan area encompasses a land area of approximately 577 hectares and is bounded by Bayview Avenue, Highway 404, Elgin Mills Road and 19th Avenue in the Town of Richmond Hill. A few commercial buildings (including Costco and Home Depot) have been completed and more are under construction at north east corner of Leslies St. and Elgin Mills Rd.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2019
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The main risk is to get approval from the Town of Richmond Hill and city of Markham as well MTO in time. Capital design will start the design of the project in advance and should get the approvals in place in time. Another risk the 19th widening work schedule may impact the pole line construction. PowerStream will work with the town to coordinate the schedule.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	To build 2 ccts pole line between Leslie St and Woodbine Ave
	1a. Main Driver	Support Capacity Delivery. The main driver for this project is to increase supply capacity to future development in Markham north & Richmond Hill. In addition the project will improve the relability of the supply and provide back up for the existing cct on Woodbine Ave north of Elgin Mills.
	1b. Priority and Reasons for Priority	High. The existing customer on Woodbine Ave north of Elgin Mills are on radial supply. Any distribution line failure on Woodbine Ave will cause prolonged outages.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	The existing customers on Woodbine Ave north of Elgin Mills are on a radial supply. The backup needs to come from Warden Ave (east) or Leslie St (West). However, there is only a single phase cct on Warden Ave between Elgin Mills and 19th Ave and therefore it cannot provide backup for customers on Woodbine Ave without being rebuilt into a 3-phase line. The backup can only from Leslie St.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.

	Project Code	Report Start Year	Number of Years	Scale
Project Summary Report	**102545**	**2015**	**6**	**Dollars**
	Project Name: New 27.6kV Pole Line on 19th Ave from Leslie to Woodbine Ave			

Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
Identify any reliability , efficiency, safety or coordination benefits	This project will improve reliability for customers in the area.
Factors Affecting Timing/Priority	The progress of the Leslie North development and Hwy 404 North impact the loading and urgency of the feeders.
Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The "do nothing" alternative is not viable as customers will continue to remain on radial supply and have lower than average reliability.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,020,587	$ -



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100959	2015	6	Dollars

Project Name

New 44 kV Feeder (13M7) Barrie TS X Huronia & Big Bay Pt. Rd

Major Category **System Service**

Project Overview

1. Additional Information	Service Territory	PowerStream North
	Location	Barrie
	Scope	The project entails the design and construction of approximately 7.5km's of 44kV circuit from Barrie TS to Huronia and Big Bay Point Road. The new circuit will require rebuilding the existing pole line from Dyment Road/John Street along John Street to Anne Street, along Anne Street to Essa Road, along Essa Road to the end of the existing pole line before Fairview Road, 300m of new build Essa Road and 550m new build Fairview Road to Little Avenue, Fairview Road from Little Avenue to Big Bay Point Road, along Big Bay Point Road past Huronia to the existing LT-B35115 switch. It should be noted that the Hwy 400 crossing already exists and the 13M7 breaker at Barrie TS is currently idle. The new feeder is to be in-service by summer 2017. The project includes engineering design, approvals, construction, and commissioning.
	Justification	The new feeder is required to provide capacity relief to the Barrie south-east area. Information obtained from the City of Barrie on proposed developments in the Sandringham Drive and Big Bay Point Road area indicates that there are a number of residential subdivisions that will result in new load growth that needs to be serviced. There are two developments currently under consideration as part of the Yonge Corridor Intensification Plan that will result in 3,137 residential units totaling an estimated 7.8MVA of load. Two other residential developments currently registered and under draft approval will result in 295 additional units with an estimated 0.8MVA of load. A new 20MVA 44/13.8kV 4 feeder substation (Painswick MS) is currently being constructed in the Yonge/Mapleview area to service the proposed future developments. The existing Big Bay Point Road MS and the future Painswick MS would be supplied by the 23M25 44kV feeder in the current system configuration. However, with Big Bay Point Road MS loaded to 30.2MVA (396A) during the summer 2013 peak and the future Painswick MS supplying the proposed 8.6MVA (113A) of residential load, the 23M25 feeder will exceed the 400A feeder planning limit in 2014 and the 600A thermal limit will be exceeded in 2018. The new feeder will ensure that the substations in the Barrie south-east area can be supplied accordingly in order to accommodate the anticipated load growth without exceeding the planning and thermal limits of the 44kV feeders.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The greatest risk to completion is securing the required approvals from the city in the allotted timeframe. The ramping up of the proposed residential developments in the area will also impact the timing of the project.
	Comparative Information on Equivalent Historical Projects (if any)	Some past projects for new circuits have taken 6-8 months to obtain the necessary approvals before proceeding with construction. Information from those historical projects has been used to help build the estimate for this planned project.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	The project entails the design and construction of approximately 7.5km's of 44kV circuit from Barrie TS to Huronia and Big Bay Point Road. The new circuit will require rebuilding the existing pole line from Dyment Road/John Street along John Street to Anne Street, along Anne Street to Essa Road, along Essa Road to the end of the existing pole line before Fairview Road, 300m of new build Essa Road and 550m new build Fairview Road to Little Avenue, Fairview Road from Little Avenue to Big Bay Point Road, along Big Bay Point Road past Huronia to the existing LT-B35115 switch. It should be noted that the Hwy 400 crossing already exists and the 13M7 breaker at Barrie TS is currently idle. The new feeder is to be in-service by summer 2017. The project includes engineering design, approvals, construction, and commissioning.

	Project Code	Report Start Year	Number of Years	Scale
Power Stream	100959	2015	6	Dollars
Project Summary Report	Project Name: New 44 kV Feeder (13M7) Barrie TS X Huronia & Big Bay Pt. Rd			

	1a. Main Driver	The main driver of the project is to provide capacity relief to the existing 44kV 23M25 feeder in the Barrie south-east area. The area has 8.6MVA of proposed residential development to take place over the next eight years. A new 20MVA 44/13.8kV 4 feeder substation (Painswick MS) is currently being constructed in the Yonge/Mapleview area to service the proposed future developments. The existing Big Bay Point Road MS and the future Painswick MS would be supplied by the 23M25 44kV feeder in the current system configuration. However, with Big Bay Point Road MS loaded to 30.2MVA (396A) during the summer 2013 peak and the future Painswick MS supplying the proposed 8.6MVA (113A) of residential load, the 23M25 feeder will exceed the 400A feeder planning limit in 2014 and the 600A thermal limit will be exceeded in 2018. The new feeder will ensure that the substations in the Barrie south-east area can be supplied accordingly in order to accommodate the anticipated load growth without exceeding the planning and thermal limits of the 44kV feeders.
	1b. Priority and Reasons for Priority	The new feeder is high priority since thermal limits will be exceeded in the Barrie south-east area beyond 2018 upon completion of the new Painswick MS and the proposed residential developments. Load transfers to the adjacent feeder are limited due to existing loading.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	The new circuit would add approximately 30MVA of capacity to the Barrie south-east area, thereby providing capacity relief to the existing 23M25 and ensuring supply capacity to the new Painswick MS. The new feeder would also provide cost savings realized from line loss reductions by decreasing the distance of the existing feeder from Midhurst TS (15km) to a much shorter distance from Barrie TS (7.5kms), resulting in approximately $100,000 of annual savings. The 'do-nothing' alternative is not viable because Big Bay Point Road MS was loaded to 30.2MVA (396A) during the summer 2013 peak and the future Painswick MS will be supplying the proposed 8.6MVA (113A) of residential load, which would result in the 23M25 feeder exceeding the 400A feeder planning limit in 2014 and the 600A thermal limit in 2018. The do-nothing alternative would not allow the accommodation of future residential load growth in the area or provide adequate feeder capacity for load transfers in contingency conditions.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	The new feeder will produce reliability benefits by providing an additional 44kV circuit to the Barrie south-east area, thereby increasing transfer options which increases reliability to customers. The new feeder will also help reduce line losses by reducing the distance of the existing feeder from Midhurst TS (15km) to a much shorter distance from Barrie TS (7.5kms).
	Factors Affecting Timing/Priority	Securing the required approvals from the city in the allotted timeframe may affect the timing of the feeder construction.

Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100959	2015	6	Dollars

Project Name

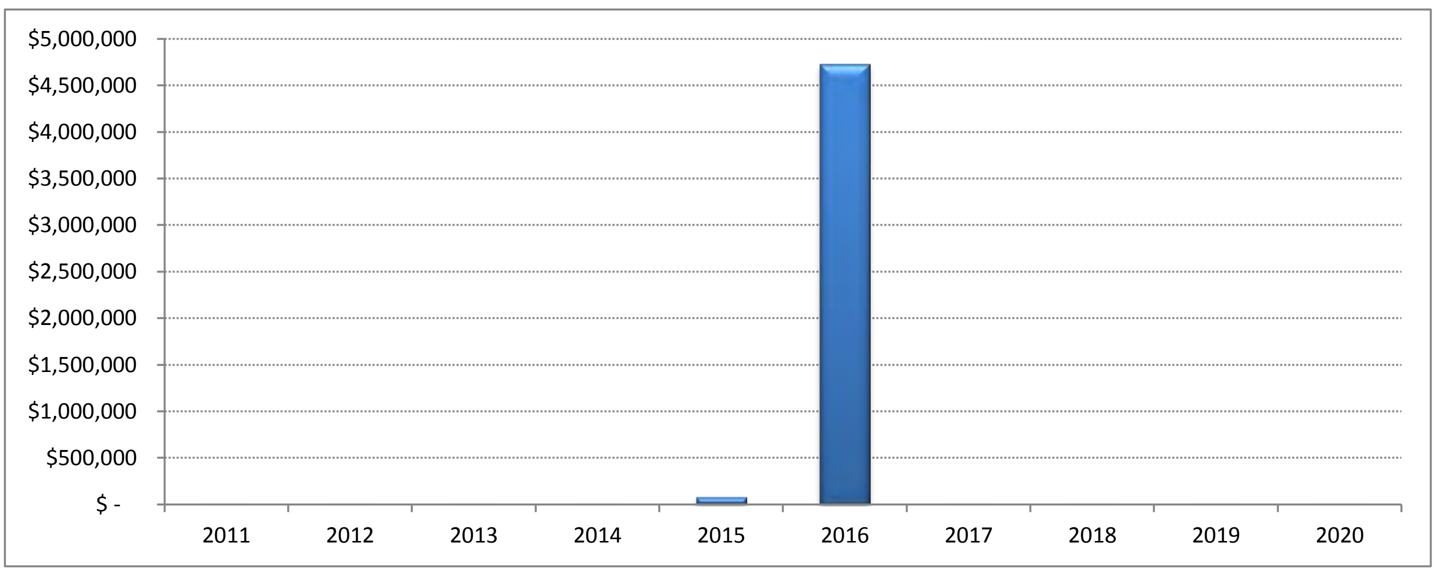
New 44 kV Feeder (13M7) Barrie TS X Huronia & Big Bay Pt. Rd

Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)

The new circuit would add approximately 30MVA of capacity to the Barrie south-east area, thereby providing capacity relief to the existing 23M25 and ensuring supply capacity to the new Painswick MS. The new feeder would also provide cost savings realized from line loss reductions by decreasing the distance of the existing feeder from Midhurst TS (15km) to a much shorter distance from Barrie TS (7.5kms), resulting in approximately $100,000 of annual savings.

The 'do-nothing' alternative is not viable because Big Bay Point Road MS was loaded to 30.2MVA (396A) during the summer 2013 peak and the future Painswick MS will be supplying the proposed 8.6MVA (113A) of residential load, which would result in the 23M25 feeder exceeding the 400A feeder planning limit in 2014 and the 600A thermal limit in 2018. The do-nothing alternative would not allow the accommodation of future residential load growth in the area or provide adequate feeder capacity for load transfers in contingency conditions.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ 76,925	$ 4,726,805	$ -	$ -	$ -	$ -



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100913	2015	6	Dollars

Project Name

Pole Line Installation Double Cct on Major Mack - Huntington Rd to Hwy 50

Major Category System Service

Project Overview

1. Additional Information	Service Territory	PowerStream South
	Location	On Major Mack Dr from Huntington Rd to Hwy 50 in Vaughan, approx. 2km. This project depends on York Region road widening work schedule.
	Scope	The objectives of this project is to install double a 27.6kV ccts pole line on Major Mack Dr from Huntington Rd to Hwy 50 in Vaughan, approx. 2km., install LIS at intersections, and connect the new ccts to the existing ccts on Hwy 50, and Huntington Rd.
	Justification	To supply new developments on Major Mack between Hwy 50 and Huntington Rd that are summarized below: Kleindor Development Kleindor development is part of OPA160 initiated in 2001 and has a planned population of approximately 3,000 people, and 1,000 residential dwelling units. The Kleindor development area that is located on the north side of Major Mackenzie Drive, east side or CP railway and west of Regional Road 27. The estimated load is approx. 2.5 MW. Nashville Heights Development Vaughan's Official Plan Amendment No. 699 (OPA 699provides land use designations and policies to guide growth in Block 61 West within the Kleinburg-Nashville Community. The Amendment area is approximately 185 hectares (457 acres) in size and is bounded on the west by Huntington Road, on the east by the CP rail line, on the south by Major Mackenzie Drive and on the north by lots fronting Nashville Road. OPA 699 has a planned population of approximately 8,000 people, 2,625 residential dwelling units and approximately 700 jobs.Based on 2.7kW per unit and 1.5 kW per job, the total demand would be 8 MW. West Vaughan Employment Area The West Vaughan Employment Area Secondary Plan sets out detailed policies to create a large economic opportunity for York Region. With over 500 hectares of employment designated lands, this area will continue to allow the City of Vaughan to attract a wide range of businesses requiring large tracks of land with excellent Regional road and provincial highway access. The Secondary Plan is planned to accommodate approximately 20,120 employees. There are 1,400 acres of vacant land on both sides of Major Mackenzie Drive that has been zoned as employment land. The potential load from these lands will be significant. The peak demand for this development is estimated to be 50MW to 80 MW when fully built out, but no time line is available at this time. Four 27.6kV feeders are required to supply the new load. York Region is going to widen Major Mackenzie Drive from Hwy 50 to Huntington Rd in 2019. There is opportunity for PowerStream to rebuild the existing single phase 4.8 kV cct to double 27.6kV ccts in conjunction with the pole line relocation project.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2019
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The risk is to get approval from the City of Vaughan and York Region in time. York Region is going to rebuild Major Mack Dr in 2019. The pole line construction schedule will depend on road widening schedule. Capital design will work closely with the Region and City to coordinate the project.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	This project is to build two ccts on Major Mack Dr between Huntington Rd and Hwy 50 to supply new customers on both side of Major Mack.
	1a. Main Driver	Support Capacity Relief. The main driver for this project is to support the capacity delivery in the in Vaughan West area. There is one single phase 4.8kV cct on Major Mack Dr between Huntington and Hwy 50. The existing feeders don't have sufficient capacity to supply future growth in the area.

	Project Code	Report Start Year	Number of Years	Scale
Power Stream	100913	2015	6	Dollars
Project Summary Report	Project Name: Pole Line Installation Double Cct on Major Mack - Huntington Rd to Hwy 50			

	1b. Priority and Reasons for Priority	High. The vacant land on both sides of Major Mack Dr are being developed and more and more customers are expected in the coming years. The existing pole line has to be relocated due to road widening work. Building 2 ccts in conjunction with the road widening project will reduce the cost and traffic impact.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	This project will add two 27.6kV ccts to the area and provide 40 MVA capacity for future growth. It will also establish ties between feeders on Hwy 50 and feeders on Huntington Rd. It will also increase power supply reliability in the west part of Vaughan.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	This project will also establish ties between feeders on Hwy 50 and feeders on Huntington Rd. It will also increase power supply reliability in the west part of Vaughan.
	Factors Affecting Timing/Priority	The new pole will be built as per Major Mack Dr road widening design. Therefore, it will be affected by the road widening schedule.
	Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The main alternative is to "do nothing" and continue to supply load growth from existing facilities. It will impact PowerStream distribution system in two following aspects: Reliability There is one single phase 4.8kV cct on Major Mack Dr between Huntington and Hwy 50. PowerStream has adopted "Open Grid Network" planning philosophy, i.e., loop supply with normal open points. The Kleindor development is supplied from Hwy 50 through a radial underground cable, meaning that any pole failure on the cable will cause large scale and prolonged outages to the customers. The Nashville Heights development is supplied from Huntington Rd through a radial underground cable, meaning that any pole failure on the cable or pole line on Huntington Rd will cause large scale and prolonged outages to the customers. Capacity There is one single phase 4.8kV cct on Major Mack Dr between Huntington and Hwy 50. It does not have the capacity to supply Kleindor development, Nashville Heights development and Vaughan West. The status quo will jeopardize PowerStream's obligation to supply new customers in Kleindor and Nashville Heights developments. The impact severity and timing will depend on the schedule of the Kleindor and Nashville Heights development. The "do nothing" alternative is not viable because PowerStream will not be able to supply new customers on Major Mack Dr.

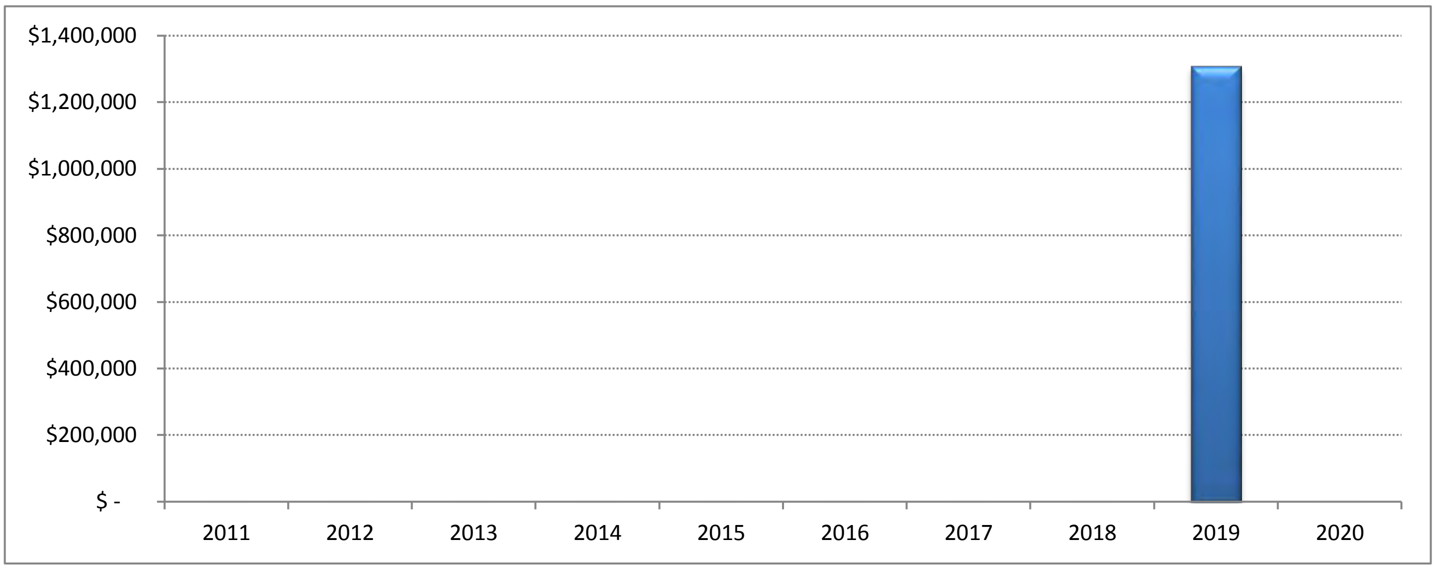
Project Summary Report

Project Code	Report Start Year	Number of Years	Scale
100913	2015	6	Dollars

Project Name

Pole Line Installation Double Cct on Major Mack - Huntington Rd to Hwy 50

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,307,147	$ -



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100909	2015	6	Dollars

Project Name

Rebuild 27.6 kV pole line for 4 Ccts on Warden Ave from Major Mack to Elgin Mills

Major Category	**System Service**	
Project Overview		
1. Additional Information	Service Territory	PowerStream South
	Location	On Warden Ave from Major Mack Dr to Elgin Mills Rd in Markham - 2 km
	Scope	Rebuild the existing single cct pole line into 4 ccts, 2 ccts now and 2 ccts provision for future on Warden Ave from Major Mack Dr to Elgin Mills Rd in Markham - 2 km, and install several load interrupter switches.
	Justification	To extend feeder 12M10/12M11 to Markham North. To increase supply capacity and reliability to Hwy 404 North area and new urban area north of Major Mack between Woodbine Ave and Kennedy Rd. York Region is working on an Official Planning Amendment which expands the Urban Area of the City of Markham to both sides of Warden Ave to provide opportunities for urban growth to the year 2031. The north Markham Future Urban Area covers about 1,288 hectares (3,183 acres bordered by Major Mackenzie Drive to the south, the Hydro Corridor and Woodbine Avenue to the west, the northerly City limits and Elgin Mills Road to the north, and the Robinson Creek to the east. Approximately 675 hectares (1,668 acres) of developable lands are designated for future neighbourhoods, located primarily between Major Mackenzie Drive and Elgin Mills Road. Approximately 300 hectares (741 acres) located north of Elgin Mills Road are designated for employment uses. In total, the Future Urban Area is intended to accommodate approximately 12,000 residential units with a population of approximately 38,000 persons, and approximately 19,000 jobs. It is expected approx. 60 MW of new loads are expected on both sides of Warden Ave north of Major Mackenzie Dr. For the new urban area, they expect to see building permit issued in 2017 and new houses in 2018. Two new 27.6kV feeders are required for the Hwy 404 Development and urban expansion in Markham. Two feeders 12M10/12M11 are planned to be rerouted to Warden Ave/Elgin Mills area to supply new growth in Markham north.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2018
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The risk is to get approval from the City of Markham and York Region in time. This project depend on Hwy 7 widening from South Towncenter Blvd to Warden Ave project to extend 12M10/12M11 from South Towncenter Blvd to Warden Ave. Capital Design has started the design of the project in advance and should get the approvals in place in time. Capital Design will also coordinate with York Region for road widening schedules.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	Rebuild the existing pole line into 4 ccts, 2 ccts now and 2 ccts provision for future on Warden Ave from Major Mack to Elgin Mills in Markham.
	1a. Main Driver	Support Capacity Delivery. The main driver for this project is to support the capacity devlivery in Markham North area . There is a load growth in the new urban area north of Major Mack between Woodbine Ave and Kennedy Rd. Based on preliminary information from Markham Official Plan Amendment (OPA), two new 27.6kV feeders are required for the Hwy 404 Development in Markham.
	1b. Priority and Reasons for Priority	High. The existing feeders supplying Markham north don't have sufficient capacity for future growth.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	This project will increase supply capacity by 40 MVA and will also increase supply reliability to Markham north.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.

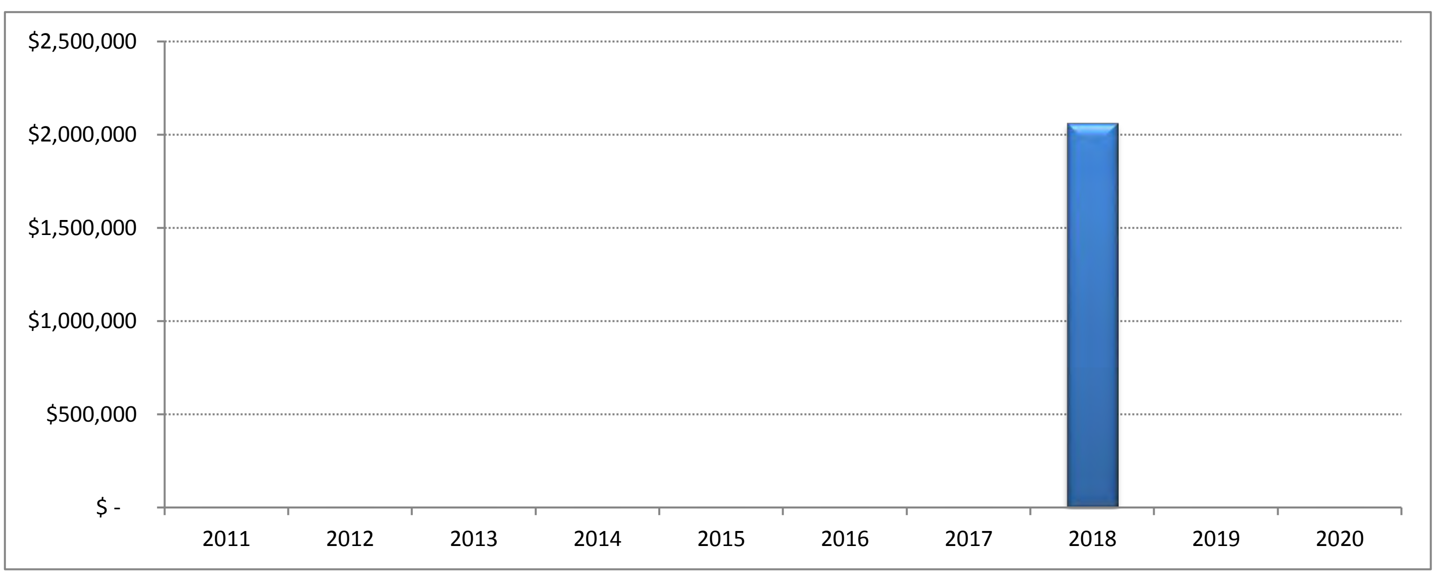
Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100909	2015	6	Dollars

Project Name

Rebuild 27.6 kV pole line for 4 Ccts on Warden Ave from Major Mack to Elgin Mills

5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	This project will increase supply reliability to Markham north.
	Factors Affecting Timing/Priority	Customers ramping up load scheduled in Markham north area will impact the timing and priority.
	Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	This project will extend two feeders into the area and increase capacity by 40 MVA. The main alternative is to "do nothing", but to continue to supply load growth from existing facilities. Markham north is supplied by two feeders by 10M2 on Woodbine Ave and 12M12 on Warden Ave. The peak in 2013 was 384A on 10M2 and 232A on 12M12. They do not have sufficient capacity to supply new loads in the Hwy 404 North development and new urban expansion. The existing feeders in Markham North do not have sufficient capacity to supply new customers. Conversely, feeders 12M10/12M11 have very little load now and are not utilized. The "do nothing" alternative is not viable as it will jeopardize PowerStream's obligation to supply new customers in Hwy 404 North and future urban area. The impact severity and timing will depend on the schedule of these developments.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,061,719	$ -	$ -



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100905	2015	6	Dollars

Project Name

Rebuild 27.6 kV pole line into 4 Ccts on Warden Ave from Hwy 7 to 16th Ave

Major Category **System Service**

Project Overview

1. Additional Information	Service Territory	PowerStream South
	Location	On Warden Ave from Hwy 7 to 16th Ave in Markham, approx 2km.
	Scope	To rebuild the existing 27.6kV pole line into 4 ccts pole line or install a new 2 ccts pole line on the other side of Warden Ave. To install two 27.6kV ccts (12M10/12M11)on Warden Ave from Hwy 7 to 16th Ave
	Justification	To extend feeder 12M10/12M11 to Markham North. To increase supply capacity and reliability to Hwy 404 North area and new urban area north of Major Mack between Woodbine Ave and Kennedy Rd. York Region is working on an Official Planning Amendment which expands the Urban Area of the City of Markham to both sides of Warden Ave to provide opportunities for urban growth to the year 2031. The north Markham Future Urban Area covers about 1,288 hectares (3,183 acres bordered by Major Mackenzie Drive to the south, the Hydro Corridor and Woodbine Avenue to the west, the northerly City limits and Elgin Mills Road to the north, and the Robinson Creek to the east. Approximately 675 hectares (1,668 acres) of developable lands are designated for future neighbourhoods, located primarily between Major Mackenzie Drive and Elgin Mills Road. Approximately 300 hectares (741 acres) located north of Elgin Mills Road are designated for employment uses. In total, the Future Urban Area is intended to accommodate approximately 12,000 residential units with a population of approximately 38,000 persons, and approximately 19,000 jobs. It is expected approx. 60 MW of new loads are expected on both sides of Warden Ave north of Major Mackenzie Dr. For the new urban area, they expect to see building permit issued in 2017 and new houses in 2018. Two new 27.6kV feeders are required for the Hwy 404 Development and urban expansion in Markham. The two feeders 12M10/12M11 have planned to be rerouted to Warden Ave/Elgin Mills area to supply new growth in Markham north.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2016
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The risk is to get approval from the City of Markham and York Region in time. This project depend on Hwy 7 widening from South Towncenter Blvd to Warden Ave project to extend 12M10/12M11 from South Towncenter Blvd to Warden Ave. Capital Design has started the design of the project in advance and should get the approvals in place in time. Capital Design will also coordinate with York Region for road widening schedules.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	This project is to add two ccts on Warden Ave from Hwy 7 to 16th Ave. It will be determined during the design if a new 2 ccts pole line can be installed on the east side of Warden Ave instead of rebuilding the existing 2 ccts pole into 4 ccts on the west side of Warden Ave.
	1a. Main Driver	Support Capacity Delivery. The main driver for this project is to support capacity delivery in Markham north. Based on preliminary information from Markham Official Plan Amendment (OPA), two new 27.6kV feeders are required for the Hwy 404 Development in Markham.
	1b. Priority and Reasons for Priority	The existing feeders supplying Markham north don't have sufficient capacity for future growth.

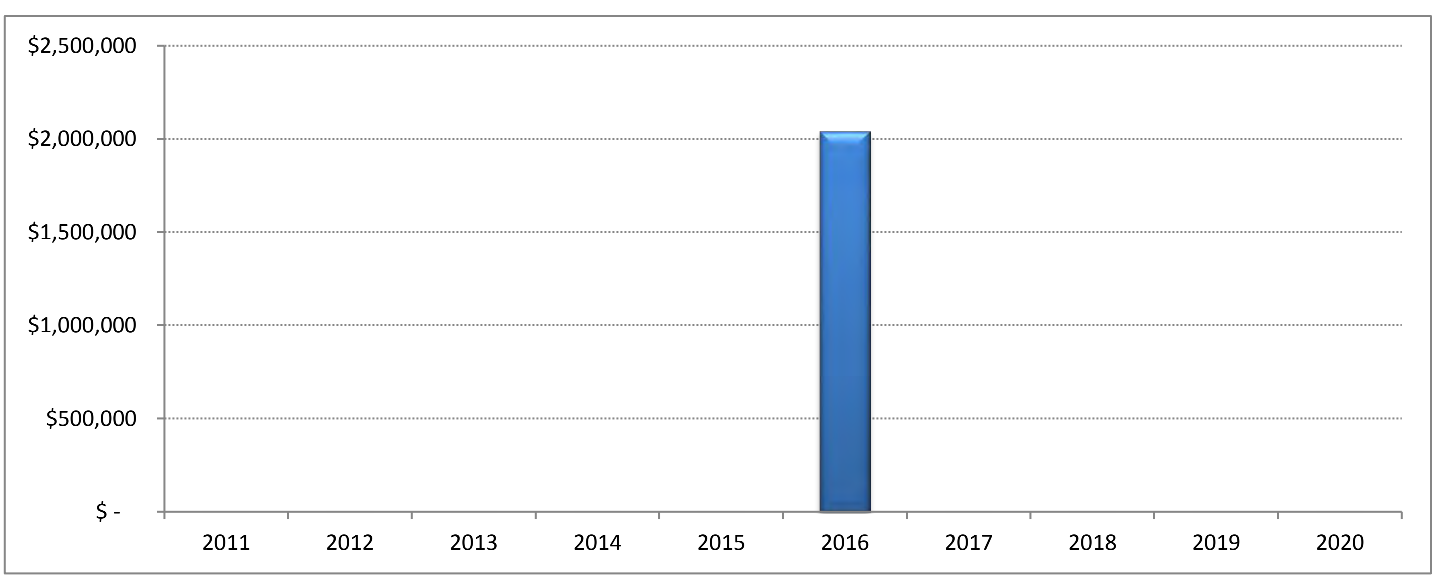
Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100905	2015	6	Dollars

Project Name

Rebuild 27.6 kV pole line into 4 Ccts on Warden Ave from Hwy 7 to 16th Ave

	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	This project will increase supply capacity by 40 MVA and will also increase supply reliability to Markham north.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	This project will increase supply reliability to Markham north.
	Factors Affecting Timing/Priority	Customers load ramping up schedule in Markham north area will impact the timing and priority.
	Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The main alternative is to "do nothing" and continue to supply load growth from existing facilities. It will impact PowerStream's distribution system capacity. Markham north is supplied by two feeders by 10M2 on Woodbine Ave and 12M12 on Warden Ave. The peak in 2013 was 384A on 10M2 and 232A on 12M12. They do not have sufficient capacity to supply new loads in the Hwy 404 North development and new urban expansion. The existing feeders in Markham North do not have sufficient capacity to supply new customers. Conversely, feeders 12M10/12M11 have very little load now and are not utilized. The "do nothing" alternative will reduce PowerStream's ability to supply new customers in Hwy 404 North and future urban area. The impact severity and timing will depend on the schedule of these developments. The "do nothing" option is not a viable alternative as it will not allow PowerStream to supply the new load growth.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ 2,039,163	$ -	$ -	$ -	$ -



Power Stream	Project Code	Report Start Year	Number of Years	Scale
	100229	2015	6	Dollars

Project Summary Report

Project Name

Rebuild 27.6 kV pole line on Warden Ave into 4 ccts from 16th Ave to Major Mack

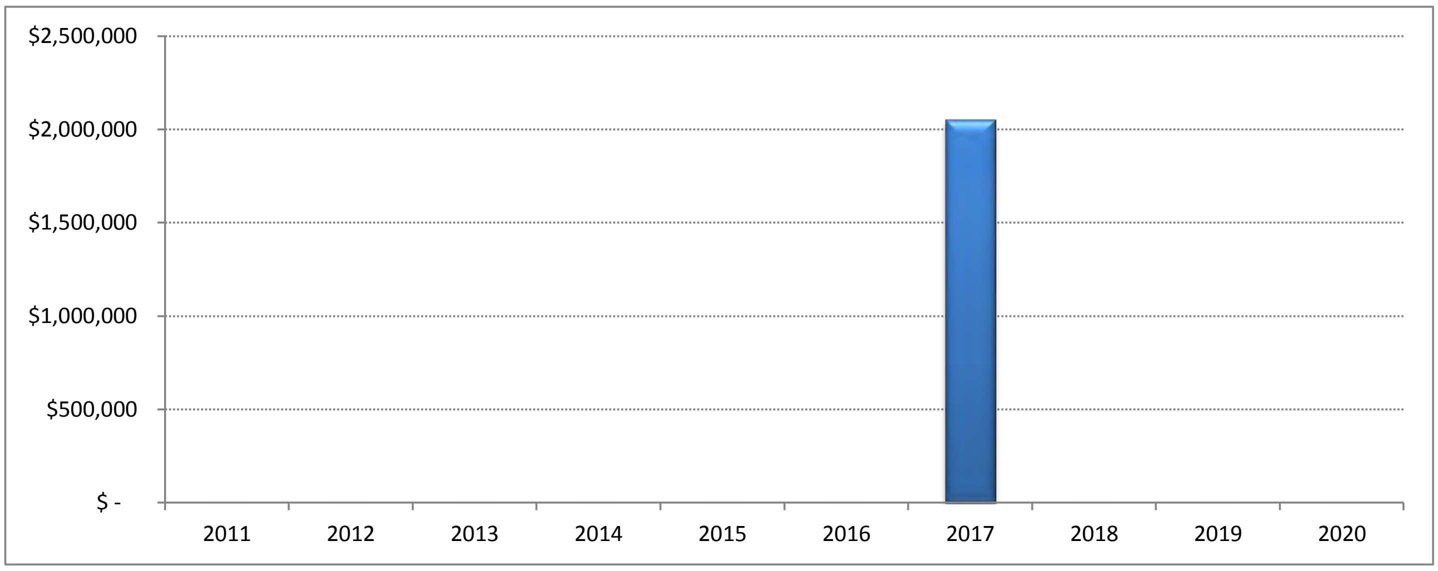
Major Category	**System Service**	
Project Overview		
1. Additional Information	Service Territory	PowerStream South
	Location	On Warden Ave from 16th to Major Mackenzie Dr in Markham, approx 2.0 km
	Scope	To rebuild the existing pole line on Warden Ave into 4 ccts pole line from 16th Ave to Major Mack Dr. Some of the poles are framed already for 4 ccts in the previous projects.
	Justification	This project is necessary to reroute feeder 12M10/12M11 to Markham North in order to increase supply capacity and reliability to Hwy 404 North area. The feeders are planned to be rerouted along Warden Ave/Major Mack area to supply new growth in Markham North.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2017
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The risk is to get approval from the City of Markham and York Region in time. This project depend on Hwy 7 widening from South Towncenter Blvd to Warden Ave project to extend 12M10/12M11 from South Towncenter Blvd to Warden Ave. Capital Design has started the design of the project in advance and should get the approvals in place in time. Capital Design will also coordinate with York Region for road widening schedules.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	This project is to add two ccts on Warden Ave from 16th Ave to Major Mack Dr by rebuilding the existing 2 ccts pole into 4 ccts on the east side of Warden Ave.
	1a. Main Driver	Support Capacity Delivery. The main driver for this project is to support capacity delivery in Markham North. Based on preliminary information from Markham Official Plan Amendment (OPA), two new 27.6kV feeders are required for the Hwy 404 Development in Markham.
	1b. Priority and Reasons for Priority	High. The existing feeders supplying Markham north don't have sufficient capacity to provide for future load growth.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	This project will increase supply capacity by 40 MVA and will also increase supply reliability to Markham north.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	This project will increase supply reliability to Markham north.
	Factors Affecting Timing/Priority	Customers load ramping up schedule in Markham north area will impact the timing and priority.
	Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The benefits of this project are to increase capacity by 40 MVA in a load constrained area. The main alternative is to "do nothing". However, that alternative is not a viable option as it will not allow PowerStream to supply the new load growth in the subject area.

Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100229	2015	6	Dollars

Project Name

Rebuild 27.6 kV pole line on Warden Ave into 4 ccts from 16th Ave to Major Mack

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,050,441	$ -	$ -	$ -



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	101499	2015	6	Dollars

Project Name

Rebuild Pole Line on 14th Ave into 4 cct -From Warden Ave to Kennedy Rd

Major Category **System Service**

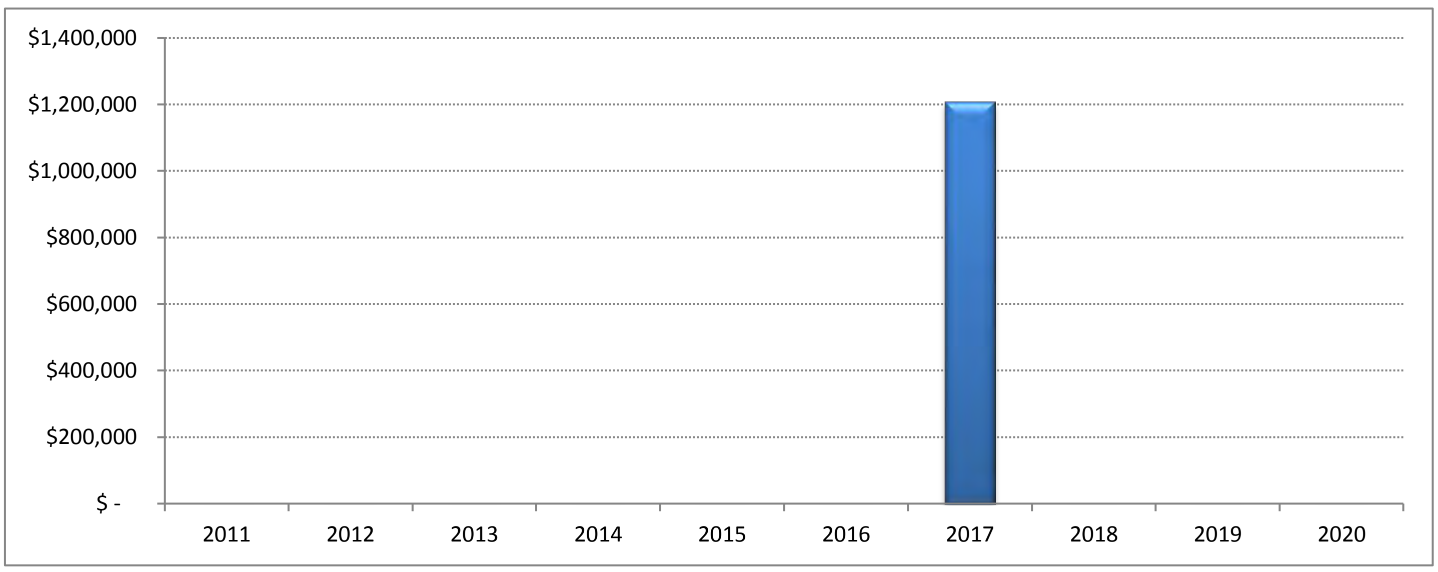
Project Overview

1. Additional Information	Service Territory	PowerStream South
	Location	On 14th Ave from Warden Ave to Kennedy Rd in Markham, approx 2 km.
	Scope	This project is to add two ccts on 14th Ave from Warden Ave to Kennedy Rd. It will be determined during the design if a new 2 ccts pole line can be installed on the north side of 14th Ave instead of rebuilding the existing 2 ccts pole into 4 ccts on the south side of 14th Ave.
	Justification	This project is necessary to increase supply capacity and reliability to the subject area. This project is going to extend two feeders into 14th Ave area between Warden Ave and Kennedy Rd. This will increase available load capacity by 40 MVA. This project will create two supply paths for customers on 14th Ave between Warden and Kennedy. There are a few big customers along 14th Ave that have two supplies to their facilities; however, they are from the same pole line on the south side of 14th Ave. The customers will lose both supplies in case of pole failures on 14th Ave and the auto transfer scheme on the secondary side of their transformers will not spare them from power outages. This project will enable customers to have one supply from the north side of 14th Ave so that pole failure will not cause outages to these customers since the customers have auto transfer scheme on the secondary side of their transformers.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2017
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The risk is to get approval from the City of Markham in time. Capital design has started the design of the project and should get the approvals in place in time.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	This project is to build 2 additional ccts between Warden Ave and Kennedy Rd either by rebuilding the existing pole line on the south side of 14th Ave from 2 ccts to 4 ccts or build a new 2 ccts pole line on the north side of 14th Ave.
	1a. Main Driver	Support Capacity Delivery. This main driver for the project is to support the capacity delivery in the Markham area (Warden and Kennedy area). It was also increase supply reliability, establish new alternate supply path and diversity.
	1b. Priority and Reasons for Priority	Very High. One data center at 371 Gough Rd has been in service in 2014. The initial load is 2 MW and ultimate load will be 7 MW by 2018. Another data center at 4175-14th Ave will be in service in 2015. The initial load will be 5MW and ultimate load will be 10 MW by 2020. The existing feeders on 14th Ave do not have sufficient capacity to supply the additional load. This project is necessary in order to improve supply reliability and ensure that customers in the area have supply diversity, i.e., supply from different stations, and from pole lines on different sides of road to reduce impact from feeder outages and pole failures.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	This project will extend two feeders into the area and increase capacity by 40 MVA. These two feeder will be 26M12 and 26M4 in 2014. 26M12 will be replaced by a new feeder 10M5 from MTS4. This project will significantly improve power supply diversity to the customers in the area. Supply to customers will be maintained even one transformer station is out of service. There is no other economically viable or practical way to supply the new load.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.

Project Summary Report	Project Code 101499	Report Start Year 2015	Number of Years 6	Scale Dollars
	Project Name Rebuild Pole Line on 14th Ave into 4 cct -From Warden Ave to Kennedy Rd			

Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
Identify any reliability , efficiency, safety or coordination benefits	This project will also provide supply reliability to exsiting customers on 14th Ave.
Factors Affecting Timing/Priority	Customers load ramping up schedule will impact the timing and priority.
Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The main benefit of this project of this project is to provide additional load capacity of 40 MVA into the subject area. In addition, some existing customers along 14th Ave already requested alternate supply path from PowerStream. The main alternative to this project is to "do nothing", however, that is not a viable option as it will not allow PowerStream to supply the new load growth.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,206,790	$ -	$ -	$ -



	Project Code	Report Start Year	Number of Years	Scale
Power Stream	102547	2015	6	Dollars

Project Summary Report

Project Name

Two Ccts on Birchmount Rd from ROW to 14th Ave

Major Category **System Service**

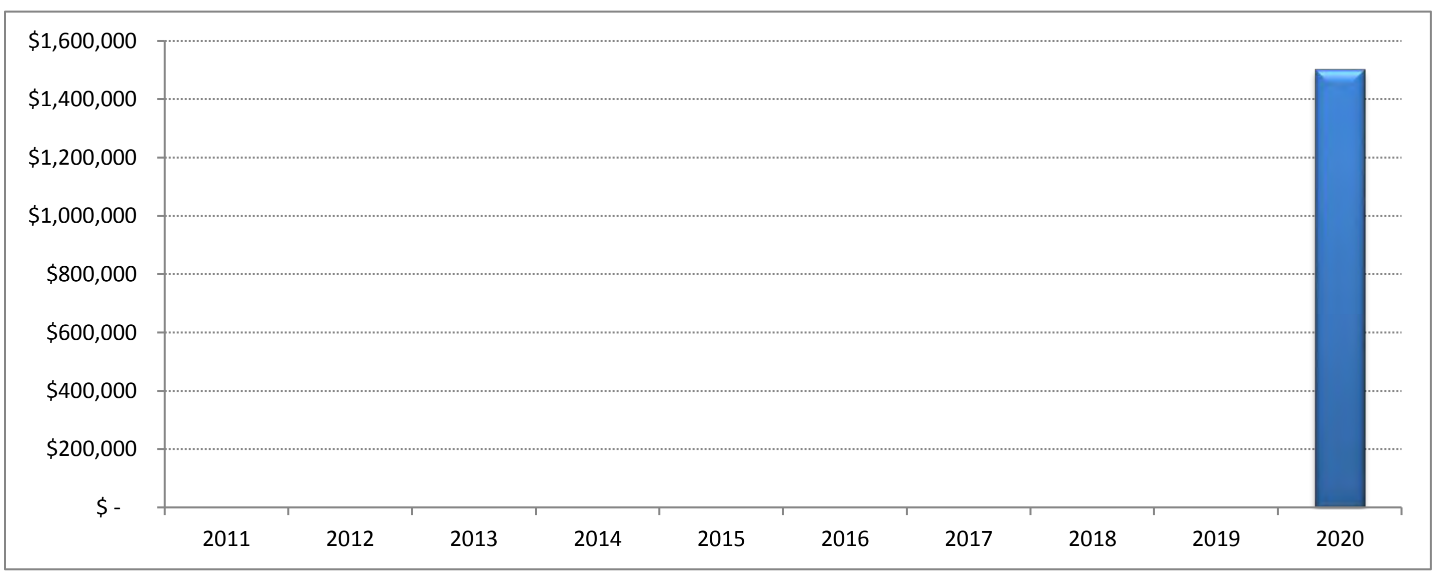
Project Overview

1. Additional Information	Service Territory	PowerStream South
	Location	On Birchmount Rd from ROW to 14th Ave in Markham - 0.8 km
	Scope	To build 2 ccts from Hydro One Right of Way (ROW) to 14th Ave To extend two feeders 26M15 and 26M16 on Birchmount Ave and 14th Ave area
	Justification	The primary driver for this investment is to increase supply reliability and supply capacity to the 14th Ave and Warden Ave area. A few data center projects are underway and the peak demand is expected to increase by 20MVA. The existing feeders don't have sufficient capacity for the new load and new feeders are required. In addition there are many industrial customers along 14th Ave that have two supplies to their facilities; however, they are on the same pole line on the south side of 14th Ave. Those customers in that area lose both supplies in case of pole failures on 14th Ave and the auto transfer scheme on the secondary side of their transformers does not prevent them from power outages. Reliability for the feeders in this area has historically been poor. A new pole line has been proposed on the north side of 14th Ave from Warden Ave to Kennedy Rd. The three feeders from MTS3 (26M13, 26M15, and 26M16) that supplies customers on 14th Ave from Warden Ave is on the same pole line, if a pole on Warden Ave between the right of way (ROW) and 14th Ave fails, it will take the three feeders out of service and cause significant outages to customers in the area.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2020
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The risk is to get approval from the City of Markham in time. Capital design will start the design of the project in advance and should get the approvals in place the prior year.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	This project is to build 2 ccts pole line on Birchmount Rd from the Right of Way (ROW) to 14th Ave. This will extend 2 feeders 26M15 and 26M16 to 14th Ave to tie with feeder 22M7/22M8 for reliability.
	1a. Main Driver	Support Capacity Delivery. The main driver for this project is improve the reliability and support the capacity delivery in Markham Warden-Denison area.
	1b. Priority and Reasons for Priority	High. One data center at 371 Gough Rd has been in service in 2014. The initial load is 2 MW and the ultimate load will be 7 MW by 2018. Another data center at 4175-14th Ave will be in service in 2015. The initial load will be 5MW and the ultimate load will be 10 MW by 2020.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	This project will extend two feeders 26M15 and 26M16 into 14th Ave and Birchmount area. This project will provide supply diversity and reliability to the customers in the area.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	This project will also provide supply reliability to new customers and existing customers on 14th Ave. This project will also provide an alternate supply path for the existing customers. Supply to customers will be maintained in case of pole failures on the existing path.

Project Summary Report	Project Code 102547	Report Start Year 2015	Number of Years 6	Scale Dollars
	Project Name Two Ccts on Birchmount Rd from ROW to 14th Ave			

Factors Affecting Timing/Priority	Customers load ramping up schedule will impact the timing and priority. Customers at both data centers are putting significant additional electrical load into service in the near future that will require additional load capacity for that area.
Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The main alternative is to "do nothing" and continue to supply load growth from existing facilities. It will impact PowerStream distribution system in two following aspects: Capacity A few data center projects are underway and the peak demand is expected to increase by 20MVA. The existing feeders don't have sufficient capacity for the new load and new feeders are required. The "do nothing" approach will reduce PowerStream's ability to supply new customers along 14th Ave. The impact severity and timing will depend on the schedule of the ramping-up of customers on 14th Ave. Reliability There are two ccts on the south side of 14th Ave between Warden Ave and Kennedy. A number of customers with high reliability needs on both sides of 14th Ave between Warden Ave and Kennedy Rd are currently supplied by the existing two ccts on 14th Ave. These two ccts are on the same pole line and the main supplies are from Warden Ave. There have been pole line failure incidents in the past that impact both ccts. This impacts power supply reliability and related customer satisfaction. The "do nothing" alternative will not allow PowerStream to provide the high reliability and supply diversity to customers in the area.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,502,063



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	102548	2015	6	Dollars

Project Name

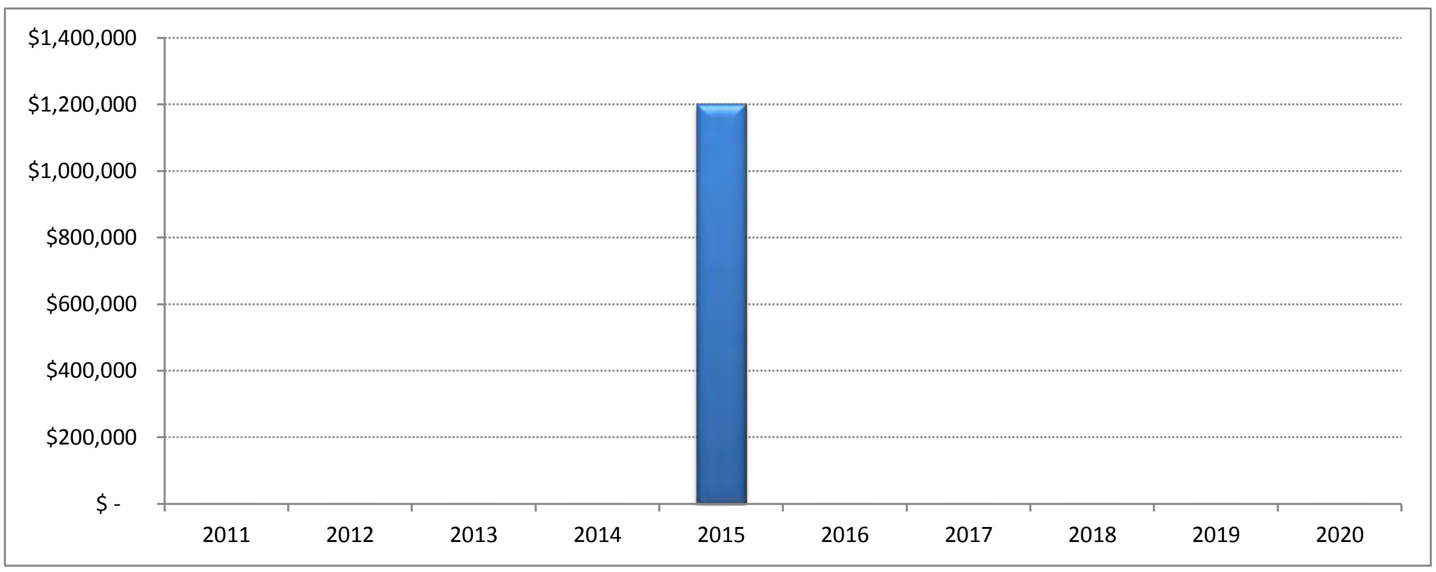
Two Ccts on Birchmount Rd from ROW to Enterprise

Major Category	System Service	
Project Overview		
1. Additional Information	Service Territory	PowerStream South
	Location	Birchmount Rd from ROW to Enterprise in Markham - 0.5 km
	Scope	To build 2 ccts from Hydro One Right of Way (ROW) underground to Enterprise Blvd. To extend two feeders 26M17 and 26M18 along Birchmount Rd to Downtown Markham area. Install two switchgears at the end of 1000 MCM Cu cable so that new 1/0 loops can be created from these two switchgears. Coordinate switchgear requirement with Subdivision Design
	Justification	This project is necessary to increase supply capacity and reliability to downtown Markham
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	This project will use existing ductbanks on Birchmount Rd. The existing one may not meet PowerStream's standard. New ductbanks will be installed if necessary.
	Comparative Information on Equivalent Historical Projects (if any)	The power supply for Vaughan Metropolitan Center (VMC) has been designed similarly, i.e., 1000 MCM (600A) loops will be brought into the development and 1/0 loops will used to supply individual buildings.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	This project is to extend two ccts 26M17 and 26M18 from Hydro One right of way (ROW) along Birchmount Rd to Enterprise Blvd to provide supply capacity to downtown Markham. Two 27.6kV switchgears will be installed on Birchmount Rd south of Enterprise to supply existing 1/0 loop and future 1/0 loops.
	1a. Main Driver	Support Capacity Delivery. The main driver for this project is to support capacity delivery in the Markham area. The existing 1/0 loop in the area does not sufficient capacity to supply future new development in Downtown Markham(30MW). New capacity is required. The two pole risers for the existing 1/0 loop are both located on Warden Ave. If a pole is hit by a vehicle or a pole on file will cause outage to the 1/0 loop and large number of residential and commercial customers in downtown Markham will have prolonged outages until the pole is replaced. Alternate supply path is required to reduce the extent & length of the possible outage.
	1b. Priority and Reasons for Priority	High. A few large buildings are under construction and additional capacity is required, including a 350,000 sq.ft office building now under construction, and it is expected to add 2500 kW load to the existing loop. There are total of 10 MVA connected transformers on the existing loop. Pole failure on Warden Ave will cause significant and prolonged outages to the customers in downtown Markham.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	This project will provide 30 MVA capacity for downtown development. It will also increase supply reliability since it is a different route than the existing 1/0 loop. Taking supply from the other direction has been explored, but is not a feasible option.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.

	Project Code	Report Start Year	Number of Years	Scale
Project Summary Report	**102548**	**2015**	**6**	**Dollars**
	Project Name: Two Ccts on Birchmount Rd from ROW to Enterprise			

Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
Identify any reliability , efficiency, safety or coordination benefits	Not Applicable.
Factors Affecting Timing/Priority	Progress of customer projects
Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The main project benefits is to provide 30 MVA of needed capacity for downtown development. It will also increase supply reliability since it is a different route than the existing 1/0 loop. Providing a supply from another direction is not feasible option. The main alternative to this project is to "do nothing" and continue to supply existing and new loads from existing distribution circuits. However, this is not a viable option, as it will not allow PowerStream to supply the forecasted loads that are materializing in the near future.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ 1,201,150	$ -	$ -	$ -	$ -	$ -



	Project Code	Report Start Year	Number of Years	Scale
Power Stream	100336	2015	6	Dollars

Project Summary Report

Project Name

Vaughan TS#4 Feeder Integration - Part 1

Major Category	System Service	

Project Overview

1. Additional Information	Service Territory	PowerStream South
	Location	On Kirby from TS4 (Kipling Ave) to Weston Rd in Vaughan - approx 4 km on Weston Rd from Kirby Sdrd to Teston Rd in Vaughan - approx 2 km
	Scope	The scope includes following: • build 4 ccts pole line on Kirby from VTS4 (Kipling Ave) to Weston Rd - 4 km • build 4 ccts pole line on Weston Rd from Kirby Sdrd to Teston Rd - 2 km • install manual or Scada-mate switches as PowerStream's design standard
	Justification	Vaughan TS4 with 2x75/125 MVA transformers and 12 feeders will be in-service in 2017. The purposes of Part 1 are: -To integrate 4 feeders from the new VTS4 into Power-Stream's distribution system. -To increase supply capacity to Vaughan north and Richmond Hill North. -To off load VTS2,VTS1, RH-TS1 and RH-TS2. -To increase supply reliability to Vaughan and Richmond Hill. The major developments in the area that are intended to be supplied by this project include: **West Vaughan Employment Area** The West Vaughan Employment Area Secondary Plan sets out detailed policies to create a large economic opportunity for York Region. With over 500 hectares of employment designated lands, it is planned to accommodate approximately 20,120 employees. The peak demand for this development is estimated to be 50MW to 80 MW when fully built out, but no time line is available at this time. VTS3 is in the center of this development and Kleinburg TS is nearby too. PowerStream has two 27.6kV feeders from Kleinburg TS and they can supply up to 40 MVA load. VTS3 has approx. 10 MVA capacity left as of 2014 and load transfer from VTS3 to VTS4 is required to allow VTS3 to supply new load in Vaughan West area. **Hwy 400 North Future Development Areas** The lands of Hwy 400 North Development are located adjacent to Highway 400 within the City of Vaughan bounded by Teston Road to the south, the King-Vaughan boundary to the north, Weston Road to the west and Jane Street to the east. The area of the subject lands is approximately 800 hectares (2,000 acres).The peak demand for this development is estimated to be 80MW to 100 MW when fully built out, but no time line is available at this time. **Vaughan Metro Center (VMC)** It establishes growth targets for the VMC of 12,000 residential units and 6,500 new jobs by 2031. As per estimates from one of the consultants for the VMC, the peak demand for the VMC will be approx. 60MW to 80 MW. **Vaughan New Hospital** The Mackenzie Vaughan Hospital Precinct Plan has an area of 32.8 ha (82 acres) and is located on the north side of Major Mackenzie Drive between Highway 400 and Jane Street, excluding the gas station site at the intersection of Jane Street and Major Mackenzie Drive.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2017
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The risk is to get approval from the City of Vaughan and York Region in time. Capital design will start the design of the project in advance and should get the approvals in place in time.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	This project is to build 4 feeders from Vaughan TS#4 to the distribution system. It is Vaughan TS4 Feeder Integration Plan Part 1. It includes: - build 4 ccts pole line on Kirby from TS4 (Kipling Ave) to Weston Rd - 4 km. - build 4 ccts pole line on Weston Rd from Kirby Sdrd to Teston Rd - 2 km. - install manual or Scada-mate switches as necessary to meet PowerStream's design standards.
	1a. Main Driver	Support Capacity Delivery. The main driver for this project is to support the capacity delivery in York region. Load growth in the Maple area, new hospital development, Vaughan Metropolitan Center and Vaughan Mills area.

Project Code	Report Start Year	Number of Years	Scale
100336	2015	6	Dollars

Project Summary Report

Project Name

Vaughan TS#4 Feeder Integration - Part 1

	1b. Priority and Reasons for Priority	Very High. All existing feeders are at their capacity and have no capacity for future development. Some feeders have low voltage issue during summer peak time due to high loading and long supply distance.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	This project is necessary to extend four feeders into the area and increase needed load capacity by 80 MVA. This project will also significantly improve power supply diversity to the customers in the area. VTS4 will be supplied from 230kV Minden Line. No existing stations are from the Minden Line. Supply to some customers will be maintained even the Parkway transmission lines are out of service. There is no other practical or viable way to supply the new loads identified above.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	This project will also improve supply reliability to existing customers in Vaughan. It will reduce line losses on the existing feeders.
	Factors Affecting Timing/Priority	Customers load ramping up schedule in VMC and other areas in Vaughan will impact the timing and priority.
	Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The main benefits of this project is to increase needed load capacity into the subject area by 80 MVA. The main alternative is to "do nothing" and continue to supply load growth from existing facilities. It will impact PowerStream distribution system in two following aspects: **Reliability** Vaughan north-east area is supplied by two feeders 20M21/20M22 from Vaughan TS1 that is located at Dufferin St and Center St. Feeder 20M22 is 18.5km and 20M21 is 14km. Both feeders had a peak of over 500A in the summer and exceeded PowerStream's feeder loading guide line of 400A: 547A on 20M21 and 512A on 20M22. In terms of the number of customers, feeder 20M21 has 9,761 customers in 2014 and 20M22 has 4,005 customers. There are no other existing feeders available in the area to off load 20M21/20M22. Therefore, new feeders are required in north-east Vaughan to off load existing feeders. **Capacity** Vaughan north is supplied by VTS1/VTS1E. The peak of VTS1/VTS1E was 335 MW in 2013 and exceeded its 10 day Limited Time Rating (LTR) of 306 MW. It does not have extra capacity to supply new loads in the Vaughan New Hospital development (approx. 10MW). The main alternative to "do nothing" will cause VTS1/VTS1E to continue exceeding their LTRs under 1-in-10 weather (extreme summer temperatures) in the long term. The impact severity and timing will depend on development in Vaughan north and the schedule of the new hospital. No other viable option is available. The "do nothing" approach is not a viable option as it will not allow PowerStream to supply the new load growth that is materializing in the subject areas.

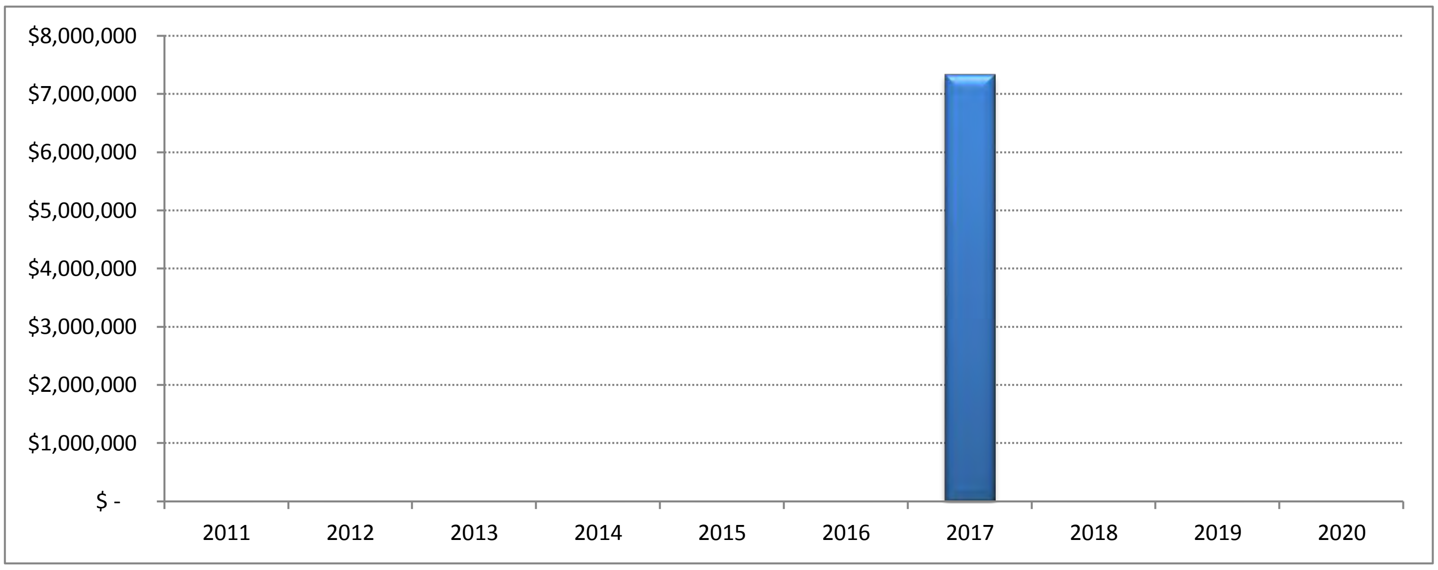
Project Code	Report Start Year	Number of Years	Scale
100336	2015	6	Dollars

Project Summary Report

Project Name

Vaughan TS#4 Feeder Integration - Part 1

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,341,955	$ -	$ -	$ -



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	102352	2015	6	Dollars
	Project Name: Vaughan TS#4 Feeder Integration - Part 2			

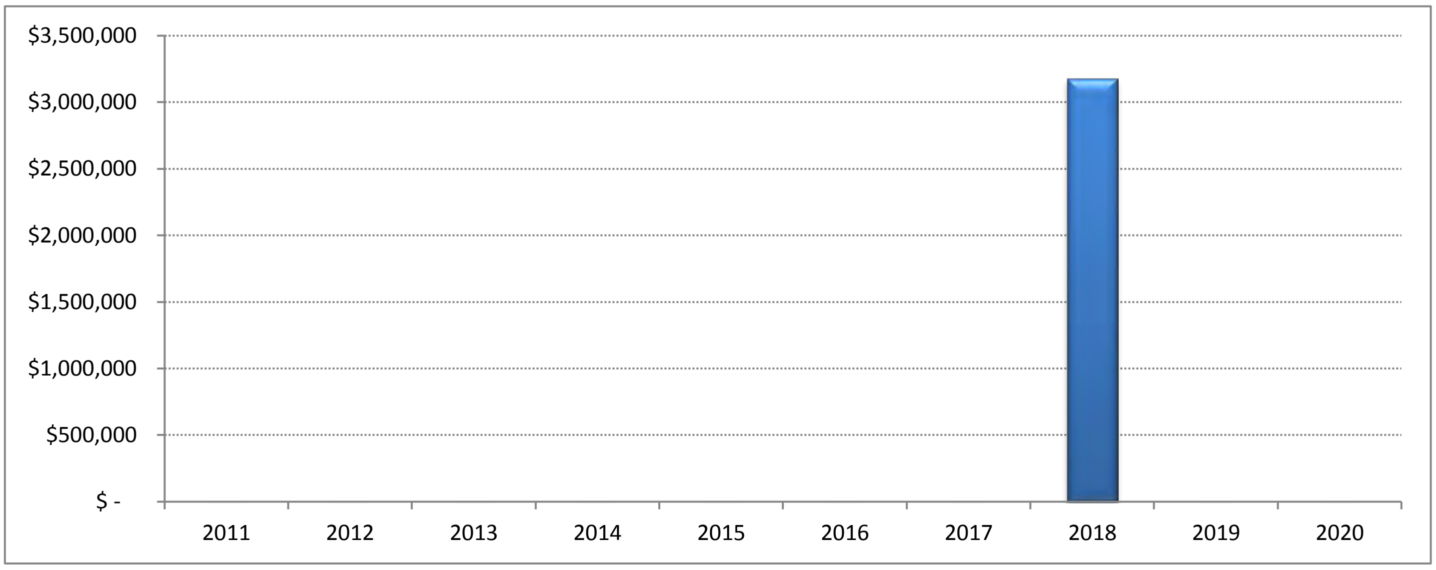
Major Category System Service

Project Overview

1. Additional Information	Service Territory Location	PowerStream South North-west corner of Kipling & Kirby, Vaughan
	Scope	The scope of this project is to build 2 feeders 25M11/25M12 to provide capacity and backup to Kleinburg and Vaughan West areas. It includes following constructions: -One additional cct on Kirby Sdrd from VTS4 to Hwy 27 – 2 km - Rebuild the existing pole line to 4 ccts.
	Justification	This project is necessary to provide supply needed load capacity to Vaughan west area, and to provide back up capacity to VTS3 and Kleinburg TS
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2018
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The risk is to get approval from the City of Vaughan in time. Capital design will start the design of the project in advance and should get the approvals in place in 2017.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	This project will build 2 feeders 25M11/25M12 to provide capacity and backup to Kleinburg and Vaughan West areas. It includes following constructions: -One additional cct on Kirby Sdrd from VTS4 to Hwy 27 – 2 km -One additional cct on Hwy 27 from Teston Rd to MMD – 2 km
	1a. Main Driver	Support Capacity Delivery. The main driver for investment is to support capacity delivery in the Vaughan area. This will provide needed capacity to meet the load growth in the Vaughan West area and will provide additional backup for VTS3 and Kleinburg TS station.
	1b. Priority and Reasons for Priority	High. All existing feeders are at their capacity and have no capacity for future development.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	This project will extend four feeders into the area and increase capacity by 40 MVA. This project will also significantly improve power supply diversity to the customers in the Vaughan west area. VTS4 will be supplied from 230kV Minden Line. No existing stations are from the Minden Line. This project will provide the additional benefits to allow supply to some customers to be maintained even when the Kleinburg transmission lines are out of service.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	This project will also improve supply reliability to existing customers in Vaughan West. It will reduce line losses on the existing feeders.
	Factors Affecting Timing/Priority	Customers load ramping up schedule will impact the timing and priority.
	Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The main benefits of this project is to increase needed capacity in the subject area by 40 MVA. Other options have been explored, but none are economically viable or practical. The main alternative to this project is to "do nothing" and continue to supply the existing and new loads from existing circuits. However, this is not a long-term viable option as it will not allow PowerStream to supply the new load growth forecasted for that area.

Power Stream **Project Summary Report**	Project Code **102352**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Vaughan TS#4 Feeder Integration - Part 2			

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,176,402	$ -	$ -



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100340	2015	6	Dollars
	Project Name	Vaughan TS#4 Feeder Integration - Part 3		

Major Category System Service

Project Overview

1. Additional Information	Service Territory Location	PowerStream South Vaughan
	Scope	The project scope includes following constructions: -New 4 ccts pole line from VTS4 to Teston Rd via Kipling Ave – 2 km -New 4 ccts pole line on Teston Rd from Kipling Ave to Pine Valley Drive – 2 km -New4 ccts pole line on Teston Rd from Pine Valley Drive (PVD) to Weston Rd (2 ccts provision for future) – 2 km -New 4 ccts pole line on Pine Valley Drive from Teston Rd to MMD (2 ccts provision for future) – 2 km -Adding 2 ccts on existing pole line on MMD from PVD to Weston Rd – 2 km -Adding 2 ccts on existing pole line on Teston Rd from Weston Rd to Jane St – 2 km -Adding 2 ccts on existing pole line or rebuild pole into 4 ccts where necessary on Weston Rd from MMD to Rutherford Rd – 2km
	Justification	This project us necessary to integrate VTS4 feeders into PowerStream's distribution system, to increase supply capacity to Vaughan north and Richmond Hill North, to off load VTS1, RH-TS1 and RH-TS2, and to increase supply reliability to Vaughan and Richmond Hill.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2019
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The risk is to get approval from the City of Vaughan in time. Capital design will start the design of the project in advance and should get the approvals in place in 2018.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	This project is necessary to bring four 27.6kV feeders 25M5/25M6/25M7/25M8) out from VTS4 and connect into the distribution system.
	1a. Main Driver	Support Capacity Delivery. The main driver for this project is to support capacity delivery in the Vaughan area.
	1b. Priority and Reasons for Priority	Very High. All existing feeders are at their capacity and have no capacity for future development. Some existing feeders have low voltage issue during summer peak time due to high loading and long supply distance.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	This project will extend four feeders into the area and increase capacity by 80 MVA. This project will also significantly improve power supply diversity to the customers in the area. VTS4 will be supplied from 230kV Minden transmission line. None of PowerStream's other existing stations are supplied from the Minden transmission line. This will allow supply to be maintained to some customers even when the Parkway transmission lines are out of service.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	This project will also improve supply reliability to existing customers in Vaughan. It will reduce line losses on the existing feeders.

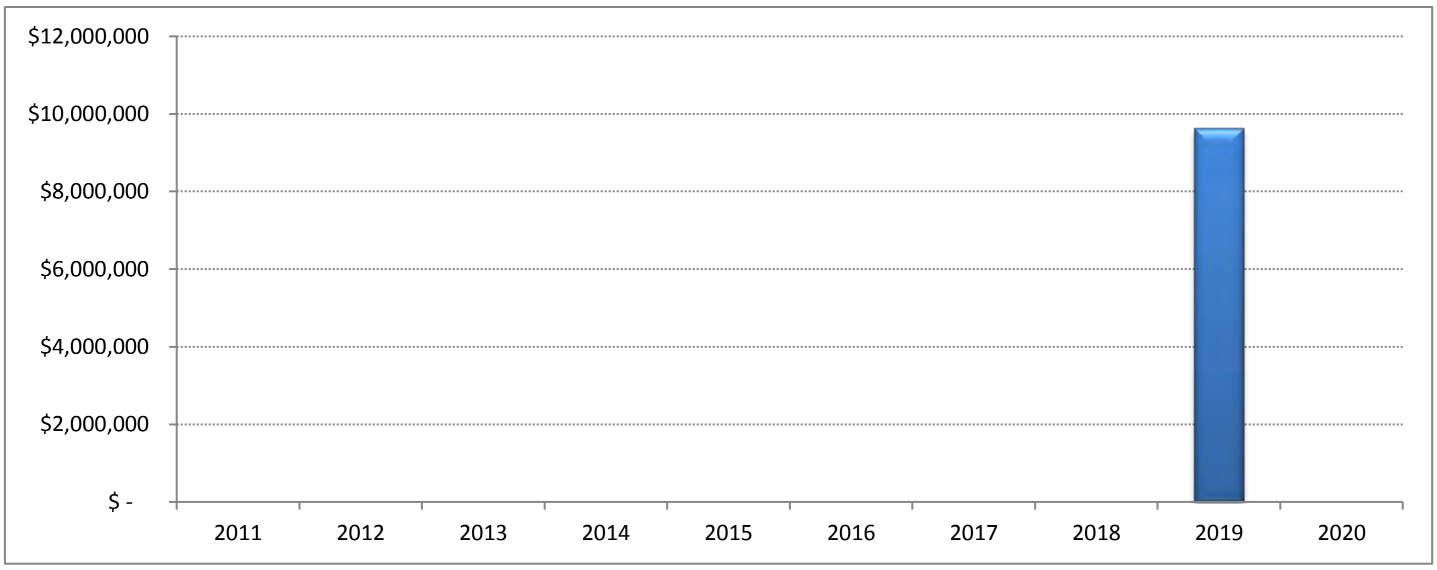
Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100340	2015	6	Dollars

Project Name

Vaughan TS#4 Feeder Integration - Part 3

Factors Affecting Timing/Priority	Customers load ramping up schedule in VMC and other areas in Vaughan will impact the timing and priority.
Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The main benefits of this project will be to extend four feeders into the subject area and increase needed load capacity by 80 MVA. The main alternative to this project is to "do nothing" and continue to supply existing and new customers from existing distribution facilities. However, the "do nothing" alternative is not a viable option as it will not allow PowerStream to supply the new load growth materializing in the subject areas.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,630,000	$ -



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100632	**2015**	**6**	**Dollars**
	Project Name	27.6 kV Pole Line on 14th Ave from Hwy 48 to 9th Line		

Major Category	**System Service**	
Project Overview		
1. Additional Information	Service Territory	PowerStream South
	Location	14th Ave from Hwy 48 to 9th Line in Markham, approx. 2km.
	Scope	Rebuild the existing 2 ccts pole line into four 27.6 kV ccts on 14th Ave between Hwy 48 and 9th Line, and install necessary load interrupter switches as per PowerStream's design standard.
	Justification	This project is needed to provide 40 MVA supply capacity to Markham east and address the loading issue of Cornell and Box Grove both in the short and long term. This project will also reduce the risk of customer outages that might arise as a result of the long and rural feeder.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2016
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The risk is to get approval from the City of Markham in time. Capital design has started the design of the project and approvals should be in place in 2015.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	This project will extend 2 feeders (24M3/24M6) on 14th Ave from Hwy 48 to 9th Line. 24M3/24M6 will connect to the existing 2 ccts on 14th Ave east of 9th Line so that feeder 24M3/24M6 can be rerouted to Box Grove area and Cornell area. The Cornell Community subdivision (OPA#20) is bounded by 16th Ave to the north, Reesor Road to the east, Hwy 7 to the south, and 9th Line to the west. When fully developed, it will accommodate approximately 16,000 dwelling units with approximately 46,000 people and 10,000 to 13,000 jobs. The total load is estimated to be 46 MW when it is fully built out. This development has been ongoing for the past 3-5 years and is about 25% completed. South of and adjacent to the Cornell Development, is the Box Grove (OPA#92) subdivision. It currently has 2,600 dwelling units and will have an additional 10,000 residents when completed. This development is about 50% complete and is expected to be fully developed within the next few years. The existing feeders in the area don't have sufficient capacity to supply future growth. The original feeder integration plan for Markham Transformer Station Four (MTS4) was to reroute two new feeders (24M3 and 24M6) to provide additional capacity for developments in Cornell and Boxgrove.

Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100632	2015	6	Dollars

Project Name

27.6 kV Pole Line on 14th Ave from Hwy 48 to 9th Line

All existing supplies to Cornell are radial from 9th Line, meaning that any pole failure on 9th Line will cause large scale and prolonged outages to the customers. This project will increase reliability of Cornell area and avoid blackout situation by supplying Cornell from Reesor Rd. These two feeders will allow loads to be supplied from both the east and west.

In the long term, 46MW of load is expected in the Cornell area when it is fully developed. This will be beyond the capacity of the 24M2 and 24M7. The future incremental capacity needs will be addressed by rerouting two existing MTS2 feeders (24M3/M6) via 14th Ave and Reesor Rd.

This project (Extend two 27.6kV circuits 24M2/24M7 on Reesor Rd from 14th Ave to Hwy 7) is a interim step of the ultimate supply plan for the Cornell area and Box Grove areas. These two circuits will become new feeders 24M3 and 24M6 once pole line on 14th Ave between Hwy 48 and 9th Line is rebuilt into 4 ccts.

The project was first proposed in 2010 and was divided into multiple sections. The ultimate plan is to have all the sections complete by year 2018.
Section 1: build 2 feeders overhead on 14th Ave from 9th Line to Reesor Rd in 2014.
Section 2: build 2 feeders overhead on Reesor Rd from 14th Ave to Hwy 7 in 2015.
Section 3: re-build existing pole line on 14th Ave into 4 ccts from 9th Line to Reesor Rd to reroute feeder 24M3 and 24M6 from Hwy 48 to 9th Line in 2016.
Section 4: build 2 feeders overhead on Reesor Rd from Hwy 7 Ave to 16th Ave in 2017.
Section 5: build 2 feeders overhead on 16th Ave from 9th Line to Reesor Rd in 2018.
This project is to build Section #1 of the overall plan.
Without the use of these feeders, staying with the status quo will jeopardize operational efficiency and reliability.

1a. Main Driver

Support Capacity Delivery. The primary driver for this Investment is to support capacity delivery and reliability. The Cornell and Box grove area are supplied by feeder 24M4, 24M5, 24M7 and 24M8.

The peaks of these feeders in 2013 were:
24M4 381A
24M5 391A
24M7 346A
24M8 138A

Feeder 24M4 and 24M5 are at planning limits and have no extra capacity to supply new loads. Feeder 24M7 has extra 2 MW capacity and 24M8 has additional 7MW capacity. In the long term, 46MW of load is expected in the Cornell area when it is fully developed. The future incremental capacity needs will be addressed by rerouting two existing MTS2 feeders (24M3/M6) via 14th Ave and Reesor Rd. Feeder 24M3/24M6 will also provide backup in alternate route for feeders that supplies Cornell including Markham Stouffville Hospital and other future high rise buildings in the area. All existing supplies to Cornell are radial from 9th Line, meaning that any pole failure on 9th Line will cause large scale and prolonged outages to the customers. This project will increase reliability of Cornell area and avoid blackout situation by supplying Cornell from Reesor Rd. These two feeders will allow loads to be supplied from both the east and west.

1b. Priority and Reasons for Priority

High. Installing two additional 27.6kV circuits on 14th Ave will:
1. Address the loading issue of Cornell and Box Grove both in the short and long term.
2. Provide alternate supply route for Cornell development to increase reliability.
3. Consistent with the original Markham TS4 feeder integration plan and business case.

	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	The status quo is to do nothing and supply the future growth from the existing area feeders: 24M4, 24M5, 24M7 and 24M8. The peaks of these feeders in July 2013 were: 24M4 413A 24M5 423A 24M7 372A 24M8 140A Feeders 24M4 and 24M5 are over planning limits and feeder 24M7 is approaching the planning limit (400A). They have no extra capacity to supply new loads. Existing load over planning limits should be redirected to alternate supplies. Feeder 24M8 has additional capacity to supply new load or to take on redirected load. Feeders 24M4/24M7/24M8 combined have only 10 MVA capacity for future load growth. A significant new load in the Cornell area is the Markham Hospital expansion. The Markham Stouffville Hospital Complex expansion is under construction and peak demand is expected to be 7MW (180A) when the expansion is complete. Feeder 24M7 supplies customers on the east side of 9th Line between Hwy 7 and Steeles Ave, and load on Reesor Rd between Steeles Ave and Major Mack Dr. The peak demand of 24M7 was 372A in 2013. The incremental capacity remaining in the feeder is insufficient to accommodate future growth in the area. In addition, feeder 24M7 is a rural feeder with a total trunk feeder length of 40 km. PowerStream's typical urban feeder length average is 10km to 16 km. To continue to supply Cornell and Box Grove from the 24M7, as configured, will result in decreased reliability (long feeder length greatly exposes customers to higher than normal interruptions) and voltage drop issues as the feeder is loaded up. In summary, there is insufficient capacity to service the Cornell and Box Grove areas after 2015. New feeder capacity is required to supply load growth in the area beyond 2014. Several sections need to be built to route capacity to the Cornell area. This project is required to meet future growth.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	These two feeders are necessary to increase supply capacity to Cornell by 40 MVA. They will increase supply reliability too. All existing supplies to Cornell are radial from 9th Line, meaning that any pole failure on 9th Line will cause large scale and prolonged outages to the customers. This project will increase reliability of Cornell area and avoid blackout situation by supplying Cornell from Reesor Rd. These two feeders will allow loads to be supplied from both the east and west.
	Factors Affecting Timing/Priority	A large number of residential and commercial projects are under construction now. New customers and load are expected in the years to come.

Project Summary Report	Project Code 100632	Report Start Year 2015	Number of Years 6	Scale Dollars
	Project Name 27.6 kV Pole Line on 14th Ave from Hwy 48 to 9th Line			

Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)

This project is necessary for the following reasons:
1. Addresses the loading issue of Cornell and Box Grove.
2. Provide alternate supply route for Cornell development

The main alternative is to "do nothing", however that is not viable for the following reasons:

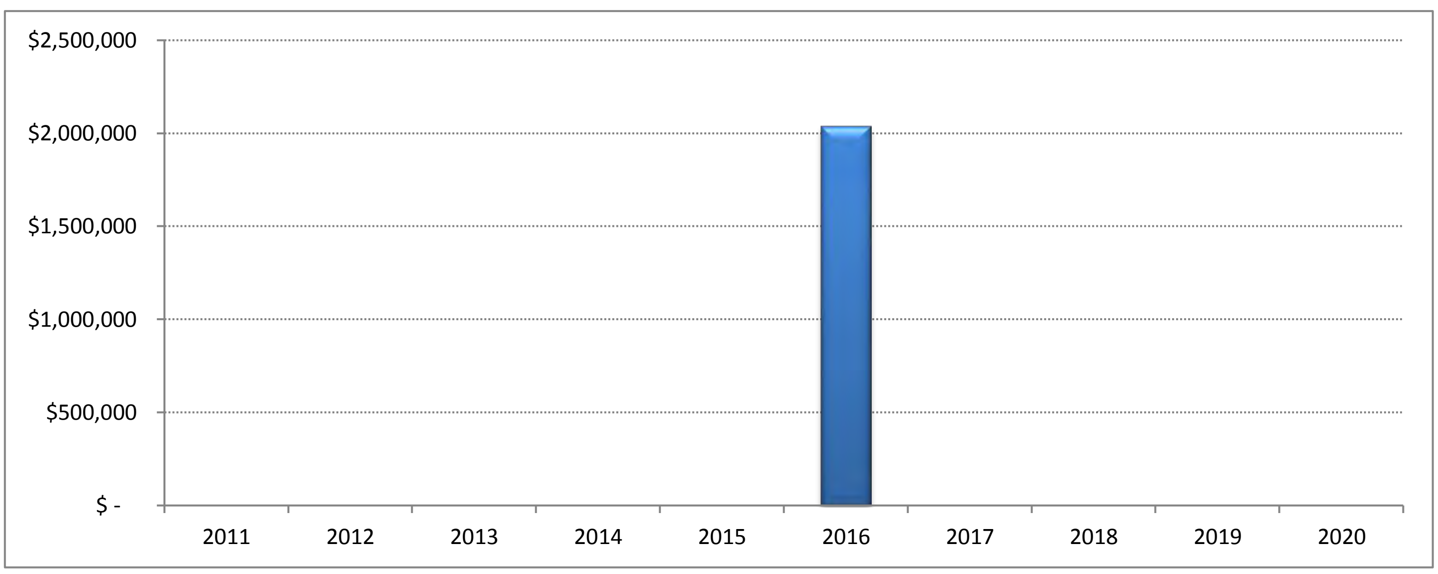
a) Does not meet short term and long term supply needs of the Cornell and Box Grove developments and open grid network philosophy.

b) Negative impacts on PowerStream reliability indices since customers in Box Grove and future developments will be supplied by a long, rural feeder 24M7 with above average exposure.

c) PowerStream will be at risk of compromising supply to new loads in the Markham east area that may have negative impacts on our corporate reputation and mission. The load to be impacted is estimated to be 30MW.

d) Customers will be at risk of lengthier outages, should an outage occur. There have been outages due to storms, tree contacts, lightning and line hardware on feeder 24M7 due to its nature as a long rural feeder. As load in the area grows, this will negatively impact SAIDI and SAIFI.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ 2,039,163	$ -	$ -	$ -	$ -



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100405	2015	6	Dollars

Project Name

27.6 kV Pole Line on Reesor Rd from Hwy 7 to 14th Ave

Major Category	System Service	

Project Overview

1. Additional Information	Service Territory	PowerStream South
	Location	Reesor Road from Hwy 7 to 14th
	Scope	To build double Circuits on Reesor Rd from Hwy 7 to 14th Ave in Markham - 2km
	Justification	To increase supply capacity and reliability to Markham East developments of Cornell and Box Grove areas; one of the fastest growing areas in PowerStream's service territory. The existing feeders on Reesor Road are small capacity 3/0 three Phase feeder. This project will increase capacity to those two developments, from a feeder loop around Box Grove/Cornell, and improve supply reliability.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2016
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The risk is to get approval from the City of Markham in time. Capital design has started the design of the project and should get the approvals in place in 2015.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	This will extend 2 circuits (24M2/24M7) on Reesor Rd from 14th Ave to Hwy 7, i.e., from Box Grove area to Cornell area.
	1a. Main Driver	Support Capacity Delivery. The main driver for this project is to support capacity delivery in the Markham area. The Cornell and Box Grove area are supplied by feeder 24M4, 24M5, 24M7 and 24M8. The peaks of these feeders in 2013 were: 24M4 381A 24M5 391A 24M7 346A 24M8 138A Feeder 24M4 and 24M5 are at planning limits and have no extra capacity to supply new loads. Feeder 24M7 has extra 2 MW capacity and 24M8 has additional 7MW capacity. Additional feeders are required in order to supply the anticipated future load. Feeder 24M2 had a peak of 150A in 2013. It has an additional capacity of 13MVA. In the short term, this project will provide additional 13MVA capacity for the Cornell and Box Grove areas by extending feeder 24M2 from 14th Ave to Hwy 7. Feeder 24M2 will also provide backup in alternate route for feeder 24M8 that supplies Markham Stouffville Hospital and other future high rise buildings in the area. All existing supplies to Cornell are radial from 9th Line, meaning that any pole failure on 9th Line will cause large scale and prolonged outages to the customers. This project will increase reliability of Cornell area and avoid blackout situation by supplying Cornell from Reesor Rd. These two feeders will allow loads to be supplied from both the east and west. In the long term, 46MW of load is expected in the Cornell area when it is fully developed. This will be beyond the capacity of the 24M2 and 24M7. The future incremental capacity needs will be addressed by rerouting two existing MTS2 feeders (24M3/M6) via 14th Ave and Reesor Rd.
	1b. Priority and Reasons for Priority	High. Installing two 27.6kV circuits on Reesor Rd will: 1. Address the loading issue of Cornell and Box Grove both in the short and long term. 2. Provide alternate supply route for Cornell development to increase reliability.

Power Stream **Project Summary Report**	Project Code **100405**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name 27.6 kV Pole Line on Reesor Rd from Hwy 7 to 14th Ave			

	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	The only alternative is to "do nothing" and supply the future growth from the existing area feeders: 24M4, 24M5, 24M7 and 24M8. The peaks of these feeders in July 2013 were: 24M4 413A 24M5 423A 24M7 372A 24M8 140A Feeders 24M4 and 24M5 are over planning limits and feeder 24M7 is approaching the planning limit (400A). They have no extra capacity to supply new loads. Existing load over planning limits should be redirected to alternate supplies. Feeder 24M8 has additional capacity to supply new load or to take on redirected load. Feeders 24M4/24M7/24M8 combined have only 10 MVA capacity for future load growth. A significant new load in the Cornell area is the Markham Hospital expansion. The Markham Stouffville Hospital Complex expansion is under construction and peak demand is expected to be 7MW (180A) when the expansion is complete. Feeder 24M7 supplies customers on the east side of 9th Line between Hwy 7 and Steeles Ave, and load on Reesor Rd between Steeles Ave and Major Mack Dr. The peak demand of 24M7 was 372A in 2013. The incremental capacity remaining in the feeder is insufficient to accommodate future growth in the area. In addition, feeder 24M7 is a rural feeder with a total trunk feeder length of 40 km. PowerStream's typical urban feeder length average is 10km to 16 km. To continue to supply Cornell and Box Grove from the 24M7, as configured, will result in decreased reliability (long feeder length greatly exposes customers to higher than normal interruptions) and voltage drop issues as the feeder is loaded up. In summary, there is insufficient capacity to service the Cornell and Box Grove areas after 2015. New feeder capacity is required to supply load growth in the area beyond 2014. Several sections need to be built to route capacity to the Cornell area. This project is required to meet future growth.
5. Category-Specific Requirements for Each Project/Activity (OEB)	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	This project is to increase supply capacity to Cornell by 13 MVA. This project will also increase supply reliability. All existing supplies to Cornell are radial from 9th Line, meaning that any pole failure on 9th Line will cause large scale and prolonged outages to the customers. This project will increase reliability of Cornell area and avoid blackout situation by supplying Cornell from Reesor Rd. These two feeders will allow loads to be supplied from both the east and west.
	Factors Affecting Timing/Priority	A large number of residential and commercial projects are under construction now. New customers and load are forecasted in the near future.

Project Code	Report Start Year	Number of Years	Scale
100405	**2015**	**6**	**Dollars**

Project Summary Report

Project Name

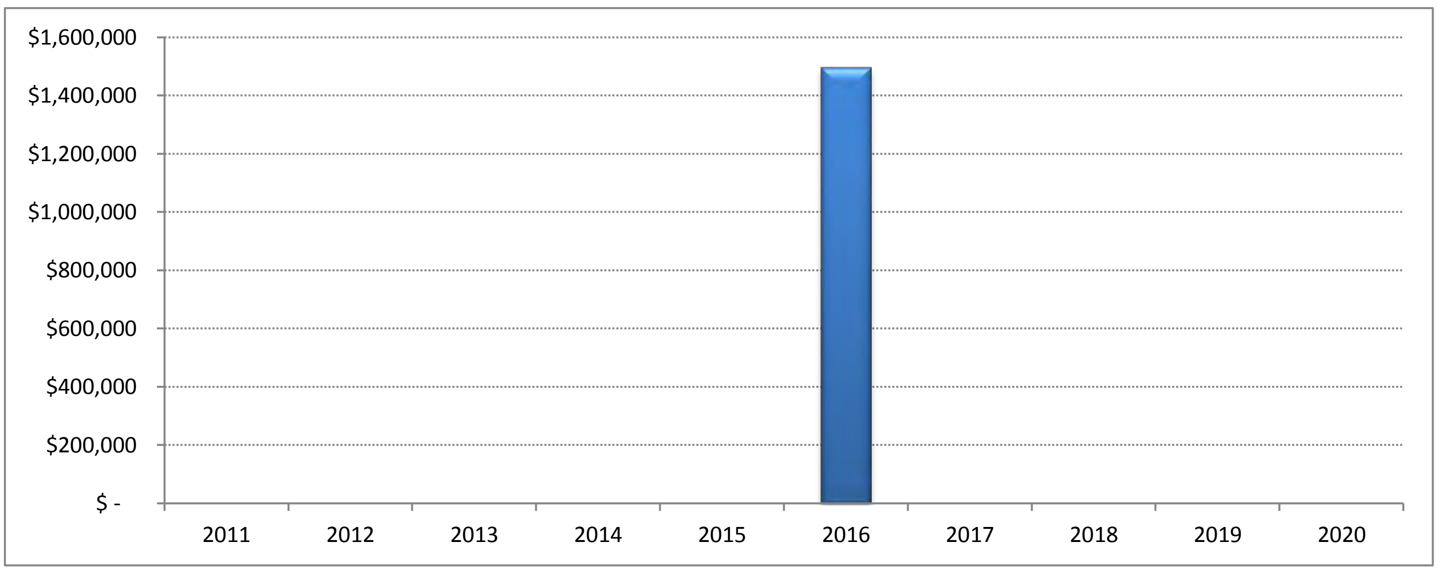
27.6 kV Pole Line on Reesor Rd from Hwy 7 to 14th Ave

Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)

This project to install two 27.6kV circuits on Reesor Rd is necessary for the following reasons:
1. Address the loading issue of Cornell and Box Grove both in the short and long term.
2. Provide alternate supply route for Cornell development

The only alternative to "do nothing" is not a viable option for the following reasons:
a) The status quo does not meet short term and long term supply needs of the Cornell and Box Grove developments and open grid network philosophy.
b) Negatively impacts on PowerStream reliability indices since customers in Box Grove and future developments will be supplied by a long, rural feeder 24M7 with above average exposure.
c) PowerStream will be constrained to supply new loads in the Markham east area. The load to be impacted is estimated to be 30MW.
d) Customers will be at risk of lengthier outages, should an outage occur. There have been outages due to storms, tree contacts, lightning and line hardware on feeder 24M7 due to its nature as a long rural feeder. As load in the area grows, this will negatively impact SAIDI and SAIFI.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned		$ -	$ -	$ -	$ -	$ 1,496,942	$ -	$ -	$ -	$ -



Project Summary Report	Project Code 101572	Report Start Year 2015	Number of Years 6	Scale Dollars
	Project Name Double Circuit existing 23M8 Circuit from Bayfield & Livingstone to Little Lake MS.			

Major Category	System Service	

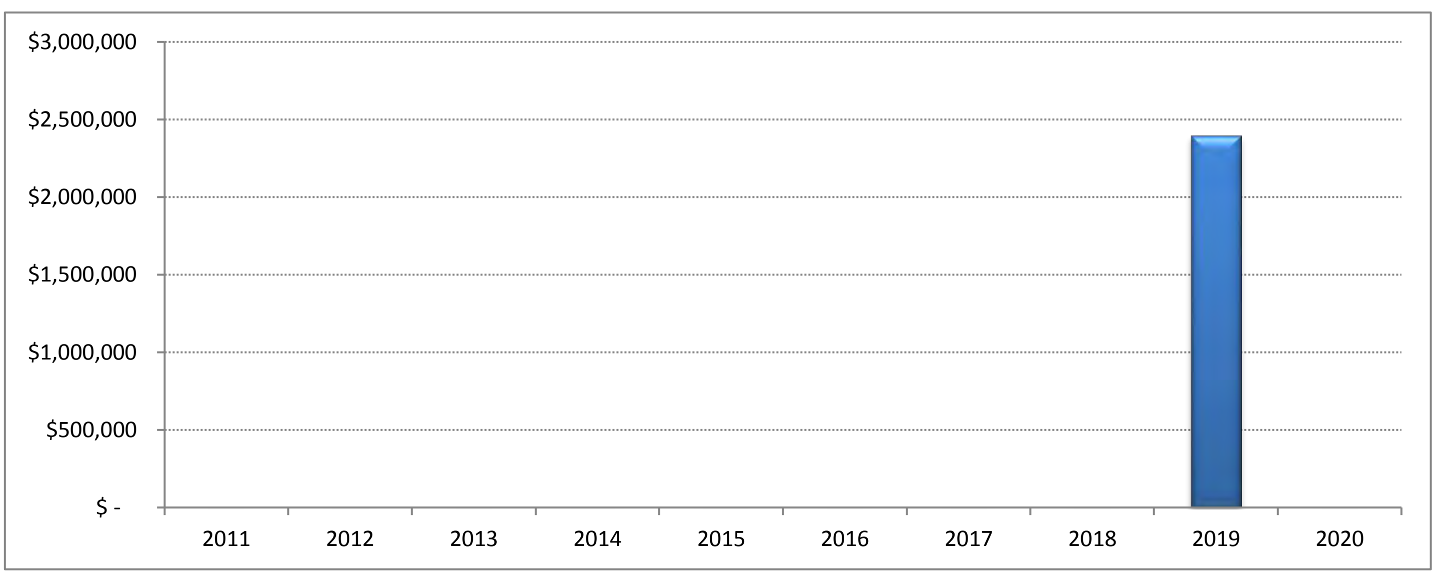
Project Overview

1. Additional Information	Service Territory	PowerStream North
	Location	Barrie
	Scope	The project entails double circuiting the existing 23M21 (formerly 23M8) with the 23M28 from Bayfield & Livingstone to Cundles & Duckworth (approx. 4.5km's) and transferring Little Lake MS from 23M21 to 23M28. The new circuit will require rebuilding the existing pole line from Bayfield/Livingstone along Livingstone to Cundles, and along Cundles to Little Lake MS. Double circuiting the 23M21 with the 23M28 should be completed by summer 2019. The project includes engineering design, approvals, construction, and commissioning.
	Justification	The new feeder is required to provide capacity relief to the existing 23M21 (formerly 23M8). Information obtained from the City of Barrie on proposed developments in the Cundles and Duckworth area indicates that a number of commercial developments will result in new load growth that needs to be serviced. The proposed Cundles and Little Lake Commercial Developments will total 8.8MVA over the next five years. A new 20MVA 44/13.8kV 4 feeder substation (Little Lake MS#2) is proposed to be in-service by 2018. The existing 23M21 (formerly 23M8) experienced a 2013 summer loading of 420A, which exceeded the planning limit of 400A. Given the proposed developments and new substation, the 23M21 is forecasted to exceed the 600A thermal limit in 2019. Double circuiting the 23M21 with the 23M28 to offload Little Lake MS from 23M21 will ensure that the area can be supplied to accommodate the anticipated load growth without exceeding the planning and thermal limits of the 44kV feeders.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2019
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The greatest risk to completion is securing the required approvals from the city in the allotted timeframe. The ramping up of the proposed commercial developments in the area will also impact the timing of the project.
	Comparative Information on Equivalent Historical Projects (if any)	Some past projects for new circuits have taken 6-8 months to obtain the necessary approvals before proceeding with construction.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	The project entails double circuiting the existing 23M21 (formerly 23M8) with the 23M28 from Bayfield & Livingstone to Cundles & Duckworth (approx. 4.5km's) and transferring Little Lake MS from 23M21 to 23M28. The new circuit will require rebuilding the existing pole line from Bayfield/Livingstone along Livingstone to Cundles, and along Cundles to Little Lake MS. Double circuiting the 23M21 with the 23M28 should be completed by summer 2019. The project includes engineering design, approvals, construction, and commissioning.
	1a. Main Driver	Support Capacity Delivery. The main driver of the project is to provide capacity relief to the existing 23M21 (formerly 23M8). Two proposed Cundles and Little Lake Commercial Developments will total 8.8MVA over the next five years. A new 20MVA 44/13.8kV 4 feeder substation (Little Lake MS#2) is proposed to be in-service by 2018. The existing 23M21 (formerly 23M8) experienced a 2013 summer loading of 420A, which exceeded the planning limit of 400A. Given the proposed developments and new substation, the 23M21 is forecasted to exceed the 600A thermal limit in 2019. Double circuiting the 23M21 with the 23M28 to offload Little Lake MS from 23M21 will ensure that the area can be supplied to accommodate the anticipated load growth without exceeding the planning and thermal limits of the 44kV feeders.
	1b. Priority and Reasons for Priority	The new feeder is high priority since thermal limits will be exceeded in the Cundles & Duckworth area beyond 2019 upon completion of the new Little Lake MS#2 and the proposed commercial developments. Load transfers to the adjacent feeder are limited due to existing loading.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	The proposed new circuit would add approximately 30MVA of capacity to the Cundles & Duckworth area, thereby providing capacity relief to the existing 23M21 and ensuring supply capacity to the new Little Lake MS#2 and commercial developments. The "do nothing" alternative is not a viable alternative because the 23M21 has already exceeded the 400A planning limit in 2013 and the 8.8MVA of proposed commercial developments will result in the 23M21 feeder exceeding the 600A thermal limit in 2019. The "do nothing" alternative would not accommodate the future commercial load growth in the area or provide adequate feeder capacity for load transfers in contingency conditions.

Project Summary Report	Project Code **101572**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Double Circuit existing 23M8 Circuit from Bayfield & Livingstone to Little Lake MS.			

	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	The new feeder will produce reliability benefits by providing an additional 44kV circuit to the Barrie north-east area, thereby increasing transfer options which increases reliability to customers.
	Factors Affecting Timing/Priority	Securing the required approvals from the city in the allotted timeframe may affect the timing of the feeder construction.
	Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The benefits of this project is that the new circuit would add approximately 30MVA of needed load capacity to the Cundles & Duckworth area, thereby providing capacity relief to the existing 23M21 and ensuring supply capacity to the new Little Lake MS#2 and commercial developments. The main alternative to this proposed project would be to "do nothing" fore the foreseeable future. However, the "do nothing" alternative is not viable because the 23M21 has already exceeded the 400A planning limit in 2013 and the 8.8MVA of proposed commercial developments will result in the 23M21 feeder exceeding the 600A thermal limit in 2019. The "do nothing" alternative would not accommodate the future commercial load growth in the area or provide adequate feeder capacity for load transfers in contingency conditions.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,395,509	$ -



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	102460	2015	6	Dollars

Project Name

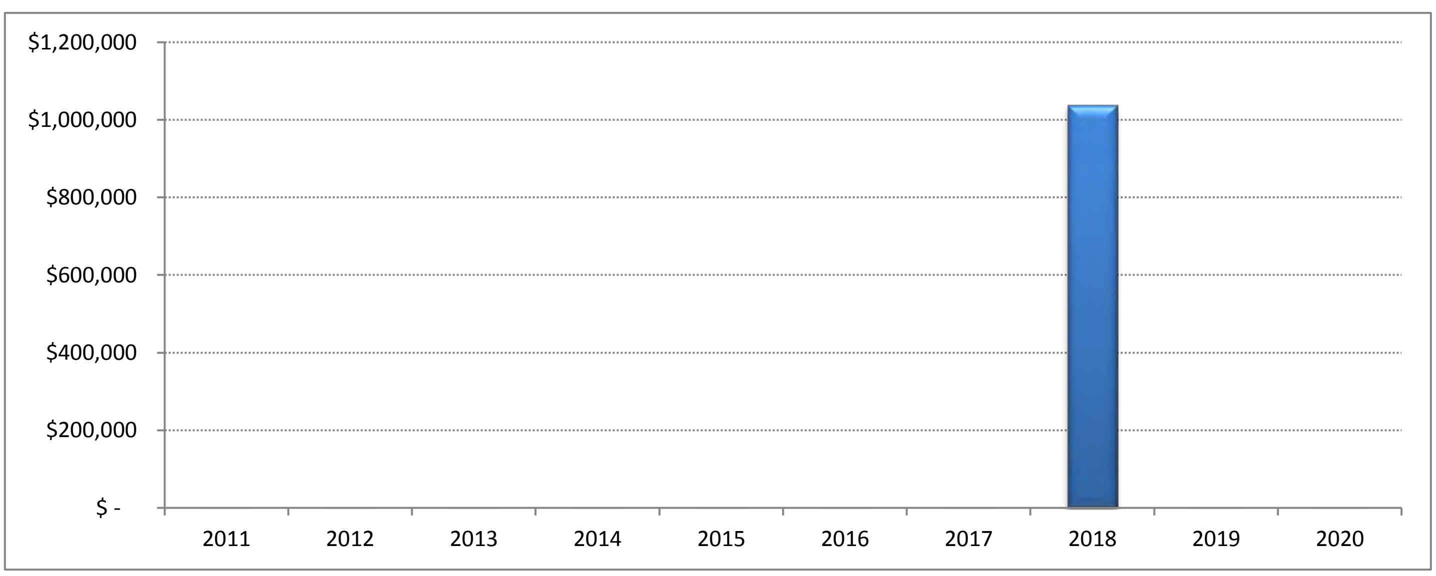
Highway Crossing Remediation - Hwy 400/ Brock St.

Major Category	**System Service**	
Project Overview		
1. Additional Information	Service Territory	PowerStream North
	Location	PowerStream North - Highway 400/ Brock St.
	Scope	This project is to carryout the engineering design review and construction necessary to replace the older two pole structure at 400/Brock St. in Barrie which currently uses steel supports installed at the base of all four poles as reinforcements indicating a potential strength issue.
	Justification	This remediation is in response to a past Highway crossing flash over caused by contact of the overhead conductor of feeder 21M9 (27.6kV circuit) April 16th, 2012 to the existing Lighting standard (Hwy 407/Weston). High winds were reported in the area at the time. This was a second case of contact with the street light post at the same location. In the light of the above incident it was decided to proactively review all highway crossings and implement corrective action for the any issues identified. PowerStream contracted an engineering consultant to identify locations in PowerStream's territory that need to be reviewed and slated for replacement due to various structure and proximity issues. At the 400/ Brock St. there are two existing crossings. The older of the two is constructed on a two pole/crossarm structure with two circuits at the same level. The newer of the two crossings is a single circuit installation that is joined to the older structure by a slack span. The preliminary pole class and guying analysis for the newer crossing indicates no concerns. Both sets of structures associated with the older crossing are supported by steel channel irons that have been driven into the ground next to the base of each pole. These channels are attached to the poles with heavy steel banding. Based on the fact that these structures have been reinforced in this manner suggests that there was a concern about their strength in the past. Of the two existing crossings at this location, the newer installation has no concerns identified with it. The older, two pole structure, was found to have had additional steel supports installed at the base of all four poles. Based on these findings, the consultant recommended that this older structure be planned for replacement. Remediation action must be taken to correct the concerns identified.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2018
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	The west side of this Hwy crossing enters the Hydro One station yard and therefore the biggest risk to completion is the coordination effort and timing required with Hydro One. In response, Engineering has already had discussions with Hydro One in 2014 to give them time to review and settle on a plan. In addition, information has been forwarded to the municipality to make them aware of any changes requiring municipal approvals. Generally, municipal approvals can be dealt with during the year of the project.
	Comparative Information on Equivalent Historical Projects (if any)	PowerStream has performed several road crossings in the past and there should be no issue here, other than coordination with HONI.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	This project is to carryout the engineering design review and construction necessary to replace the older of the two pole structures at 400/Brock St. in Barrie which currently uses steel supports installed at the base of all four poles as reinforcements indicating a potential strength issue.
	1a. Main Driver	Safety. Consultant has identified that the older pole structure at this crossing currently uses steel supports installed at the base of all four poles as reinforcements indicating a potential strength issue.
	1b. Priority and Reasons for Priority	Any failure of this crossing would pose a major safety issue to vehicles driving on Hwy#400 in the vicinity of Brock St. Based on the time expected to coordinate with Hydro One, this project has been prioritized to take place in 2018 or sooner.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	PowerStream's engineering consultant has identified this crossing as a concern and PowerStream Engineering has estimated the cost to rebuild at $1,030,215. This cost is signifcantly less than the potential costs to rebuild the line in an emergency. PowerStream has an obligation to act on the consultant's findings and therefore the 'do nothing' alternative is not a viable option. There is an alternative to delay action however the lead time for this project has already been predicted at approx 2 years, therefore it is prudent that project is planned for 2018 or sooner.

Project Summary Report	Project Code **102460**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Highway Crossing Remediation - Hwy 400/ Brock St.				

5. Category-Specific Requirements for Each Project/Activity (OEB)	2. Safety	Any failure of this crossing would pose a major safety issue to vehicles driving on Hwy#400 in the vicinity of Brock St.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	Not Applicable.
	Factors Affecting Timing/Priority	The west side of this Hwy crossing enters the Hydro One station yard and therefore this project requires additional time for coordination. The project has therefore been prioritized for 2018 or sooner.
	Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The benefits of this project are mainly to remedy a public safety concern that has been identified by PowerStream's engineering consultant. There are few, if any, alternatives to this proposed project. The "do nothing" alternative is not viable as it does nothing to correct the public safety concerns of PowerStream's distribution facilities in this area.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,038,486	$ -	$ -



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	102459	2015	6	Dollars

Project Name

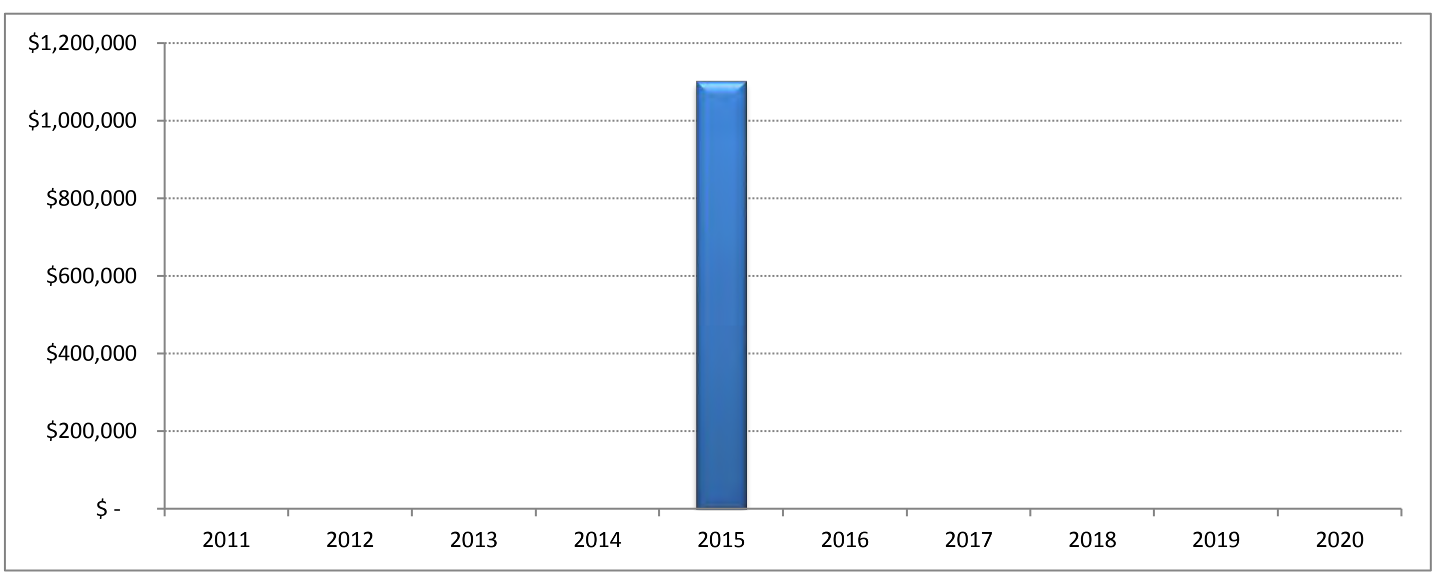
Highway Crossing Remediation - Hwy 407/ East of Dufferin

Major Category	System Service	
Project Overview		
1. Additional Information	Service Territory	PowerStream South
	Location	PowerStream South - Highway 407 Crossing, east of Dufferin.
	Scope	Carryout the Engineering Design review and construction necessary to remediate the structure/tension concerns noted at the 407/ East of Dufferin highway crossing as per findings of PowerStream's engineering consultant.
	Justification	This remediation is in response to a past Highway crossing flash over caused by contact of the overhead conductor of feeder 21M9 (27.6kV circuit) April 16th, 2012 to the existing Lighting standard (Hwy 407/Weston). High winds were reported in the area at the time. This was a second case of contact with the street light post at the same location. In the light of the above incident it was decided to proactively review all highway crossings and implement corrective action for the any issues identified. PowerStream's engineering consultant identified locations in PowerStream's territory that need to be reviewed and slated for replacement due to various structure and proximity issues. The 407/East of Dufferin highway crossing carries four 27.6kV circuits, which is more than any of the other crossings structures. The pole on the south side of the 407ETR is bowed due to the pre-loading of the guy wires at installation. As a result, the guy wires are extremely tight under normal conditions and the amount of pre-loading is difficult to determine. The communication guys that would support the span over the highway are hanging against the pole and it is not evident if they were broken or never connected. In addition to being not connected, the communication guy wire attachments at the pole are dug into the pole deeper than normal. This might indicate a significant amount of tension is present or that the pole is weakened by the vertical cracking. The pole was found to have several large vertical cracks within the 3.0 meters (10') above grade. These cracks were at least 75mm-100mm (3"-4" deep) and the ant activity in the cracks was significant. The rough guying review of the south pole of this crossing indicates that several of the guy strands may be overloaded under maximum conditions. It is recommended that the sag of the conductors be field measured to determine the expected maximum design tension and the guying be reviewed and modifications be made as required. The broken/missing communications guying should be corrected immediately and the bundle information be obtained from the third parties so that the loads can be factored into the guying analysis. Given that this crossing has four circuits, the engineering consultant has recommended that this work be made a high priority. Remediation action must be taken to correct these concerns as identified.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	This crossing was originally designed to cross east of the 407 cloverleaf on-ramps as requested by the MTO. The rebuilt crossing is planned to move closer to the bridge and cloverleaf in order to avoid complications with the municipality VIA changes on Highway 7. Negotiations have already begun with the 407 owners to get approval for the new proposed crossing.
	Comparative Information on Equivalent Historical Projects (if any)	PowerStream has performed several road crossings in the past and there should be no unexpected issues here, apart from the necessary approvals from the 407 which are being managed.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	This project is to carryout the engineering design review and construction necessary to remediate the structure/tension concerns.
	1a. Main Driver	Safety. The main driver for this project is to eliminate the safety risk and maintain the system integrity. PowerStream's engineering consultant noted the 407/ East of Dufferin highway crossing has structure/tension concerns that need to be addressed.
	1b. Priority and Reasons for Priority	Any failure of this crossing would pose a major safety issue to vehicles driving on Hwy#407 in the vicinity of Dufferin St. Based on the weighting given to this crossing by the AESI report, this project has been prioritized to take place in 2015.

Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	102459	2015	6	Dollars
	Project Name: Highway Crossing Remediation - Hwy 407/ East of Dufferin			

	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	PowerStream's engineering consultant has identified this crossing as a concern and PowerStream Engineeing has estimated the cost to rebuild at $1,099,072. This cost is significantly less than the potential costs to rebuild the line in an emergency. PowerStream has an obligation to act on the engineering consultant's findings and therefore the 'do nothing' alternative is not a viable option. There is an alternative to delay action however the significance of the concerns requires the project to start ASAP in 2015.
	2. Safety	Any failure of this crossing would pose a major safety issue to vehicles driving on Hwy#407 in the vicinity of Dufferin St.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	Not Applicable.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	Not Applicable.
	Factors Affecting Timing/Priority	The significance of the safety concerns have resulted in this project being proposed as soon as possible in 2015.
	Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The benefits of this project are mainly to remedy a public safety concern that has been identified by PowerStream's engineering consultant. There are few, if any, alternatives to this proposed project. The "do nothing" alternative is not viable as it does nothing to correct the public safety concerns of PowerStream's distribution facilities in this area.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ 1,100,409	$ -	$ -	$ -	$ -	$ -



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	100886	2015	6	Dollars
	Project Name: Distribution Automation Switches / Reclosers			

Major Category System Service

Project Overview

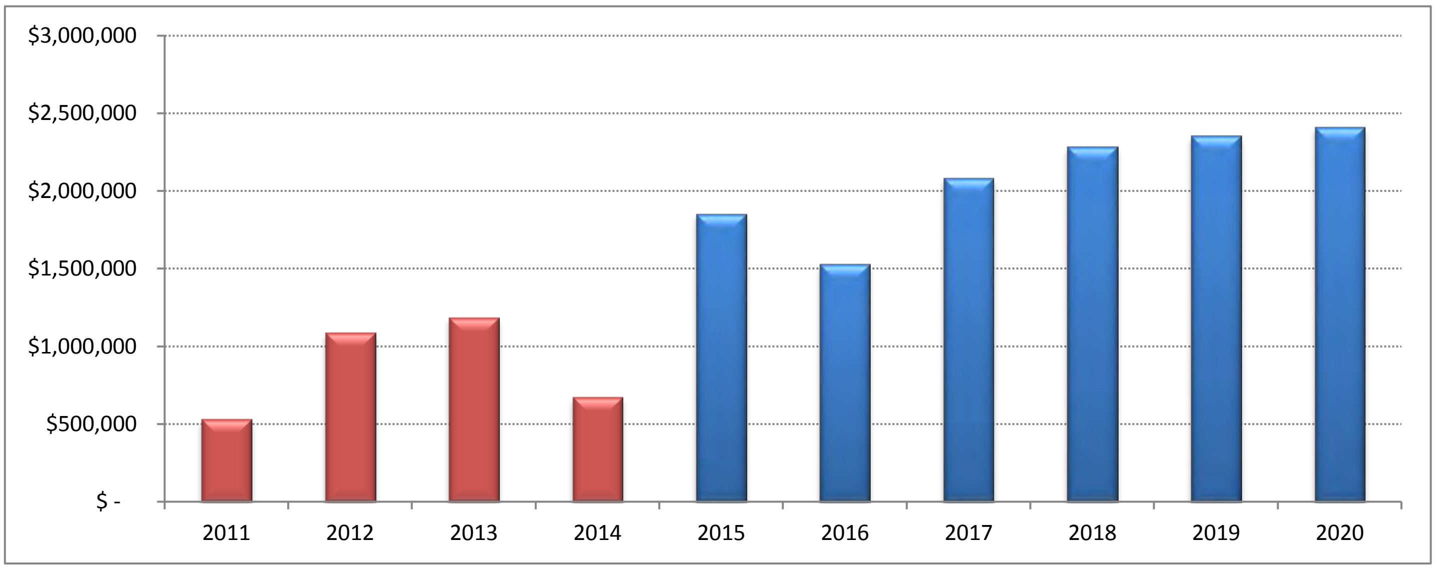
1. Additional Information	Service Territory	PowerStream North & South
	Location	Various locations in PowerStream North and South. The locations will be determined by Planning in conjunction with the Control Room.
	Scope	This project involves the installation of Distribution Automation Scadamate Switches / Reclosers at various locations. This has been an annual program for the past 6 years. In 2015 it is proposed to install 16 Automated units, with approximately the same number of devices installed in the succeeding years.
	Justification	High service reliability and rapid response to power outages is critical to mission success and customer satisfaction in supplying electricity. RTU controlled switches (predominantly SCADA-Mates) provide rapid transfer of loads in emergencies, reduce restoration time which improves reliability, provide flexibility to reconfigure the system to avoid feeder and station over loads during summer peak, provide real time system readings, reduce the risk of personnel injury and are the platform for the complete distribution automation system. Engineering Planning released a strategy report in 2005 titled "Distribution Automation Report ", which was subsequently updated in 2012. The report recommended that automatic switches be installed at strategic locations over a number of years to: - Reduce feeder down time in case of outages - Reduce the number of customers affected by outages. To determine potential switch candidates, PowerStream planning department ranks Feeders based on the FAIDI, FAIFI and SAIFI contributions to the systems and determines Worst Performing Feeders. Planning also reviews the outage causes, feeder load balancing plan and location of existing automatic switches to identify and determine the location for additional switches and re-closers wherein it is most beneficial in CMI reduction and operational needs. Finally, automatic switch locations are jointly determined among System Planning, System Operations, and Lines by selecting potential switch candidates to address the following requirements: - Customer Service reliability needs - Feeder loading emergency back-up and load transfer needs - Control Room operations needs on outage sectionization and restoration
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Unforseen delays from municipal road widening projects for proposed recloser locations. Generally, new locations are selected in this circumstance and completed within the budget year.
	Comparative Information on Equivalent Historical Projects (if any)	This program has been on-going for the past 6 years.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	Installation of Distribution Automation Scadamate Switches / Reclosers at various locations. This has been an annual program for the past 6 years. In 2015 it is proposed to install 16 units.
	1a. Main Driver	Reliability. The main driver of the Investment is to improve the reliability and system efficiency. RTU controlled switches provide rapid transfer of loads in emergencies, reduce restoration time which improves reliability, provide flexibility to reconfigure the system to avoid feeder and station over loads during summer peak, provide real time system readings, reduce the risk of personnel injury and are the platform for the complete distribution automation system.
	1b. Priority and Reasons for Priority	PowerStream authored a Distribution Automation Report that identified that several feeders were lacking automated devices thereby affecting PowerStreams ability to reduce feeder down time in case of outages, and to reduce the number of customers affected by outages. This program was recommended in order to increase PowerStream's overall reliability.

	Project Code	Report Start Year	Number of Years	Scale
Project Summary Report	100886	2015	6	Dollars
	Project Name: Distribution Automation Switches / Reclosers			

	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	PowerStream's 2012 Distribution Automation Report identified that 2 to 3 DA switches per feeder represent the best value investment vs. received reliability improvement, using the following equation [%improvement = 0.5*NSW/(NSW+1)*100]. In 2014, on average, each area had the following number of normally open R.T.U. controlled Switches per feeder: Markham=1.23, RichmondHill =0.77, Vaughan=0.98, North area=1.35. Between 2008-2011, PowerStream had been installing an average of 8-10 switches per year in an attempt to meet it's Level 1 automation targets. In 2013, the Distribution Automation Capital Program was increased to 23 units/year (14 Scada-Mates and 9 Reclosers) in order to meet the DA targets identified in the 2012 DA report within 6 years, where the report called for 70 N.C. Switches or reclosers to sectionalize feeders, and 67 N.O. switches to build ties between feeders. The alternative is to continue to utilize manual LIS (Load Interrupting Switch) switches. However, this alternative will require Lines crews to operate a significant number of manual switches to isolate faults or transfer loads between feeders. This will increase outage resoration time and have a negative impact on system reliability.
	2. Safety	The aspects related to safety for this project include: 1. Allowing switching to occur without staff in contact with the equipment during change of state from open to close or visa versa. 2. Allowing switching to occur during an emergency. i.e. customer contact with lines via vehicle or cut down tree, critical injury, fire or explosion.
	3. Cyber-Security, Privacy	Automated Switches and Reclosers communicate back to the control room via private network.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	The financial risk calculations are based on the following assumptions and estimates (per Distribution Automation switch unit): - Frequency of interruption: 2/year - Duration of interruption: 30 minutes (0.5 hours). This is the estimated incremental time for manual switching in comparison to remote automatic switching - Number of customers affected in an outage: 500 customers - Customer load affected in an outage: 2000 kW - Customer Interruption Cost (Frequency): $20.00/kW (mixed Residential , Commercial & Industrial) - Customer Interruption Cost (Duration): $20.00/kWh (mixed Residential, Commercial & Industrial) - Delivery Charge, etc. for loss of revenue calculation: $0.0179/kWh Cost to Customers: - Customer Interruption Cost (Frequency) = Not Applicable - Customer Interruption Cost (Duration) = 2000 kW x 0.5 hrs x $20/kWh x 2 failures/year= $40,000 Cost Comparison: -Total Cost to Customers/year (Interruption) = Cost (Freq) + Cost (Dur) = $0 + $40,000 = $40,000 -Average cost of Switch/Recloser = $88,000.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	All Scada-Mate switches are capable to participate in distribution automation schemes (self healing loops) if required for future Smart Grid strategies.
	Identify any reliability , efficiency, safety or coordination benefits	RTU controlled switches provide the following benefits: - rapid transfer of loads in emergencies, - reduce restoration time which improves reliability, (without automation = 50-80min, with automation = 2-5min) - provide flexibility to reconfigure the system to avoid feeder and station over loads during summer peak, - provide real time system readings, - reduce the risk of personnel injury - more efficient planned outages - enable participation in the complete distribution automation system.
	Factors Affecting Timing/Priority	Not Applicable.
	Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The main alternative to this project would be to "do nothing" and keep the number of distribution automation switches at current levels. However, "doing nothing" would not allow PowerStream to make the necessary improvements to increase the reliability of its distribution system.

Power Stream	Project Code 100886	Report Start Year 2015	Number of Years 6	Scale Dollars
Project Summary Report	Project Name Distribution Automation Switches / Reclosers			

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ 530,166	$ 1,085,802	$ 1,184,597	$ 671,797	$ 1,850,276	$ 1,530,249	$ 2,080,457	$ 2,283,805	$ 2,354,895	$ 2,409,740



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	102851	2015	6	Dollars
	Project Name: Purchase of a Mobile Unit Station			

Major Category System Service

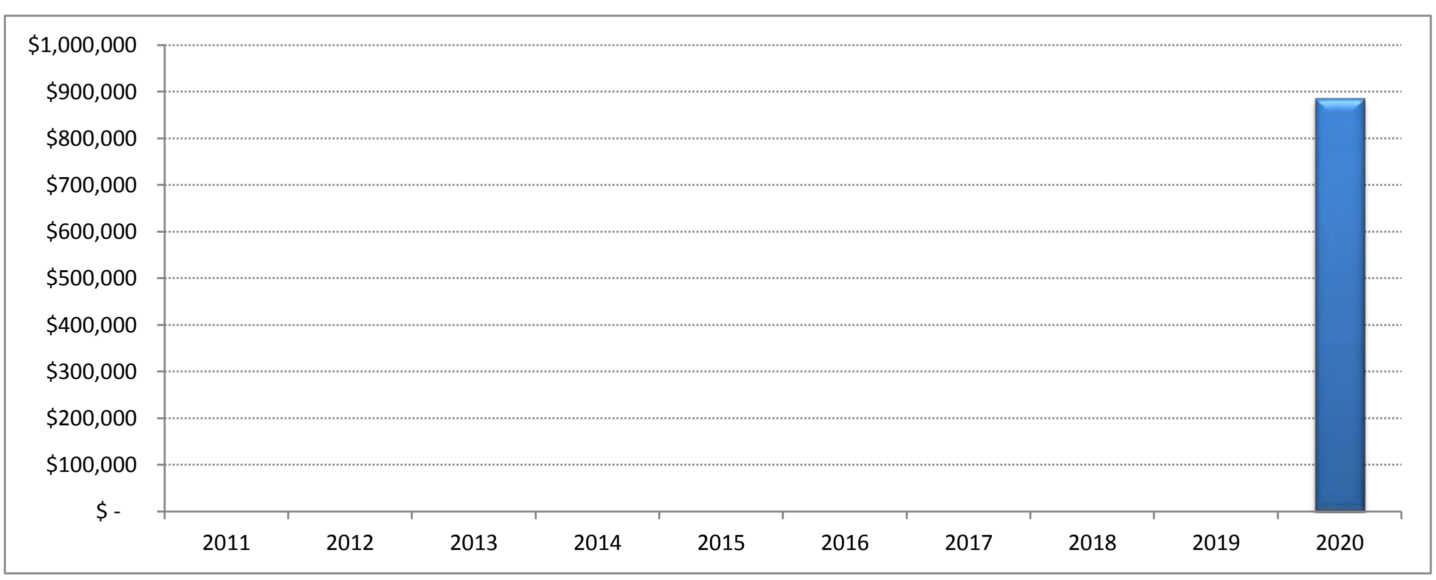
Project Overview

1. Additional Information	Service Territory	PowerStream North & South
	Location	All MS Stations
	Scope	Purchase of a 5MVA dual primary and multiple secondary Mobile Unit Station (MES) complete with 3 outgoing feeder circuits.
	Justification	There exists a number of stations that have no available backup in the event of equipment damage that causes an outage. Also, PowerStream has rented a unit from a neighbouring utility in order to allow customers to remain with power while critical station equipment is either changed out or repaired. Powerstream has been fortunate that the neighbouring utility had the unit available when we required it. We had to pay a rental charge for the use of the unit and had to arrange for the transportation to and from the neighbouring utility. The MS stations that are "islanded" are not maintained as they should be because a MES has to be obtained and the station has to be comlpetely disconnected from the grid and the feeders have to be reconnected to the MES. In order to install monitoring equipment on these stations, a rental unit has to be rented and installed. It is expected that the unit would be used at many locations where loading is an issue, while equipment that fails in high load season can be repaired and when an emergency occurs and portable power is required, Powerstream can provide power to key customers during an extended outage.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2020
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Mobile Station will be purchased as a turnkey system. It will be ordered in early Q1 and received in Q4. The components are off the shelf equipment that is assembled on a flat bed trailer. There are more than one outfit that manufacturers mobile stations.
	Comparative Information on Equivalent Historical Projects (if any)	No Comparative Projects
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	Purchase of a 5MVA dual primary and multiple secondary Mobile Unit Station (MES) complete with 3 outgoing feeder circuits.
	1a. Main Driver	Reliability. There exists a number of stations that have no available backup in the event of equipment damage that causes an outage. Also, PowerStream has rented a unit from a neighboring utility in order to allow customers to remain with power while critical station equipment is either changed out or repaired. PowerStream has been fortunate that the neighboring utility had the unit available when we required it. We had to pay a rental charge for the use of the unit and had to arrange for the transportation to and from the neighboring utility. The MS stations that are "islanded" are not maintained as they should be because a MES has to be obtained and the station has to be completely disconnected from the grid and the feeders have to be reconnected to the MES. In order to install monitoring equipment on these stations, a rental unit has to be rented and installed. It is expected that the unit would be used at many locations where loading is an issue, while equipment that fails in high load season can be repaired and when an emergency occurs and portable power is required, PowerStream can provide power to key customers during an extended outage.
	1b. Priority and Reasons for Priority	The time of restoration of customers would be significantly improved for the locations where presently there is no choice but to have an extended or forced outage. The exists some MS stations and Customer stations that have no redundancy available. These stations can not be easily maintained and equipment cannot be properly diagnosed because the effort and the customer disruption is unacceptable. The mobile unit could also serve to provide power when a station is disconnected for scheduled service. Customers and load arrangements are easier to manage for the system control operators.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	The unit can be used for the following purposes: Restore power quickly to Key customer in the event of a failure of either the utilities equipment or the customers equipment (e.g. data centre or hospital). The unit can be used to offload a station that is in an overload state (during high peak time). the unit can be used to keep feeders energized while a station is maintained (all year long). The unit can be loaned/rented to neighboring LDCs when not needed.

Project Summary Report	Project Code **102851**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Purchase of a Mobile Unit Station			

	2. Safety	The mobile unit provides added safety to stations that are out for repair or maintenance. The permanent equipment can be properly tested and not rushed to complete. The equipment can be better assessed on its condition.
	3. Cyber-Security, Privacy	There is no cyber security privacy issues with the purchase of a mobile substation.
	4. Coordination, Interoperability	Not Applicable
	5. Economic Development	Not Applicable
	6. Environmental Benefits	The environmental benefits for having a mobile substation is that a piece of equipment that is leaking at one of the stations that cannot be totally isolated without a customer prolonged outage can be properly repaired/replaced. The amount of contamination is minimized as the outage can easily be scheduled and the equipment repaired without having to find a mobile unit for temporary use. rental units are not always available.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable	It is expected that customers want to have reliable power all of the time. Without a mobile unit, equipment at some locations cannot be maintained properly unless a full outage is planned. Customers are out of power during this time.
	Regional Electricity Infrastructure Requirements which affect Project, if applicable	Not Applicable.
	Description of Incorporation of Advanced Technology, if applicable	Not Applicable.
	Identify any reliability , efficiency, safety or coordination benefits	The mobile unit can also be used to provide emergency power during extended outages, or to large or critical customers if required. Without a mobile unit station, the impact of a station failure without backup would be significant. An extended outage would result, and the cost to repair would be significant if the failed equipment failed catastrophically.
	Factors Affecting Timing/Priority	PowerStream presently relies on other utilities to be able to supply it with a mobile station under planned maintenance conditions. If the condition is an emergency, there is no guarantee that a mobile station will be available. This increases significantly the duration of the outage. If an islanded station has a failure that requires extensive repairs (eg. transformer or switchgear replacement), then the amount of time to restore the customer(s) will be significant.
	Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (including qualitative factors if applicable)	The main alternative to this project would be to "do nothing" and continue with the status quo and not have the necessary mobile equipment to provide service in an emergency situation. It should be noted that the mobile unit station is available from a number of vendors. The procurement of the unit would be subjected to PowerStream's competitive bidding process. By having a mobile station available, it will serve to maintain power to customers when maintenance or repairs are required at a station. PowerStream's Reactive and Emergency reoair costs will be reduced as work could therefore be planned and performed under regular working hours.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 885,481



Project Code	Report Start Year	Number of Years	Scale
102180	2015	6	Dollars

Project Summary Report

Project Name

CIS Modifications

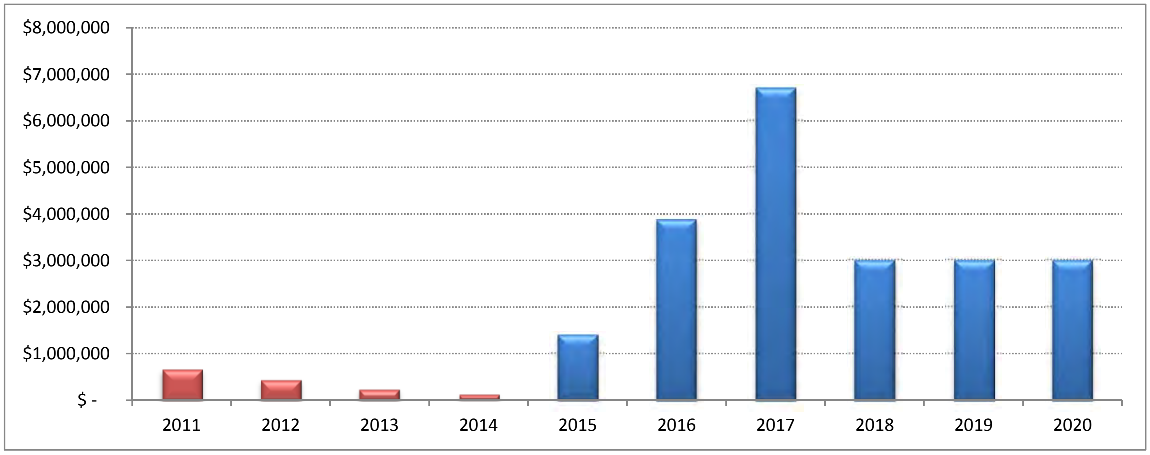
Major Category	**General Plant**	
Project Overview		
1. Additional Information	Service Territory	PowerStream North & South
	Location	PowerStream North and South
	Scope	CIS Enhancements - Regulatory and Business Driven Version Upgrade Hardware Upgrade CIS Interfaces
	Justification	To allocate capital dollars to ensure PowerStream's Customer Information System continues operate efficiently and meet the regulatory requirements. The enhancements represent normal capital upgrade to the CIS system that meets regulatory requirements and operational needs.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Ensure proper project management and solftware development lifecycle processes are adhered, along with a steering commitee, vendor management, evaluation criteria & priority.
	Comparative Information on Equivalent Historical Projects (if any)	PowerStream's CCB target go-live date is Apr 2015. Based on the number of continuous changes in the legacy system, PowerStream expects the same for the new CC&B system.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	Enhancement to application to support process improvement and regulatory requirements. 1) Upgrade the version of software. 2) Hardware upgrade
	1a. Main Driver	Customer Service. Improve processes, customer experience and regulatory compliance.
	1b. Priority and Reasons for Priority	Not Applicable.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Not Applicable.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Impact of Deferral/"Do Nothing" Option	Not Applicable.
	Net Benefits of Project in Monetary Terms (where practicable)	Not Applicable.

Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	102180	2015	6	Dollars

Project Name

CIS Modifications

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ 654,419	$ 423,082	$ 220,853	$ 107,203	$ 1,403,400	$ 3,884,100	$ 6,708,900	$ 2,996,000	$ 2,996,000	$ 2,996,000



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	101991	2015	6	Dollars
	Project Name			
	CIS Replacement Project			

Major Category General Plant

Project Overview

1. Additional Information	Service Territory	PowerStream North & South
	Location	The Project will be developed and implemented at PowerStream's Jane Street Vaughan location. However, once implemented, the CC&B system will be accessible from all of PowerStream's work locations.
	Scope	The Customer Information System ("CIS") Replacement Project implemented Oracle's Customer Care and Billing ("CC&B") software to replace the former T&W Info-Systems Ltd. ("T&W") CIS System along with the integration of approximately 20 existing ancillary systems linked to the CIS. The T&W CIS System was over 30 years old, utilized outdated technology, was difficult to maintain and was no longer sustainable. PowerStream had no viable option but to replace the T&W System due age and obsolescence of the system and the critical nature of the CIS in billing and supporting customers. The CIS System replacement is one of several initiatives outlined in Powerstream's IS Strategy and supports the Company in addressing key business drivers such as providing efficient service, meeting evolving customer needs and market consolidation. Modernizing the CIS System by replacing it with a scalable system, based on leading technologies, allows PowerStream to apply innovation in order to harness technology as a strategic enterprise asset. The Oracle CC&B solution allows PowerStream to leverage technology solutions in order to streamline and automate core business processes and achieve operational excellence. A description of work related to the CIS Replacement Project was included in PowerStream's 2013 Electricity Distribution Rate Application, EB-2012-0161 (Exhibit B1, Tab 1, Schedule 5). At that time, the anticipated project cost was $34,495K, with a projected in-service date in the second quarter of 2014. The CIS replacement project was included in the capital funding envelope approved in the Ontario Energy Board ("Board") Decision and Order related to that proceeding, dated December 21, 2012. The CIS project is scheduled to be in-service in Q2 2015.
	Justification	Implementation of the new Oracle CC&B system: - was essential given the technological age, unsustainability and limited flexibility of the former T&W System - provides PowerStream with the flexibility to meet its current and future business requirements; - allows PowerStream to meet regulatory and industry changes along with data management requirements in a cost effective manner; - utilizes out-of-the-box CC&B Software functionalities (as defined in the Implementation Scope of Work (SOW)) to standardize business process where possible - re-engineers PowerStream's business processes to align with industry best practices, as established by the new system; - provides scalability to meet future customer growth; - effectively integrates the CC&B System with PowerStream's technology, architecture and infrastructure; and - implements a documented data model that is scalable, open, and available to other enterprise applications and functionality.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Project Risks were managed through the following practices: - structured project governance with strong executive support - a core project team with best resources - timely monitoring and reporting of project status (e.g. scope, schedule, cost) – within project team and to PowerStream senior management and Board of Directors - a communication plan for various stakeholders - scope change management and control process - organizational change management, linking human resources to best practices - well defined functional requirements - minimizing complex product customisations and changes - ensuring accuracy of data migration - tracking and reporting of benefits
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.

Project Summary Report	Project Code **101991**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name CIS Replacement Project			

	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	The CIS is a critical and comprehensive business system for PowerStream. The Legacy CIS was over 30 years old, owned by PowerStream and supported on site by the vendor, T&W. The principal of T&W was past normal retirement age and continued to lead the support of the system and retain the knowledge of the core programming. The Legacy CIS System had been heavily customized over the years with very limited documentation related to these customizations. The Legacy CIS provided the full meter-to-cash applications required to meet a core business mandate of providing services related to account management, billing, collections, payments, meter management and meter reading. It was also a hub system providing inbound and outbound information to approximately twenty other interface systems both internal and external to PowerStream. PowerStream's core Legacy CIS System had further evolved through the series of amalgamations, mergers and acquisitions with Markham Hydro, Hydro Vaughan, Richmond Hill Hydro, Aurora Hydro and Barrie Hydro. In addition, frequent changes to the Legacy CIS System prompted by government initiatives amongst other requirements, were putting customers and the Company at too great a risk for system failure. The Legacy T&W CIS System served PowerStream well, however it had reached its limits in terms of technological support and further development. In 2011, PowerStream purchased an Oracle Customer Care and Billing (CC&B) System to replace the existing T&W System that was no longer viable. This purchase was based on a review and assessment of needs, functionality and a formal evaluation process. Other LDC's that had recently replaced or were considering replacing their CIS were consulted in order to determine the best system solution for PowerStream. Oracle was chosen as the successful vendor after an evaluation alongside a SAP customer system solution. Subsequently, an RFP was issued to select a vendor to integrate the system which was the largest single cost of the overall project. The CC&B Solution is comprised of Oracle's Customer Care and Billing System Version 2.3.1 and Oracle's Custom Code for the Ontario Market (CCOM). The Project was structured into two phases each governed under a separate contract with the System's Integrator (CGI Inc.). The first phase was "Discovery". The Discovery Phase identified gaps between the current state represented by the legacy T&W System and the future or desired state represented by the CC&B Solution. This process was executed in a series of facilitated working sessions that focused on key functional areas, for example each session addressed a designated system area such as Billing, Credit & Collections and Customer Care, etc. The outputs from these sessions were used to establish business rules and configuration parameters and design decisions to be applied to the future state system. The duration of this phase was six months. The Discovery phase mapped all functionality of the Legacy CIS. Where required functionality was not
	1a. Main Driver	Customer Service
	1b. Priority and Reasons for Priority	Not Applicable.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Not Applicable.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.

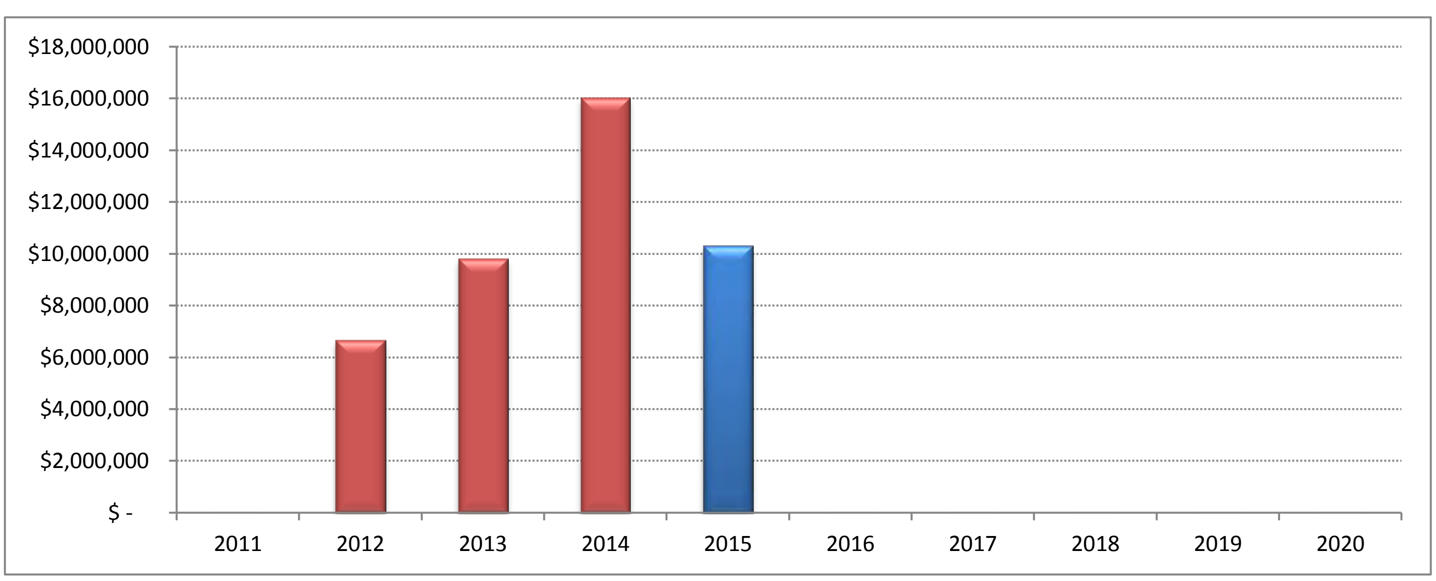
Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	101991	2015	6	Dollars

Project Name

CIS Replacement Project

5. Category-Specific Requirements for Each Project/Activity (OEB)	Impact of Deferral/"Do Nothing" Option	(1) The intellectual knowledge of the core T&W programming resides with one individual who is the principle and long-time staff of T&W. The loss of this individual would seriously impede the ability to continue to make the necessary modifications for regulatory or business requirements or future M&A opportunities. Specific T&W staff have some knowledge of core program functionality but further training and development of these and other staff is required to mitigate this risk. Even with this, PowerStream is at risk for support from a small single vendor. (2) Compounding this matter is the lack of documentation with no easy way of fixing this without pulling key knowledgeable staff off of normal maintenance duties. (3) The system has reached its capacity. From a pure number of customers perspective, it was used at Toronto Hydro with ~450,000 customers. The system, though, is overly customized making it unrealistic to sustain any further substantial growth. (4) Being 1970's vintage, the T&W product is a "green screen" technology written in Basic which makes it considerably more cumbersome to enhance for automation and integration of new technologies compared to the newer table driven and configurable software available today. PowerStream's customer satisfaction can be expected to remain as is (at best) but will be at risk to deterioration when compared to other large LDCs who have implemented more comprehensive state of the art systems with more customer care and self-serve functionality than exists in T&W. PowerStream's annual maintenance and capital costs can be expected to increase as new modifications are required to be made to an already highly customized system. The adoption of the status quo approach is attractive in the immediate timeframe as it avoids the capital cost of implementing a CIS replacement solution. It can be expected though that PowerStream will eventually have to adopt a replacement CIS to stay abreast of current and emerging CIS needs and to support its growth aspirations. Any capital costs incurred to modify the existing CIS will be wasted if a replacement CIS solution is ultimately required. Maintenance costs for the existing system will also increase due to age and complexity of changes required to meet regulatory requirements.
	Net Benefits of Project in Monetary Terms (where practicable)	Being part of an Oracle users group will allow greater influence on proposed regulatory changes and how they are implemented and put into production. This greater level of influence presents opportunities to achieve changes in more cost effective ways to the benefit of the organization and our customers. The new system offers a number of predefined reports and the ability to conduct more effective had hoc reports compared to the existing system. This will allow the ability to drill deeper into processes in order to conduct custom analytics that will be used as part of the divisions efforts towards continuous improvement and cost savings. Currently this type of analysis requires custom programming by our vendor T&W which is often a lengthy and expensive process. Although not proven, this system has the potential to reduce the need to increase future staff resources due to the inherent efficiencies and improved functionality built into the system.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ 6,651,576	$ 9,802,211	$ 16,013,679	$ 10,300,000	$ -	$ -	$ -	$ -	$ -



Project Summary Report	Project Code **102968**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name JD Edwards Application Upgrade			

Major Category **General Plant**

Project Overview

1. Additional Information	Service Territory	PowerStream North & South
	Location	161 Cityview Blvd
	Scope	JD Edwards is PowerStream's Enterprise Environment System. The scope of this project is to RFP to select the vendor to assist in the upgrade, and the implementation of the upgrade.
	Justification	Gain benefit of new features within the version upgrade. Maintain a more current release of the product ensuring Oracle supportability.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2019
	Parent WO#	311281
	Job Number	C14051
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Supportability of the core financial system becomes problematic after extended support expires. The timing on this project is to dovetail into the end of support for the current version, into the latest version regaining 5 years of supportability. By not moving forward, the risk of issues occurring with a long delay in resolution is high.
	Comparative Information on Equivalent Historical Projects (if any)	Keeping software current is a best practice scenario, allowing for current release benefits, as well as ease of interoperability.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	Embark on an RFP to either upgrade or replace our existing JD Edwards platform. Decision to replace may result in a longer term project than planned. Upgrade of existing to new will follow past practice methods of implementation of upgrades.
	1a. Main Driver	Capital Investment Support. The supportability of the current level of JD Edwards will be ending. The intention of this project timing is to dovetail into the end of support on the old, and introduce the latest version of the software, regaining 5 years of supportability. Subsequent factors include taking advantage of new technology changes in the system from the previous version, resulting in improved productivity within the application.
	1b. Priority and Reasons for Priority	Pushing software past its supportability is not without risk. There are ways to mitigate this risk, however the longer you go past the date, the harder it becomes to mitigate.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Detailed review of benefits as well as the overall project will be handled the year prior to the actual planned upgrade.
	2. Safety	There is no perceived benefit or degradation to safety.
	3. Cyber-Security, Privacy	Implementation of the newer system may result in better security options, limiting exposures that may be present in the existing system.
	4. Coordination, Interoperability	Having newer systems results in smoother interoperability with newer systems. The further out of sync a system is, the tougher it is to work with other, newer systems.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	No perceived environmental impacts, positive or negative.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Impact of Deferral/"Do Nothing" Option	Increased risk of issues as a result of system failure, or regulatory changes.
	Net Benefits of Project in Monetary Terms (where practicable)	By keeping the software updated, issues with the software will be supported and corrected by the vendor. This allows PowerStream to avoid having to contract a 3rd party contractor for fixes and patches when the system is no longer supported by the original vendor.

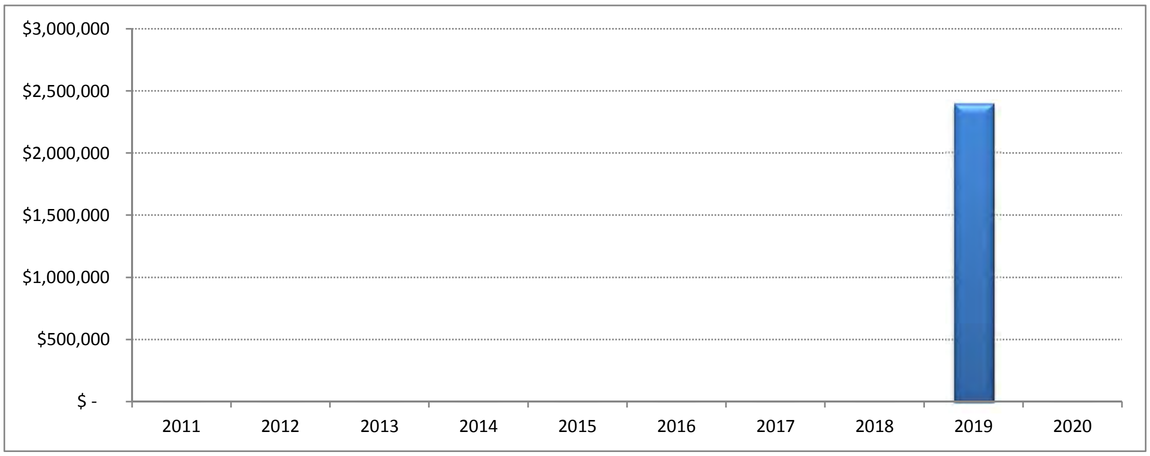
Project Summary Report

Project Code	Report Start Year	Number of Years	Scale
102968	2015	6	Dollars

Project Name

JD Edwards Application Upgrade

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,396,800	$ -



Power Stream	Project Code	Report Start Year	Number of Years	Scale
Project Summary Report	**103204**	**2015**	**6**	**Dollars**
	Project Name			
	MSBPI Microsoft Business Productivity software			

Major Category **General Plant**

Project Overview

1. Additional Information	Service Territory	PowerStream North & South
	Location	PowerStream North and South
	Scope	This project is to upgrade Microsoft Business Productivity software (Word, Excel, Access, Powerpoint, Project, Visio, SharePoint, etc.)
	Justification	Improve productivity of end user with up to date technology, increase security with current security standards, and improve/provision compatibility with new technologies.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2016
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Risks to completion include resourcing and priority.
	Comparative Information on Equivalent Historical Projects (if any)	PowerStream last did a MSBPI upgrade in 2011 - cost and improved functionality documented.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	Improve productivity of end user with up to date technology, increase security with current security standards, and improve/provision compatibility with new technologies.
	1a. Main Driver	Capital Investment Support. Improved end user productivity and security of processing information.
	1b. Priority and Reasons for Priority	Ensure that security is current as well as take advantage of new technology to improve productivity.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Realistically, technical project alternatives will be reviewed at project initiation. But, the alternative to remaining status quo is unacceptable as technology advances will have compromised security and interoperability of existing systems.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Upgrade end user tools to current technology standards.
	4. Coordination, Interoperability	Upgraded systems are crucial to interoperability with other systems as rapid technological advances require that these systems are upgraded to current standards in order to work with any new technology (introduced or desired to be introduced at PowerStream).
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Impact of Deferral/"Do Nothing" Option	The alternative to "do nothing" is not a viable alternative - security of old systems are continuously compromised as technology advances, and our systems have to be improved to keep pace.
	Net Benefits of Project in Monetary Terms (where practicable)	This initiative is based more to address the risk associated with the necessity to keep current with advancing security and technology standards than to increase net monetary benefit.

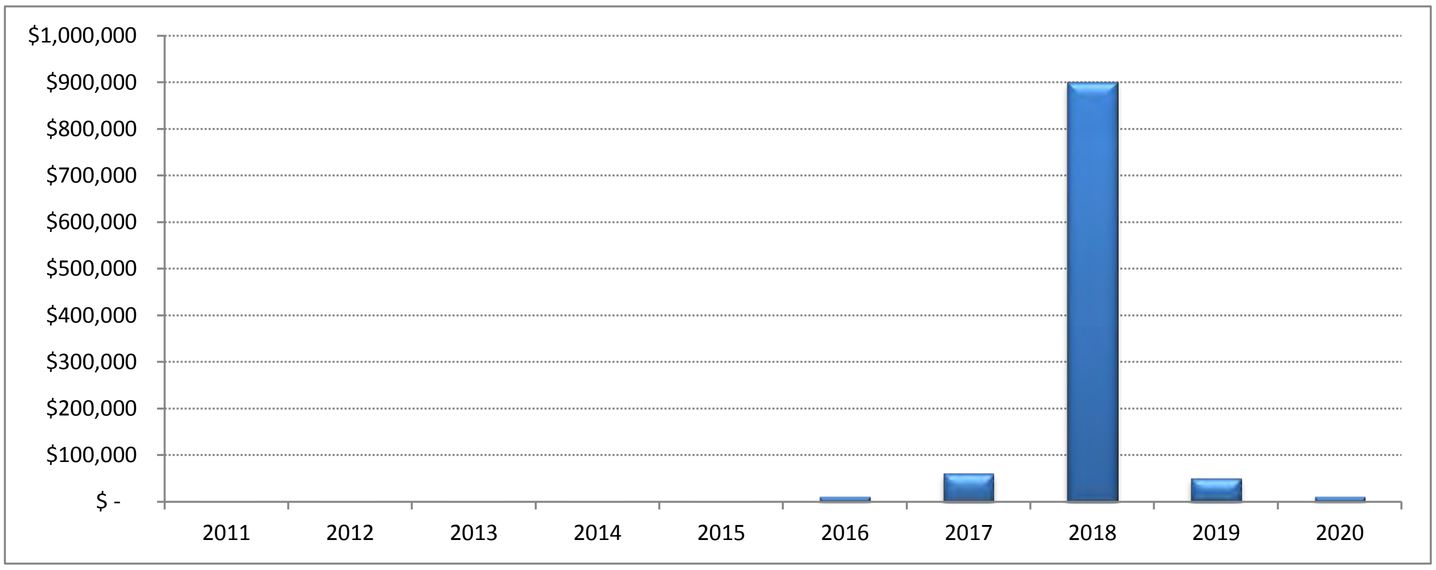
Project Summary Report

Project Code	Report Start Year	Number of Years	Scale
103204	2015	6	Dollars

Project Name

MSBPI Microsoft Business Productivity software

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ 10,000	$ 60,000	$ 899,999	$ 50,000	$ 10,000



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	102169	2015	6	Dollars

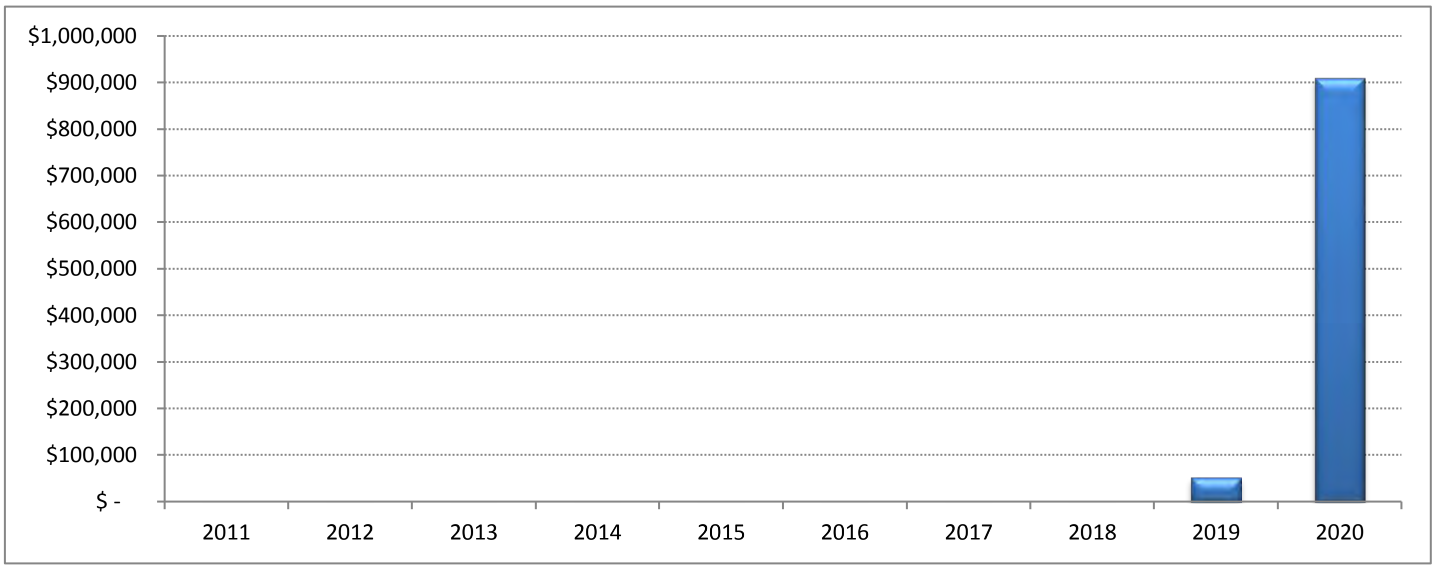
Project Name

Phone System Enhancement Upgrade

Major Category	General Plant	
Project Overview		
1. Additional Information	Service Territory	PowerStream North & South
	Location	PS North and South
	Scope	The scope of this project is to implement a complete Phone System Enhancement Upgrade.
	Justification	New functionality is required to support business needs, existing phone system will be out of support and will be approaching 5 years old at the time the new system is implemented.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2019
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Risks are anticipated to be minimal. PowerStream has completed large phone system upgrades in the past with no incidents. Full Implementation Plans and Risk Mitigation Plans are in place at all time throughout the project.
	Comparative Information on Equivalent Historical Projects (if any)	A similar system upgrade was completed in 2013 at a cost of $380,000 but did not include phone handsets.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	This project encompasses the hardware and software upgrades of main servers and handsets as per recommendations for 2018 telecommunications planned review. This will include expanded licensing and enable the acquisition of additional phone sets to support growth.
	1a. Main Driver	Customer Service. At time of implementation, the current phone system will be at the end of supportability (purchased and rolled out in 2013) - 5 years in production. The phone system is central to PowerStream's business as it provides the main contact center for customers as well as Outage Management. Any downtime would effect the way PowerStream communicate with them. PowerStream needs to ensure the system is current, supportable and maintains enough capacity to support the business. Also needs to be able to allow for growth and support EPP/pandemic/large scale outages and a work from home solution.
	1b. Priority and Reasons for Priority	PowerStream rates this as a high priority for 2019/2020 because if the system is no longer supported and it goes down, PowerStream would have to activate external support. If the system couldn't be internally fixed PowerStream would have no choice but to upgrade and the downtime would be significant.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	No suitable alternatives exist to allow for an objective analysis. An alternative could be to do nothing until the system fails, but would run the risk of incurring various issues and not being able to fix them.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	This project will ensure the new system is able to integrate as needed, such as with Exchange and IVR system. PowerStream will need to ensure scalability to meet evolving business needs.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Impact of Deferral/"Do Nothing" Option	"Do nothing", is not a feasible option as the call center and outage management calls relies on the phone system. However, if PowerStream did not upgrade the phone system, it risks potential system failure and long duration of phone system outage.
	Net Benefits of Project in Monetary Terms (where practicable)	Not Applicable.

Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	102169	2015	6	Dollars
	Project Name: Phone System Enhancement Upgrade			

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 50,500	$ 908,999



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	102009	2015	6	Dollars

Project Name

Storage Expansion (Data)

Major Category	**General Plant**	

Project Overview

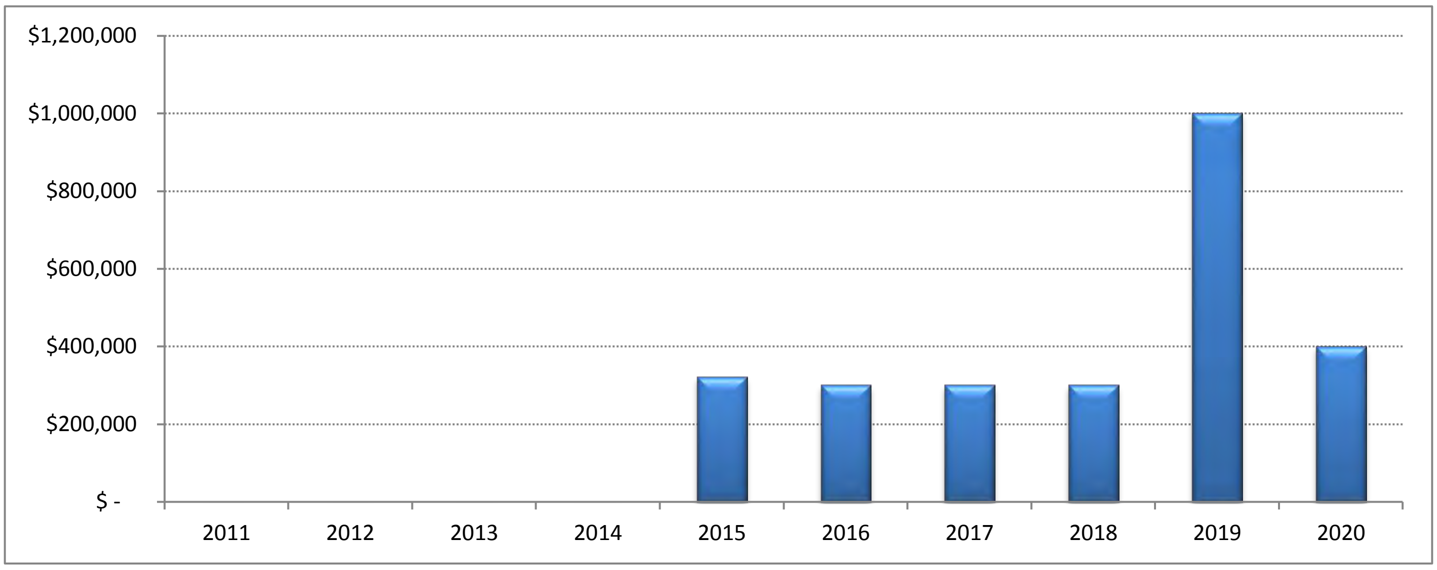
1. Additional Information	Service Territory Location	PowerStream North & South Cityview & Addiscott
	Scope	To provision for data storage growth (in Production and DR environments)
	Justification	PowerStream IS is required to provide data storage to accommodate all necessary aspects of the PowerStream corporate systems and corporate data. PowerStream's data growth rate through additional data and new systems is in line with industry average of 50% per year, this entails that each year PowerStream IS must provision data storage infrastructure to meet this growing demand. Because technology and pricing of technology changes drastically from year to year, it is most effective it PowerStream IS plans and expands this data as required - as opposed to provisioning for future years. Beyond simply providing storage space, other factors are required, such as; Optimum performance of data writes and retrieval, Tools to manage the data effectively, minimizing excessive and unnecessary data growth, High level of uptime and availability, minimize impact in a Disaster scenario, and provide an easy means for Business Continuity. With that, the primary objectives of Storage Expansion are; 1. Provide appropriate SAN data storage capacity and performance for the key Strategic initiatives coming in the near future (i.e. Customer Information System, Asset and Inventory Management System & Work Force Management System, to highlight the top four items) 2. Provide appropriate SAN data storage capacity and performance to accommodate organic data growth of the existing Systems currently on the SAN (i.e. email, GIS, OMS) 3. Provide a scalable disk storage system to support PowerStream's annual growth rate, as well as new planned and unplanned Systems 4. Continue to provide Disaster Recovery and Business Continuity of all key systems on the SAN and their respective Corporate data that these systems contain. 5. Provide SAN specific monitoring and management tools to manage the SAN System and specifically Data growth. Moore's Law states that computer technology will double every 2 years, this was stated and has proven accurate since 1975. Based upon that computer hardware is a very perishable commodity, therefore PowerStream purchased a SAN (in 2013) that was scalable with plans to purchase required hardware each year to meet business data growth requirements. Historically, computer hardware has doubled every 2 years with the price remaining the same, the year over year price per TB (Terabyte) of storage drops by roughly 25%, keeping in mind that our data needs grow at 50% we have budgeted each year to purchase more storage hardware.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	309881
	Job Number	C13056
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	No risks to the completion of this project have been identified.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0

	Project Code	Report Start Year	Number of Years	Scale
Project Summary Report	102009	2015	6	Dollars
	Project Name: Storage Expansion (Data)			

4. Evaluation Criteria (OEB)	Project Summary	Every component of PowerStream's Corporate Infrastructure has at least one touch point to the SAN (Storage Area Network - a centralized system of Storage devices, i.e. Hard Drives). Each System is allocated storage space on the SAN, either for the "data" only, or as well as including the Server Operating System (OS) files and the data. Every user within PowerStream is allocated and uses storage space on the SAN. Any data that is entered in any system, emails that are sent and received, as well as logs generated by intelligent devices are stored in the SAN. From an Information Technology perspective corporate data is our most valuable and irreplaceable asset, systems can change but customer data, meter data, grid data, once collected must be safeguarded and saved for future use. Every component of PowerStream's Corporate Infrastructure has at least one touch point to the SAN (Storage Area Network - a centralized system of Storage devices, i.e. Hard Drives). Each System is allocated storage space on the SAN, either for the "data" only, or as well as including the Server Operating System (OS) files and the data. Every user within PowerStream (including contractors, summer students etc.) are allocated storage space on the SAN, primarily for business files and communication data (email, voicemail). Organic growth coupled with planned growth and the trending of SAN storage space is an increasing curve. The industry average for data growth is listed at 50% year on year; This translates into a large volume of data with no "plateau" in the foreseeable future. PowerStream data metrics show that they are following in line with the industry average. Other factors, such as new initiatives or mergers could increase this requirement significantly. PowerStream purchased and implemented a new state-of-the-art SAN in 2013 robust SAN solution in 2013. This SAN has been designed to be scalable to serve PowerStream for 5 years based upon current organic growth rates of the business and the past associated data growth rate. When purchasing the SAN in 2013 it was initially sized to successfully meet business growth through 2014, to have the scalability to meet business growth through 2018 based upon IS adding the necessary capacity to meet growth each year. The goal is to purchase data storage space as required to meet (and stay slightly ahead of) business requirements.
	1a. Main Driver	Capital Investment Support.
	1b. Priority and Reasons for Priority	Not Applicable.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Not Applicable.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Available.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable
5. Category-Specific Requirements for Each Project/Activity (OEB)	Impact of Deferral/"Do Nothing" Option	If this project does not proceed, a new initiative that included saving or utilizing electronic data would be hampered. As well, PowerStream could be in conflict with regulatory compliance with the OEB or Ministry of Energy if we are unable to store certain customer, meter or financial data.
	Net Benefits of Project in Monetary Terms (where practicable)	Cost savings by maintaining PowerStream's ability to store required data and meet its regulatory obligations as well as maintain or improve its customer data and customer satisfaction ratings. Operating - Soft Financial Benefits 2015 - $820,000 2016 - $828,200 2017 - $836,482 2018 - $844,847 2019 - $853,295 Soft Financial Benefits are calculated by employees saving/effectively utilizing 40 hours each per year due to having sufficient access to system data due to Storage Expansion. Every employee at Powerstream accesses and created business data ever working day. Many of the systems that require this data are critical to the daily operation of the business, and the above estimate is that for each employee utilizing technology to help perform their daily job function as opposed to performing in manually saves 40 hours per employee per year.

Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	102009	2015	6	Dollars
	Project Name	Storage Expansion (Data)		

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ 321,000	$ 300,000	$ 300,000	$ 300,000	$ 1,000,000	$ 400,000



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	102263	2015	6	Dollars

Project Name

Work Force Management / Mobile Dispatch

Major Category **General Plant**

Project Overview

1. Additional Information

Service Territory: PowerStream North & South

Location: PowerStream North & South

Scope:

This is part of a multi-year plan involving AM/Mobile/WFM/AA&PO Solution. Powerstream does not have an enterprise workforce or work flow management solution. JDE in combination with FileNexus is used to house specific project information and work instructions. Work process flow is managed through a multitude of ways including Access Database, JDE, CIS, Excel and FileNexus. JDE in combination with Executive Console is used to provide project costing and resource usage information on specific projects. This information is used upon project closing but reviewed minimally through project execution. Any scheduling that is done is completed using Excel and/or Microsoft Project. Much of the work lands on the Field/Trades Supervisor's desk and they manually sort through and decide which projects go on which day. There is little communication or information available while a project is executing and resource information is limited and difficult to put together to get insight and control around much of the work that is occurring. Productivity is lost through unnecessary extra field trips, scheduling errors and less than optimal resource allocation. It was identified during the discovery phase of the New CIS project that the new Customer Care and Billing (CC&B) software cannot support the work flow process for New Services that currently exists within the T&W CIS System.

An interim, temporary solution is to keep a portion of the T&W running to manage the work flow for New Services. This is planned to be a short term (2-3 years) solution until a permanent solution can be put in place. With respect to mobile dispatch and reporting, PowerStream has made an initial investment into a mobile workforce solution and has used the solution for implementing smart meter deployment. The solution uses handheld field devices. Other uses of mobile have been or are being implemented - e.g. Mobile GIS; Mobile DigSmart; Mobile Responder. These implementations are through the use of tough books or laptops. Since PowerStream does not have a mobile workforce solution, most of the workforce receives their work instructions through paper. Work instructions are entered into JDE and /or filed in FileNexus and have to be printed out. The paper is taken to the field for staff to review. Additional information on projects may or may note be available depending upon what was printed. Staff report time spent and vehicles used on the projects using paper time sheets. Information about material installations and replacements is done through the AEx, which is a new in-house designed tool to allow computer based in put of the required information. There are still a number of installations that are not being recorded. Staff report findings on inspections or outages etc. on various paper forms. The forms are then brought into the office and entered by various staff into JDE, GIS, Responder or Excel spreadsheets. The information, once entered into the systems, is sometimes entered incorrectly. The information, once entered is sometimes difficult to find, difficult to pull for analytical purposes and only available to limited individuals.

Justification:

In 2011 PowerStream developed an IT Strategy. It was updated in 2012 and in 2013. The strategy identified four solutions to be considered for implementation over 2014 & 2015. These solutions were Asset Management; Mobile Workforce; Workforce Management; and Asset Analytics and Project Optimization. There are three main drivers for changing the status quo. First - the current systems and processes in place are combined systems and practices from predecessor utilities. They have served the predecessor utilities well. As smaller utilities using programs such as Excel, Microsoft Project, Access Database, paper, etc. to manage assets and work, it was easier as the volume of data and work was more manageable and the number of people involved in the process needing access to the data were fewer. With increased staff, assets, projects, and geography those tools are no longer viable to be used. Second - the regulatory environment and customers demand that utilities continue to gain efficiencies in the execution of the work. Specific targets are set by the regulator for improved efficiencies. Improved workforce management and processes/systems for data capture and analytics is an area where efficiencies can be gained through the implementation of new systems and processes. Third - the regulatory environment is placing increased demands for solid analytics in defending appropriate spend levels. In order to provide sophisticated analytics, new tools and processes are required to ensure current and historical data is fully available, and to aid in the efficient and effective completion of the analysis.

Power Stream **Project Summary Report**	Project Code **102263**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Work Force Management / Mobile Dispatch			

		In 2013 PowerStream undertook to perform a high level needs analysis of these four solutions and subsequently developed a high level implementation plan. As a result of this work it was identified that there is a need to purchase new systems software and implement new processes for Workforce Management, Work Flow Management, Mobile Dispatch and Mobile Reporting. This work is of priority as the current systems in these areas are largely paper based. There is some use systems of JDEdwards, FileNexus, Excel and Access Databases for Workflow Management. The systems are not integrated and information can be entered in multiple systems. It is believed that efficiencies can be gained in a multiple of ways through the implementation of new technology. These include: reduced input of information multiple times, reduced number of process steps and wait times in the execution of work with one source for project information; increased efficiency in crew scheduling with optimized drive times, and optimized schedules filling in the small gaps of time with appropriate work. These pieces can be defined as: Workforce Management A technology solution that enables resource managers to allocate, schedule & assign work to resources. The solution would include the ability to report on crew/individual performance in the completion of the work. Workflow Management A technology solution that provides an easy way to track a project through various stages, milestones & triggers. The solution would allow capture of all necessary project information & allow the sending of automatic emails upon specific trigger events Mobile WFM The ability to interface with the Work Management System to automate dispatch of jobs. The solution includes the ability to view work instructions electronically & report on job completion, asset information & timesheets in the field, at time of job completion.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	311271
	Job Number	C14042
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	At present, PowerStream does not have a computerised WFM system, so this is a new tool to be implemented. The new system will impact several Departments, particularly Lines, Metering, Engineering, and Customer Service. The system will have to integrate with other enterprise systems, such as JDE and OMS. Change management will be required for employees to adapt to the new tool. IS resources will be required to support the implementation. PowerStream has adopted a systematic and prudent approach to this project. The WFM tool will be phased in over several years, with implementation commencing in 2015. Planning activities are being undertaken in 2014. A cross-functional Project Team, comprising key stakeholders from across the company, has been assembled and a Project Governance model is in place. A consultant will be engaged to assist the Project Team with the identification and analysis of needs, opportunities for improvement, and benefits. The consultant will be a subject matter expert in the WFM field, and will also assist the team to understand the relative strengths and weaknesses of various solutions available on the market, as well as lessons learned from similar WFM implementations. A detailed project plan will be prepared with clearly defined project phases, goals, and timelines. Existing business processes are being documented in detail and opportunities for streamlining and automation will be explored. A change management plan will be prepared and executed to ensure that employees are engaged in the change process and adopt the new tool. Mobile technology (that is, field computing devices and accessories) is a critical component of this project, as it enables real-time, digital communication with field resources. The implementation of Mobile technology in the field is part of the WFM project, and key leaders of the Mobile initiative are also part of the WFM Project Team. This ensures that there is alignment of goals and activities of the two initiatives. IS resources are also part of the Project Team, which will ensure that IS resources are available to support the WFM project and also that critical issues such as security are addressed.
	Comparative Information on Equivalent Historical Projects (if any)	PowerStream has successfully managed the implementation of several significant computerised systems, including SCADA, Outage Management System, GIS, and the C55 Optimiser system. PowerStream is presently undertaking an upgrade to its enterprise Customer Information System.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0

Power Stream — Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	102263	2015	6	Dollars
	Project Name: Work Force Management / Mobile Dispatch			

4. Evaluation Criteria (OEB)	Project Summary	The WFM Project will include the following functionality: •Computerised tool to schedule jobs and allocate resources, with the ability to automate some functions; •Electronic dispatch of jobs to field crews; •Real-time tracking of jobs while in progress; •Tracking of crew schedules and performance; •Electronic recording and transmission of field data; •Automation of processes such as timekeeping; and •Route optimisation.
	1a. Main Driver	Capital Investment Support. Process improvements in terms of how work is dispatched to the field; improved resource allocation and job scheduling; achieve insight into how work is executed and gain efficiencies.
	1b. Priority and Reasons for Priority	This project is ranked as high priority because the volume and variety of capital and maintenance activity at PowerStream has reached levels where a computerised tool is required to assist resource managers with resource allocation, job scheduling, and dispatch. At present, these activities and associated workflow processes are primarily manual, labour-intensive, and paper-based. The implementation of a computerised tool will facilitate process automation, streamlining, and improvement. The new tool will allow jobs to be scheduled (or rescheduled) and dispatched more efficiently. The WFM system will also provide insight into how work is carried out into the field and provide data on crew performance, thereby allowing analysis into how productivity can be improved.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	The alternative to this project is to maintain the status quo and continue to rely on manual, labour-intensive workflow, resource allocation, and scheduling processes. Data on how field crews carry out work would continue to be not readily available. Maintaining the status quo is not considered acceptable because PowerStream would forego the opportunity to realise efficiencies and improve productivity.
	2. Safety	This project will not have an adverse impact on personnel or public safety. Safety will be considered throughout the project, and particularly for the Mobile aspects of the project. For example, field computers will be mounted in vehicles in a manner that is not detrimental to employee safety or wellness. In addition, technical options are being explored to prevent a driver from using the field computer while the vehicle is in motion.
	3. Cyber-Security, Privacy	The WFM system will be a critical system that interfaces with other enterprise tools such as JDE, OMS, and CIS. Issues of cyber-security and privacy are therefore of critical importance. The Project Team will work closely with IS and the successful vendor to ensure that these issues are addressed.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Environmental benefits are anticipated, in the form of reduced carbon dioxide emissions from fleet vehicles due to route optimisation. Specific benefits will be quantified in 2014 as part of the Planning phase.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Impact of Deferral/"Do Nothing" Option	Continue to rely on existing manual, labour-intensive workflow, resource allocation, and scheduling processes and forego the opportunity to realise efficiencies and improve productivity.
	Net Benefits of Project in Monetary Terms (where practicable)	This project is expected to yield net benefits in terms of productivity and efficiency. These benefits will be quantified as part of the 2014 Planning phase. Expected benefits include: - reduced time spent on allocating resources and scheduling jobs; - productivity gains in the execution of field work; - reduced fuel costs due to route optimisation.

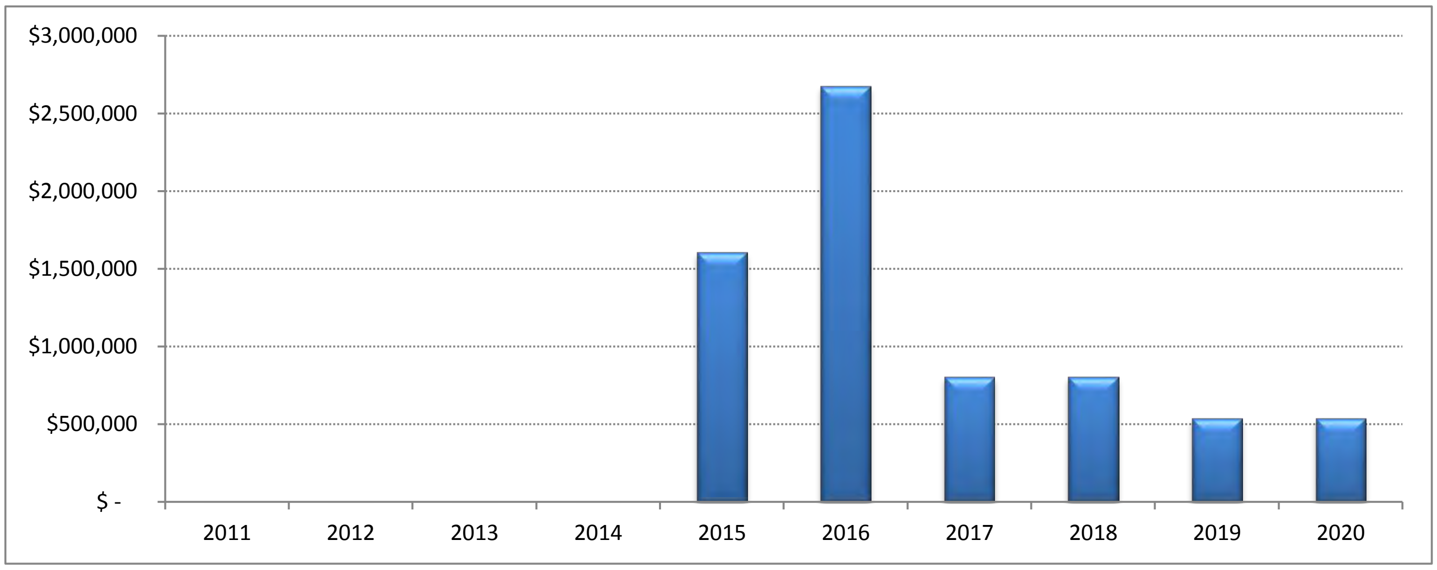
Project Summary Report

Project Code	Report Start Year	Number of Years	Scale
102263	2015	6	Dollars

Project Name

Work Force Management / Mobile Dispatch

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ 1,605,000	$ 2,675,000	$ 802,500	$ 802,500	$ 535,000	$ 535,000



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	104022	2015	6	Dollars
	Project Name: Barrie Building Renovation Project 2015			

Major Category	**General Plant**	

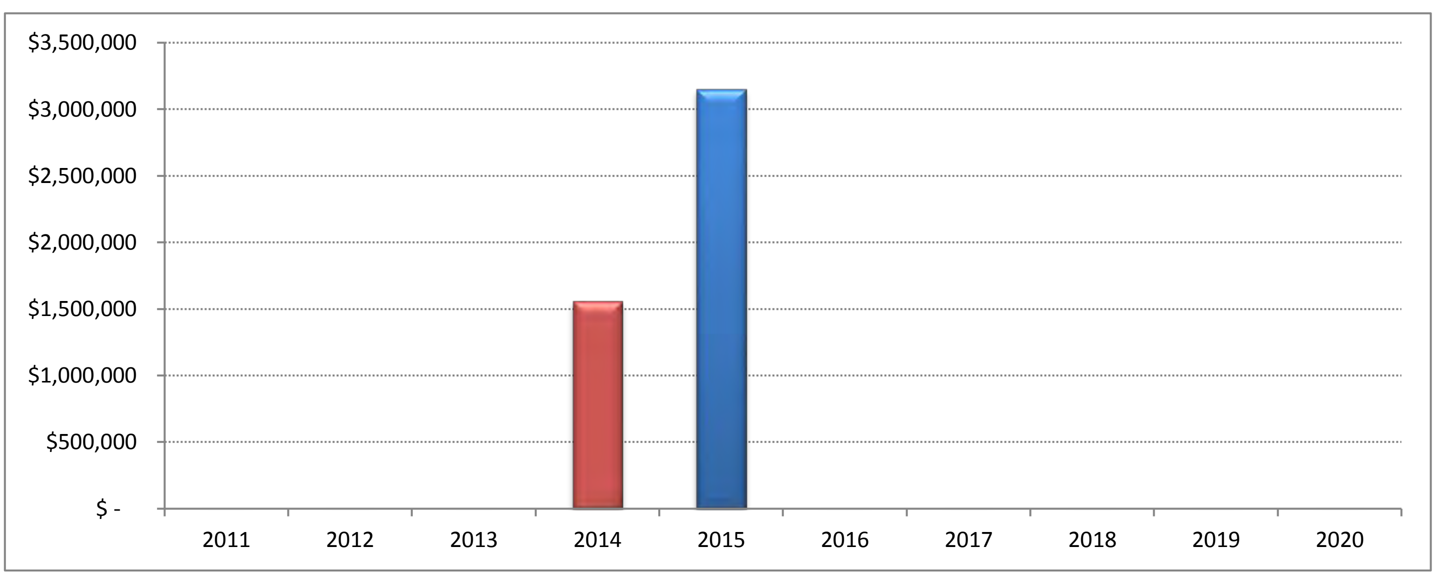
Project Overview

1. Additional Information	Service Territory	PowerStream North
	Location	55 Patterson Road, Barrie
	Scope	The scope of this project is to implement a renovation of the building and facilities at PowerStream's Patterson facility in Barrie. The Patterson Road facility operates as the North Operations Centre. It became part of PowerStream's facility portfolio as a result of the 2009 merger with Barrie Hydro. The building, constructed approximately 20 years ago on a 15.8 acre site, comprises an estimated 40,832 square feet of two-story office space together with 41,000 square feet of industrial space. similar to the make up of the Addiscott-Markham facility. The interior spaces require a reconfiguration and a "facelift" to improve the overall functionality of the office spaces as well as the quality of the interior environment. Offices and workstations at Patterson are not constructed to the same standards as other PowerStream locations. Furniture is general older, with some being hand-me-downs for other facilities. This should be addressed to provide uniformity, and ensure the staff in this building are being treated the same as those in other PowerStream buildings. Technology and connectivity in the Barrie office is considered to be below PowerStream standards. Meeting rooms are not fully equipped and there are no formal hotelling stations in the building. In updating the Patterson building, it will create an environment that is comparable in quality to the South Operations Centre at Addiscott - Markham. This will ensure all PowerStream work environments are aligned through the facility portfolio. The goal is to improve the space utilization and efficiency so that all teams are working within a defined space and not dispersed throughout the building. This renovation place also provides for future growth. The renovation will allow for the leasing of space on the 2nd floor to a 3rd party which will allow for the partial recovery of the lease hold improvements to the building.
	Justification	The Patterson building was constructed approximately 20 years ago on a 15.8 acre site, comprises an estimated 40,832 square feet of two-story office space together with 41,000 square feet of industrial space, and is similar in make up to PowerStream's Addiscott Court, Markham facility. CRESA was engaged to prepare the high level construction estimate documents that were submitted in the original Business Case. A formal tender was conducted to obtain a Construction Management company that would assist in the design and overall project management of the renovation project. Compass Construction Resources was the successful bidder. Part of Compass's Scope was to review the preliminary drawings and confirm PowerStream's original budget estimate.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	No risks to completion have been identified. The budget has been approved, and a contract with a general contractor is in place. All work required has been obtained through a formal tendering process.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable. No other PowerStream owned building has been renovated to this extent.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	Not Applicable.
	1a. Main Driver	Capital Investment Support

Power Stream	Project Code	Report Start Year	Number of Years	Scale
Project Summary Report	**104022**	**2015**	**6**	**Dollars**
	Project Name: Barrie Building Renovation Project 2015			

	1b. Priority and Reasons for Priority	The priority of this project is driven by the following factors. The offices and workstations at Patterson are not constructed to the same standards as other PowerStream locations. Furniture is generally older, with some hand-me-downs from other facilities. This is being addressed to provide uniformity, and ensure that staff in this building is being treated the same as those in other PowerStream buildings. A secondary activity was also undertaken along with the renovations, to review and determine the existing conditions of the current mechanical and electrical systems of the building. MMM Group was retained to complete the analysis and make recommendations. It was determined that there were significant mechanical upgrades required that should be made in connection with the current building renovations. This would minimize rework in the years to come after the original renovation has been completed, and would also bring forward repairs and upgrades that would have been required as stand-alone projects. This would help to eliminate reworking building upgrades that had just been completed and thereby reduce costs.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Not Applicable.
	2. Safety	New updated building automation systems are being added and security systems being upgraded, which should improve building safety.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	PowerStream is working towards obtaining LEED Existing Building certification.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Impact of Deferral/"Do Nothing" Option	The main alternative to this project is to "do nothing", which would result in no renovations or updates to the building. This will impact PowerStream's J2E (Journey to Excellence) as not all work locations would have the same corporate culture as a result of lack of standardization.
	Net Benefits of Project in Monetary Terms (where practicable)	There is a potential opportunity to lease extra space to a 3rd party tenant as a result of better space utilization.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ 1,556,753	$ 3,149,489	$ -	$ -	$ -	$ -	$ -



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	103358	2015	6	Dollars
	Project Name: Replace various Light Duty and Medium Duty Vehicles and Equipment			

Major Category General Plant

Project Overview

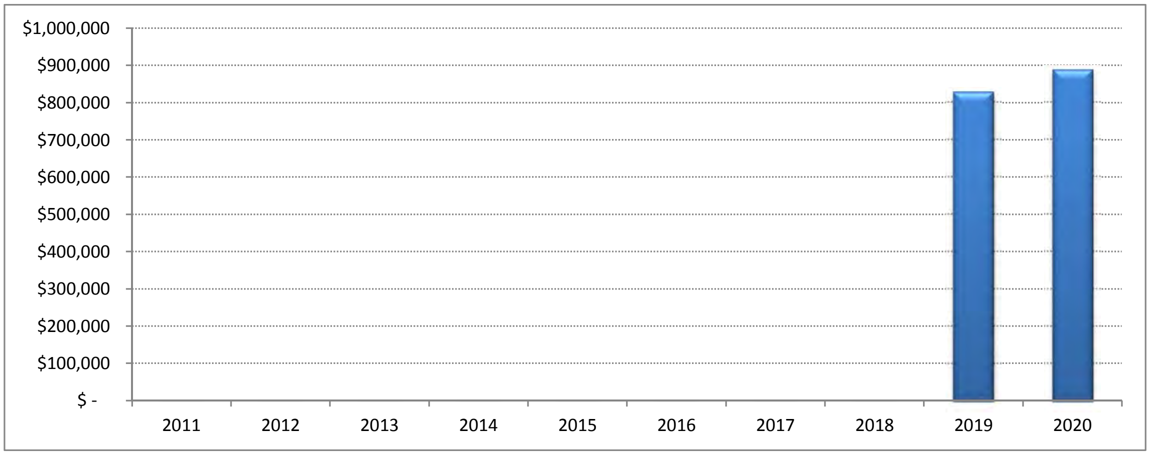
1. Additional Information	Service Territory	PowerStream North & South
	Location	North and South Various Departments.
	Scope	Replace 12 various Light and Medium Duty vehicles and equipment in 2019. Replace 16 various Light and Medium Duty Vehicles in 2020.
	Justification	Vehicles are expected to meet PowerStream's replacement guidlines.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2019
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Not Applicable.
	Comparative Information on Equivalent Historical Projects (if any)	Estimated costs are based on historical costs for similar vehicles. High-dollar vehicles are usually procured through RFP's (Request for Proposal), and after a thorough evaluation of the bids, the contract is awarded to the preferred bidder.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	Replacement of light duty vehicles.
	1a. Main Driver	Capital Investment Support. Present vehicles to be replaced have exceeded either their mileage, hours, or age thresholds.
	1b. Priority and Reasons for Priority	Not Applicable.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Light Duty Vehicle: 1. Cars, SUV's and Passenger Vans: Due for replacement when vehicle reaches 200,000KM and shows an upward trend in Unscheduled Maintenance cost for last three years. Also taken into account is the projected Unscheduled Maintenance cost based on technical assessment. 2. Pick-Up Trucks: Due for replacement when vehicle reaches 275,000KM and shows an upward trend in Unscheduled Maintenance cost for last three years. Also taken into account is the projected Unscheduled Maintenance cost based on technical assessment. 3. Miscellaneous Class: Pole Trailers 20 Years Tension Machine 15 Years Reel Trailer 15 Years Forklift 15 Years Traffic Signals – Technical Assessment on condition and estimated repairs. Loaders - Technical Assessment on condition and estimated repairs.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	If economically viable, the replacement vehicle may incorporate hybrid energy saving technologies, which could count towards Environmental Benefits.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Impact of Deferral/"Do Nothing" Option	While it is possible to keep older vehicles in service almost perpetually with additional maintenance and replacement of key components, eventually the cost to do so becomes excessive.
	Net Benefits of Project in Monetary Terms (where practicable)	Not Applicable.

Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	103358	2015	6	Dollars

Project Name

Replace various Light Duty and Medium Duty Vehicles and Equipment

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 829,250	$ 888,100



	Project Code	Report Start Year	Number of Years	Scale
Project Summary Report	**103357**	**2015**	**6**	**Dollars**
	Project Name	Replace various Single Bucket and Double Bucket Line Trucks		

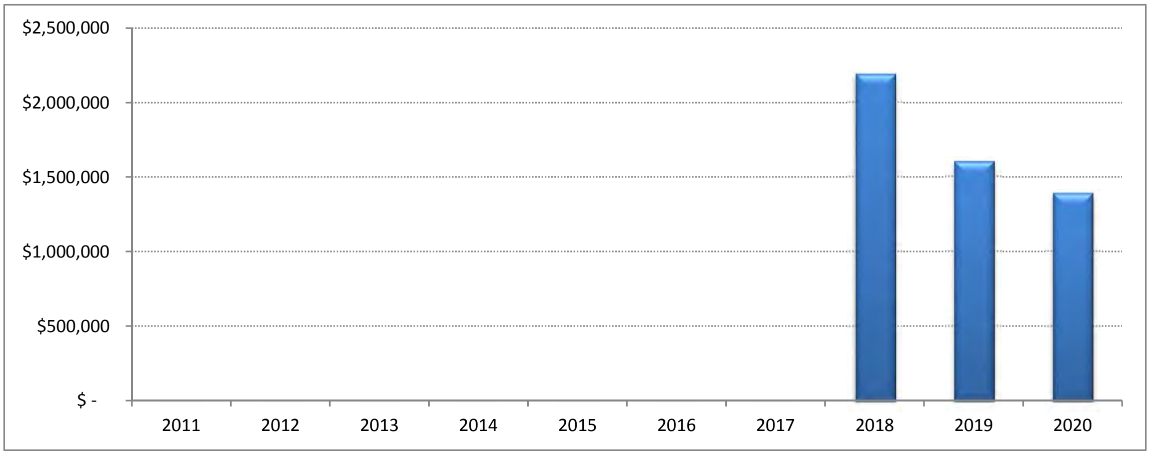
Major Category **General Plant**

Project Overview

1. Additional Information	Service Territory	PowerStream North & South
	Location	North and South Lines Dept
	Scope	Replace 1 single bucket and 3 double bucket trucks in 2018. Replace 1 single bucket and 2 double bucket trucks in 2019. Replace 1 single bucket and 2 double bucket trucks in 2020.
	Justification	Vehicles are expected to meet our replacement guidlines.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2020
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Not Applicable.
	Comparative Information on Equivalent Historical Projects (if any)	Estimated costs are based on historical costs of similar vehicles. High-dollar vehicles are usually procured through RFP's (Request for Proposal), and after a thorough evaluation of the bids, the contract is awarded to the preferred bidder.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	Replacement of single-bucket and double-bucket line trucks.
	1a. Main Driver	Capital Investment Support. Present vehicles to be replaced have exceeded either their mileage, hours or age thresholds.
	1b. Priority and Reasons for Priority	Not Applicable.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Replacement Guideline Heavy Duty Vehicle: Due for replacement when the vehicle reaches 250,000KM or 12000 Engine Hours and shows an upward trend in Unscheduled Maintenance cost for last three years. Also taken into account is the projected Unscheduled Maintenance cost based on technical assessment.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	If economically viable, the replacement vehicle may incorporate hybrid energy saving technologies, which could count toward Environmental Benefits.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Impact of Deferral/"Do Nothing" Option	While it is possible to keep older vehicles in service almost perpetually with additional maintenance and replacement of key components, eventually the cost to do so becomes excessive.
	Net Benefits of Project in Monetary Terms (where practicable)	Not Applicable.

Project Summary Report	Project Code 103357	Report Start Year 2015	Number of Years 6	Scale Dollars
	Project Name Replace various Single Bucket and Double Bucket Line Trucks			

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,193,500	$ 1,605,000	$ 1,391,000



Project Summary Report	Project Code	Report Start Year	Number of Years	Scale
	102247	2015	6	Dollars
	Project Name: Interest Capitalization			

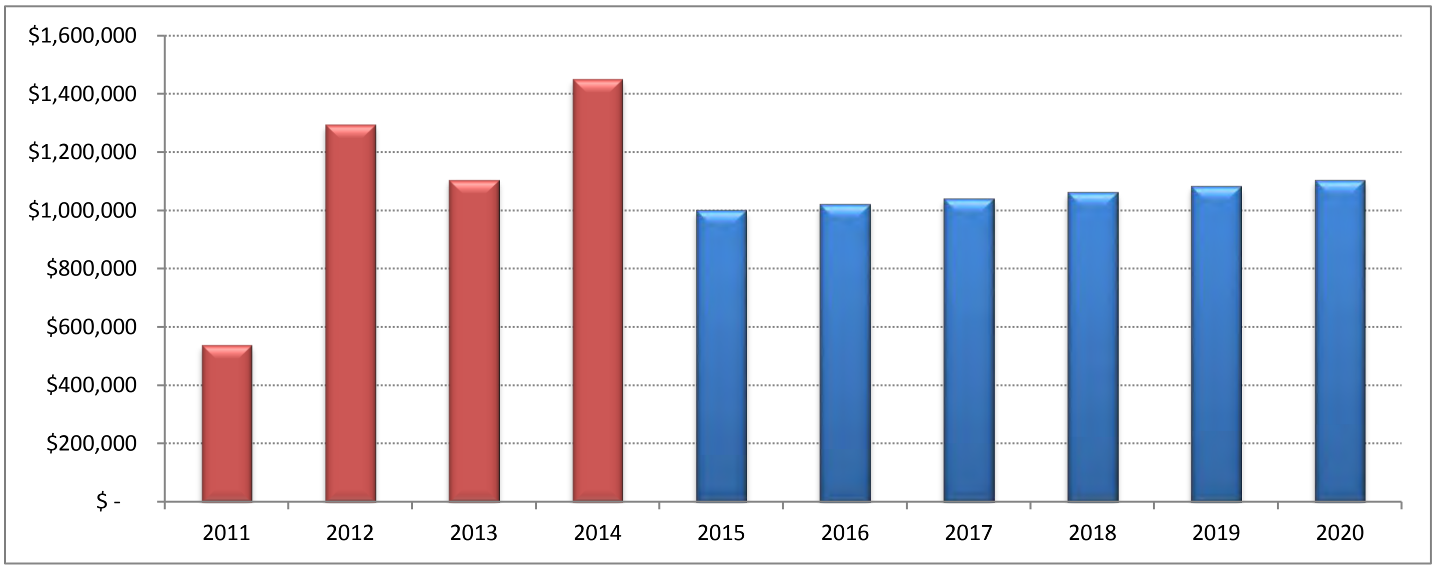
Major Category General Plant

Project Overview

1. Additional Information	Service Territory	PowerStream North & South
	Location	PowerStream
	Scope	As per IFRS Interest Capitalization is a requirement. This expenditure is to capture interest expense on capital spending that is in the work-in-progress stage before it finally put into production. Interest Capitalization - 2012 capitalized interest is based on capital spending of $60,000,000.00, at interest rate of 4.0%.
	Justification	According to accounting rules and OEB regulation, LDCs are allowed to capitalize interest expenses on work-in-progress projects before they are complete. Once the projects are complete interest capitalization ceases and depreciation commences.
2. General Project Information (OEB)	Contributed Capital	Contributed Capital 0%
	Fiscal Year	2015
	Parent WO#	
	Job Number	
3. General Information on the Project/Activity (OEB)	Risks to Completion and Risk Management	Not Applicable.
	Comparative Information on Equivalent Historical Projects (if any)	Not Applicable.
	Total Capital and OM&A Costs for Renewable Energy Generation portion of Projects (if any)	0
4. Evaluation Criteria (OEB)	Project Summary	As per IFRS Interest Capitalization is a requirement. This expenditure is to capture interest expense on capital spending that is in the work-in-progress stage before it finally put into production. Interest Capitalization - 2012 capitalized interest is based on capital spending of $60,000,000.00, at interest rate of 4.0%.
	1a. Main Driver	Capital Investment Support
	1b. Priority and Reasons for Priority	Not Applicable.
	1c. Qualitative and Quantitative Analysis of Project and Project Alternatives	Not Applicable.
	2. Safety	Not Applicable.
	3. Cyber-Security, Privacy	Not Applicable.
	4. Coordination, Interoperability	Not Applicable.
	5. Economic Development	Not Applicable.
	6. Environmental Benefits	Not Applicable.
5. Category-Specific Requirements for Each Project/Activity (OEB)	Impact of Deferral/"Do Nothing" Option	Not Applicable.
	Net Benefits of Project in Monetary Terms (where practicable)	Not Applicable.

Power Stream **Project Summary Report**	Project Code **102247**	Report Start Year **2015**	Number of Years **6**	Scale **Dollars**
	Project Name Interest Capitalization			

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenditures Historical/Planned	$ 536,625	$ 1,293,687	$ 1,104,548	$ 1,450,629	$ 1,000,000	$ 1,020,000	$ 1,040,000	$ 1,061,000	$ 1,082,000	$ 1,104,000



Appendix B

OPA Letters

Delivered: February 24, 2015

ONTARIO POWER AUTHORITY

120 Adelaide Street West
Suite 1600
Toronto, Ontario M5H 1T1

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F 416-967-1947
www.powerauthority.on.ca

June 14, 2013

Mr. Bing Young
Director, Transmission System Development
Hydro One Networks, Inc.
483 Bay Street
Toronto, Ontario M5G 2P5

<u>Initiating a Regional Infrastructure Planning Process for Near-Term Transmission Projects in York Region</u>

Dear Bing:

The purpose of this letter is to:

- Request that Hydro One initiate a Regional Infrastructure Planning (RIP) process to develop and implement the near-term transmission component of the integrated plan to meet the near- and medium-term reliability needs of York Region.

- Hand off from the Ontario Power Authority (OPA) the lead responsibility for the planning process associated with the near-term transmission component of the York Region Integrated Regional Resource Planning (IRRP) process to Hydro One to initiate the RIP process.

This is consistent with the regional planning process endorsed by the Ontario Energy Board (OEB) as part of its Renewed Regulatory Framework for Electricity.

The York Region Working Group (Working Group), consisting of staff from the OPA, the Independent Electricity System Operator (IESO), Hydro One and the York Region local distribution companies, has been conducting an IRRP process for York Region. In combination with conservation and local generation options, the Working Group has identified two transmission projects for meeting the reliability needs of the area for the near and medium term. These projects are located at Holland TS, and along the Parkway Belt transmission corridor.

The Working Group has identified these projects for near-term implementation and has discussed preliminary options. However, more detailed study and development work is required before these projects can be implemented. Continued development of both projects is best accomplished through Hydro One's RIP process, guided by the information and requirements provided below from the IRRP process.

The objectives and scope of these two projects are provided in Attachment 1.

To facilitate the transition to the RIP process, the OPA will provide Hydro One with the following information:

- Relevant system base cases
- Demand forecasts
- Conservation and distributed generation forecasts
- Any other relevant information

We look forward to information, results and deliverables from the York Region near-term transmission projects, as part of the York Region Working Group activities, and to continuing to work with and support Hydro One on the implementation of these projects.

Best Regards,

R.F. Chow

Bob Chow
Director, Transmission Integration
Power System Planning Division
Ontario Power Authority

CC York Region Working Group members:

PowerStream
Irv Klajman
Richard Wang
Riaz Shaikh

Newmarket-Tay Power
Larry Herod

Hydro One Distribution
Charlie Lee

Hydro One Networks
Farooq Qureshy
Paul Cook
E. Warren King

IESO
Peter Drury

OPA
Nicole Hopper
Bernice Chan
Alexandra Barrett
Kun Xiong
Joe Toneguzzo

Attachment 1 – Project Objectives and Scope

Holland TS Project Objectives:

The objectives of the Holland TS project are as follows:

- To increase the load-meeting capability of the Claireville-to-Brown Hill transmission line (B82V/B83V) to accommodate forecast load growth in northwest Vaughan and northern York Region in the near and medium term, and the connection of Vaughan #4 MTS, a new load supply station planned to be in service in spring 2017.
- To improve the capability to restore customer loads in northern York Region following a major outage affecting the main B82V/B83V transmission line, in accordance with the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC).

Holland TS Project Scope:

The Working Group has discussed options for meeting the above objectives and recommends proceeding with the following measures:

- Installation of two in-line breakers and associated motorized disconnect switches on the B82V/B83V circuits at, or near, the Holland TS property.
- Design and implementation of a Load Rejection (L/R) scheme for the stations connected to the B82V/B83V transmission line, or have available operational measures adequate for providing similar relief, as permitted by ORTAC.

Based on technical studies by the Working Group, with the addition of the in-line breakers and implementation of the L/R scheme described above, a load-meeting capability of 750 MW can be achieved for the system consisting of the B82V/B83V circuits and local generation (York Energy Centre). The switching facilities will also enable fast isolation of faulted line sections and allow restoration of customer loads, with York Energy Centre as a local supply source, following a major outage on the main transmission line, in accordance with ORTAC.

Hydro One will confirm the scope and cost of the above facilities to meet the identified reliability needs and to optimize their specifications and configuration.

Initiating these measures through the RIP process will allow restoration criteria to be met and provide sufficient capacity to supply forecast net load growth in Vaughan and northern York Region for the near and medium term. In the longer term (2020-2025 based on current load forecasts), the Working Group recognizes that a solution will be needed to support continued load growth in York Region and is planning engagement with affected communities, Aboriginal communities, and stakeholders on a long-term York Region Integrated Regional Resource Plan (IRRP).

The Holland TS project is needed in northern York Region to meet ORTAC restoration criteria today. In addition, it will be necessary to coordinate the development of this project with the connection of Vaughan #4 MTS to ensure there is sufficient capacity to supply this station when it connects in spring 2017. Therefore, the Holland TS project should be targeted to be in service by spring 2017.

Parkway Belt Project Objectives:

The objective of the Parkway Belt project is to improve the reliability of supply to customers supplied from the 230 kV "Parkway Belt" circuits (V71P/V75P), specifically in the following areas:

- To enable the Parkway Belt to meet ORTAC's 600 MW load security limit. Currently, the amount of load that could be lost by configuration in a double-circuit contingency exceeds 700 MW during peak demand conditions.
- To enable customer loads supplied from the Parkway Belt circuits to be restored following a major outage affecting the V71P/V75P circuits in accordance with ORTAC.

Parkway Belt Project Scope:

There are a number of options for meeting the above objectives, including a new switching station or line option, and the optimal solution has not been determined at this time. Development work, as part of the RIP, is required to assess the feasibility, cost and development timelines of the various options before the project can be fully scoped. There may be potential for a coordinated transmission and distribution solution.

This project is needed to meet ORTAC load security and restoration criteria today. As the project scope has yet to be defined, the in-service date will be established in accordance with the development timeline for the selected option.

ONTARIO POWER AUTHORITY

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December 14, 2012

Mark Henderson
EVP Asset Management and Chief Operating Officer
PowerStream Inc.
161 Cityview Boulevard
Vaughan, Ontario L4H 0A9

Dear Mr. Henderson:

RE: Siting Vaughan #4 MTS for connecting to the Claireville-Minden line

The purpose of this letter is to support the York Region Working Group's ("Working Group") choice of the option to connect PowerStream's next transformer station in Vaughan ("Vaughan #4 MTS") to the Claireville-to-Minden line (B82/83V).

In early 2011, a Working Group, consisting of representatives of the Ontario Power Authority (OPA), the Independent Electricity System Operator (IESO), Hydro One Networks, Hydro One Distribution, PowerStream and Newmarket-Tay Power, was established to assess electricity reliability in York Region over a 20-year period. The Working Group has confirmed the need for a new transformer station in the Vaughan area to supply load growth in southern York Region. While planned conservation and distributed generation are expected to offset over 30% of forecast load growth in this area, the remaining net load growth is expected to exceed the combined capacity of the existing stations in and around Vaughan by 2017. An acceptable transmission supply point must be determined as soon as possible.

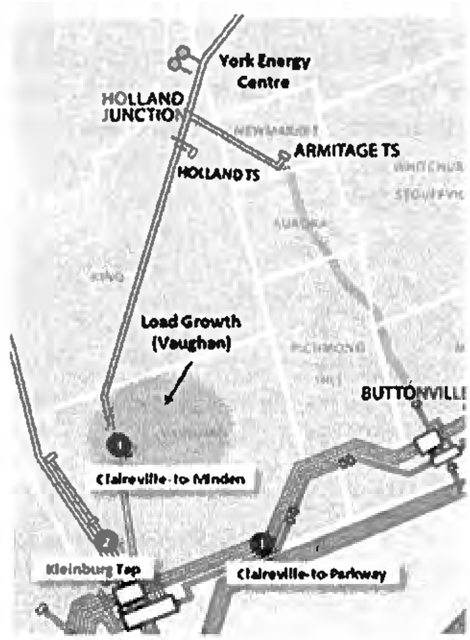


Figure 1. Potential Supply Points for Vaughan #4 MTS

Based on the existing system configuration, the Working Group identified three potential transmission supply points for Vaughan #4 MTS: the Parkway-to-Claireville line, the Kleinburg Tap, and the Claireville-to-Minden line, as shown in Figure 1.

From a distribution perspective, the Claireville-to-Minden supply point is preferred because the centre of forecast load growth to be supplied by the new station is near the northern boundary of the City of Vaughan. The Claireville-to-Minden line passes directly through this area, allowing the station to be ideally located to minimize distribution system expansion. PowerStream's staffs have indicated that suitable sites for the new transformer station near the Claireville-to-Minden corridor have been identified. The Parkway-to-Claireville line and the Kleinburg Tap are respectively located approximately 10 km to the south and 6 km to the west of this area of growth. Siting Vaughan #4 MTS near these supply points would require extensive and costly distribution expansion in areas with limited available road allowances.

All three of the potential supply points have limitations that would prevent them from supplying a new station without transmission system reinforcement. With this understanding, the Working Group considered the connection of Vaughan #4 MTS in the context of the long-term integrated plan for York Region. In addition to Vaughan #4 MTS, a new transformer station is forecast to be needed in Northern York Region around 2020, and two additional stations in Markham and Vaughan are forecast for the longer-term (after 2020). Planning, stakeholder engagement and development of a long-term solution to meet these combined capacity needs will require several years' lead time, so to respect the expected in-service date of Vaughan #4 MTS the Working Group considered means to leverage the existing system to meet the near-to-medium term needs of the area.

In the near-to-medium term, York Energy Centre (a new single-cycle peaking generation plant identified as part of a 2005 Integrated Plan for Northern York Region, which came into service in Spring 2012) will provide additional supply capacity on the Claireville-to Minden line and improve the reliability of supply to customers in Northern York Region. In order to fully realize the capacity and reliability benefits of York Energy Centre, additional station facilities, including switching facilities at Holland TS, would need to be installed. These proposed facilities would need to be in service in time for the connection of Vaughan #4 MTS on the Claireville-to-Minden line in 2017.

The Working Group also understands that a longer term solution will be needed to support continued load growth in York Region and the intention to move ahead with stakeholder engagement on a long-term York Region Integrated Electricity Plan.

Best Regards,

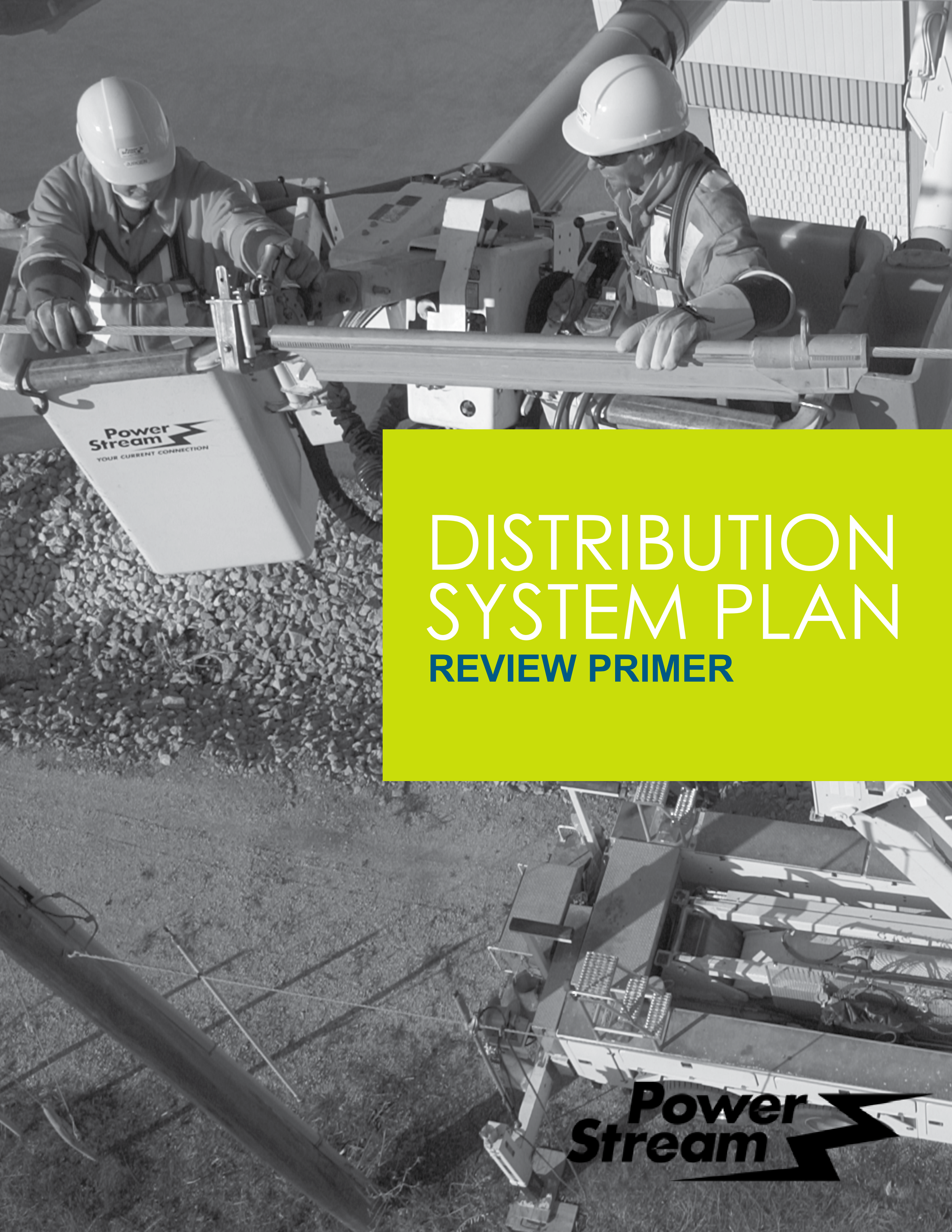
Amir Shalaby
Vice President, Power System Planning
Ontario Power Authority

CC
Kristin Jenkins, Mike Lyle, Bob Chow, and Nicole Hopper, OPA
Bing Young and Farooq Qureshy, Hydro One Networks
Barbara Constantinescu and Peter Drury, IESO
Larry Herod, Newmarket-Tay Power
Charlie Lee, Hydro One Distribution

Appendix C

Distribution System Plan Review - Residential

Delivered: February 24, 2015



DISTRIBUTION SYSTEM PLAN

REVIEW PRIMER

Power Stream

PowerStream is a community-owned energy company providing power and related services to more than 370,000 customers residing or owning a business in Alliston, Aurora, Barrie, Beeton, Bradford West Gwillimbury, Markham, Penetanguishene, Richmond Hill, Thornton, Tottenham and Vaughan as well as Collingwood, Stayner, Creemore and Thornbury through a partnership with the Town of Collingwood in the ownership of Collus PowerStream.

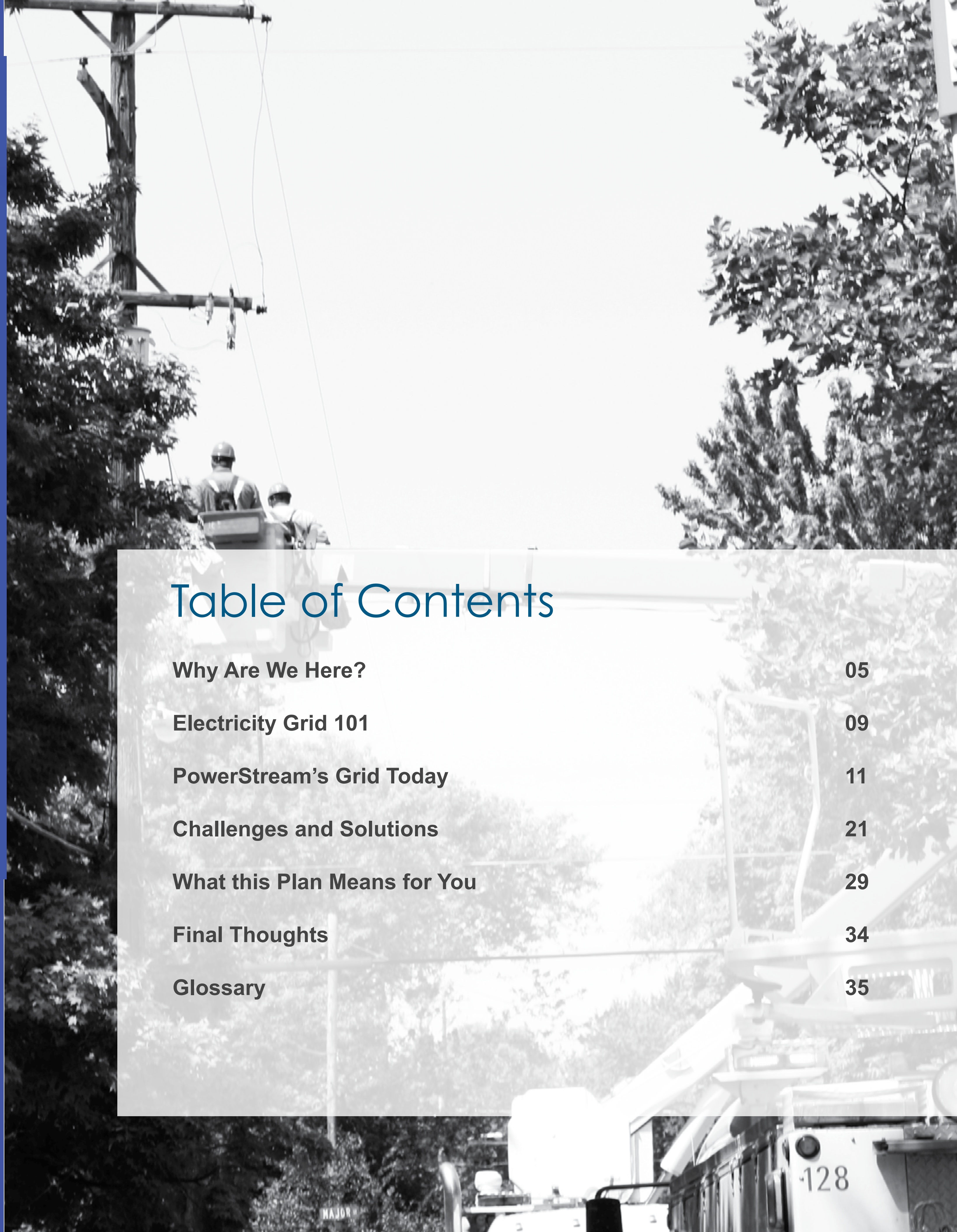


Table of Contents

Planning for Future Energy Needs

This primer and consultation concentrates on the short-term plan for PowerStream's distribution system over the next five years. The graphic below shows the various planning initiatives ongoing within the Province. In addition to the short-term distribution plan being discussed in this primer, there are other planning initiatives undertaken to ensure that the electricity system maintains reliability and works efficiently for the benefit of customers.

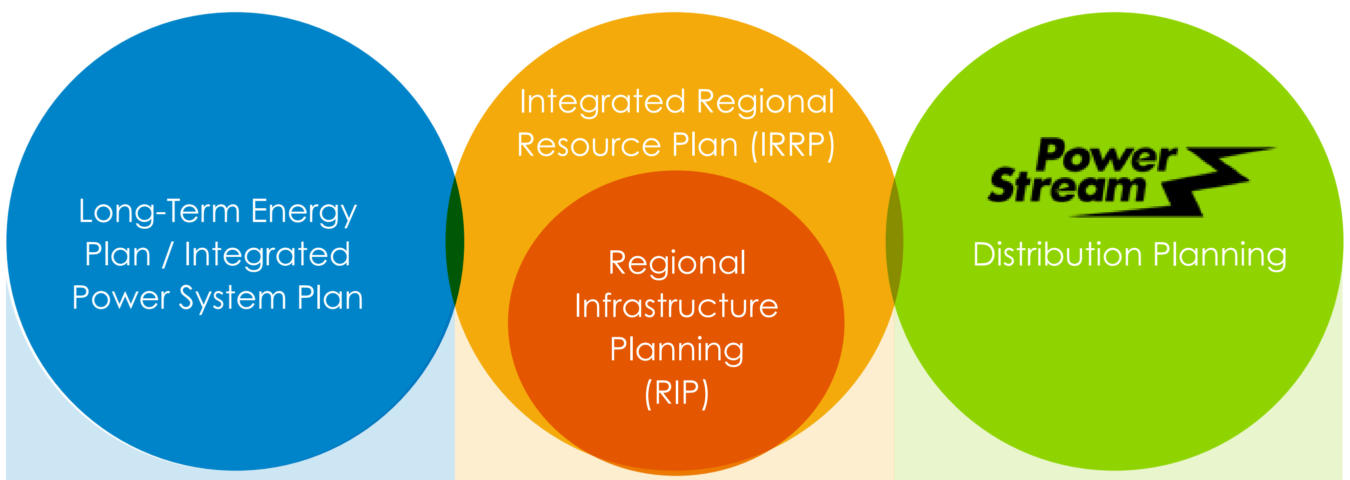
Energy planning occurs at the provincial level (by the Ministry of Energy and government agencies such as the Ontario Power Authority) and at the regional and municipal level as well as by each electricity distributor for their service territory and relevant agencies.

If you're interested in broader medium and long term electricity issues such as Ontario's Long-Term Energy Plan, regional planning, conservation planning and general energy policy in the province, there are other opportunities to provide your feedback.

Ontario's Long Term Energy Plan:
The Ontario Government's plan details how electricity will be generated and the longer-term conservation strategy for the province. It can be found at this website:
http://www.energy.gov.on.ca/en/ltep/

Regional Planning:
The Ontario Power Authority (OPA) looks ahead to the future electricity needs of your region and how those needs can be addressed through Conservation and Demand Management (CDM), local generation, and electricity from outside the region. You can follow the OPA`s regional planning process at this website:
http://www.powerauthority.on.ca/power-planning/regional-planning

Ontario's Energy Planning Diagram



Provincial System Planning

This involves more long-term planning on how Ontario's electricity system is designed and operated.

This includes planning on:

- Provincial electricity supply mix (e.g. greening the grid and phasing out coal)
- System supply and demand forecasting
- Interconnections and grid design

Regional Planning

Regional planning involves near- and medium-term plans to meet the needs of a region of the province, and ensure all key players (i.e. transmission and distribution operators) are coordinated moving forward.

This planning process is focused on considering whether CDM & local generation options have been considered, in addition to core infrastructure ("wires") solutions.

Distribution Network Planning

Distribution planning involves plans, both near- and longer-term, to ensure the local distribution system has the adequate capacity to meet required reliability and safety standards, and to otherwise meet the needs of customers.

Why Are We Here?

The electricity industry in Ontario is regulated by the Ontario Energy Board (OEB), which requires distribution companies, such as PowerStream, to prepare and submit a distribution system plan to show how it will sustain the area's electricity distribution system over the next five years.

The OEB recently developed a new regulatory requirement for distribution system plans that requires distribution companies, to gather information about customer needs and preferences on distribution system investments and report on how they responded. PowerStream needs your participation to ensure its plan addresses your needs and expectations.

You don't have to be an electricity expert to participate

This consultation is not about technical issues. The OEB hearing process will allow experts representing various consumer and interest groups (called intervenors) to challenge the detailed engineering and business decisions within PowerStream's plan. This consultation focuses on the goals of the system. Should PowerStream focus more on reducing the number of outages or the lengths of outages? Should reliability be increased even if rates go higher, or should PowerStream maintain the current level of reliability and keep rate increases lower?

This primer has been developed to guide you through PowerStream's plan. As you proceed, it asks questions designed to collect your feedback. In order to facilitate this, the primer is divided into several sections that explain the distribution system, the challenges it faces and, more importantly, how PowerStream will be responding to those challenges.

Your input, and PowerStream's response to your input, will be presented to the OEB and intervenors when PowerStream files its rate application for 2016 to 2020 in the spring of 2015.

PowerStream's Rate Application Process

- PowerStream assesses system needs
- Collects customers needs and preferences
- Refines plan (where necessary)
- Reports on how plan responds to customer input
- Files plan with OEB
- Interrogatories and OEB rate hearing process
- OEB sets PowerStream's distribution rates

Innovative Research Group Inc. has been engaged by PowerStream to collect participant feedback and will deliver it to PowerStream to assist them in shaping their plans.

? Feedback

1. How familiar are you with the electricity system in Ontario, and the services PowerStream is responsible for?

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

Your Electricity Bill

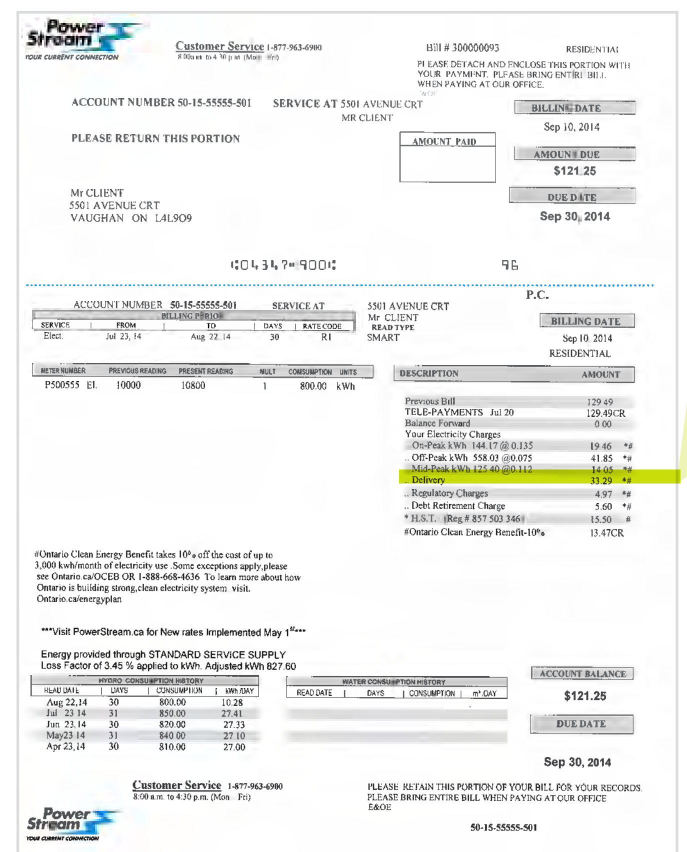
Every item and charge on the bill is mandated by the provincial government or regulated by the OEB. There are two distinct cost areas that make up the "Delivery" charge on your bill: distribution and transmission. While PowerStream collects both, it remits the transmission charge to Hydro One. The distribution charges are what PowerStream uses to fund its utility needs.

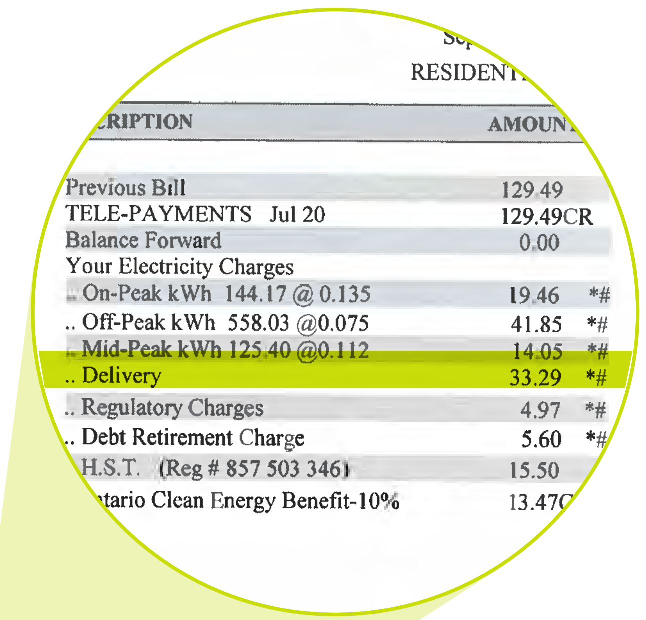
Distribution charges are one of several charges on your bill. Current monthly distribution charges are approximately $27 for a typical PowerStream residential customer who consumes 800 kWh in a month. The amount you pay varies depending on the amount of electricity you use.

PowerStream's distribution rates are subject to the review and approval of the OEB. The rate revenue covers PowerStream's capital investments and operating expenses.

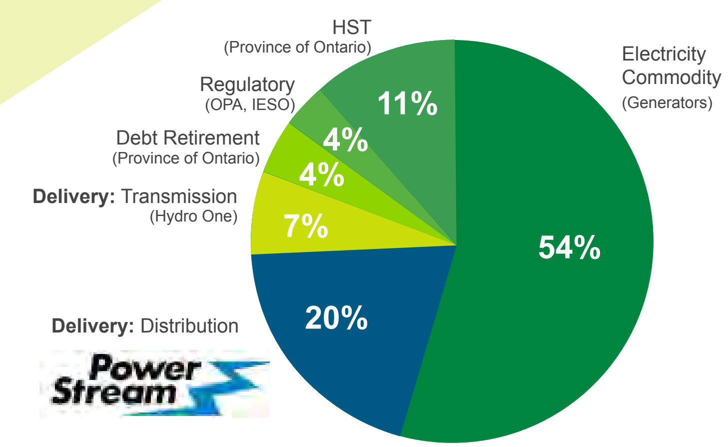
The plan PowerStream is proposing will maintain reliability at or above its current level. The resulting levels of capital investment and operational spending over the next five years will result in an increase of **$2.14** per month or **7.7 per cent** annually on the distribution rates charged by PowerStream. At the end of the plan in 2020, the average residential household will be paying an estimated **$10.72** more per month on the distribution portion of their electricity bill. Other items on your bill may also increase.

Sample Electricity Bill





About 20 per cent of the average residential electricity bill goes to PowerStream



How are Electricity Rates Determined?

PowerStream is funded by the distribution rates paid by its customers. Periodically, PowerStream is required to file an application with the OEB to determine the funding available to operate and maintain the distribution system. PowerStream must submit evidence to justify the amount of funding it needs to safely and reliably distribute electricity.

Who Protects Consumer Interests?

PowerStream's evidence is assessed in an open and transparent public process known as a rate hearing. A number of public intervenors with electricity industry expertise submit their own evidence challenging PowerStream's plans and assumptions. At the end of the process, the OEB weighs the evidence and decides on the rates PowerStream can charge for distribution.

Electricity Grid 101

Who Does What in Ontario's Electricity System?

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

GENERATION Generating facilities convert various forms of energy into electric power.	**EXAMPLES** Ontario Power Generation TransCanada Energy Ltd Bruce Power Samsung Renewable
TRANSMISSION Transmission lines (high voltage lines) connect the power produced at generating facilities to transformer stations.	**EXAMPLE** Hydro One
DISTRIBUTION Distribution lines (at medium voltages) carry electricity to homes and businesses.	**EXAMPLES** PowerStream Toronto Hydro Newmarket Hydro
CONSUMERS Electricity is delivered to homes and businesses.	**EXAMPLES** Residential Commercial Industrial

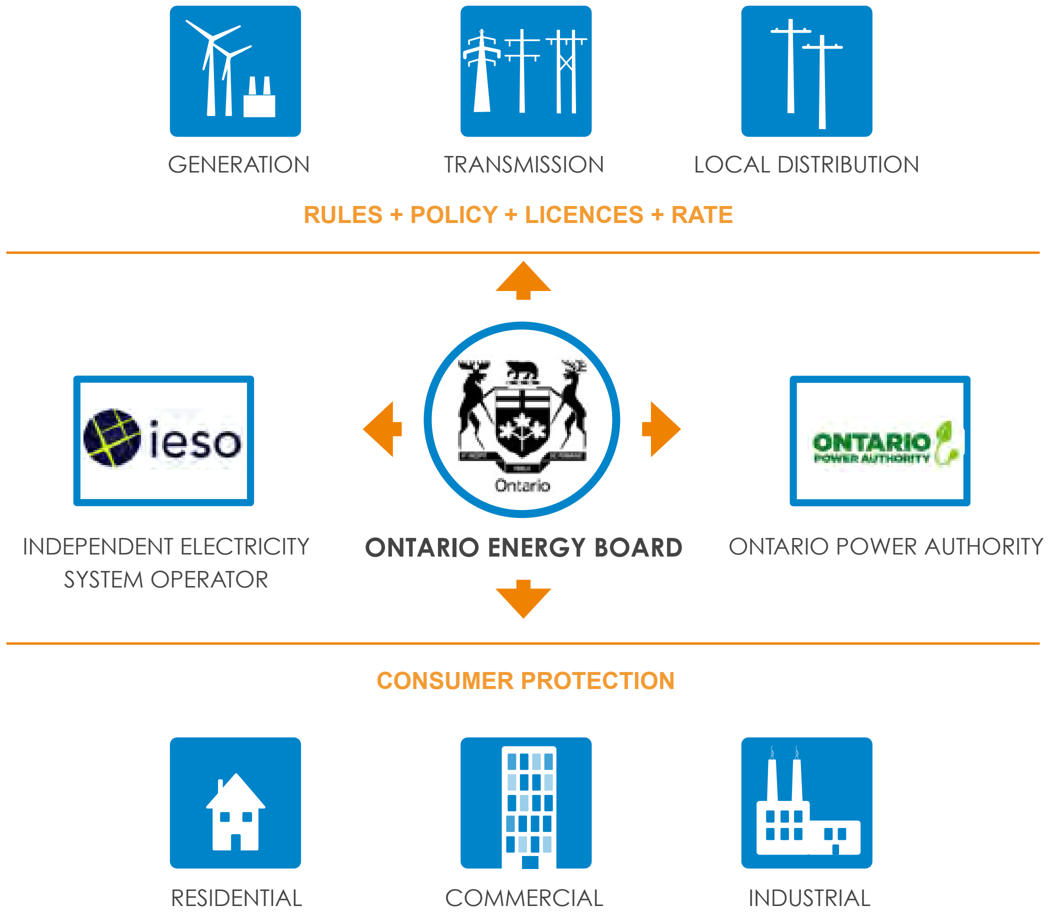
How is Ontario's Electricity System Regulated?

The **Ontario Ministry of Energy** sets energy policy. It sets the rules and establishes key planning and regulatory agencies through legislation.

The mission of the **Ontario Energy Board** (OEB) is to promote a viable, sustainable and efficient energy sector that serves the public interest and assists consumers to obtain reliable energy services at reasonable cost. It is an independent body established by legislation that sets the rules and regulations for the provincial electricity sector. One of the OEB's roles is to review the distribution plans of all electricity distributors and set their rates.

The **Ontario Power Authority** (OPA) is responsible for medium and long-term electricity planning to ensure an adequate supply of electricity is available for Ontario residents and businesses. The OPA receives directives from the Ministry of Energy (i.e. energy supply mix, Green Energy Act), but otherwise works at arm's-length from the government.

The **Independent Electricity System Operator** (IESO) is responsible for electricity supply over the short-term. It operates the grid in real-time to ensure that Ontario has the electricity it needs, where and when it needs it.



PowerStream's Grid Today

This section describes the construction of PowerStream's distribution grid including its overhead, underground and secondary systems. It also explains the corporation's historical growth and current electrical infrastructure.

The Background of PowerStream's Distribution Grid

PowerStream owns and operates $1.17 billion in capital assets and is the second largest municipally- owned electricity distribution utility in Ontario. It distributes about eight per cent of Ontario's electricity demand. PowerStream's electrical grid is comprised of overhead, underground and secondary systems of various voltages. PowerStream was formed in 2004 from the amalgamation of Hydro Vaughan, Markham Hydro, and Richmond Hill Hydro. Aurora Hydro was purchased in 2005, and in 2009, Barrie Hydro merged with PowerStream.

Each original utility operated independent distribution systems, and as a result, the infrastructure varies from region to region. PowerStream has been working to gradually standardize this equipment, which will help improve reliability and safety across the regions, and make maintaining the system more efficient.

PowerStream is owned by three municipalities and regulated by the OEB. As such, any profits obtained by the utility are provided to the municipalities as a dividend, or reinvested into the distribution system.

A Look at PowerStream's Growth

PowerStream has been serving York Region since 2004 and Simcoe County since 2009, and has seen remarkable change and innovation through the years. Although PowerStream as an entity dates back to 2004, the first electric system and street lights in the service territory were installed in Barrie in 1888, Markham in 1890-1891, and in neighbouring areas soon after.

PowerStream has a mix of older and newer distribution systems across all of its service territory. PowerStream is systematically and prudently upgrading older areas. Of course, even as this work is completed, the overall system continues to age.

PowerStream is a product of the largest voluntary consolidation of local distributors and is an organization committed to becoming an innovative and socially responsible leader in power distribution and related services. Growth is a key performance driver for PowerStream, and is achieved through increases to its residential and commercial customer bases.

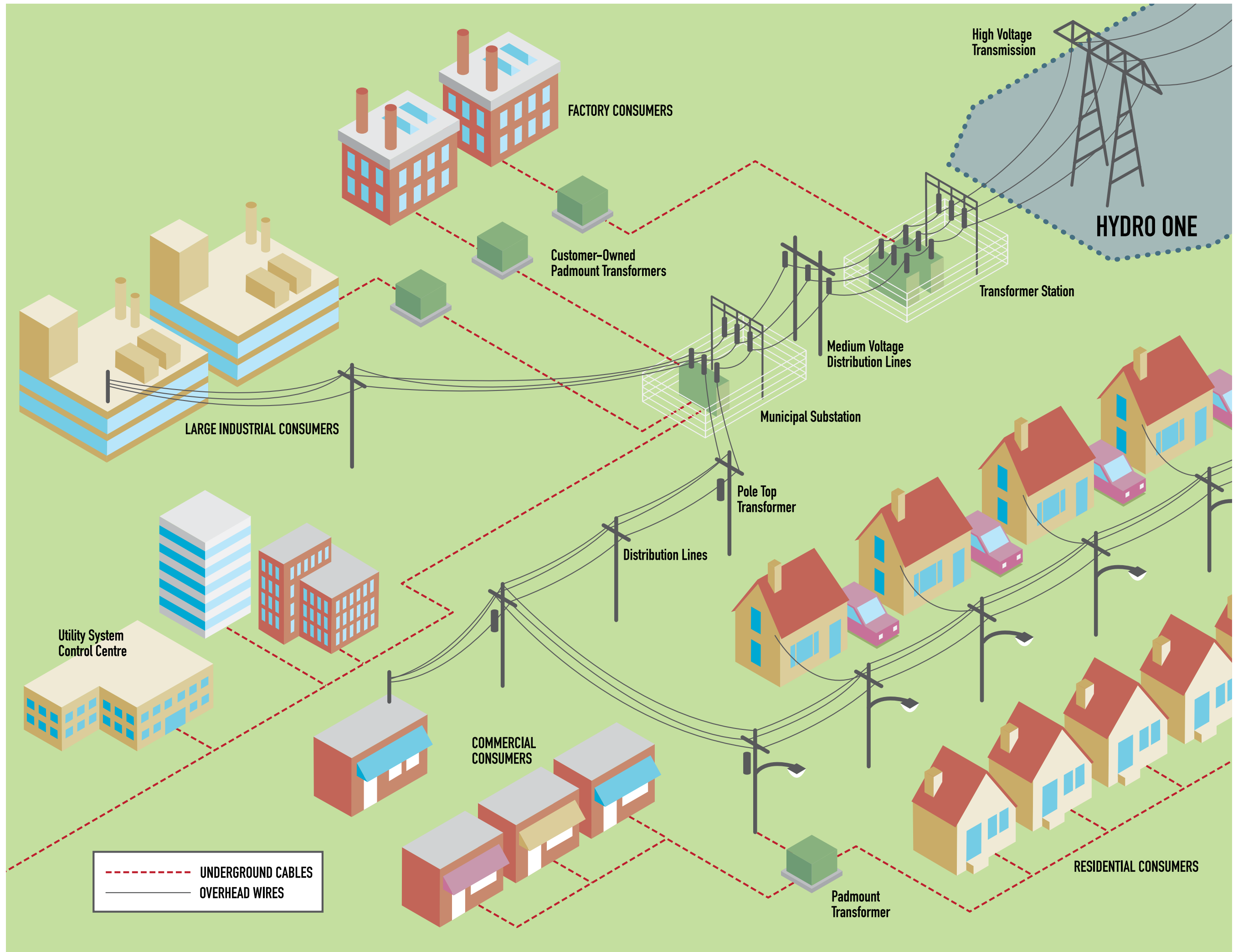
Large projects currently underway include the new Vaughan Metropolitan Centre project at Hwy 7 and Jane Street, the new Vaughan Campus of Mackenzie Health, and the expansion of the Toronto Transit Commission subway into York Region. All of these projects highlight the expansion and growth occurring in PowerStream's service territory.

PowerStream's Distribution System

Every system is unique with its own history and challenges. In order to better understand the current PowerStream system, we first have to understand all of the different components and how they impact the way in which you receive electricity when you need it. The image below and following terms and definitions will help guide you through the system from when you turn a switch on to when you receive your bill.

PowerStream's distribution system is made up of a number of components which work together to transport electricity to your house or business.

Distribution System Diagram



Transformer Stations and Municipal Substations

PowerStream owns 11 of the 25 Transformer Stations (TSs) that connect PowerStream's distribution system to the 230 Kilovolt (kV) provincial transmission grid owned by Hydro One and operated by the IESO. In fact, the very first municipally-owned transformer station in Ontario was built in PowerStream's service territory (Markham) back in 1985.

Municipal Substations (MSs), 54 in total, also play an important role in PowerStream's distribution system, further transforming higher voltage electricity to a lower voltage that is suitable for local distribution to customers.

Transformers – Important pieces of equipment that reduce the voltage of electricity from a high level to a level that can be safely distributed to your area, or to your residence/business.

Breakers – Devices that protect the distribution system by interrupting a circuit if a higher than normal amount of power flow is detected.

Switches – Control the flow of electricity and steer the current to the correct circuits.

Feeder Circuits – Are the wires that connect the stations to the broader distribution system in order to deliver electricity to customers.

PowerStream's Overhead System

The overhead system is made up of distribution lines that operate at various voltages depending on their purpose and destination. PowerStream has 2,535 km of overhead distribution lines in its service territory. These distribution lines are attached to the top of hydro poles.

Along the distribution line, pole-top transformers step the voltage down to useable levels of 120V-600V. From there, the electricity is delivered to customers through a secondary line that runs from the transformer to an individual home or business.

PowerStream has 3,500 switches, and over 330 pole-mounted remote-controlled switches located throughout its distribution system. These switches, which are controlled from PowerStream's Main System Control Centre, greatly improve operating efficiencies, and reduce restoration times whenever a power interruption occurs.

PowerStream's Underground System

PowerStream's underground system consists of high and low voltage cables, metal enclosed switchgear and transformers situated on concrete pads. In residential areas, underground cables distribute electricity from the TSs or MSs to padmount transformers located on the municipal boulevards. Like the overhead system, these transformers step the electricity down to useable voltages of 120V-600V, and the power is then delivered to customers through over 5,000 km of buried low voltage wires.

When distributing electricity to urban areas or larger customers, larger transformers are used.

PowerStream has 1,800 gears, and over 40 padmounted switchgears that are controlled remotely from its System Control Centre. These remote-controlled switches are critical for improving operating efficiencies and power restoration times in the underground distribution system.

Feedback

2. How well do you feel you understand the important parts of the electricity system, how they work together, and which services PowerStream is responsible for?

- Very well
- Somewhat well
- Not very well
- I don't understand at all

3. Generally speaking, how satisfied are you with the service you are receiving from PowerStream? Would you say …

- Very satisfied
- Somewhat satisfied
- Somewhat dissatisfied
- Very dissatisfied
- Don't know

4. Is there is anything in particular that PowerStream can do to improve its service to you?

Reliability

Delivering reliable power safely is PowerStream's fundamental purpose. Three key standard industry measures are used to track system reliability. They include:

SAIFI

System Average Interruption Frequency Index
This measure shows the number of outages an average PowerStream customer experiences in a year.

SAIDI

System Average Interruption Duration Index
This measure shows the amount of time an average PowerStream customer is without power in a year.

CAIDI

Customer Average Interruption Duration Index
This measure indicates on average how long it takes for PowerStream to restore power to a customer after a power outage.

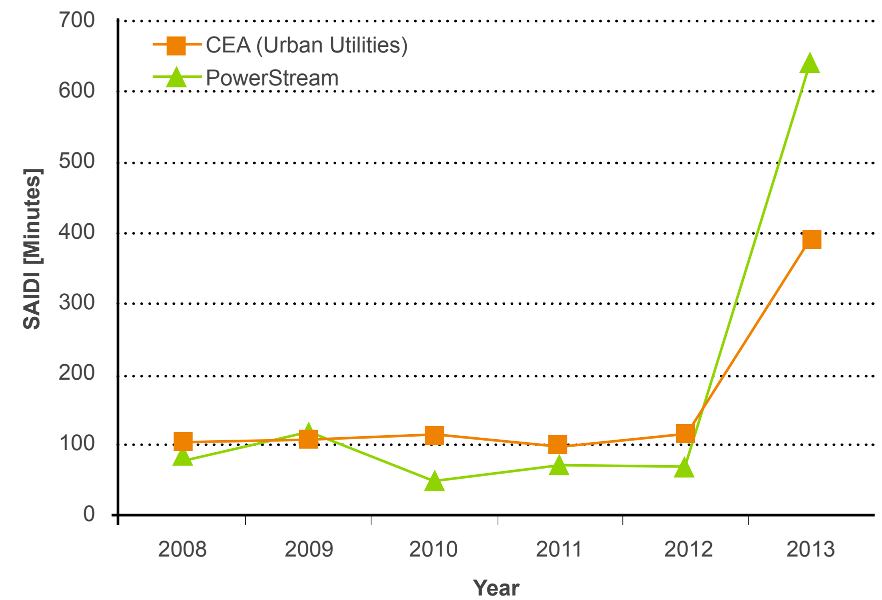
All planned and unplanned sustained interruptions are used to calculate these indices.

How is PowerStream Performing:

For reliability performance, the OEB expects that the distributor's current reliability performance (SAIDI, SAIFI, CAIDI) should, at minimum, remain within the range of its historical previous three year performance. PowerStream's plan aims to meet this requirement.

As seen in the chart below, PowerStream's SAIDI performance has been at par or better than average of the other comparable Canadian urban utilities with the exception of 2013 when PowerStream was hit hard by an unusual weather event (December Ice Storm).

PowerStream SAIDI [minutes] Comparison to Other CEA (Canadian Electricity Association) Urban Utilities for All Outages



Controllable vs. Uncontrollable Factors

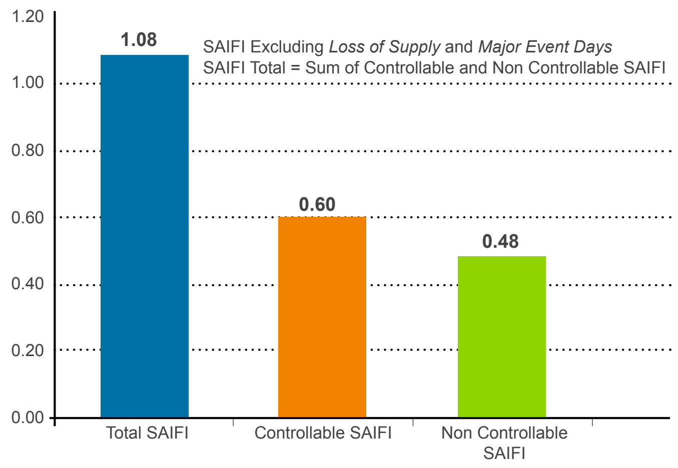
Electricity outages can be caused by factors that PowerStream can and cannot control.

Uncontrollable events include lightning, adverse weather, adverse environment (e.g. salt contamination) and third party created events.

Controllable events include scheduled outages in order to perform work on the distribution system, tree contacts, defective equipment and errors caused by people.

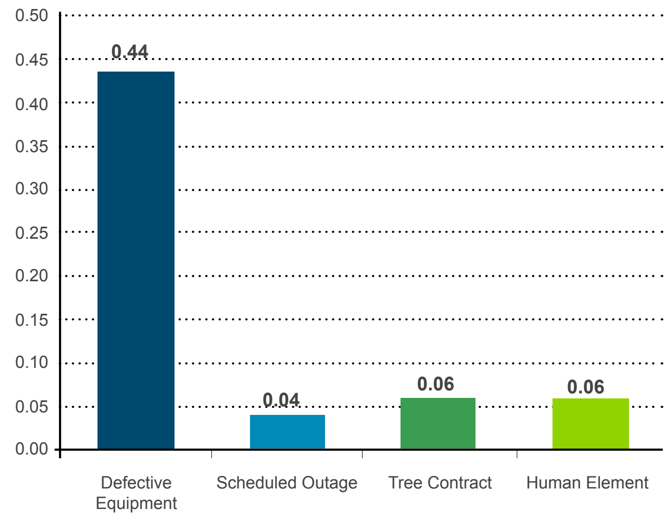
The chart below shows that more than half of the outages PowerStream customers experience are caused by controllable events.

Total SAIFI, Controllable & Uncontrollable SAIFI [2008-2013]



As the breakdown in the chart below illustrates, defective equipment is far and away the largest contributor of controllable outages.

Breakdown of Controllable SAIFI Excluding *Loss of Supply* and *Major Event Days* [2008-2013]



Capital Expenditure and Outages

Managing equipment failure is a never-ending race. Each year PowerStream invests in replacement or rehabilitation of its oldest assets and systems. The assets in the poorest condition are identified through an annual inspection programs. However with each passing year the rest of the assets get older and a new set of assets falls into poor condition.

Outages are also targeted as a result of poor performing feeders identified through reliability statistics each year. As these feeders are worked on and reliability improves, a new set of feeders falls to the bottom of the performance ratings.

As you will see in the following pages, over the next five years, PowerStream is planning investments in new equipment and the rehabilitation of existing equipment, such as underground cables, to reduce the number of outages due to equipment failure.

While outages are to some degree chance events, the investment in new equipment matches the aging profile of the system and is expected to sustain the current level of reliability and to achieve reliability improvement in the worst performing areas.

Capital Expenditure and Restoration Times

Restoration time is an area where PowerSteam actively pursues improvement. Restoration times depend on three things - the physical capacity to work around a problem, the speed at which the utility can re-route electricity through that physical network, and the speed by which the broken parts can be repaired.

As PowerStream expands the system through system service updates such as higher voltage lines, new stations and feeder lines or similar system improvements, the utility is building more capacity to work around outages.

As PowerStream adds remote monitors to pin-point where faults are occurring and add remote or automated switches to avoid the need to send a crew to manually flip a switch, the utility is increasing the speed by which power can be restored.

Finally, investments in areas such as equipment standardization, GPS devices and improved scheduling tools all contribute to our ability to replace broken equipment more quickly.

Feedback

5. As far as you know, in the past year, did you experience any outages due to unusual weather such as the ice storm, microbursts or tornados?

- Yes
- No
- Don't know

6. Whether you were personally affected or not, how satisfied are you with the way PowerStream responded to these events? Would you say …

- Very satisfied
- Somewhat satisfied
- Somewhat dissatisfied
- Very dissatisfied
- Don't know

7. Is there is anything in particular PowerStream can do to improve its service to you during these extreme weather events?

8. Other than outages during unusual weather events, how many outages did you experience in the past year?

- Zero
- One
- Two
- Three
- Four
- Five or more

9. Aside from unusual weather events, if you experienced an outage in the past year, what was the longest you experienced?

- Less than 15 minutes
- 15 to less than 30 minutes
- 30 minutes to less than 1 hour
- 1 hour to less than 3 hours
- 3 hours to less than 6 hours
- 6 hours to less than 12 hours
- 12 to less than 24 hours
- More than 24 hours
- Don't know

10. If you experienced an outage, how satisfied are you with the way PowerStream responded to the outage? Would you say …

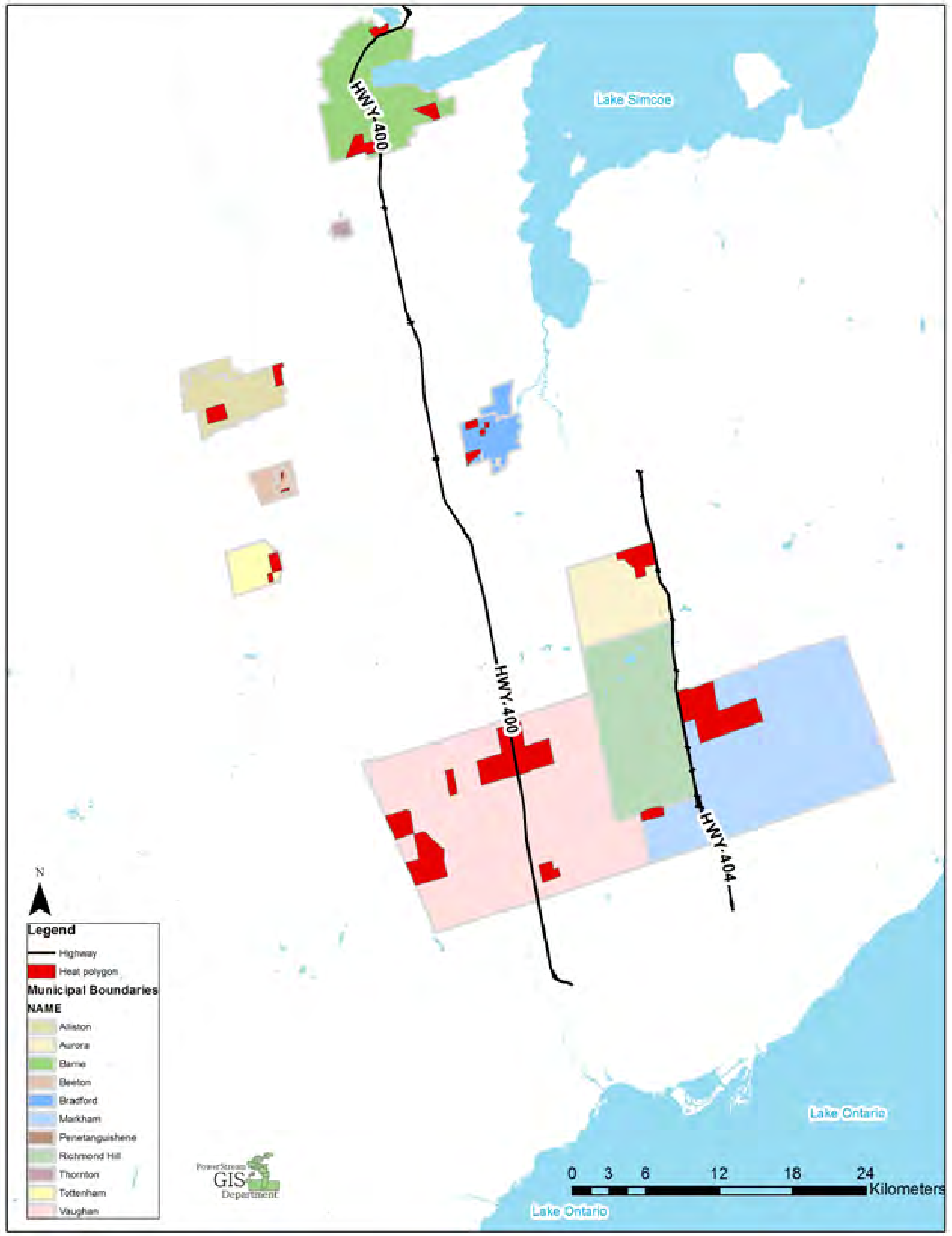
- Very satisfied
- Somewhat satisfied
- Somewhat dissatisfied
- Very dissatisfied
- Don't know

11. Is there is anything in particular PowerStream can do to improve its service to you during outages?

12. Most years, the average PowerStream customer loses power due to outages for about 100 minutes over the whole year. This is at or below the average for similar utilities. Do you feel this level of reliability is …

- Very good
- Good
- Acceptable
- Poor
- Very poor
- Don't know

Capacity Constrained Areas of PowerStream's Service Territory



Challenges and Solutions

Pressure: Growth

Fueled by increased economic development and demand for new housing in York Region and Simcoe County, PowerStream adds over 8,000 new customers to its existing customer base every year. This growth in customers and load puts increasing pressure on PowerStream's distribution system, which requires extending power lines, upgrading capacity to existing power lines, and adding new capacity to load constrained areas.

The map on the previous page shows the capacity constrained areas of PowerStream's service territory. Red highlighting indicates areas that require increased investment to provide additional capacity in the near term to ensure system reliability.

Challenges	Solutions
Lines and equipment that cannot carry the increased load and maintain the increased reliability expected by customers.	• New **substations, transformer stations**, and power **lines** where needed to increase supply capacity. • **Voltage** Conversion Projects: existing 8kV and 13.8kV power lines converted to 27.6kV to increase load capacity. • Station Investments: intended to ensure stations have peak loadings maintained at or below their 10 day Limited Term Rating to prevent damage to station equipment and avoid brownouts and blackouts.
Development of new subdivisions resulting from increased demand for new homes, which requires expansion of the distribution system lines and stations.	• Need investments to increase **station** and power line capacity to maintain the loading of existing municipal **substations** and to ensure sufficient space capacity exists such that if there is a loss of one substation, the neighbouring **substations** can accommodate the lost **capacity.**

Pressure: Aging Equipment

PowerStream's distribution system consists of various equipment (**poles, transformers, cables**, etc.) with different installation date profiles. While the majority of the distribution system was installed or rebuilt after 1980, a significant amount of distribution system equipment was installed in the 1970s, 1960s or even earlier, and is still in service today. While that old equipment continues to operate for the time being, it is well past its intended service life, and much of it will need to be replaced soon.

Equipment that is still operating beyond its intended service life is more likely to fail, and cause long power interruptions. As time goes on, more and more of the distribution system assets will be operating past end-of-life, unless replaced. This requires investment in system renewal projects and programs.

While PowerStream and its predecessor utilities have historically managed asset replacement programs efficiently with moderate levels of investment, the growing number of old assets needing replacement requires a higher level of investment than ever before.

PowerStream plans to proactively replace the oldest and worst condition equipment before it fails. Generally, proactive equipment replacement is less expensive than replacing equipment after an unexpected failure.

Some distribution assets such as pole mounted transformers and residential padmounted transformers, as well as secondary cables, are not proactively replaced. These assets are replaced once they fail. This "run to failure" approach is considered normal utility practice in the industry.

Asset Summary Chart – main assets by quantity

Asset Types	Asset Count (approx)	Average Life (approx)	Oldest Assets (approx)
Wood Poles	46,500	35-75	1940
Distribution Transformers	44,000	25-60	1956
Underground Primary Cable	7900 km	20-55	1965
Distribution Switchgear	1800	30-85	1978
Station Circuit Breakers	399	35-65	1958
Municipal Station Primary Switches	66	30-60	1956
Municipal Station Transformers	65	30-60	1958
Station Reactors	34	25-60	1986
Transformer Station Transformers	22	30-60	1986
Transformer Station 230kV High-Voltage Switches	22	30-60	1986
Station Capacitors	5	25-40	1990

Note: Above data and figures provided from PowerStream Asset Condition Assessment, Rev. 2, November 27, 2012.

Challenges	Solutions
The need to replace poles that are at or nearing end-of-life.	• Proactive replacement: PowerStream plans to replace or reinforce approximately 400 of the worst condition poles per year in order to minimize risk.
Underground primary cables that are at, or near, end-of-life, and the resulting high negative impact this has on reliability for affected customers.	• PowerStream proposes to replace approximately 52 km/year of the worst condition **underground cables**, and use silicon injection to extend the life of another estimated 47 km/year of underground cables. • PowerStream's approach for **cable** replacement is determined by prioritizing the cable sections that have the worst reliability and the highest customer impact.
Aging padmounted switchgear cubicles.	• Proactive replacement: PowerStream plans to replace approximately 31 of the poorest condition **switchgear** units in 2015, rising to 36 per year in 2016-2020.
The need to replace padmounted transformers, where concerns about condition have been reported.	• PowerStream commenced a proactive replacement program in 2013. • PowerStream proposes to proactively replace approximately 60 **padmounted transformers** per year.
Automated/remote-controlled switches, switches that are at, or near, end-of-life and therefore likely to fail compromising the ability to prevent feeder and station overloads during the summer peak.	• PowerStream proposes to replace five per year. • These are important for a number of reasons, including preventing station overloads during summer peaks, as well as improving reliability and restoration times.

Pressure: New Technology

PowerStream is finding that in general, customers have increased expectations. They want to communicate with us around the clock and in new ways, such as through social media. Some customers are seeking a detailed understanding of their electricity consumption, and how their bill is calculated. PowerStream information systems must support these customer needs.

The delivery model of the distribution system is changing. Renewable or other forms of generation have changed power flow from unidirectional to multidirectional. Managing this fundamental change requires increased technological investments.

Challenges	Solutions
The requirement to develop and support smart grid technology to meet the high reliability demands of today's electricity consumers.	• Improvements to the **distribution system** to support growing numbers of Electric Vehicles. • Improvements to the distribution system to support increased renewable **generation** and **energy storage** initiatives. • Develop and promote consumer energy management initiatives to reduce energy demand.
An outdated billing system, over 35 years old, that cannot support a growing number of customers, has limited ability for interactive features, and no longer has vendor support.	• A new modern **billing system**, expandable in the future as required, to provide a more efficient platform for customers with increased interactive support and customer information security. A new modern billing system will also provide increased efficiencies by integrating with other systems, and produce long-term cost savings.
The replacement of end-of-life remote-controlled switches to ensure rapid and automatic transfer of loads in emergencies and reduce restoration times.	• Installation of new smart remote-controlled power line **switches** and **reclosers**. • A formal decision-making process for determining the most cost effective quantity of **switches**, and the optimal locations, for providing the maximum benefit to the largest number of customers.
The need to replace old and difficult to operate "mini-rupter" (high capacity isolating) switches in commercial/ industrial locations.	• Installation of new high-capacity isolating **switches** that increase operational efficiencies and reduce the need for costly power interruptions when performing routine maintenance.
New OEB regulations that require higher intelligence metering equipment for all commercial/industrial customers over 50kW by 2020.	• Replace 4400 meters with new **smart technology** meters in a pre-planned efficient multi-year program.

Pressure: Security

As technology continues to be utilized in every aspect of the utility's business, there is an increasing risk of cyber security attacks that could potentially affect confidential customer or corporate information, customer privacy, power delivery, and even the safety of employees or customers through the unauthorized use of PowerStream technology. One incident could do serious damage to the corporation and to its corporate image. In addition, there is the on-going risk of physical security; the physical protection of buildings and stations, and the monitoring of critical equipment to protect from impending failure.

Challenges	Solutions
Evolving risks to cyber security of customer information and grid due to aging and unsecure IT equipment.	• Firewall/Intrusion Detection System/Intrusion Protection System—this is a security checkpoint between the trusted and untrusted network/device/users and is also used to continuously monitor for any malicious activity and can automatically take action in certain instances. • Network Access Control—this dynamically monitors and controls devices, applications and users to deny unauthorized external access to the network. • Identity and Access Management—this manages user access and privileges granted throughout the PowerStream environment • Security Information and Event Management—this is real-time logging and analysis of security alerts. • Vulnerability Assessment Tool—this scans, identifies, quantifies and prioritizes vulnerabilities in the PowerStream environment and suggests remediation solutions. • Mobile Device Management—this controls mobile devices connected to our network and can authorize, wipe, secure and encrypt corporate information as required. • Enterprise Change Management—this process and associated technology allows PowerStream to effectively deal with constant change through a structured approach to transitioning systems, applications and technologies from current to desired future states.
Risk of vandalism to substation buildings and equipment.	• Install equipment monitoring Infrared cameras at 16 additional stations over the next 6 years. • Install perimeter video surveillance cameras at 17 additional stations over the next 6 years.

Pressure: Obsolescence

Despite an ever increasing number of weather-related interruptions each year, PowerStream has worked hard to stay within the boundary of its average historical reliability performance targets of one outage totalling 60 minutes per customer, per year.

While PowerStream continues to demonstrate strong reliability performance in the operation of its distribution network, it is not without its challenges. There are areas and pockets within the PowerStream distribution system that suffer poor reliability due to the type of legacy construction that was once considered acceptable or even preferable. An example of this would be older houses connected to overhead power lines located in the back lot (rear lot) of those properties.

The reliability of rear lot supply connections is worse under severe weather conditions than the current standard front lot connections. In addition, the cost to maintain these rear-lot connections is much higher than the cost to maintain front lot connections.

Challenges	Solutions
Rear Lot Conversion program: Capital work required to address reliability, safety, operations and customer service concerns on rear lot supply connections.	• There are 49 areas of rear lot construction scattered among eight of the municipalities of PowerStream. Most of those areas were constructed in the 1950's, 1960's and 1970's. The oldest dates back to 1948. • PowerStream proposes to replace the worst areas of rear lot connections on an annual basis over many years until all areas are converted. • The average cost of this conversion work is estimated to be $1.2M per rear lot area. • Elimination of rear lot supply connections will result in long-term operational efficiencies and reduced maintenance costs.

Pressure: Major Events

PowerStream's system is built to quickly restore power after the loss of one or two key elements in the electricity grid. But what happens when there is a major disruption to the system?

PowerStream has been severely impacted by weather–related events over the past year. The December 2013 ice storm, microbursts in York region and tornados in the North service area have all highlighted the risk to the grid from major events. Major events are rare events that have a major impact. The Insurance Bureau of Canada reports that severe weather is likely to increase over the next 40 years.

The December 2013 Ice Storm in Ontario severely tested the emergency preparedness of electrical utilities in Southern Ontario including the Greater Toronto Area where hundreds of thousands of customers were left without power, some for as long as a week, or even longer. An independent assessment of PowerStream's response to that storm highlighted a number of areas where improvements are required at PowerStream to be better prepared for future severe storms and emergency events. Key areas identified for improvement include:

1. Improve external communications with customers.
2. Improvements to Customer Care systems and staffing.
3. Improve Outage Management Systems and utilize outage reporting via existing Smart Meters.
4. Improve vegetation management.
5. Elimination of rear lot services, and convert to front lot.
6. Upgrade or underground key distribution lines.

Challenges	Solutions
The need for emergency preparedness during unplanned events and expenses.	• Prepare contingency plans for the immediate replacement of assets (i.e. **poles, transformers**, etc.) due to unanticipated failure, storms, motor vehicle accidents, vandalism, etc. • Ensure adequate levels of spare equipment and materials are available for emergencies.
The need to improve the supply to those customers who are more vulnerable to outages and duration of outages, specifically rear lot supply.	• Plan to replace rear lot supplies on an annual basis until all are remediated.
The need to make changes to key distribution lines to withstand increased severity of weather events.	• Plan to increase structural integrity of key assets (i.e. tension cables designed to add stability to poles). • Upgrade or underground key wires.

The investments discussed earlier in the primer are focused on minimizing day-to-day outages and increasing the speed by which electricity is restored. Additional investments could help "harden" the system and speed up power restoration during a major event. There is no practical limit to potential ways of making the system more resilient in a major event, it is fundamentally a question of money.

13. A significant amount of PowerStream's distribution system equipment was installed in the 1970s, 1960s or even earlier, and is still in-service today. PowerStream works hard to extend the life of our existing equipment because it helps to keep rates down, but as equipment gets older it becomes more likely to fail. PowerStream has two approaches to older equipment.

- If the failure of a piece of equipment will impact a large number of people, result in a long outage or if an inspection shows the equipment is in poor condition, PowerStream does initiate equipment replacement before failure.
- When an equipment failure has only a limited impact and can be quickly replaced, PowerStream's policy is to leave the equipment in place until it breaks down to get all the value possible from that equipment.

What do you think of this policy?

- ■ I am willing to pay more to replace all equipment before it fails.
- ■ I support the current approach of allowing equipment to run to failure when that failure impacts only a few customers for a limited period of time.
- ■ Don't Know

14. When it comes to replacing aging equipment, which of the following points of view is closest to your own?

- ■ PowerStream should invest what it takes to replace the system's aging infrastructure to reduce the risk of power outages; even if that means my electricity bill will increase by a few dollars per month.
- ■ PowerStream should scale back their investment in renewing the system's aging infrastructure to reduce the size of any bill increase; even if that means more or longer power service interruptions.
- ■ Don't Know

15. While there are clear benefits from new technology, there are also costs. The system functions well on the old technology. Do we want to pay more to secure the benefits new technology can deliver?

When it comes to investing in new technology, which of the following points of view is closest to your own?

- ■ Investments in new technologies are more a luxury than a necessity and should be a low priority for PowerStream.
- ■ I think the benefits of new technology are important and investments in new technology should be a priority for PowerStream.
- ■ Don't know

16. The investments discussed earlier in the primer are focused on minimizing the day-to-day outages and increasing the speed by which electricity is restored. There are additional investments could help "harden" the system and speed up power restoration during a major event. There is no practical limit to potential ways of making the system more resilient in a major event, it is fundamentally a question of money.

Currently, the average residential customer pays $27 a month to PowerStream to operate and maintain the local distribution system. How much more are you willing to pay each month for investments that would help the system better withstand major events such as extreme weather?

$

What this Plan Means for You

It all comes down to what you pay and what you receive in return.

What will you get? PowerStream's plan for 2016 to 2020 deals with the challenges outlined in this primer to deliver a system that will maintain or achieve modest improvements in reliability and service.

What will it cost? Residential customers with an average monthly consumption of 800 kWh may see an increase of **$2.14** per month or **7.7 per cent** annually on the distribution portion of their bill over the next five years. As such by 2020, the average residential household will be paying an estimated **$10.72** more per month on the distribution portion of their electricity bill. It is important to note that other increases on the bill by other entities are also possible.

There are two main elements in that increase:

- An increase of approximately **2.4 per cent** or **66 cents** per month in operating costs which reflects inflation and new costs which are offset in part by efficiency savings;
- An increase of approximately **5.3 per cent** or **$1.48** per month for new capital investments to deal with the issues discussed earlier such as growth, aging infrastructure and new technology.

In addition, in the first year of the plan there is a "catch-up" increase to deal with expenses that were not properly covered under the existing rate adjustment formula. The next section explains the need for that catch-up.

Current Revenue Shortfall

The formula for setting PowerStream's rates in 2014 and 2015 is not keeping up with the need for new investment.

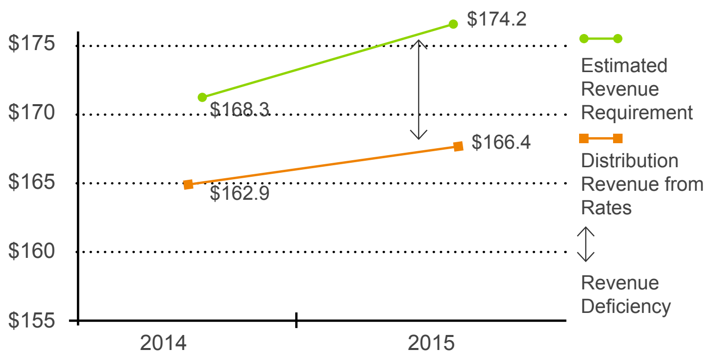
PowerStream's rates were set in 2013 using the cost of service method where the OEB sets rates at the level needed to fund the operation of the utility. That worked well in 2013.

However, in 2014 and 2015, rates were not based on actual costs. Instead, a formula was applied which adjusted rates for inflation less an adjustment for efficiency, referred to as a price cap index (PCI) adjustment. This formula does not provide enough revenue in rates to fund the actual capital investments being made in these years.

The OEB recognized that problem and created the new Custom Incentive Regulation rate setting method which PowerStream will be using in this rate filing. This method will alleviate this issue going forward but there is still a need to deal with 2014 and 2015 investments.

The chart below compares the revenue from rates using the PCI to the revenue needed to fund utility operations on a cost of service basis. Over 2014 and 2015, there will be a revenue shortfall of approximately $13.2 million. This shortfall is being funded by PowerStream's municipal shareholders from past earnings retained in the company. However, using savings to make up for the missing revenue will restrict PowerStream's ability to make the necessary future investments to maintain its system and the level of service provided to its customers. The catch-up will enable PowerStream to fund those needed investments.

Revenue Shortfall ($millions)



($ Millions)	2014	2015	Total
Estimated Revenue Requirement	$168.3	$174.2	$342.5
Distribution Revenue from Rates	$162.9	$166.4	329.3
Revenue Deficiency	($5.4)	($7.8)	($13.2)

Most of the rate increase in 2016 is to provide funding for capital investments in 2014 and 2015. This will result in an increase of $3.86 a month for the average residential customer consuming 800 kWh a month.

One of these major capital investments is a new billing system. PowerStream made the second largest investment in its 10 year history when it decided to bring in a new billing system in 2014/2015. PowerStream is committed to providing customers with accurate billing information from meter to payment. However, the old system was implemented 30 years ago and just wasn't keeping up with new demands such as mobile access and self-service options customers have said that they expect today. Changing to a modern system requires both a significant capital investment and an increased operating budget. Not only will it provide much better access for customers and staff, it will do so with a much higher level of security for personal information, a key concern in these times. This system will be fully implemented in 2015.

Increased Capital Spending

PowerStream has developed a list of capital investment drivers and proposes capital investment programs based on these key drivers. The definitions of the key drivers are below.

Service Requests

PowerStream has an obligation to connect a customer to its distribution system. This includes both traditional demand customers and distributed generation customers. Requests also can include system modifications to support infrastructure development by government agencies, road authorities and developers. Normal connection costs are recovered through the revenue from new customers. Unusual connection costs are paid by the customer being connected.

Increased Delivery Capacity

As new customers are connected, PowerStream needs to expand the core elements of its distribution system, including expanded or new distribution stations and enhanced or new feeder lines. This is the fundamental infrastructure that allows new customers to be hooked up to the distribution system and is paid for by the extra revenue from new customers served over time.

System Efficiency

To provide customers with the best service possible, there is always a need to improve restoration capability. As the population in PowerStream's service territory continues to grow, the system also needs to grow in order to be able to handle new connections.

Mandated Compliance

Environmental, reliability and safety standards are updated on a regular basis and PowerStream's system must be updated to keep up with these standards. Agencies that impact PowerStream include the Ministry of Energy, Measurement Canada, the OEB, the IESO and/or other regulators.

Obsolescence

Improvements in technology can require PowerStream to replace equipment that is still functional but no longer meets current operating practices or current standards. Reasons for replacement include:

- the equipment is no longer manufactured;
- there are no spare parts;
- are unable to have maintenance performed on them;
- there are operational constraints or conflicts, which can result in increased reliability and/or safety-related risks.

Aging or Poor Performing Equipment

Where there is the imminent risk of failure due to age or condition deterioration, and these potential failures will result in severe reliability impacts to customers as well as potential safety risks to crew workers or to the public, refurbishment or replacement is required.

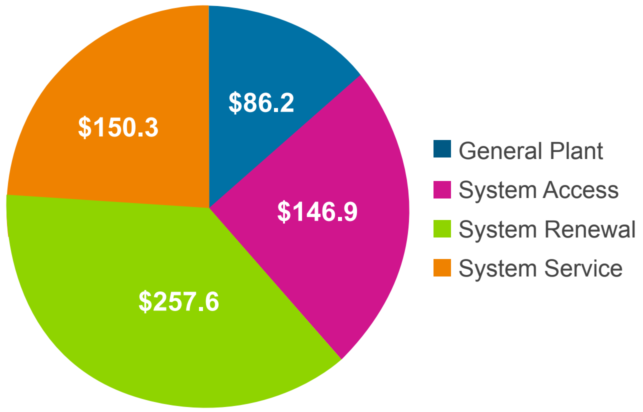
Business Support Costs

PowerStream is not just the local electricity grid itself, it is the business that operates that grid. The utility needs storage facilities for equipment, workshops to maintain and repair equipment and offices for people who manage your accounts and the electricity system. PowerStream needs vehicles for its crews, as well as computer systems to manage customer accounts, track equipment and operate the grid. While this is a relatively small slice of the capital spending over the next several years, it is just as critical to have IT systems identify where an outage is and where the needed parts are stored as to have the replacement parts themselves.

	Capital Investment Drivers	Primary Driver	Source
System Access	Subdivisions and New Connections Road Authority Metering Other Customer Initiated Work	Service Requests	Developers, Customers, Road Authorities
System Service	Reliability including Distribution Automation Additional Capacity - Lines Additional Capacity - Stations (TS and MS) Security Smart Grid Safety	Reliability Support Capacity Delivery System Efficiency Safety	PowerStream
System Renewal	Distribution Lines - Emergency/Reactive Replacement Overhead Lines and Assets Planned Replacement Underground Cable and Asset Planned Replacement Rear Lot Conversion Program Stations/Protection & Control Asset Replacement (Planned & Emergency)	Mandated Compliance Obsolescence Mitigate Failure Risks Safety	Regulator Safety Authority PowerStream
General Plant	Interest Capitalization Customer Service Information Service and Communication Systems Buildings/Facilities Fleet Tools	Capital Investment Support Customer Service	PowerStream

Looking ahead at the next five years and all the categories identified above, PowerStream is proposing to spend $641 million on new capital investments. This will result in an annual increase of about 6 per cent on the distribution portion of your bill which is about three quarters of the proposed rate increase.

2016 - 2020 Forecasted Capital Expenditures ($ millions)



With the proposed levels of capital and operating budgets for 2016 to 2020, in 2020 PowerStream will continue to operate on less revenue per customer than the average Ontario local distribution company.

Feedback

17. Given what you know and what you have read so far, how well do you feel you understand the challenges facing the PowerStream system and what they are planning to do to meet those challenges?

- ☐ Very well
- ☐ Somewhat well
- ☐ Not very well
- ☐ I don't understand at all

18. From what you have read and what you may have heard elsewhere, does PowerStream's investment plan seem like it is going in the right direction or the wrong direction?

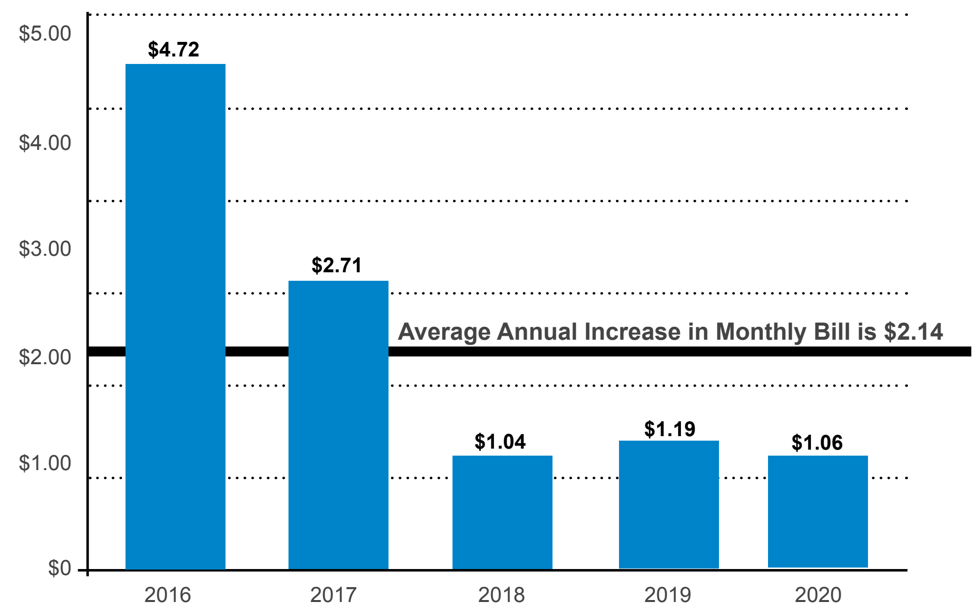
- ☐ Right direction
- ☐ Wrong direction
- ☐ Don't know

19. And why do you feel that way?

The Impact on Your Bill

Residential customers with an average monthly consumption of 800 kWh will see an increase of **$2.14** per month or **7.7 per cent** annually on the distribution portion of their bill over the next five years. As such by 2020, the average residential household will be paying an estimated **$10.72** more per month on the distribution portion of their electricity bill.

Estimated Typical Residential Annual Increase in Monthly Bill



Feedback

20. Considering what you know about the local distribution system, which of the following best represents your point of view:

- ☐ The rate increase is reasonable and I support it
- ☐ I don't like it, but I think the rate increase is necessary
- ☐ The rate increase is unreasonable and I oppose.
- ☐ Don't know

21. And why do you feel that way?

Final Thoughts

PowerStream values your feedback. This outreach is a new requirement, so this is the first time that the utility has conducted a review about its upcoming investment plan in this type of format.

General Impression - Overall, what did you think about this primer?

Volume of Information: Did PowerStream provide too much information, not enough, or just the right amount?

Content Covered: Was there any content missing that you would have liked to have seen included?

Outstanding Questions: Is there anything that you would still like answered?

Suggestions for Future Consultations: How would you prefer to participate in these consultations?

Glossary

Breakers: Devices that protect the distribution system by interrupting a circuit if a higher than normal amount on power flow is detected.

Feeder Circuit: Is a wire that connects stations to the broader distribution system in order to deliver electricity to customers.

Generation Station: A facility designed to produce electric energy from another form of energy, such as fossil fuel, nuclear, hydroelectric, geothermal, solar thermal, and wind.

Kilowatt (kW): 1000 watts.

Local Distribution Company (LDC): In Ontario, these are the companies that take electricity from the transmission grid and distribute it around a community.

OM&A: Operations, Maintenance and Administration

Stations: These include tranformer stations and distribution stations. They are used to switch generators, equipment, and circuits or lines in and out of a system. It also is used to change AC voltages from one level to another.

Switches: These control the flow of electricity—they direct which supply of electricity is used and which circuits are energized. Distribution systems have switches installed at strategic locations to redirect power flows for load balancing or sectionalizing.

System Access: Projects required to respond to customer requests for new connections or new infrastructure development. These are usually a regulatory requirement to complete.

System Renewal: Projects to replace aging infrastructure in poor condition.

System Service: Primarily projects that improve reliability.

General Plant: Investments in things like tools, vehicles, buildings and information technology (IT) equipment that are needed to support the distribution system.

Transmission lines: Transmit high-voltage electricity from the generation source or station to another station in the electricity grid.

Transformer: A piece of equipment that reduces the voltage of electricity from a high level to a level that can be safely distributed to your area or to your residence/business.

Underground Cable: A conductor with insulation, or a stranded conductor with or without insulation and other coverings (single-conductor cable), or a combination of conductors insulated from one another (multiple-conductor cable).

Volt (V): A unit of measure of the force, or 'push,' given the electrons in an electric circuit. One volt produces one ampere of current when acting on a resistance of one ohm.

Watt (W): The unit of electric power, or amount of work (J), done in a unit of time. One ampere of current flowing at a potential of one volt produces one watt of power.

Wire: A conductor wire or combination of wires not insulated from one another, suitable for carrying electric current.

If you have any additional questions or comments about PowerStream's Distribution System Plan Review please email:

CustomerFocus@powerstream.ca

or send your questions or comments to:

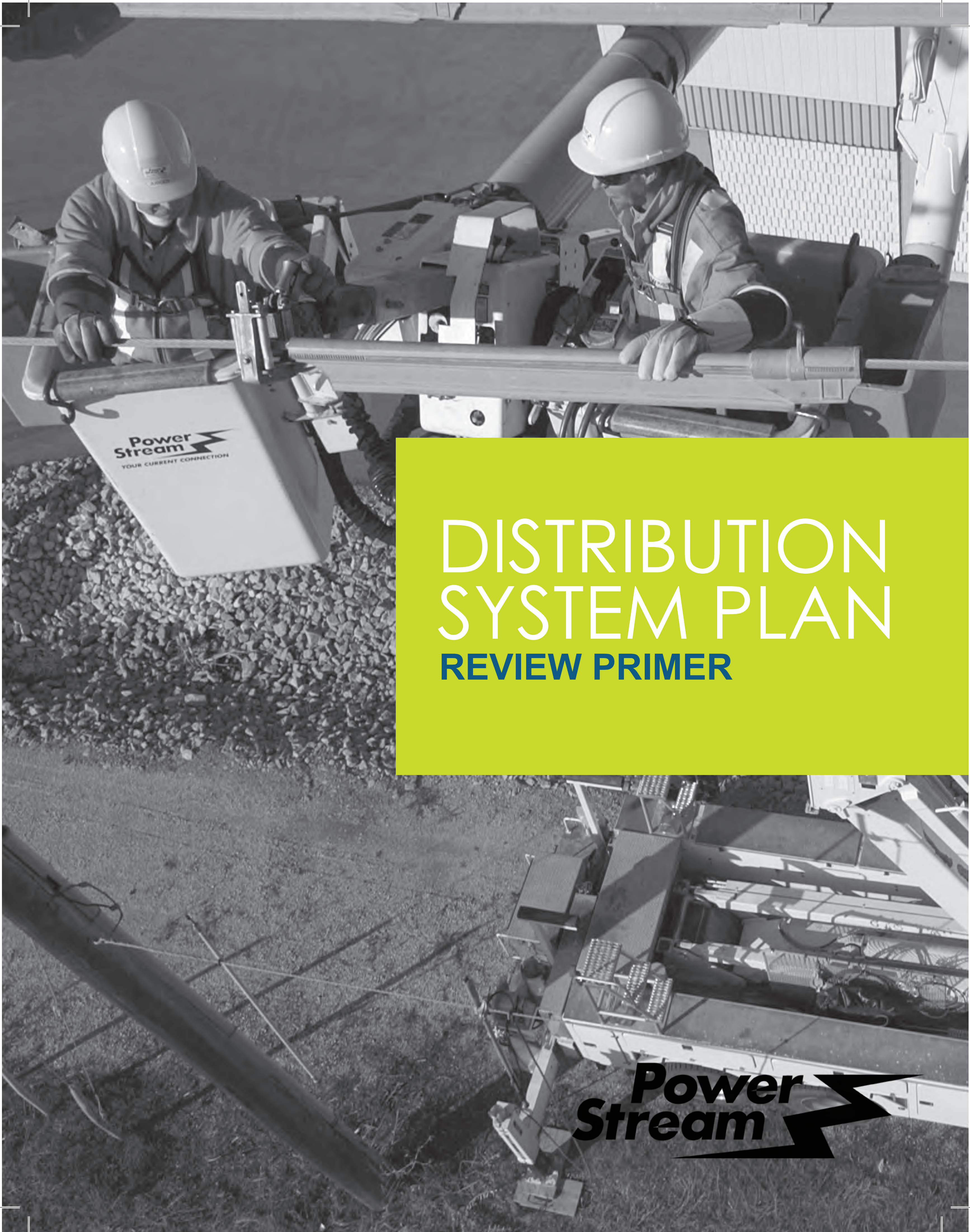
PowerStream
Attn: DSP Review
161 Cityview Boulevard,
Vaughan, Ontario
L4H 0A9

PowerStream

Appendix D

Distribution System Plan Review – General Service Over 50

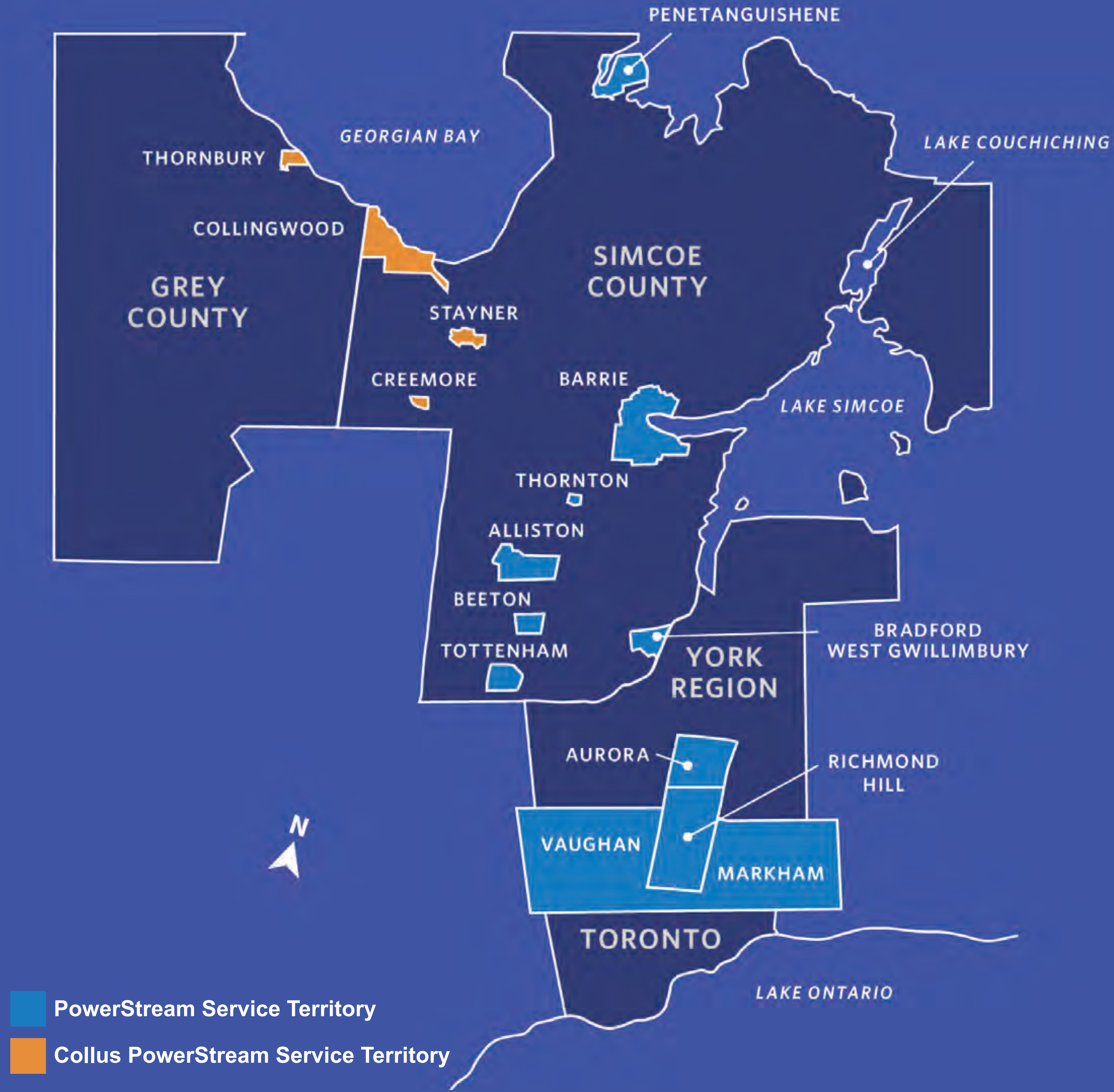
Delivered: February 24, 2015



DISTRIBUTION SYSTEM PLAN

REVIEW PRIMER

Power Stream



PowerStream is a community-owned energy company providing power and related services to more than 370,000 customers residing or owning a business in Alliston, Aurora, Barrie, Beeton, Bradford West Gwillimbury, Markham, Penetanguishene, Richmond Hill, Thornton, Tottenham and Vaughan as well as Collingwood, Stayner, Creemore and Thornbury through a partnership with the Town of Collingwood in the ownership of Collus PowerStream.

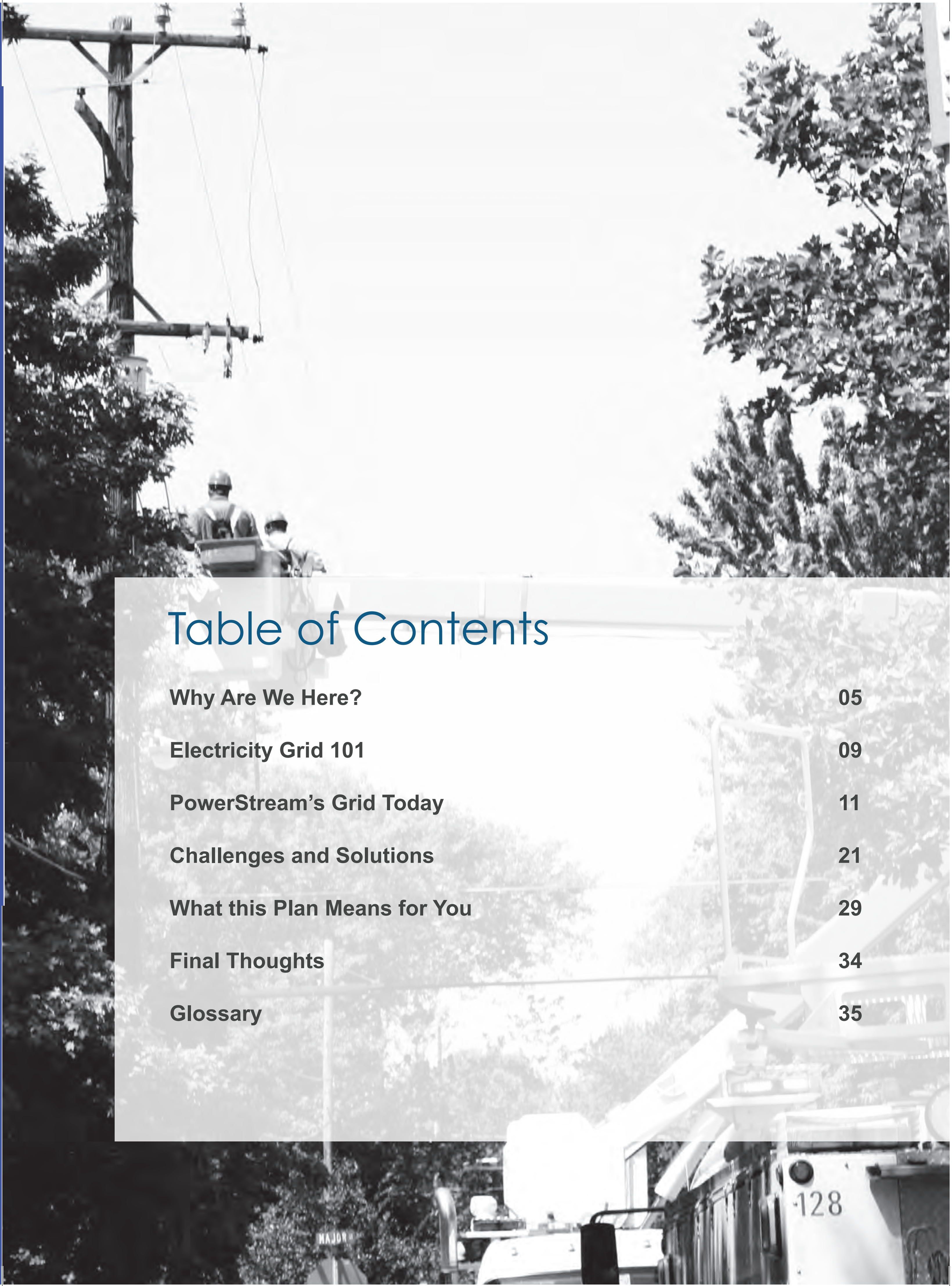


Table of Contents

Planning for Future Energy Needs

This primer and consultation concentrates on the short-term plan for PowerStream's distribution system over the next five years. The graphic below shows the various planning initiatives ongoing within the Province. In addition to the short-term distribution plan being discussed in this primer, there are other planning initiatives undertaken to ensure that the electricity system maintains reliability and works efficiently for the benefit of customers.

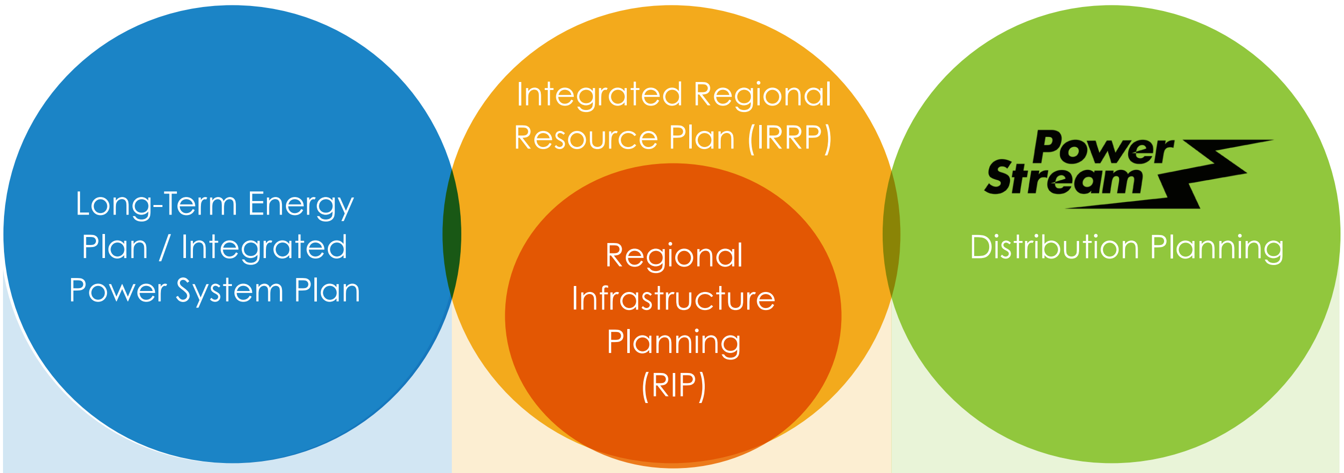
Energy planning occurs at the provincial level (by the Ministry of Energy and government agencies such as the Ontario Power Authority) and at the regional and municipal level as well as by each electricity distributor for their service territory and relevant agencies.

If you're interested in broader medium and long term electricity issues such as Ontario's Long-Term Energy Plan, regional planning, conservation planning and general energy policy in the province, there are other opportunities to provide your feedback.

Ontario's Long Term Energy Plan:
The Ontario Government's plan details how electricity will be generated and the longer-term conservation strategy for the province. It can be found at this website:
http://www.energy.gov.on.ca/en/ltep/

Regional Planning:
The Ontario Power Authority (OPA) looks ahead to the future electricity needs of your region and how those needs can be addressed through Conservation and Demand Management (CDM), local generation, and electricity from outside the region. You can follow the OPA`s regional planning process at this website:
http://www.powerauthority.on.ca/power-planning/regional-planning

Ontario's Energy Planning Diagram



Provincial System Planning

This involves more long-term planning on how Ontario's electricity system is designed and operated.

This includes planning on:

- Provincial electricity supply mix (e.g. greening the grid and phasing out coal)
- System supply and demand forecasting
- Interconnections and grid design

Regional Planning

Regional planning involves near- and medium-term plans to meet the needs of a region of the province, and ensure all key players (i.e. transmission and distribution operators) are coordinated moving forward.

This planning process is focused on considering whether CDM & local generation options have been considered, in addition to core infrastructure ("wires") solutions.

Distribution Network Planning

Distribution planning involves plans, both near- and longer-term, to ensure the local distribution system has the adequate capacity to meet required reliability and safety standards, and to otherwise meet the needs of customers.

Why Are We Here?

The electricity industry in Ontario is regulated by the Ontario Energy Board (OEB), which requires distribution companies, such as PowerStream, to prepare and submit a distribution system plan to show how it will sustain the area's electricity distribution system over the next five years.

The OEB recently developed a new regulatory requirement for distribution system plans that requires distribution companies, to gather information about customer needs and preferences on distribution system investments and report on how they responded. PowerStream needs your participation to ensure its plan addresses your needs and expectations.

You don't have to be an electricity expert to participate

This consultation is not about technical issues. The OEB hearing process will allow experts representing various consumer and interest groups (called intervenors) to challenge the detailed engineering and business decisions within PowerStream's plan. This consultation focuses on the goals of the system. Should PowerStream focus more on reducing the number of outages or the lengths of outages? Should reliability be increased even if rates go higher, or should PowerStream maintain the current level of reliability and keep rate increases lower?

This primer has been developed to guide you through PowerStream's plan. As you proceed, it asks questions designed to collect your feedback. In order to facilitate this, the primer is divided into several sections that explain the distribution system, the challenges it faces and, more importantly, how PowerStream will be responding to those challenges.

Your input, and PowerStream's response to your input, will be presented to the OEB and intervenors when PowerStream files its rate application for 2016 to 2020 in the spring of 2015.

PowerStream's Rate Application Process

PowerStream assesses system needs

↓

Collects customers needs and preferences

↓

Refines plan (where necessary)

↓

Reports on how plan responds to customer input

↓

Files plan with OEB

↓

Interrogatories and OEB rate hearing process

↓

OEB sets PowerStream's distribution rates

Innovative Research Group Inc. has been engaged by PowerStream to collect participant feedback and will deliver it to PowerStream to assist them in shaping their plans.

Feedback

1. How familiar are you with the electricity system in Ontario, and the services PowerStream is responsible for?

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

Your Electricity Bill

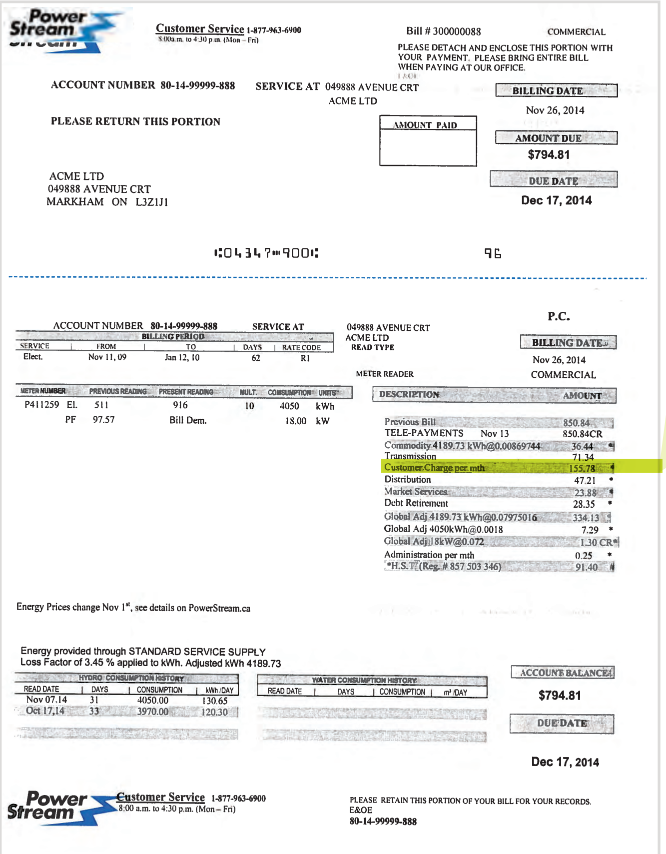
Every item and charge on the bill is mandated by the provincial government or regulated by the OEB. There are two distinct cost areas that make up the “Delivery” charge on your bill: distribution and transmission. While PowerStream collects both, it remits the transmission charge to Hydro One. The distribution charges are what PowerStream uses to fund its utility needs.

Distribution charges are one of several charges on your bill. Current monthly distribution charges are approximately $963 for a typical PowerStream general service customer with a peak monthly demand of 250 kWh. The amount you pay varies depending on your peak demand.

PowerStream’s distribution rates are subject to the review and approval of the OEB. The rate revenue covers PowerStream’s capital investments and operating expenses.

The plan PowerStream is proposing will maintain reliability at or above its current level. The resulting levels of capital investment and operational spending over the next five years will result in an increase of **$74.60** per month or **6.7 per cent** annually on the distribution rates charged by PowerStream. At the end of the plan in 2020, the average GS > 50 kW customer will be paying an estimated **$373.00** more per month on the distribution portion of their electricity bill. Other items on your bill may also increase.

Sample Electricity Bill



Customer Service 1-877-963-6900
8:00a.m. to 4:30 p.m. (Mon – Fri)

Bill # 300000088 COMMERCIAL

PLEASE DETACH AND ENCLOSE THIS PORTION WITH YOUR PAYMENT. PLEASE BRING ENTIRE BILL WHEN PAYING AT OUR OFFICE.

ACCOUNT NUMBER 80-14-99999-888 SERVICE AT 049888 AVENUE CRT ACME LTD

BILLING DATE Nov 26, 2014

PLEASE RETURN THIS PORTION

AMOUNT PAID

AMOUNT DUE $794.81

ACME LTD
049888 AVENUE CRT
MARKHAM ON L3Z1J1

DUE DATE Dec 17, 2014

⑆0434 7⑈900⑆ 96

ACCOUNT NUMBER 80-14-99999-888 SERVICE AT 049888 AVENUE CRT ACME LTD

READ TYPE

P.C.

BILLING DATE Nov 26, 2014 COMMERCIAL

METER READER

SERVICE	FROM	TO	DAYS	RATE CODE
Elect.	Nov 11, 09	Jan 12, 10	62	R1

METER NUMBER		PREVIOUS READING	PRESENT READING	MULT.	CONSUMPTION	UNITS
P411259	El.	511	916	10	4050	kWh
	PF	97.57	Bill Dem.		18.00	kW

DESCRIPTION	AMOUNT	
Previous Bill	850.84	
TELE-PAYMENTS Nov 13	850.84CR	
Commodity 4189.73 kWh@0.00869744	36.44	*
Transmission	71.34	
Customer Charge per mth	155.78	*
Distribution	47.21	*
Market Services	23.88	*
Debt Retirement	28.35	*
Global Adj 4189.73 kWh@0.07975016	334.13	
Global Adj 4050kWh@0.0018	7.29	*
Global Adj 18kW@0.072	1.30 CR	*
Administration per mth	0.25	*
*H.S.T. (Reg. # 857 503 346)	91.40	#

Energy Prices change Nov 1st, see details on PowerStream.ca

Energy provided through STANDARD SERVICE SUPPLY
Loss Factor of 3.45 % applied to kWh. Adjusted kWh 4189.73

HYDRO CONSUMPTION HISTORY

READ DATE	DAYS	CONSUMPTION	kWh /DAY
Nov 07.14	31	4050.00	130.65
Oct 17,14	33	3970.00	120.30

WATER CONSUMPTION HISTORY

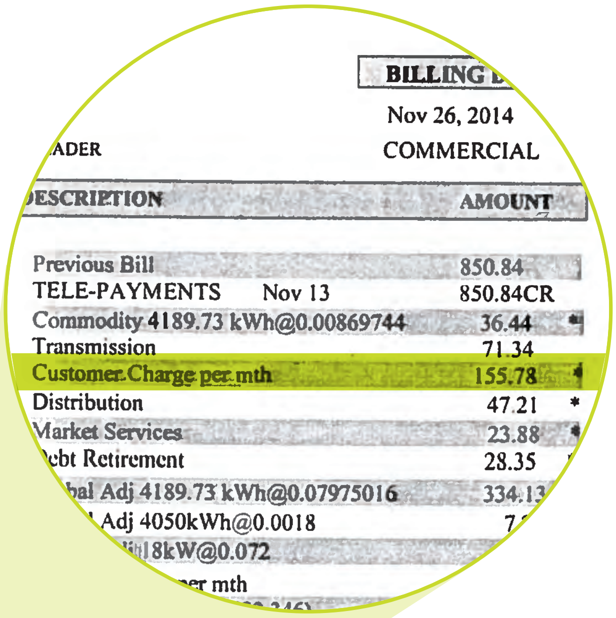
READ DATE	DAYS	CONSUMPTION	m³ /DAY

ACCOUNT BALANCE $794.81

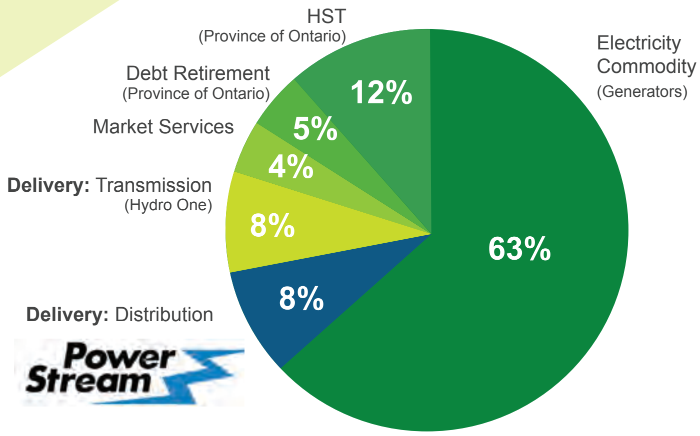
DUE DATE Dec 17, 2014

Customer Service 1-877-963-6900
8:00 a.m. to 4:30 p.m. (Mon – Fri)

PLEASE RETAIN THIS PORTION OF YOUR BILL FOR YOUR RECORDS.
E&OE
80-14-99999-888



About eight per cent of the average electricity bill goes to PowerStream for general service customers with a peak demand over 50 kW.



How are Electricity Rates Determined?

PowerStream is funded by the distribution rates paid by its customers. Periodically, PowerStream is required to file an application with the OEB to determine the funding available to operate and maintain the distribution system. PowerStream must submit evidence to justify the amount of funding it needs to safely and reliably distribute electricity.

Who Protects Consumer Interests?

PowerStream's evidence is assessed in an open and transparent public process known as a rate hearing. A number of public intervenors with electricity industry expertise submit their own evidence challenging PowerStream's plans and assumptions. At the end of the process, the OEB weighs the evidence and decides on the rates PowerStream can charge for distribution.

Electricity Grid 101

Who Does What in Ontario's Electricity System?

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

GENERATION

Generating facilities convert various forms of energy into electric power.

EXAMPLES

Ontario Power Generation
TransCanada Energy Ltd
Bruce Power
Samsung Renewable

TRANSMISSION

Transmission lines (high voltage lines) connect the power produced at generating facilities to transformer stations.

EXAMPLE

Hydro One

DISTRIBUTION

Distribution lines (at medium voltages) carry electricity to homes and businesses.

EXAMPLES

PowerStream
Toronto Hydro
Newmarket Hydro

CONSUMERS

Electricity is delivered to homes and businesses.

EXAMPLES

Residential
Commercial
Industrial

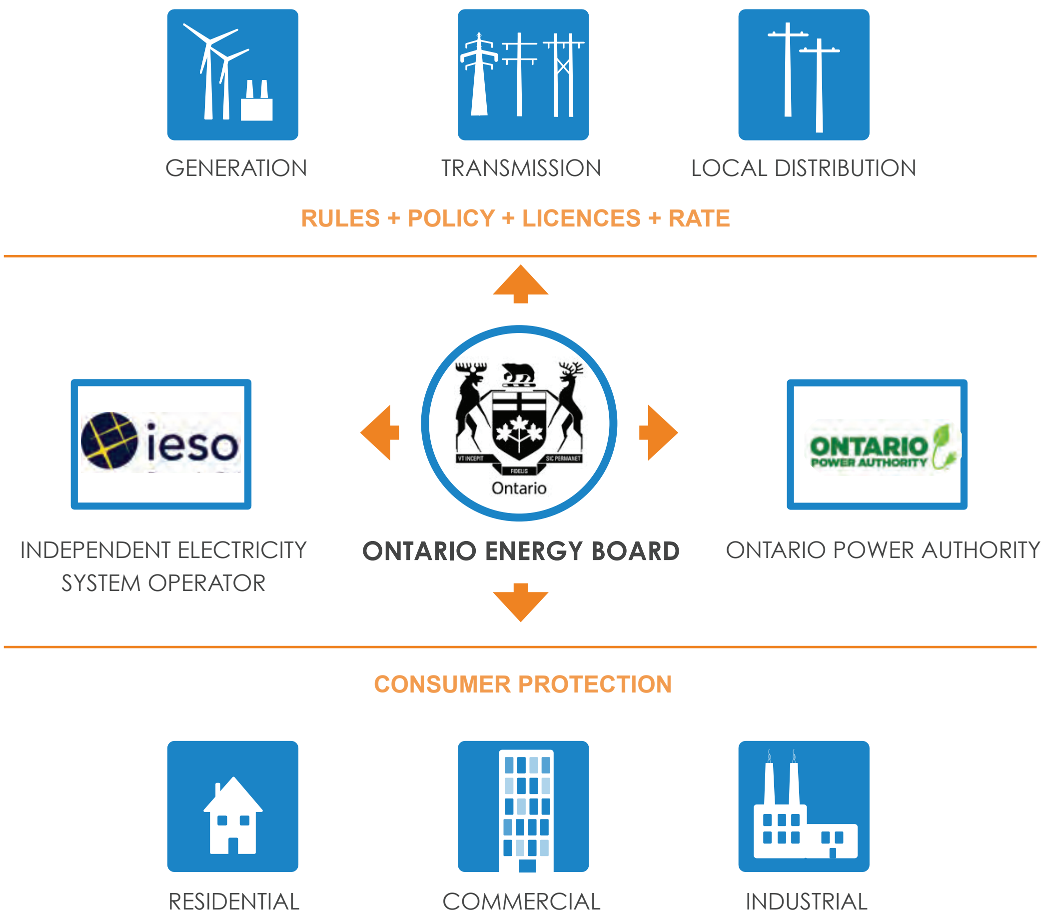
How is Ontario's Electricity System Regulated?

The **Ontario Ministry of Energy** sets energy policy. It sets the rules and establishes key planning and regulatory agencies through legislation.

The mission of the **Ontario Energy Board** (OEB) is to promote a viable, sustainable and efficient energy sector that serves the public interest and assists consumers to obtain reliable energy services at reasonable cost. It is an independent body established by legislation that sets the rules and regulations for the provincial electricity sector. One of the OEB's roles is to review the distribution plans of all electricity distributors and set their rates.

The **Ontario Power Authority** (OPA) is responsible for medium and long-term electricity planning to ensure an adequate supply of electricity is available for Ontario residents and businesses. The OPA receives directives from the Ministry of Energy (i.e. energy supply mix, Green Energy Act), but otherwise works at arm's-length from the government.

The **Independent Electricity System Operator** (IESO) is responsible for electricity supply over the short-term. It operates the grid in real-time to ensure that Ontario has the electricity it needs, where and when it needs it.



PowerStream's Grid Today

This section describes the construction of PowerStream's distribution grid including its overhead, underground and secondary systems. It also explains the corporation's historical growth and current electrical infrastructure.

The Background of PowerStream's Distribution Grid

PowerStream owns and operates $1.17 billion in capital assets and is the second largest municipally- owned electricity distribution utility in Ontario. It distributes about eight per cent of Ontario's electricity demand. PowerStream's electrical grid is comprised of overhead, underground and secondary systems of various voltages. PowerStream was formed in 2004 from the amalgamation of Hydro Vaughan, Markham Hydro, and Richmond Hill Hydro. Aurora Hydro was purchased in 2005, and in 2009, Barrie Hydro merged with PowerStream.

Each original utility operated independent distribution systems, and as a result, the infrastructure varies from region to region. PowerStream has been working to gradually standardize this equipment, which will help improve reliability and safety across the regions, and make maintaining the system more efficient.

PowerStream is owned by three municipalities and regulated by the OEB. As such, any profits obtained by the utility are provided to the municipalities as a dividend, or reinvested into the distribution system.

A Look at PowerStream's Growth

PowerStream has been serving York Region since 2004 and Simcoe County since 2009, and has seen remarkable change and innovation through the years. Although PowerStream as an entity dates back to 2004, the first electric system and street lights in the service territory were installed in Barrie in 1888, Markham in 1890-1891, and in neighbouring areas soon after.

PowerStream has a mix of older and newer distribution systems across all of its service territory. PowerStream is systematically and prudently upgrading older areas. Of course, even as this work is completed, the overall system continues to age.

PowerStream is a product of the largest voluntary consolidation of local distributors and is an organization committed to becoming an innovative and socially responsible leader in power distribution and related services. Growth is a key performance driver for PowerStream, and is achieved through increases to its residential and commercial customer bases.

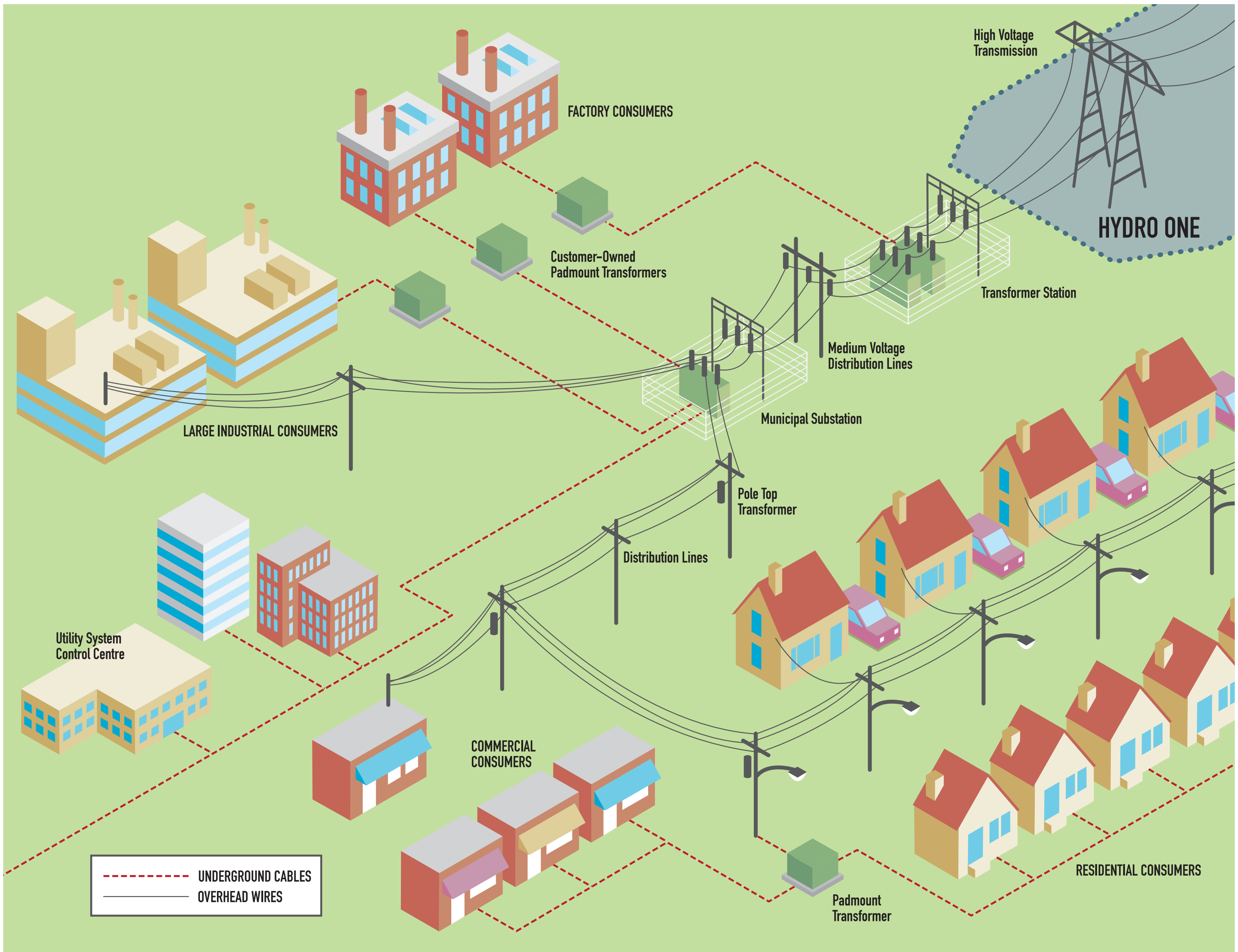
Large projects currently underway include the new Vaughan Metropolitan Centre project at Hwy 7 and Jane Street, the new Vaughan Campus of Mackenzie Health, and the expansion of the Toronto Transit Commission subway into York Region. All of these projects highlight the expansion and growth occurring in PowerStream's service territory.

PowerStream's Distribution System

Every system is unique with its own history and challenges. In order to better understand the current PowerStream system, we first have to understand all of the different components and how they impact the way in which you receive electricity when you need it. The image below and following terms and definitions will help guide you through the system from when you turn a switch on to when you receive your bill.

PowerStream's distribution system is made up of a number of components which work together to transport electricity to your house or business.

Distribution System Diagram



Transformer Stations and Municipal Substations

PowerStream owns 11 of the 25 Transformer Stations (TSs) that connect PowerStream's distribution system to the 230 Kilovolt (kV) provincial transmission grid owned by Hydro One and operated by the IESO. In fact, the very first municipally-owned transformer station in Ontario was built in PowerStream's service territory (Markham) back in 1985.

Municipal Substations (MSs), 54 in total, also play an important role in PowerStream's distribution system, further transforming higher voltage electricity to a lower voltage that is suitable for local distribution to customers.

Transformers – Important pieces of equipment that reduce the voltage of electricity from a high level to a level that can be safely distributed to your area, or to your residence/business.

Breakers – Devices that protect the distribution system by interrupting a circuit if a higher than normal amount of power flow is detected.

Switches – Control the flow of electricity and steer the current to the correct circuits.

Feeder Circuits – Are the wires that connect the stations to the broader distribution system in order to deliver electricity to customers.

PowerStream's Overhead System

The overhead system is made up of distribution lines that operate at various voltages depending on their purpose and destination. PowerStream has 2,535 km of overhead distribution lines in its service territory. These distribution lines are attached to the top of hydro poles.

Along the distribution line, pole-top transformers step the voltage down to useable levels of 120V-600V. From there, the electricity is delivered to customers through a secondary line that runs from the transformer to an individual home or business.

PowerStream has 3,500 switches, and over 330 pole-mounted remote-controlled switches located throughout its distribution system. These switches, which are controlled from PowerStream's Main System Control Centre, greatly improve operating efficiencies, and reduce restoration times whenever a power interruption occurs.

PowerStream's Underground System

PowerStream's underground system consists of high and low voltage cables, metal enclosed switchgear and transformers situated on concrete pads. In residential areas, underground cables distribute electricity from the TSs or MSs to padmount transformers located on the municipal boulevards. Like the overhead system, these transformers step the electricity down to useable voltages of 120V-600V, and the power is then delivered to customers through over 5,000 km of buried low voltage wires.

When distributing electricity to urban areas or larger customers, larger transformers are used.

PowerStream has 1,800 gears, and over 40 padmounted switchgears that are controlled remotely from its System Control Centre. These remote-controlled switches are critical for improving operating efficiencies and power restoration times in the underground distribution system.

Feedback

2. How well do you feel you understand the important parts of the electricity system, how they work together, and which services PowerStream is responsible for?

- ☐ Very well
- ☐ Somewhat well
- ☐ Not very well
- ☐ I don't understand at all

3. Generally speaking, how satisfied are you with the service you are receiving from PowerStream? Would you say …

- ☐ Very satisfied
- ☐ Somewhat satisfied
- ☐ Somewhat dissatisfied
- ☐ Very dissatisfied
- ☐ Don't know

4. Is there anything in particular that PowerStream can do to improve its service to you?

Reliability

Delivering reliable power safely is PowerStream's fundamental purpose. Three key standard industry measures are used to track system reliability. They include:

SAIFI

System Average Interruption Frequency Index
This measure shows the number of outages an average PowerStream customer experiences in a year.

SAIDI

System Average Interruption Duration Index
This measure shows the amount of time an average PowerStream customer is without power in a year.

CAIDI

Customer Average Interruption Duration Index
This measure indicates on average how long it takes for PowerStream to restore power to a customer after a power outage.

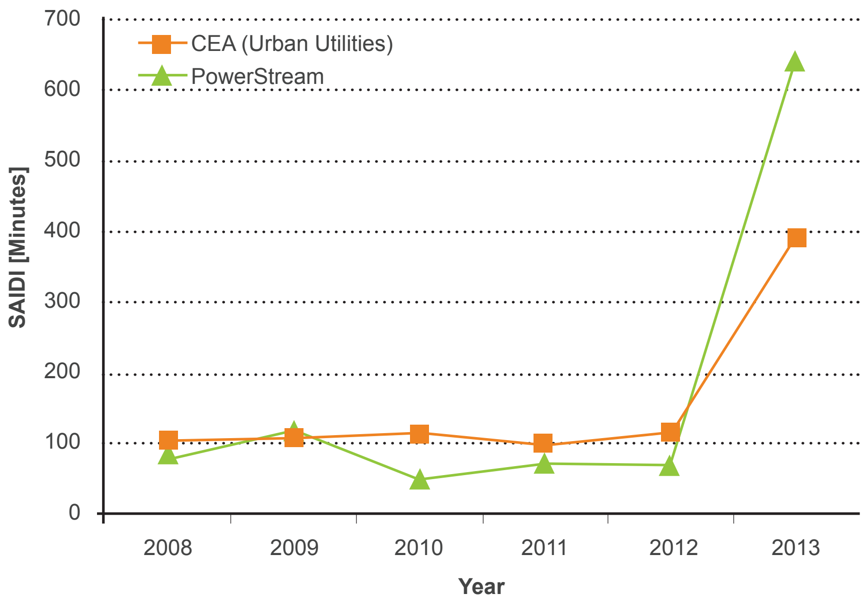
All planned and unplanned sustained interruptions are used to calculate these indices.

How is PowerStream Performing:

For reliability performance, the OEB expects that the distributor's current reliability performance (SAIDI, SAIFI, CAIDI) should, at minimum, remain within the range of its historical previous three year performance. PowerStream's plan aims to meet this requirement.

As seen in the chart below, PowerStream's SAIDI performance has been at par or better than average of the other comparable Canadian urban utilities with the exception of 2013 when PowerStream was hit hard by an unusual weather event (December Ice Storm).

PowerStream SAIDI [minutes] Comparison to Other CEA (Canadian Electricity Association) Urban Utilities for All Outages



Controllable vs. Uncontrollable Factors

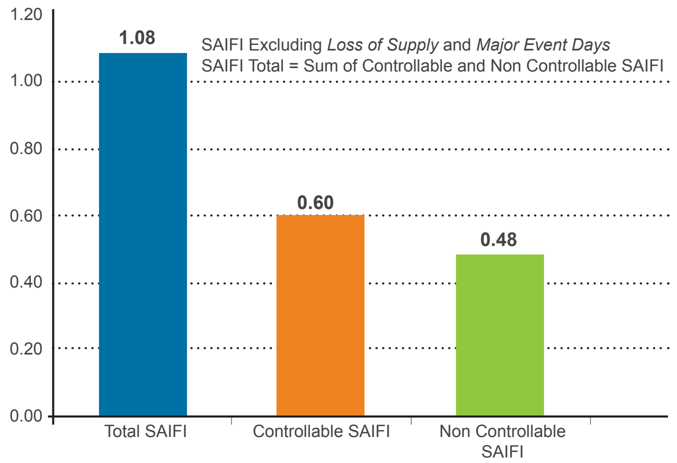
Electricity outages can be caused by factors that PowerStream can and cannot control.

Uncontrollable events include lightning, adverse weather, adverse environment (e.g. salt contamination) and third party created events.

Controllable events include scheduled outages in order to perform work on the distribution system, tree contacts, defective equipment and errors caused by people.

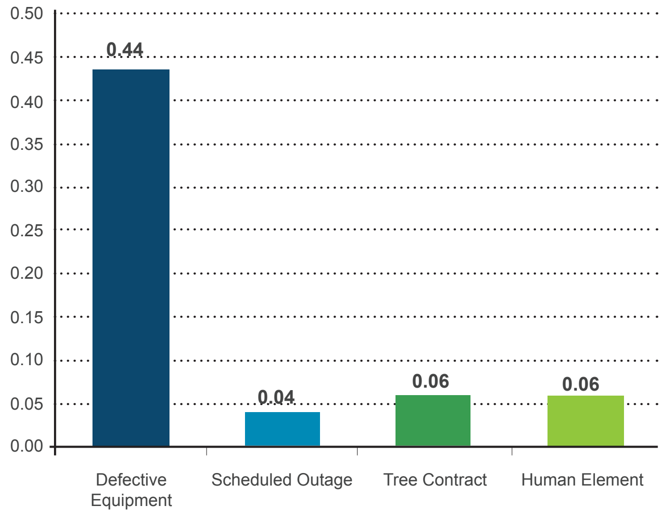
The chart below shows that more than half of the outages PowerStream customers experience are caused by controllable events.

Total SAIFI, Controllable & Uncontrollable SAIFI [2008-2013]



As the breakdown in the chart below illustrates, defective equipment is far and away the largest contributor of controllable outages.

Breakdown of Controllable SAIFI Excluding *Loss of Supply* and *Major Event Days* [2008-2013]



Capital Expenditure and Outages

Managing equipment failure is a never-ending race. Each year PowerStream invests in replacement or rehabilitation of its oldest assets and systems. The assets in the poorest condition are identified through an annual inspection programs. However with each passing year the rest of the assets get older and a new set of assets falls into poor condition.

Outages are also targeted as a result of poor performing feeders identified through reliability statistics each year. As these feeders are worked on and reliability improves, a new set of feeders falls to the bottom of the performance ratings.

As you will see in the following pages, over the next five years, PowerStream is planning investments in new equipment and the rehabilitation of existing equipment, such as underground cables, to reduce the number of outages due to equipment failure.

While outages are to some degree chance events, the investment in new equipment matches the aging profile of the system and is expected to sustain the current level of reliability and to achieve reliability improvement in the worst performing areas.

Capital Expenditure and Restoration Times

Restoration time is an area where PowerSteam actively pursues improvement. Restoration times depend on three things - the physical capacity to work around a problem, the speed at which the utility can re-route electricity through that physical network, and the speed by which the broken parts can be repaired.

As PowerStream expands the system through system service updates such as higher voltage lines, new stations and feeder lines or similar system improvements, the utility is building more capacity to work around outages.

As PowerStream adds remote monitors to pin-point where faults are occurring and add remote or automated switches to avoid the need to send a crew to manually flip a switch, the utility is increasing the speed by which power can be restored.

Finally, investments in areas such as equipment standardization, GPS devices and improved scheduling tools all contribute to our ability to replace broken equipment more quickly.

Feedback

5. As far as you know, in the past year, did you experience any outages due to unusual weather such as the ice storm, microbursts or tornados?

- ☐ Yes
- ☐ No
- ☐ Don't know

6. Whether you were personally affected or not, how satisfied are you with the way PowerStream responded to these events? Would you say …

- ☐ Very satisfied
- ☐ Somewhat satisfied
- ☐ Somewhat dissatisfied
- ☐ Very dissatisfied
- ☐ Don't know

7. Is there anything in particular that PowerStream can do to improve its service to you during these extreme weather events?

8. Other than outages during unusual weather events, how many outages did you experience in the past year?

- Zero
- One
- Two
- Three
- Four
- Five or more

9. Aside from unusual weather events, if you experienced an outage in the past year, what was the longest you experienced?

- Less than 15 minutes
- 15 to less than 30 minutes
- 30 minutes to less than 1 hour
- 1 hour to less than 3 hours
- 3 hours to less than 6 hours
- 6 hours to less than 12 hours
- 12 to less than 24 hours
- More than 24 hours
- Don't know

10. If you experienced an outage, how satisfied are you with the way PowerStream responded to the outage? Would you say …

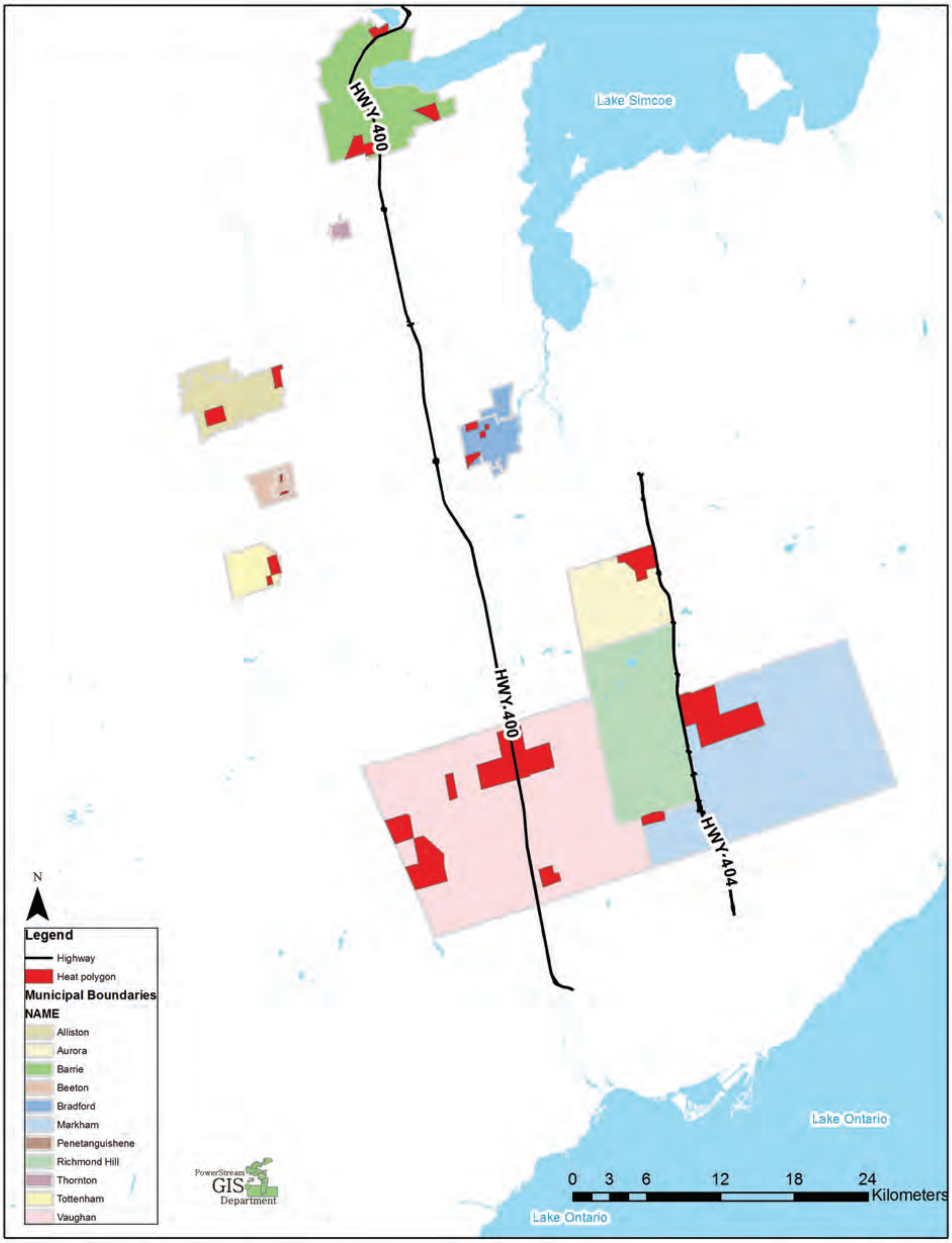
- Very satisfied
- Somewhat satisfied
- Somewhat dissatisfied
- Very dissatisfied
- Don't know

11. Is there anything in particular that PowerStream can do to improve its service to you during outages?

12. Most years, the average PowerStream customer loses power due to outages for about 100 minutes over the whole year. This is at or below the average for similar utilities. Do you feel this level of reliability is …

- Very good
- Good
- Acceptable
- Poor
- Very poor
- Don't know

Capacity Constrained Areas of PowerStream's Service Territory



Challenges and Solutions

Pressure: Growth

Fueled by increased economic development and demand for new housing in York Region and Simcoe County, PowerStream adds over 8,000 new customers to its existing customer base every year. This growth in customers and load puts increasing pressure on PowerStream's distribution system, which requires extending power lines, upgrading capacity to existing power lines, and adding new capacity to load constrained areas.

The map on the previous page shows the capacity constrained areas of PowerStream's service territory. Red highlighting indicates areas that require increased investment to provide additional capacity in the near term to ensure system reliability.

Challenges	Solutions
Lines and equipment that cannot carry the increased load and maintain the increased reliability expected by customers.	• New **substations, transformer stations**, and power **lines** where needed to increase supply capacity. • **Voltage** Conversion Projects: existing 8kV and 13.8kV power lines converted to 27.6kV to increase load capacity. • Station Investments: intended to ensure stations have peak loadings maintained at or below their 10 day Limited Term Rating to prevent damage to station equipment and avoid brownouts and blackouts.
Development of new subdivisions resulting from increased demand for new homes, which requires expansion of the distribution system lines and stations.	• Need investments to increase **station** and power line capacity to maintain the loading of existing municipal **substations** and to ensure sufficient space capacity exists such that if there is a loss of one substation, the neighbouring **substations** can accommodate the lost **capacity.**

Pressure: Aging Equipment

PowerStream's distribution system consists of various equipment (**poles, transformers, cables**, etc.) with different installation date profiles. While the majority of the distribution system was installed or rebuilt after 1980, a significant amount of distribution system equipment was installed in the 1970s, 1960s or even earlier, and is still in service today. While that old equipment continues to operate for the time being, it is well past its intended service life, and much of it will need to be replaced soon.

Equipment that is still operating beyond its intended service life is more likely to fail, and cause long power interruptions. As time goes on, more and more of the distribution system assets will be operating past end-of-life, unless replaced. This requires investment in system renewal projects and programs.

While PowerStream and its predecessor utilities have historically managed asset replacement programs efficiently with moderate levels of investment, the growing number of old assets needing replacement requires a higher level of investment than ever before.

PowerStream plans to proactively replace the oldest and worst condition equipment before it fails. Generally, proactive equipment replacement is less expensive than replacing equipment after an unexpected failure.

Some distribution assets such as pole mounted transformers and residential padmounted transformers, as well as secondary cables, are not proactively replaced. These assets are replaced once they fail. This "run to failure" approach is considered normal utility practice in the industry.

Asset Summary Chart – main assets by quantity

Asset Types	Asset Count (approx)	Average Life (approx)	Oldest Assets (approx)
Wood Poles	46,500	35-75	1940
Distribution Transformers	44,000	25-60	1956
Underground Primary Cable	7900 km	20-55	1965
Distribution Switchgear	1800	30-85	1978
Station Circuit Breakers	399	35-65	1958
Municipal Station Primary Switches	66	30-60	1956
Municipal Station Transformers	65	30-60	1958
Station Reactors	34	25-60	1986
Transformer Station Transformers	22	30-60	1986
Transformer Station 230kV High-Voltage Switches	22	30-60	1986
Station Capacitors	5	25-40	1990

Note: Above data and figures provided from PowerStream Asset Condition Assessment, Rev. 2, November 27, 2012.

Challenges	Solutions
The need to replace poles that are at or nearing end-of-life.	• Proactive replacement: PowerStream plans to replace or reinforce approximately 400 of the worst condition poles per year in order to minimize risk.
Underground primary cables that are at, or near, end-of-life, and the resulting high negative impact this has on reliability for affected customers.	• PowerStream proposes to replace approximately 52 km/year of the worst condition **underground cables**, and use silicon injection to extend the life of another estimated 47 km/year of underground cables. • PowerStream's approach for **cable** replacement is determined by prioritizing the cable sections that have the worst reliability and the highest customer impact.
Aging padmounted switchgear cubicles.	• Proactive replacement: PowerStream plans to replace approximately 31 of the poorest condition **switchgear** units in 2015, rising to 36 per year in 2016-2020.
The need to replace padmounted transformers, where concerns about condition have been reported.	• PowerStream commenced a proactive replacement program in 2013. • PowerStream proposes to proactively replace approximately 60 **padmounted transformers** per year.
Automated/remote-controlled switches, switches that are at, or near, end-of-life and therefore likely to fail compromising the ability to prevent feeder and station overloads during the summer peak.	• PowerStream proposes to replace five per year. • These are important for a number of reasons, including preventing station overloads during summer peaks, as well as improving reliability and restoration times.

Pressure: New Technology

PowerStream is finding that in general, customers have increased expectations. They want to communicate with us around the clock and in new ways, such as through social media. Some customers are seeking a detailed understanding of their electricity consumption, and how their bill is calculated. PowerStream information systems must support these customer needs.

The delivery model of the distribution system is changing. Renewable or other forms of generation have changed power flow from unidirectional to multidirectional. Managing this fundamental change requires increased technological investments.

Challenges	Solutions
The requirement to develop and support smart grid technology to meet the high reliability demands of today's electricity consumers.	• Improvements to the **distribution system** to support growing numbers of Electric Vehicles. • Improvements to the distribution system to support increased renewable **generation** and **energy storage** initiatives. • Develop and promote consumer energy management initiatives to reduce energy demand.
An outdated billing system, over 35 years old, that cannot support a growing number of customers, has limited ability for interactive features, and no longer has vendor support.	• A new modern **billing system**, expandable in the future as required, to provide a more efficient platform for customers with increased interactive support and customer information security. A new modern billing system will also provide increased efficiencies by integrating with other systems, and produce long-term cost savings.
The replacement of end-of-life remote-controlled switches to ensure rapid and automatic transfer of loads in emergencies and reduce restoration times.	• Installation of new smart remote-controlled power line **switches** and **reclosers**. • A formal decision-making process for determining the most cost effective quantity of **switches**, and the optimal locations, for providing the maximum benefit to the largest number of customers.
The need to replace old and difficult to operate "mini-rupter" (high capacity isolating) switches in commercial/ industrial locations.	• Installation of new high-capacity isolating **switches** that increase operational efficiencies and reduce the need for costly power interruptions when performing routine maintenance.
New OEB regulations that require higher intelligence metering equipment for all commercial/industrial customers over 50kW by 2020.	• Replace 4400 meters with new **smart technology** meters in a pre-planned efficient multi-year program.

Pressure: Security

As technology continues to be utilized in every aspect of the utility's business, there is an increasing risk of cyber security attacks that could potentially affect confidential customer or corporate information, customer privacy, power delivery, and even the safety of employees or customers through the unauthorized use of PowerStream technology. One incident could do serious damage to the corporation and to its corporate image. In addition, there is the on-going risk of physical security; the physical protection of buildings and stations, and the monitoring of critical equipment to protect from impending failure.

Challenges	Solutions
Evolving risks to cyber security of customer information and grid due to aging and unsecure IT equipment.	• Firewall/Intrusion Detection System/Intrusion Protection System—this is a security checkpoint between the trusted and untrusted network/device/users and is also used to continuously monitor for any malicious activity and can automatically take action in certain instances. • Network Access Control—this dynamically monitors and controls devices, applications and users to deny unauthorized external access to the network. • Identity and Access Management—this manages user access and privileges granted throughout the PowerStream environment • Security Information and Event Management—this is real-time logging and analysis of security alerts. • Vulnerability Assessment Tool—this scans, identifies, quantifies and prioritizes vulnerabilities in the PowerStream environment and suggests remediation solutions. • Mobile Device Management—this controls mobile devices connected to our network and can authorize, wipe, secure and encrypt corporate information as required. • Enterprise Change Management—this process and associated technology allows PowerStream to effectively deal with constant change through a structured approach to transitioning systems, applications and technologies from current to desired future states.
Risk of vandalism to substation buildings and equipment.	• Install equipment monitoring Infrared cameras at 16 additional stations over the next 6 years. • Install perimeter video surveillance cameras at 17 additional stations over the next 6 years.

Pressure: Obsolescence

Despite an ever increasing number of weather-related interruptions each year, PowerStream has worked hard to stay within the boundary of its average historical reliability performance targets of one outage totalling 60 minutes per customer, per year.

While PowerStream continues to demonstrate strong reliability performance in the operation of its distribution network, it is not without its challenges. There are areas and pockets within the PowerStream distribution system that suffer poor reliability due to the type of legacy construction that was once considered acceptable or even preferable. An example of this would be older houses connected to overhead power lines located in the back lot (rear lot) of those properties.

The reliability of rear lot supply connections is worse under severe weather conditions than the current standard front lot connections. In addition, the cost to maintain these rear-lot connections is much higher than the cost to maintain front lot connections.

Challenges	Solutions
Rear Lot Conversion program: Capital work required to address reliability, safety, operations and customer service concerns on rear lot supply connections.	• There are 49 areas of rear lot construction scattered among eight of the municipalities of PowerStream. Most of those areas were constructed in the 1950's, 1960's and 1970's. The oldest dates back to 1948. • PowerStream proposes to replace the worst areas of rear lot connections on an annual basis over many years until all areas are converted. • The average cost of this conversion work is estimated to be \$1.2M per rear lot area. • Elimination of rear lot supply connections will result in long-term operational efficiencies and reduced maintenance costs.

Pressure: Major Events

PowerStream's system is built to quickly restore power after the loss of one or two key elements in the electricity grid. But what happens when there is a major disruption to the system?

PowerStream has been severely impacted by weather–related events over the past year. The December 2013 ice storm, microbursts in York region and tornados in the North service area have all highlighted the risk to the grid from major events. Major events are rare events that have a major impact. The Insurance Bureau of Canada reports that severe weather is likely to increase over the next 40 years.

The December 2013 Ice Storm in Ontario severely tested the emergency preparedness of electrical utilities in Southern Ontario including the Greater Toronto Area where hundreds of thousands of customers were left without power, some for as long as a week, or even longer. An independent assessment of PowerStream's response to that storm highlighted a number of areas where improvements are required at PowerStream to be better prepared for future severe storms and emergency events. Key areas identified for improvement include:

1. Improve external communications with customers.
2. Improvements to Customer Care systems and staffing.
3. Improve Outage Management Systems and utilize outage reporting via existing Smart Meters.
4. Improve vegetation management.
5. Elimination of rear lot services, and convert to front lot.
6. Upgrade or underground key distribution lines.

Challenges	Solutions
The need for emergency preparedness during unplanned events and expenses.	• Prepare contingency plans for the immediate replacement of assets (i.e. **poles, transformers**, etc.) due to unanticipated failure, storms, motor vehicle accidents, vandalism, etc. • Ensure adequate levels of spare equipment and materials are available for emergencies.
The need to improve the supply to those customers who are more vulnerable to outages and duration of outages, specifically rear lot supply.	• Plan to replace rear lot supplies on an annual basis until all are remediated.
The need to make changes to key distribution lines to withstand increased severity of weather events.	• Plan to increase structural integrity of key assets (i.e. tension cables designed to add stability to poles). • Upgrade or underground key wires.

The investments discussed earlier in the primer are focused on minimizing day-to-day outages and increasing the speed by which electricity is restored. Additional investments could help "harden" the system and speed up power restoration during a major event. There is no practical limit to potential ways of making the system more resilient in a major event, it is fundamentally a question of money.

13. A significant amount of PowerStream's distribution system equipment was installed in the 1970s, 1960s or even earlier, and is still in-service today. PowerStream works hard to extend the life of our existing equipment because it helps to keep rates down, but as equipment gets older it becomes more likely to fail. PowerStream has two approaches to older equipment.

- If the failure of a piece of equipment will impact a large number of people, result in a long outage or if an inspection shows the equipment is in poor condition, PowerStream does initiate equipment replacement before failure.
- When an equipment failure has only a limited impact and can be quickly replaced, PowerStream's policy is to leave the equipment in place until it breaks down to get all the value possible from that equipment.

What do you think of this policy?

- ☐ I am willing to pay more to replace all equipment before it fails.
- ☐ I support the current approach of allowing equipment to run to failure when that failure impacts only a few customers for a limited period of time.
- ☐ Don't Know

14. When it comes to replacing aging equipment, which of the following points of view is closest to your own?

- ☐ PowerStream should invest what it takes to replace the system's aging infrastructure to reduce the risk of power outages; even if that means my electricity bill will increase by a few dollars per month.
- ☐ PowerStream should scale back their investment in renewing the system's aging infrastructure to reduce the size of any bill increase; even if that means more or longer power service interruptions.
- ☐ Don't Know

15. While there are clear benefits from new technology, there are also costs. The system functions well on the old technology. Do we want to pay more to secure the benefits new technology can deliver?

When it comes to investing in new technology, which of the following points of view is closest to your own?

- ☐ Investments in new technologies are more a luxury than a necessity and should be a low priority for PowerStream.
- ☐ I think the benefits of new technology are important and investments in new technology should be a priority for PowerStream.
- ☐ Don't know

16. The investments discussed earlier in the primer are focused on minimizing the day-to-day outages and increasing the speed by which electricity is restored. There are additional investments could help "harden" the system and speed up power restoration during a major event. There is no practical limit to potential ways of making the system more resilient in a major event, it is fundamentally a question of money.

Currently, the average GS > 50 kW customer pays $963 a month to PowerStream to operate and maintain the local distribution system. How much more are you willing to pay each month for investments that would help the system better withstand major events such as extreme weather?

$ ________

What this Plan Means for You

It all comes down to what you pay and what you receive in return.

What will you get? PowerStream's plan for 2016 to 2020 deals with the challenges outlined in this primer to deliver a system that will maintain or achieve modest improvements in reliability and service.

What will it cost? GS > 50 kW customers with peak montly demand of 250 kWh may see an increase of **$74.60** per month or **6.7 per cent** annually on the distribution portion of their bill over the next five years. As such by 2020, the average GS > 50 kW customer will be paying an estimated **$373.00** more per month on the distribution portion of their electricity bill. It is important to note that other increases on the bill by other entities are also possible.

There are two main elements in that increase:

- An increase of approximately **2.1 per cent** or **$23.38** per month in operating costs which reflects inflation and new costs which are offset in part by efficiency savings;
- An increase of approximately **4.6 per cent** or **$51.22** per month for new capital investments to deal with the issues discussed earlier such as growth, aging infrastructure and new technology.

In addition, in the first year of the plan there is a "catch-up" increase to deal with expenses that were not properly covered under the existing rate adjustment formula. The next section explains the need for that catch-up.

Current Revenue Shortfall

The formula for setting PowerStream's rates in 2014 and 2015 is not keeping up with the need for new investment.

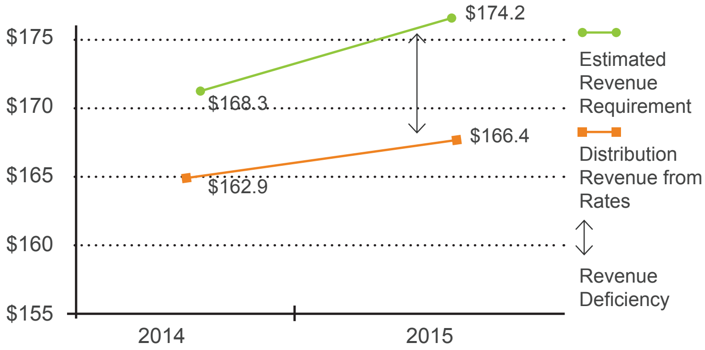
PowerStream's rates were set in 2013 using the cost of service method where the OEB sets rates at the level needed to fund the operation of the utility. That worked well in 2013.

However, in 2014 and 2015, rates were not based on actual costs. Instead, a formula was applied which adjusted rates for inflation less an adjustment for efficiency, referred to as a price cap index (PCI) adjustment. This formula does not provide enough revenue in rates to fund the actual capital investments being made in these years.

The OEB recognized that problem and created the new Custom Incentive Regulation rate setting method which PowerStream will be using in this rate filing. This method will alleviate this issue going forward but there is still a need to deal with 2014 and 2015 investments.

The chart below compares the revenue from rates using the PCI to the revenue needed to fund utility operations on a cost of service basis. Over 2014 and 2015, there will be a revenue shortfall of approximately $13.2 million. This shortfall is being funded by PowerStream's municipal shareholders from past earnings retained in the company. However, using savings to make up for the missing revenue will restrict PowerStream's ability to make the necessary future investments to maintain its system and the level of service provided to its customers. The catch-up will enable PowerStream to fund those needed investments.

Revenue Shortfall ($millions)



($ Millions)	2014	2015	Total
Estimated Revenue Requirement	$168.3	$174.2	$342.5
Distribution Revenue from Rates	$162.9	$166.4	329.3
Revenue Deficiency	($5.4)	($7.8)	($13.2)

Most of the rate increase in 2016 is to provide funding for capital investments in 2014 and 2015. This will result in an increase of **$76.35** a month for the average GS > 50 kW customer with peak monthly demand of 250 kW.

One of these major capital investments is a new billing system. PowerStream made the second largest investment in its 10 year history when it decided to bring in a new billing system in 2014/2015. PowerStream is committed to providing customers with accurate billing information from meter to payment. However, the old system was implemented 30 years ago and just wasn't keeping up with new demands such as mobile access and self-service options customers have said that they expect today. Changing to a modern system requires both a significant capital investment and an increased operating budget. Not only will it provide much better access for customers and staff, it will do so with a much higher level of security for personal information, a key concern in these times. This system will be fully implemented in 2015.

Increased Capital Spending

PowerStream has developed a list of capital investment drivers and proposes capital investment programs based on these key drivers. The definitions of the key drivers are below.

Service Requests

PowerStream has an obligation to connect a customer to its distribution system. This includes both traditional demand customers and distributed generation customers. Requests also can include system modifications to support infrastructure development by government agencies, road authorities and developers. Normal connection costs are recovered through the revenue from new customers. Unusual connection costs are paid by the customer being connected.

Increased Delivery Capacity

As new customers are connected, PowerStream needs to expand the core elements of its distribution system, including expanded or new distribution stations and enhanced or new feeder lines. This is the fundamental infrastructure that allows new customers to be hooked up to the distribution system and is paid for by the extra revenue from new customers served over time.

System Efficiency

To provide customers with the best service possible, there is always a need to improve restoration capability. As the population in PowerStream's service territory continues to grow, the system also needs to grow in order to be able to handle new connections.

Mandated Compliance

Environmental, reliability and safety standards are updated on a regular basis and PowerStream's system must be updated to keep up with these standards. Agencies that impact PowerStream include the Ministry of Energy, Measurement Canada, the OEB, the IESO and/or other regulators.

Obsolescence

Improvements in technology can require PowerStream to replace equipment that is still functional but no longer meets current operating practices or current standards. Reasons for replacement include:

- the equipment is no longer manufactured;
- there are no spare parts;
- are unable to have maintenance performed on them;
- there are operational constraints or conflicts, which can result in increased reliability and/or safety-related risks.

Aging or Poor Performing Equipment

Where there is the imminent risk of failure due to age or condition deterioration, and these potential failures will result in severe reliability impacts to customers as well as potential safety risks to crew workers or to the public, refurbishment or replacement is required.

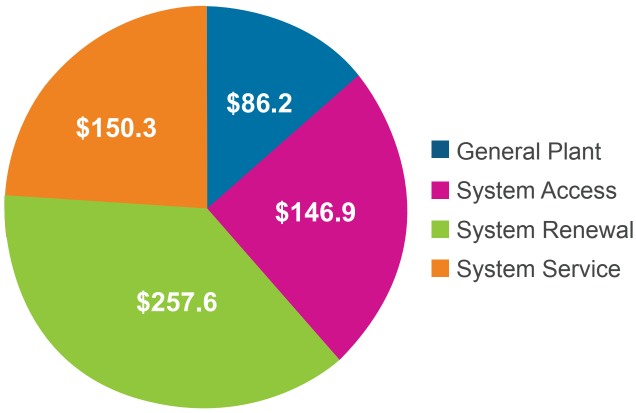
Business Support Costs

PowerStream is not just the local electricity grid itself, it is the business that operates that grid. The utility needs storage facilities for equipment, workshops to maintain and repair equipment and offices for people who manage your accounts and the electricity system. PowerStream needs vehicles for its crews, as well as computer systems to manage customer accounts, track equipment and operate the grid. While this is a relatively small slice of the capital spending over the next several years, it is just as critical to have IT systems identify where an outage is and where the needed parts are stored as to have the replacement parts themselves.

	Capital Investment Drivers	Primary Driver	Source
System Access	Subdivisions and New Connections Road Authority Metering Other Customer Initiated Work	Service Requests	Developers, Customers, Road Authorities
System Service	Reliability including Distribution Automation Additional Capacity - Lines Additional Capacity - Stations (TS and MS) Security Smart Grid Safety	Reliability Support Capacity Delivery System Efficiency Safety	PowerStream
System Renewal	Distribution Lines - Emergency/Reactive Replacement Overhead Lines and Assets Planned Replacement Underground Cable and Asset Planned Replacement Rear Lot Conversion Program Stations/Protection & Control Asset Replacement (Planned & Emergency)	Mandated Compliance Obsolescence Mitigate Failure Risks Safety	Regulator Safety Authority PowerStream
General Plant	Interest Capitalization Customer Service Information Service and Communication Systems Buildings/Facilities Fleet Tools	Capital Investment Support Customer Service	PowerStream

Looking ahead at the next five years and all the categories identified above, PowerStream is proposing to spend $641 million on new capital investments. This will result in an annual increase of about 6 per cent on the distribution portion of your bill which is about three quarters of the proposed rate increase.

2016 - 2020 Forecasted Capital Expenditures ($ millions)



With the proposed levels of capital and operating budgets for 2016 to 2020, in 2020 PowerStream will continue to operate on less revenue per customer than the average Ontario local distribution company.

Feedback

17. Given what you know and what you have read so far, how well do you feel you understand the challenges facing the PowerStream system and what they are planning to do to meet those challenges?

- ☐ Very well
- ☐ Somewhat well
- ☐ Not very well
- ☐ I don't understand at all

18. From what you have read and what you may have heard elsewhere, does PowerStream's investment plan seem like it is going in the right direction or the wrong direction?

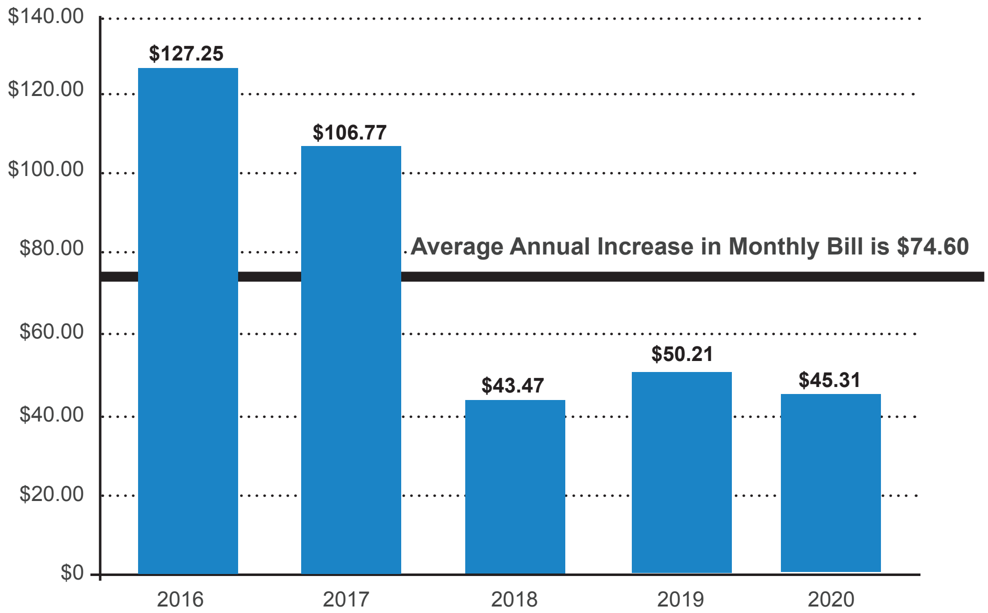
- ☐ Right direction
- ☐ Wrong direction
- ☐ Don't know

19. And why do you feel that way?

The Impact on Your Bill

GS > 50 kW customers with an average peak montly demand of 250 kW will see an increase of **$74.60** per month or **6.7 per cent** annually on the distribution portion of their bill over the next five years. As such by 2020, the average GS > 50 kW customer will be paying an estimated **$373.00** more per month on the distribution portion of their electricity bill.

Estimated Typical GS > 50 kW Annual Increase In Monthly Bill



Feedback

20. Considering what you know about the local distribution system, which of the following best represents your point of view:

- ☐ The rate increase is reasonable and I support it
- ☐ I don't like it, but I think the rate increase is necessary
- ☐ The rate increase is unreasonable and I oppose.
- ☐ Don't know

21. And why do you feel that way?

Final Thoughts

PowerStream values your feedback. This outreach is a new requirement, so this is the first time that the utility has conducted a review about its upcoming investment plan in this type of format.

General Impression - Overall, what did you think about this primer?

Volume of Information: Did PowerStream provide too much information, not enough, or just the right amount?

Content Covered: Was there any content missing that you would have liked to have seen included?

Outstanding Questions: Is there anything that you would still like answered?

Suggestions for Future Consultations: How would you prefer to participate in these consultations?

Glossary

Breakers: Devices that protect the distribution system by interrupting a circuit if a higher than normal amount on power flow is detected.

Feeder Circuit: Is a wire that connects stations to the broader distribution system in order to deliver electricity to customers.

Generation Station: A facility designed to produce electric energy from another form of energy, such as fossil fuel, nuclear, hydroelectric, geothermal, solar thermal, and wind.

Kilowatt (kW): 1000 watts.

Local Distribution Company (LDC): In Ontario, these are the companies that take electricity from the transmission grid and distribute it around a community.

OM&A: Operations, Maintenance and Administration

Stations: These include tranformer stations and distribution stations. They are used to switch generators, equipment, and circuits or lines in and out of a system. It also is used to change AC voltages from one level to another.

Switches: These control the flow of electricity—they direct which supply of electricity is used and which circuits are energized. Distribution systems have switches installed at strategic locations to redirect power flows for load balancing or sectionalizing.

System Access: Projects required to respond to customer requests for new connections or new infrastructure development. These are usually a regulatory requirement to complete.

System Renewal: Projects to replace aging infrastructure in poor condition.

System Service: Primarily projects that improve reliability.

General Plant: Investments in things like tools, vehicles, buildings and information technology (IT) equipment that are needed to support the distribution system.

Transmission lines: Transmit high-voltage electricity from the generation source or station to another station in the electricity grid.

Transformer: A piece of equipment that reduces the voltage of electricity from a high level to a level that can be safely distributed to your area or to your residence/business.

Underground Cable: A conductor with insulation, or a stranded conductor with or without insulation and other coverings (single-conductor cable), or a combination of conductors insulated from one another (multiple-conductor cable).

Volt (V): A unit of measure of the force, or 'push,' given the electrons in an electric circuit. One volt produces one ampere of current when acting on a resistance of one ohm.

Watt (W): The unit of electric power, or amount of work (J), done in a unit of time. One ampere of current flowing at a potential of one volt produces one watt of power.

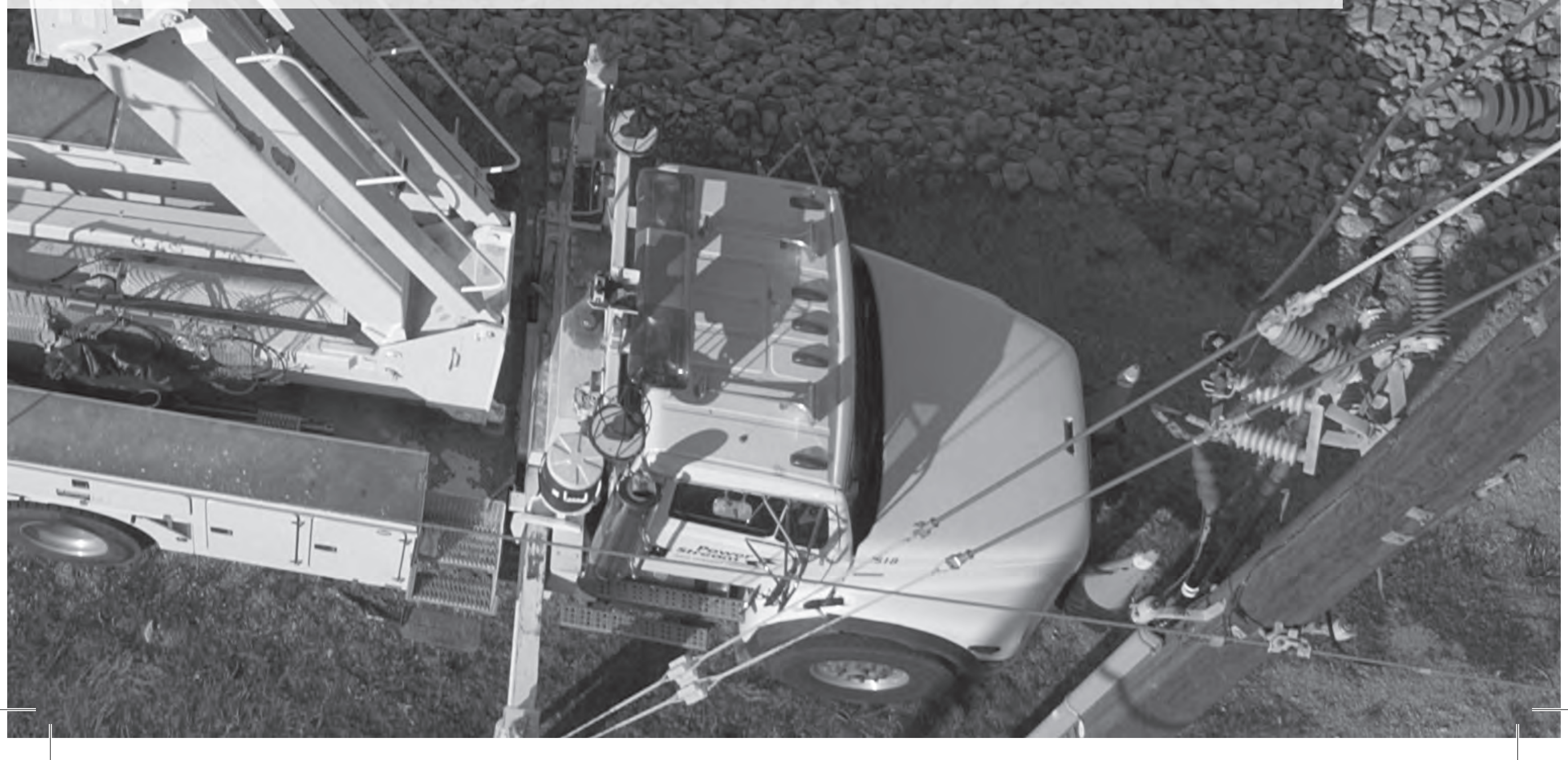
Wire: A conductor wire or combination of wires not insulated from one another, suitable for carrying electric current.

If you have any additional questions or comments about PowerStream's Distribution System Plan Review please email:

CustomerFocus@powerstream.ca

or send your questions or comments to:

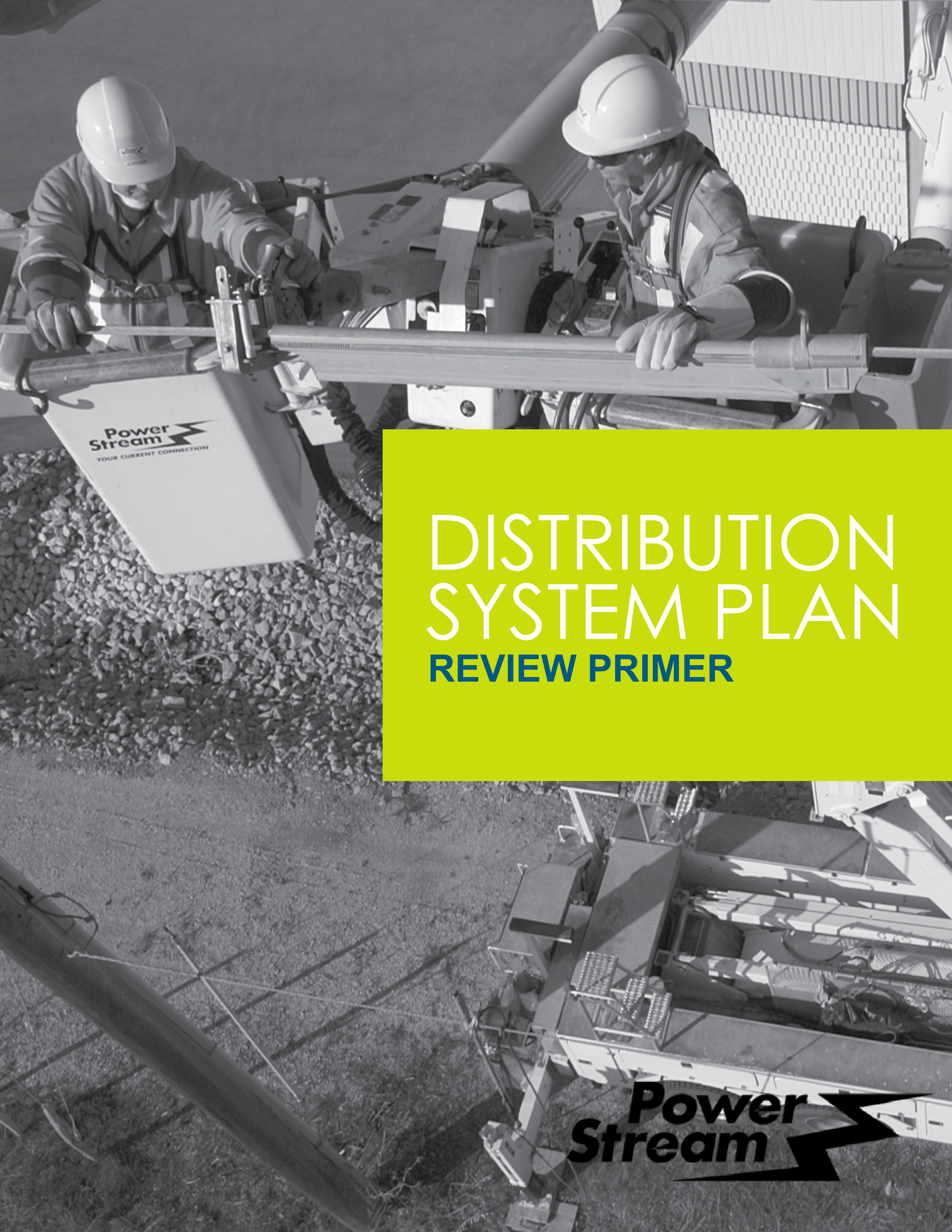
PowerStream
Attn: DSP Review
161 Cityview Boulevard,
Vaughan, Ontario
L4H 0A9



Appendix E

PowerStream Work Book

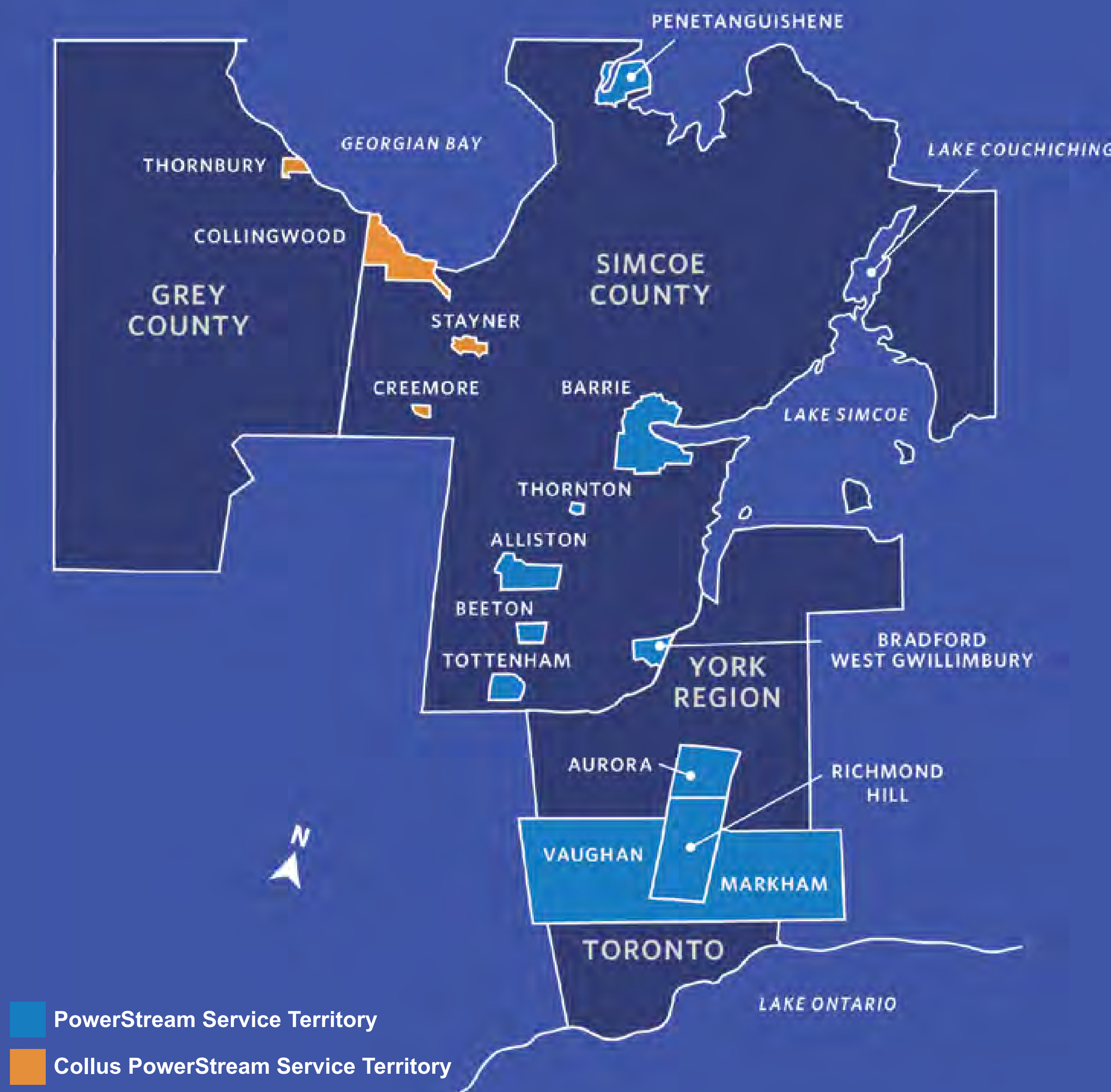
Delivered: February 24, 2015



DISTRIBUTION SYSTEM PLAN

REVIEW PRIMER

Power Stream



PowerStream is a community-owned energy company providing power and related services to more than 370,000 customers residing or owning a business in Alliston, Aurora, Barrie, Beeton, Bradford West Gwillimbury, Markham, Penetanguishene, Richmond Hill, Thornton, Tottenham and Vaughan as well as Collingwood, Stayner, Creemore and Thornbury through a partnership with the Town of Collingwood in the ownership of Collus PowerStream.

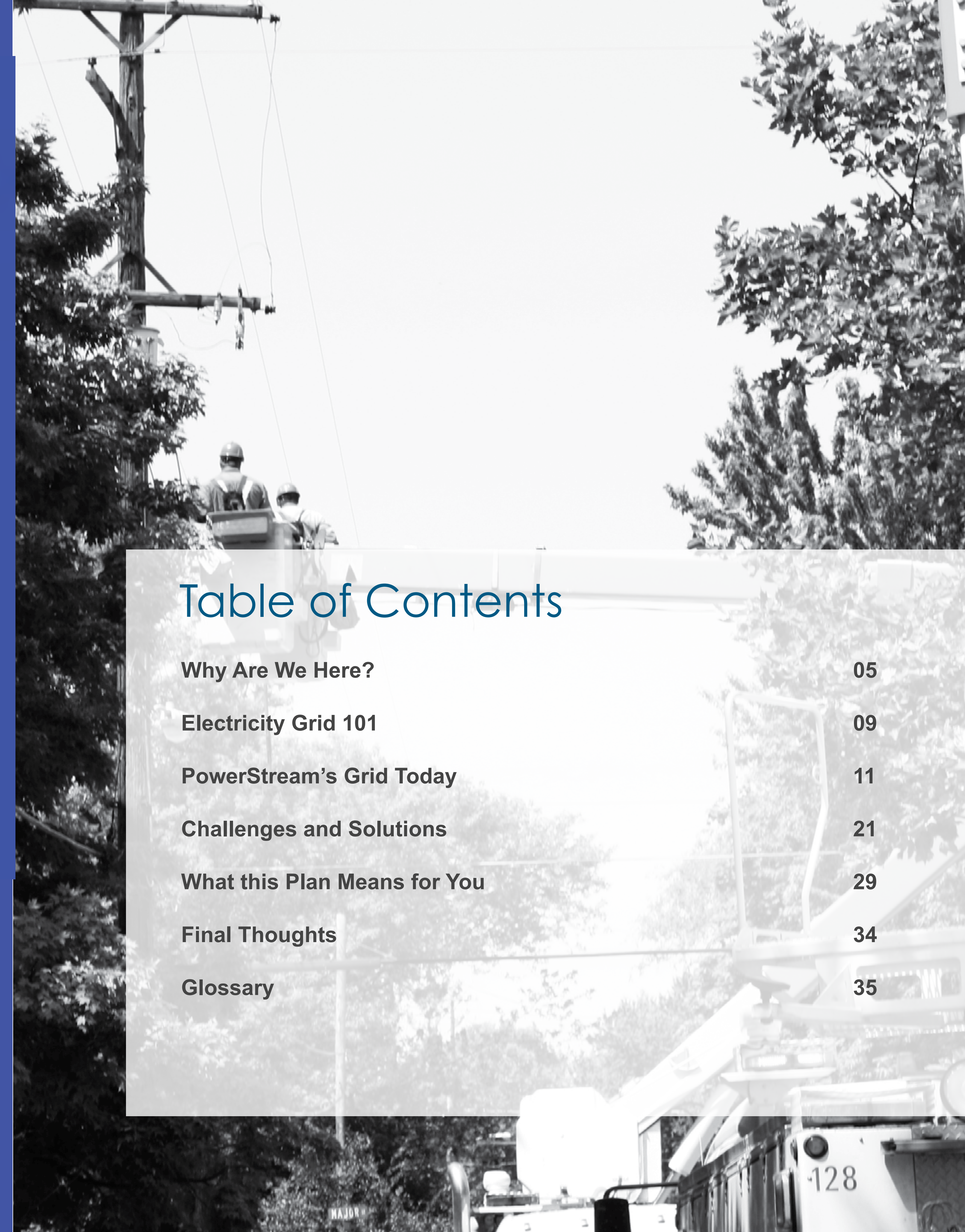


Table of Contents

Planning for Future Energy Needs

This primer and consultation concentrates on the short-term plan for PowerStream's distribution system over the next five years. The graphic below shows the various planning initiatives ongoing within the Province. In addition to the short-term distribution plan being discussed in this primer, there are other planning initiatives undertaken to ensure that the electricity system maintains reliability and works efficiently for the benefit of customers.

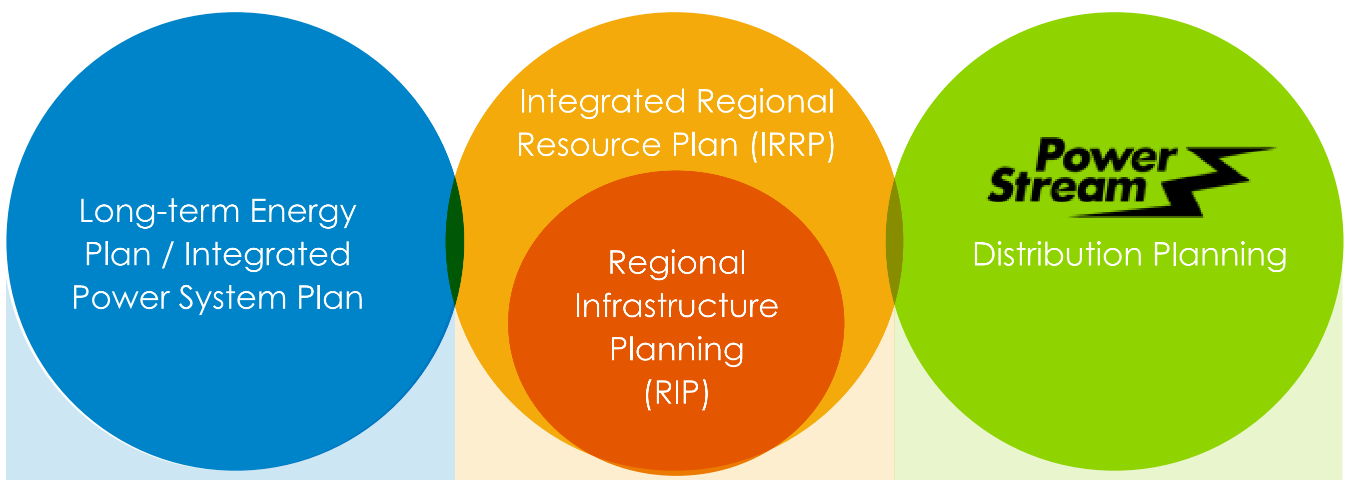
Energy planning occurs at the provincial level (by the Ministry of Energy and government agencies such as the Ontario Power Authority) and at the regional and municipal level as well as by each electricity distributor for their service territory and relevant agencies.

If you're interested in broader medium and long term electricity issues such as Ontario's Long-Term Energy Plan, regional planning, conservation planning and general energy policy in the province, there are other opportunities to provide your feedback.

Ontario's Long Term Energy Plan:
The Ontario Government's plan details how electricity will be generated and the longer-term conservation strategy for the province. It can be found at this website:
http://www.energy.gov.on.ca/en/ltep/

Regional Planning:
The Ontario Power Authority (OPA) looks ahead to the future electricity needs of your region and how those needs can be addressed through Conservation and Demand Management (CDM), local generation, and electricity from outside the region. You can follow the OPA`s regional planning process at this website:
http://www.powerauthority.on.ca/power-planning/regional-planning

Ontario's Energy Planning Diagram



Provincial System Planning

This involves more long-term planning on how Ontario's electricity system is designed and operated.

This includes planning on:

- Provincial electricity supply mix (e.g. greening the grid and phasing out coal)
- System supply and demand forecasting
- Interconnections and grid design

Regional Planning

Regional planning involves near- and medium-term plans to meet the needs of a region of the province, and ensure all key players (i.e. transmission and distribution operators) are coordinated moving forward.

This planning process is focused on considering whether CDM & local generation options have been considered, in addition to core infrastructure ("wires") solutions.

Distribution Network Planning

Distribution planning involves plans, both near- and longer-term, to ensure the local distribution systems has the adequate capacity to meet required reliability and safety standards, and to otherwise meet the needs of customers.

Why Are We Here?

The electricity industry in Ontario is regulated by the Ontario Energy Board (OEB), which requires distribution companies, such as PowerStream, to prepare and submit a distribution system plan to show how it will sustain the area's electricity distribution system over the next five years.

The OEB recently developed a new regulatory requirement for distribution system plans that requires distribution companies, such as PowerStream, to gather information about customer needs and preferences on distribution system investments and report on how they responded. PowerStream needs your participation to ensure its plan addresses your needs and expectations.

You don't have to be an electricity expert to participate

This consultation is not about technical issues. The OEB hearing process will allow experts representing various consumer and interest groups (called intervenors) to challenge the detailed engineering and business decisions within PowerStream's plan. This consultation focuses on the goals of the system. Should PowerStream focus more on reducing the number of outages or the lengths of outages? Should reliability be increased even if rates go higher, or should PowerStream maintain the current level of reliability and keep rate increases lower.

This primer has been developed to guide you through PowerStream's plan. As you proceed, it asks questions designed to collect your feedback. In order to facilitate this, the primer is divided into several sections that explain the distribution system, the challenges it faces and, more importantly, how PowerStream will be responding to those challenges.

Your input, and PowerStream's response to your input, will be presented to the OEB and intervenors when PowerStream files its rate application for 2016 to 2020 in the spring of 2015.

PowerStream's Rate Application Process

- PowerStream assesses system needs
- Collect customers needs and preferences
- Refine plan (where necessary)
- Reports on how plan responds to customer input
- Files plan with OEB
- Interrogatories and OEB rate hearing process
- OEB sets PowerStream's distribution rates

Innovative Research Group Inc. has been engaged by PowerStream to collect participant feedback and will deliver it to PowerStream to assist them in shaping their plans.

Feedback

1. How familiar are you with the electricity system in Ontario, and the services PowerStream is responsible for?

- Very familiar
- Somewhat familiar
- Not very familiar
- Not at all familiar
- Don't know

Your Electricity Bill

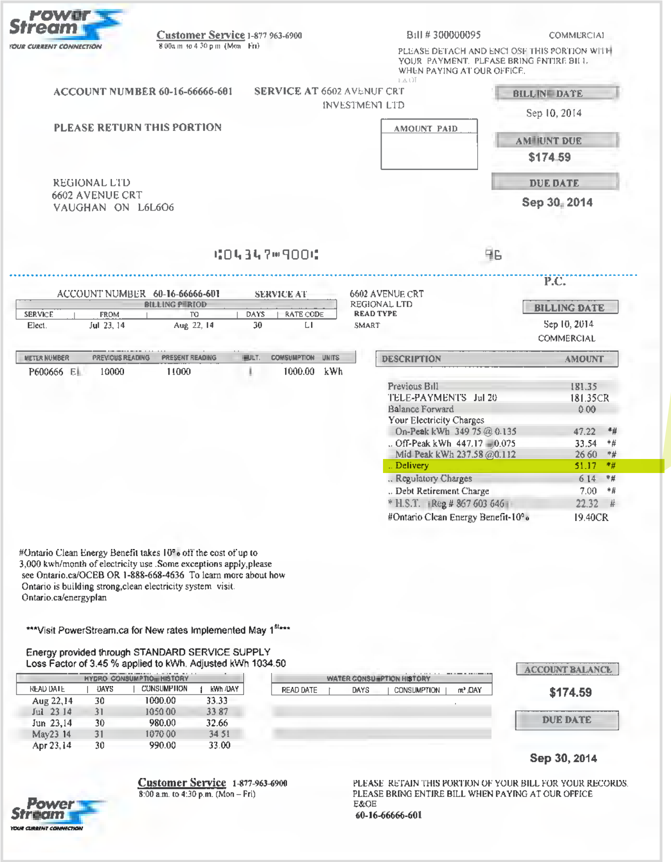
Every item and charge on the bill is mandated by the provincial government or regulated by the OEB. There are two distinct cost areas that make up the "Delivery" charge on your bill: distribution and transmission. While PowerStream collects both, it remits the transmission charge to Hydro One. The distribution charges are what PowerStream uses to fund its utility needs.

Distribution charges are one of several charges on your bill. Current monthly distribution charges are approximately $61 for a typical PowerStream general service customer who consumes 2000 kWh in a month. The amount you pay varies depending on the amount of electricity you use.

PowerStream's distribution rates are subject to the review and approval of the OEB. The rate revenue covers PowerStream's capital investments and operating expenses.

The plan PowerStream is proposing will maintain reliability at or above its current level. The resulting levels of capital investment and operational spending over the next 5 years will result in an average annual increase of **$5.25** per month or **8.2 per cent** on the distribution rates charged by PowerStream. At the end of the plan in 2020, the average general service business will be paying an estimated **$26.24** more per month on the distribution portion of their electricity bill. Other items on your bill may also increase.

Sample Electricity Bill



PowerStream YOUR CURRENT CONNECTION

Customer Service 1-877 963-6900
8:00 a.m. to 4:30 p.m. (Mon – Fri)

Bill # 300000095 COMMERCIAL

PLEASE DETACH AND ENCLOSE THIS PORTION WITH YOUR PAYMENT. PLEASE BRING ENTIRE BILL WHEN PAYING AT OUR OFFICE.

ACCOUNT NUMBER 60-16-66666-601 SERVICE AT 6602 AVENUE CRT INVESTMENT LTD

PLEASE RETURN THIS PORTION

AMOUNT PAID

BILLING DATE Sep 10, 2014

AMOUNT DUE $174.59

DUE DATE Sep 30, 2014

REGIONAL LTD
6602 AVENUE CRT
VAUGHAN ON L6L6O6

ACCOUNT NUMBER 60-16-66666-601 SERVICE AT 6602 AVENUE CRT REGIONAL LTD

P.C.

SERVICE	FROM	TO	DAYS	RATE CODE
Elect.	Jul 23, 14	Aug 22, 14	30	L1

READ TYPE SMART

BILLING DATE Sep 10, 2014 COMMERCIAL

METER NUMBER	PREVIOUS READING	PRESENT READING	MULT.	CONSUMPTION	UNITS
P600666 El	10000	11000	1	1000.00	kWh

DESCRIPTION	AMOUNT	
Previous Bill	181.35	
TELE-PAYMENTS Jul 20	181.35CR	
Balance Forward	0.00	
Your Electricity Charges		
.. On-Peak kWh 349.75 @ 0.135	47.22	*#
.. Off-Peak kWh 447.17 @0.075	33.54	*#
.. Mid-Peak kWh 237.58 @0.112	26.60	*#
.. Delivery	51.17	*#
.. Regulatory Charges	6.14	*#
.. Debt Retirement Charge	7.00	*#
* H.S.T. (Reg # 867 603 646)	22.32	#
#Ontario Clean Energy Benefit-10%	19.40CR	

#Ontario Clean Energy Benefit takes 10% off the cost of up to 3,000 kwh/month of electricity use. Some exceptions apply, please see Ontario.ca/OCEB OR 1-888-668-4636 To learn more about how Ontario is building strong, clean electricity system visit. Ontario.ca/energyplan

Visit PowerStream.ca for New rates Implemented May 1st

Energy provided through STANDARD SERVICE SUPPLY
Loss Factor of 3.45 % applied to kWh. Adjusted kWh 1034.50

HYDRO CONSUMPTION HISTORY

READ DATE	DAYS	CONSUMPTION	kWh /DAY
Aug 22,14	30	1000.00	33.33
Jul 23 14	31	1050.00	33.87
Jun 23,14	30	980.00	32.66
May23 14	31	1070.00	34.51
Apr 23,14	30	990.00	33.00

WATER CONSUMPTION HISTORY

READ DATE	DAYS	CONSUMPTION	m³ /DAY

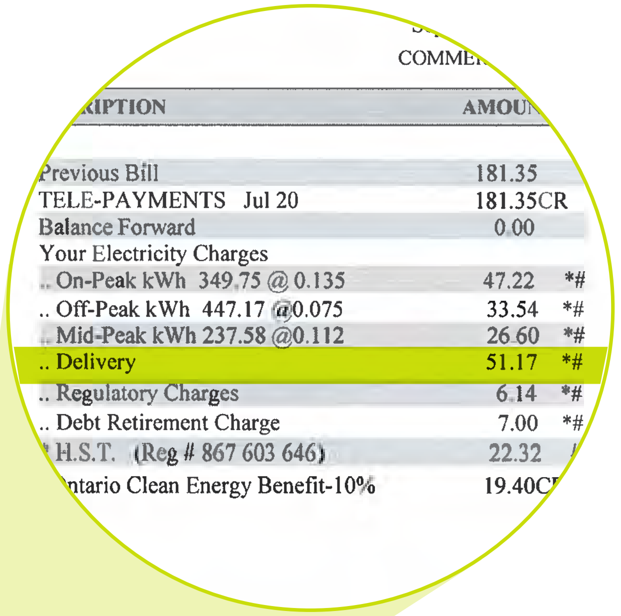
ACCOUNT BALANCE $174.59

DUE DATE Sep 30, 2014

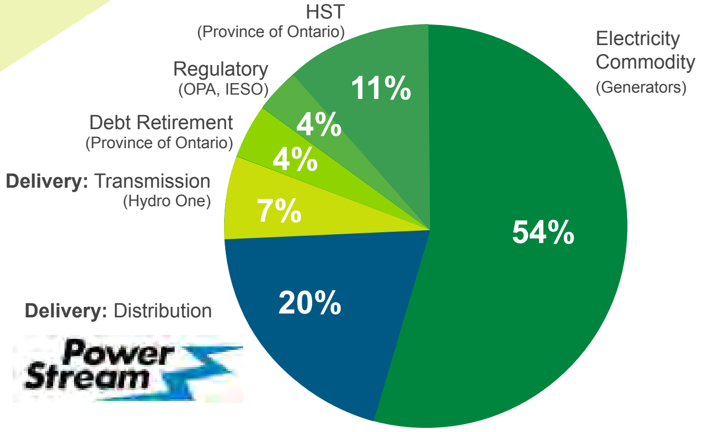
Customer Service 1-877-963-6900
8:00 a.m. to 4:30 p.m. (Mon – Fri)

PLEASE RETAIN THIS PORTION OF YOUR BILL FOR YOUR RECORDS.
PLEASE BRING ENTIRE BILL WHEN PAYING AT OUR OFFICE
E&OE
60-16-66666-601

PowerStream YOUR CURRENT CONNECTION



About 20 per cent of the average general service electricity bill goes to PowerStream



How are Electricity Rates Determined?

PowerStream is funded by the distribution rates paid by its customers. Periodically, PowerStream is required to file an application with the OEB to determine the funding available to operate and maintain the distribution system. PowerStream must submit evidence to justify the amount of funding it needs to safely and reliably distribute electricity.

Who Protects Consumer Interests?

PowerStream's evidence is assessed in an open and transparent public process known as a rate hearing. A number of public intervenors with electricity industry expertise submit their own evidence challenging PowerStream's plans and assumptions. At the end of the process, the OEB weighs the evidence and decides on the rates PowerStream can charge for distribution.

Electricity Grid 101

Who Does What in Ontario's Electricity System?

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

GENERATION Generating facilities convert various forms of energy into electric power.	**EXAMPLES** Ontario Power Generation TransCanada Energy Ltd Bruce Power Samsung Renewable
TRANSMISSION Transmission lines (high voltage lines) connect the power produced at generating facilities to transformer stations.	**EXAMPLE** Hydro One
DISTRIBUTION Distribution lines (at medium voltages) carry electricity to homes and businesses.	**EXAMPLES** PowerStream Toronto Hydro Newmarket Hydro
CONSUMERS Electricity is delivered to homes and businesses.	**EXAMPLES** Residential Commercial Industrial

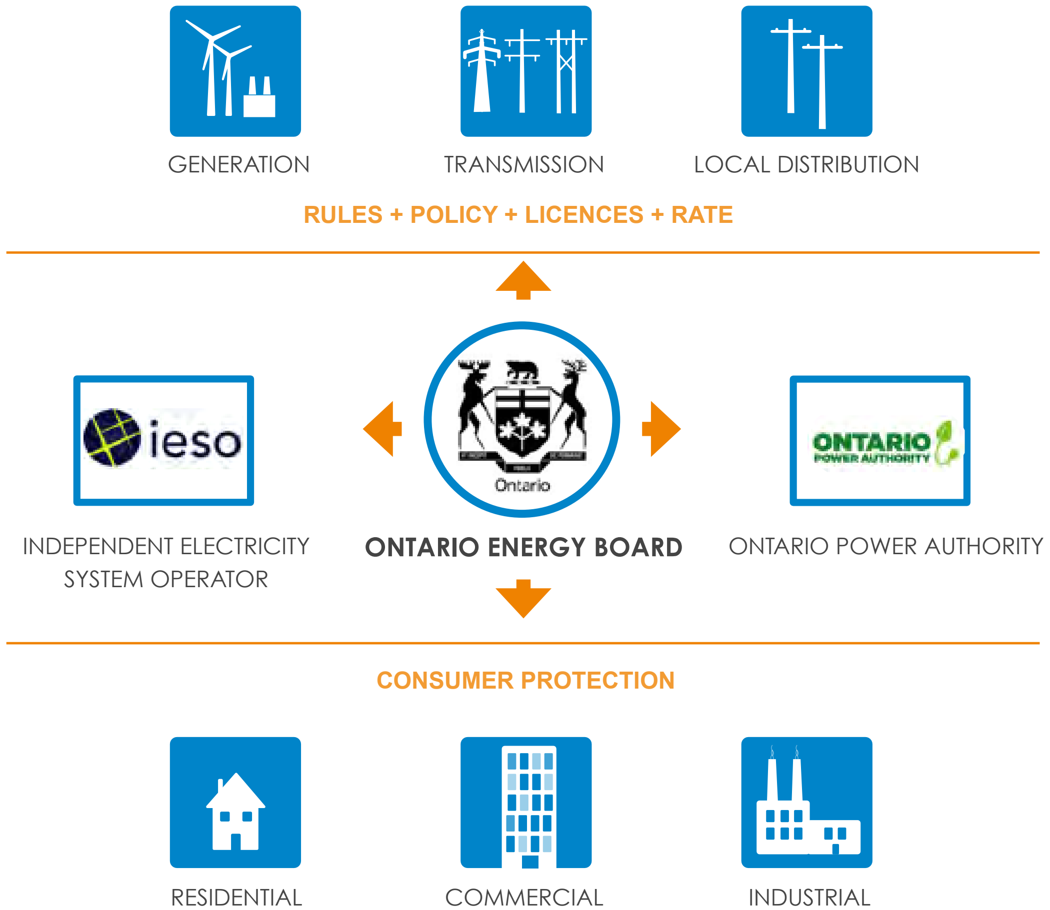
How is Ontario's Electricity System Regulated?

The **Ontario Ministry of Energy** sets energy policy. It sets the rules and establishes key planning and regulatory agencies through legislation.

The mission of the **Ontario Energy Board** (OEB) is to promote a viable, sustainable and efficient energy sector that serves the public interest and assists consumers to obtain reliable energy services at reasonable cost. It is an independent body established by legislation that sets the rules and regulations for the provincial electricity sector. One of the OEB's roles is to review the distribution plans of all electricity distributors and set their rates.

The **Ontario Power Authority** (OPA) is responsible for medium and long-term electricity planning to ensure an adequate supply of electricity is available for Ontario residents and businesses. The OPA receives directives from the Ministry of Energy (i.e. energy supply mix, Green Energy Act), but otherwise works at arm's-length from the government.

The **Independent Electricity System Operator** (IESO) is responsible for electricity supply over the short-term. It operates the grid in real-time to ensure that Ontario has the electricity it needs, where and when it needs it.



PowerStream's Grid Today

This section describes the construction of PowerStream's distribution grid including its overhead, underground and secondary systems. It also explains the corporation's historical growth and current electrical infrastructure.

The Background of PowerStream's Distribution Grid

PowerStream owns and operates $1.17 billion in capital assets and is the second largest municipally- owned electricity distribution utility in Ontario. It distributes about eight per cent of Ontario's electricity demand. PowerStream's electrical grid is comprised of overhead, underground and secondary systems of various voltages. PowerStream was formed in 2004 from the amalgamation of Hydro Vaughan, Markham Hydro, and Richmond Hill Hydro. Aurora Hydro was purchased in 2005, and in 2009, Barrie Hydro merged with PowerStream.

Each original utility operated independent distribution systems, and as a result, the infrastructure varies from region to region. PowerStream has been working to gradually standardize this equipment, which will help improve reliability and safety across the regions, and make maintaining the system more efficient.

PowerStream is owned by three municipalities and regulated by the OEB. As such, any profits obtained by the utility are provided to the municipalities as a dividend, or reinvested into the distribution system.

A Look at PowerStream's Growth

PowerStream has been serving York Region since 2004 and Simcoe County since 2009, and has seen remarkable change and innovation through the years. Although PowerStream as an entity dates back to 2004, the first electric system and street lights in the service territory were installed in Barrie in 1888, Markham in 1890-1891, and in neighbouring areas soon after.

PowerStream has a mix of older and newer distribution systems across all of its service territory. PowerStream is systematically and prudently upgrading older areas. Of course, even as this work is completed, the overall system continues to age.

PowerStream is a product of the largest voluntary consolidation of local distributors and is an organization committed to becoming an innovative and socially responsible leader in power distribution and related services. Growth is a key performance driver for PowerStream, and is achieved through increases to its residential and commercial customer bases.

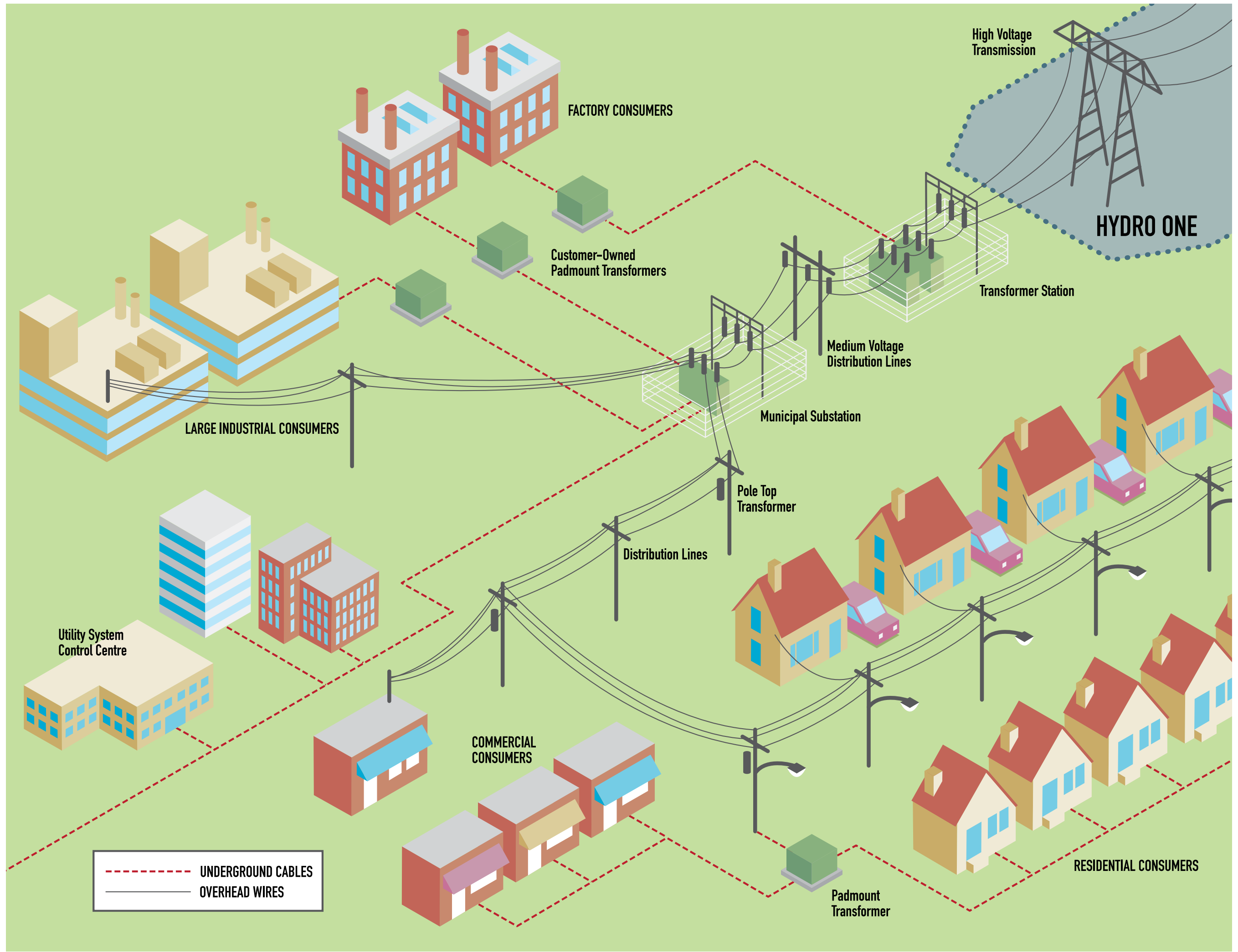
Large projects currently underway include the new Vaughan Metropolitan Centre project at Hwy 7 and Jane Street, the new Vaughan Campus of Mackenzie Health, and the expansion of the Toronto Transit Comission subway into York Region. All of these projects highlight the expansion and growth occurring in PowerStream's service territory.

PowerStream's Distribution System

Every system is unique with its own history and challenges. In order to better understand the current PowerStream system, we first have to understand all of the different components and how they impact the way in which you receive electricity when you need it. The image below and following terms and definitions will help guide you through the system from when you turn a switch on to when you receive your bill.

PowerStream's distribution system is made up of a number of components which work together to transport electricity to your house or business.

Distribution System Diagram



Transformer Stations and Municipal Substations

PowerStream owns 11 of the 25 Transformer Stations (TSs) that connect PowerStream's distribution system to the 230 Kilovolt (kV) provincial transmission grid owned by Hydro One and operated by the IESO. In fact, the very first municipally-owned transformer station in Ontario was built in PowerStream's service territory (Markham) back in 1985.

Municipal Substations (MSs), 54 in total, also play an important role in PowerStream's distribution system, further transforming higher voltage electricity to a lower voltage that is suitable for local distribution to customers.

Transformers – Important pieces of equipment that reduce the voltage of electricity from a high level to a level that can be safely distributed to your area, or to your residence/business.

Breakers – Devices that protect the distribution system by interrupting a circuit if a higher than normal amount of power flow is detected.

Switches – Control the flow of electricity and steer the current to the correct circuits.

Feeder Circuits – Are the wires that connect the stations to the broader distribution system in order to deliver electricity to customers.

PowerStream's Overhead System

The overhead system is made up of distribution lines that operate at various voltages depending on their purpose and destination. PowerStream has 2,535 km of overhead distribution lines in its service territory. These distribution lines are attached to the top of hydro poles.

Along the distribution line, pole-top transformers step the voltage down to useable levels of 120V-600V. From there, the electricity is delivered to customers through a secondary line that runs from the transformer to an individual home or business.

PowerStream has 3500 switches, and over 330 pole-mounted remote-controlled switches located throughout its distribution system. These switches, which are controlled from PowerStream's Main System Control Centre, greatly improve operating efficiencies, and reduce restoration times whenever a power interruption occurs.

PowerStream's Underground System

PowerStream's underground system consists of high and low voltage cables, metal enclosed switchgear and transformers situated on concrete pads. In residential areas, underground cables distribute electricity from the TSs or MSs to padmount transformers located on the municipal boulevards. Like the overhead system, these transformers step the electricity down to useable voltages of 120V-600V, and the power is then delivered to customers through over 5000 km of buried low voltage wires.

When distributing electricity to urban areas or larger customers, larger transformers are used.

PowerStream has 1800 gears, and over 40 padmounted switchgears that are controlled remotely from its System Control Centre. These remote-controlled switches are critical for improving operating efficiencies and power restoration times in the underground distribution system.

Feedback

2. How well do you feel you understand the important parts of the electricity system, how they work together, and which services PowerStream is responsible for?

- ☐ Very well
- ☐ Somewhat well
- ☐ Not very well
- ☐ I don't understand at all

3. Generally speaking, how satisfied are you with the service you are receiving from PowerStream? Would you say …

- ☐ Very satisfied
- ☐ Somewhat satisfied
- ☐ Somewhat dissatisfied
- ☐ Very dissatisfied
- ☐ Don't know

4. Is there is anything in particular that PowerStream can do to improve its service to you?

Reliability

Delivering reliable power safely is PowerStream's fundamental purpose. Three key standard industry measures are used to track system reliability. They include:

SAIFI
System Average Interruption Frequency Index
This measure shows the number of outages an average PowerStream customer experiences in a year.

SAIDI
System Average Interruption Duration Index
This measure shows the amount of time an average PowerStream customer is without power in a year.

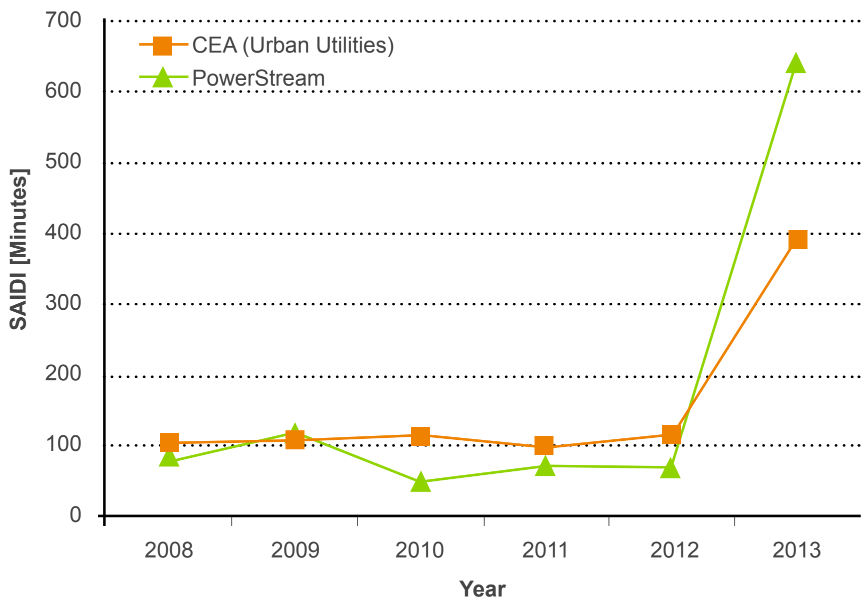
CAIDI
Customer Average Interruption Duration Index
This measure indicates on average how long it takes for PowerStream to restore power to a customer after a power outage.

All planned and unplanned sustained interruptions are used to calculate these indices.

How is PowerStream Performing:
For reliability performance, the OEB expects that the distributor's current reliability performance (SAIDI, SAIFI, CAIDI) should, at minimum, remain within the range of its historical previous 3 year performance. PowerStream's plan aims to meet this requirement.

As seen in the chart below, PowerStream's SAIDI performance has been at par or better than average of the other comparable Canadian urban utilities with the exception of 2013 when PowerStream was hit hard by an unusual weather event (December Ice Storm).

PowerStream SAIDI [minutes] Comparison to Other CEA (Canadian Electricity Association) Urban Utilities for All Outages



Controllable vs. Uncontrollable Factors

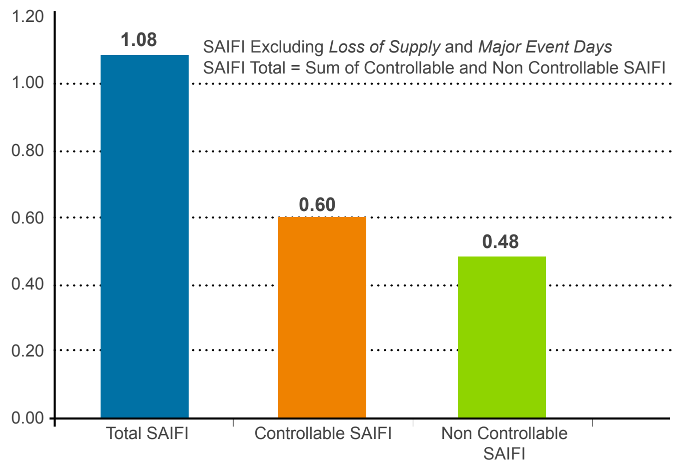
Electricity outages can be caused by factors that PowerStream can and cannot control.

Uncontrollable events include lightning, adverse weather, adverse environment (e.g. salt contamination) and 3rd party created events.

Controllable events include scheduled outages in order to perform work on the distribution system, tree contacts, defective equipment and errors caused by people.

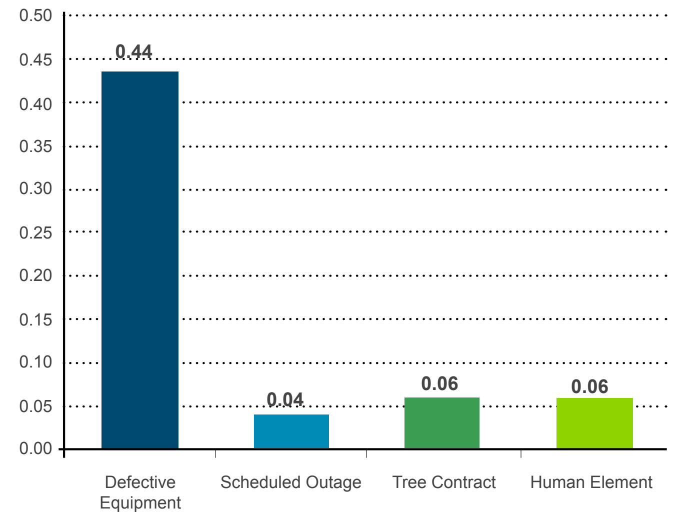
The chart below shows that more than half of the outages PowerStream customers experience are caused by controllable events.

Total SAIFI, Controllable & UnControllable SAIFI [2008-2013]



As the breakdown in the chart below illustrates, defective equipment is far and away the largest contributor of controllable outages.

Breakdown of Controllable SAIFI Excluding *Loss of Supply* and *Major Event Days* [2008-2013]



Capital Expenditure and Outages

Managing equipment failure is a never-ending race. Each year PowerStream invests in replacement or rehabilitation of its oldest assets and systems. The assets in the poorest condition are identified through an annual inspection program. However with each passing year the rest of the assets get older and a new set of assets falls into poor condition.

Outages are also targeted as a result of poor performing feeders identified through reliability statistics each year. As these feeders are worked on and reliability improves, a new set of feeders falls to the bottom of the performance ratings.

As you will see in the following pages, over the next five years, PowerStream is planning investments in new equipment and the rehabilitation of existing equipment, such as underground cables, to reduce the number of outages due to equipment failure.

While outages are to some degree chance events, the investment in new equipment matches the aging profile of the system and is expected to sustain the current level of reliability and to achieve reliability improvement in the worst performing areas.

Capital Expenditure and Restoration Times

Restoration time is an area where PowerSteam actively pursues improvement. Restoration times depend on three things - the physical capacity to work around a problem, the speed at which the utility can re-route electricity through that physical network, and the speed by which the broken parts can be repaired.

As PowerStream expands the system through system service updates such as higher voltage lines, new stations and feeder lines or similar system improvements, the utility is building more capacity to work around outages.

As PowerStream adds remote monitors to pin-point where faults are occurring and add remote or automated switches to avoid the need to send a crew to manually flip a switch, the utility is increasing the speed by which power can be restored.

Finally, investments in areas such as equipment standardization, GPS devices and improved scheduling tools all contribute to our ability to replace broken equipment more quickly.

Feedback

5. As far as you know, in the past year, did you experience any outages due to unusual weather such as the ice storm, microbursts or tornados?

- ☐ Yes
- ☐ No
- ☐ Don't know

6. Whether you were personally affected or not, how satisfied are you with the way PowerStream responded to these events? Would you say …

- ☐ Very satisfied
- ☐ Somewhat satisfied
- ☐ Somewhat dissatisfied
- ☐ Very dissatisfied
- ☐ Don't know

7. Is there is anything in particular PowerStream can do to improve its service to you during these extreme weather events?

8. Other than outages during unusual weather events, how many outages did you experience in the past year?

- ☐ Zero
- ☐ One
- ☐ Two
- ☐ Three
- ☐ Four
- ☐ Five or more

9. Aside from unusual weather events, if you experienced an outage in the past year, what was the longest you experienced?

- ☐ Less than 15 minutes
- ☐ 15 to less than 30 minutes
- ☐ 30 minutes to less than 1 hour
- ☐ 1 hour to less than 3 hours
- ☐ 3 hours to less than 6 hours
- ☐ 6 hours to less than 12 hours
- ☐ 12 to less than 24 hours
- ☐ More than 24 hours
- ☐ Don't know

10. If you experienced an outage, how satisfied are you with the way PowerStream responded to the outage? Would you say …

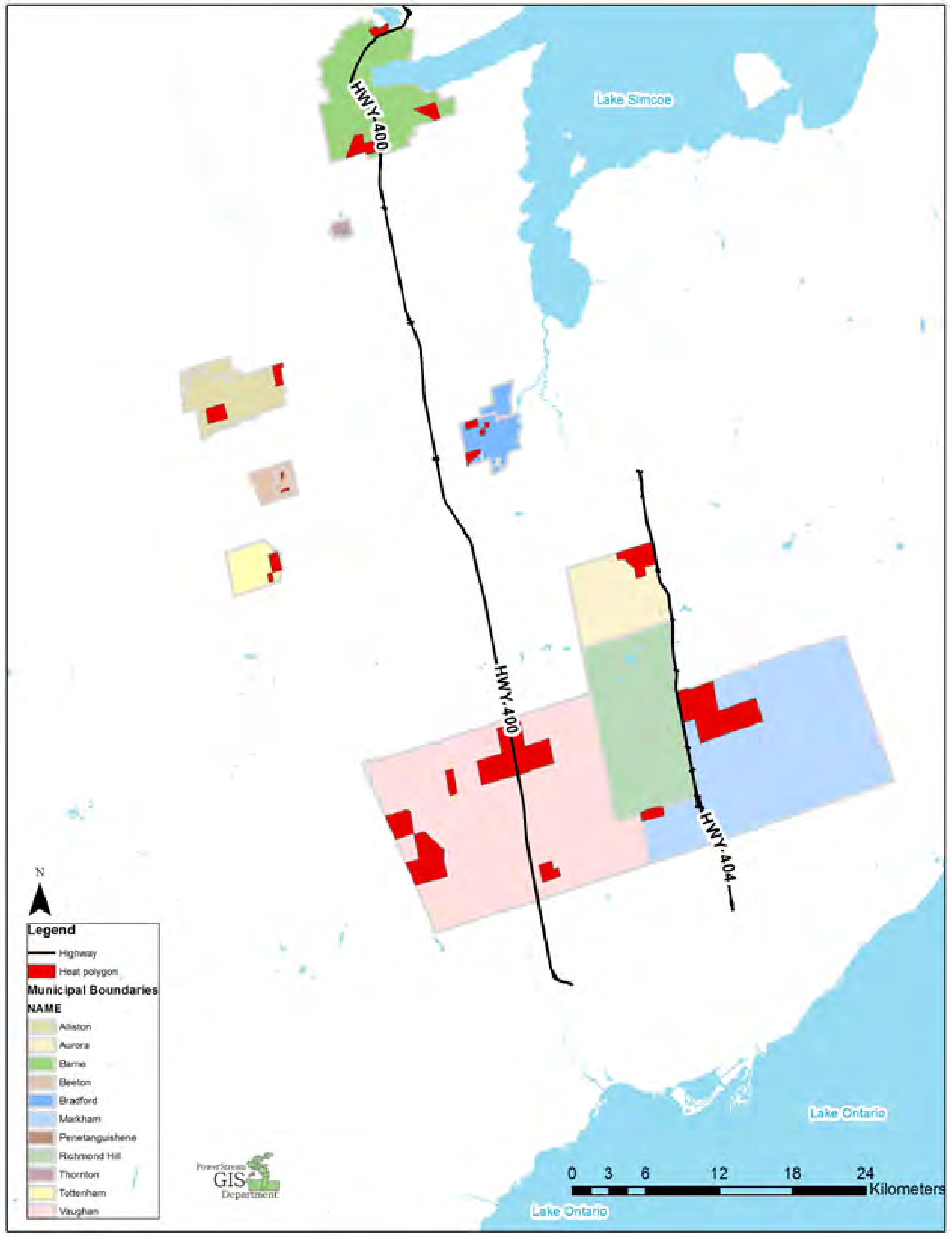
- ☐ Very satisfied
- ☐ Somewhat satisfied
- ☐ Somewhat dissatisfied
- ☐ Very dissatisfied
- ☐ Don't know

11. Is there is anything in particular PowerStream can do to improve its service to you during outages?

12. Most years, the average PowerStream customer loses power due to outages for about 100 minutes over the whole year. This is at or below the average for similar utilities. Do you feel this level of reliability is …

- ☐ Very good
- ☐ Good
- ☐ Acceptable
- ☐ Poor
- ☐ Very poor
- ☐ Don't know

Capacity Constrained Areas of PowerStream's Service Territory



Challenges and Solutions

Pressure: Growth

Fueled by increased economic development and demand for new housing in York Region and Simcoe County, PowerStream adds over 8,000 new customers to its existing customer base every year. This growth in customers and load puts increasing pressure on PowerStream's distribution system, which requires extending power lines, upgrading capacity to existing power lines, and adding new capacity to load constrained area.

The map on the previous page shows the capacity constrained areas of PowerStream's service territory. Red highlighting indicates areas that require increased investment to provide additional capacity in the near term to ensure system reliability.

Challenges	Solutions
Lines and equipment that cannot carry the increased load and maintain the increased reliability expected by customers.	• New **substations, transformer stations**, and power **lines** where needed to increase supply capacity. • **Voltage** Conversion Projects: existing 8kV and 13.8kV power lines converted to 27.6kV to increase load capacity. • Station Investments: intended to ensure stations have peak loadings maintained at or below their 10 day Limited Term Rating to prevent damage to station equipment and avoid brownouts and blackouts.
Development of new subdivisions resulting from increased demand for new homes, which requires expansion of the distribution system lines and stations.	• Need investments to increase **station** and power line capacity to maintain the loading of existing municipal **substations** and to ensure sufficient space capacity exists such that if there is a loss of one substation, the neighbouring **substations** can accommodate the lost **capacity.**

Pressure: Aging Equipment

PowerStream's distribution system consists of various equipment (**poles, transformers, cables**, etc.) with different installation date profiles. While the majority of the distribution system was installed or rebuilt after 1980, a significant amount of distribution system equipment was installed in the 1970s, 1960s or even earlier, and is still in service today. While that old equipment continues to operate for the time being, it is well past its intended service life, and much of it will need to be replaced soon.

Equipment that is still operating beyond its intended service life is more likely to fail, and cause long power interruptions. As time goes on, more and more of the distribution system assets will be operating past end-of-life, unless replaced. This requires investment in system renewal projects and programs.

While PowerStream and its predecessor utilities have historically managed asset replacement programs efficiently with moderate levels of investment, the growing number of old assets needing replacement requires a higher level of investment than ever before.

PowerStream plans to proactively replace the oldest and worst condition equipment before it fails. Generally, proactive equipment replacement is less expensive than replacing equipment after an unexpected failure.

Some distribution assets such as pole mounted transformers and residential padmounted transformers, as well as secondary cables, are not proactively replaced. These assets are replaced once they fail. This "run to failure" approach is considered normal utility practice is the industry.

Asset Summary Chart – main assets by quantity

Asset Types	Asset Count (approx)	Average Life (approx)	Oldest Assets (approx)
Wood Poles	46,500	35-75	1940
Distribution Transformers	44,000	25-60	1956
Underground Primary Cable	7900 km	20-55	1965
Distribution Switchgear	1800	30-85	1978
Station Circuit Breakers	399	35-65	1958
Municipal Station Primary Switches	66	30-60	1956
Municipal Station Transformers	65	30-60	1958
Station Reactors	34	25-60	1986
Transformer Station Transformers	22	30-60	1986
Transformer Station 230kV High-Voltage Switches	22	30-60	1986
Station Capacitors	5	25-40	1990

Note: Above data and figures provided from PowerStream Asset Condition Assessment, Rev. 2, November 27, 2012.

Challenges	Solutions
The need to replace poles that are at or nearing end-of-life.	• Proactive replacement: PowerStream plans to replace or reinforce approximately 400 of the worst condition poles per year in order to minimize risk.
Underground primary cables that are at, or near, end-of-life, and the resulting high negative impact this has on reliability for affected customers.	• PowerStream proposes to replace approximately 52 km/year of the worst condition **underground cables**, and use silicon injection to extend the life of another estimated 47 km/year of underground cables. • PowerStream's approach for **cable** replacement is determined by prioritizing the cable sections that have the worst reliability and the highest customer impact.
Aging padmounted switchgear cubicles.	• Proactive replacement: PowerStream plans to replace approximately 31 of the poorest condition **switchgear** units in 2015, rising to 36 per year in 2016-2020.
The need to replace padmounted transformers, where concerns about condition have been reported.	• PowerStream commenced a proactive replacement program in 2013. • PowerStream proposes to proactively replace approximately 60 **padmounted transformers** per year.
Automated/remote-controlled switches, switches that are at, or near, end-of-life and therefore likely to fail compromising the ability to prevent feeder and station overloads during the summer peak.	• PowerStream proposes to replace five per year. • These are important for a number of reasons, including preventing station overloads during summer peaks, as well as improving reliability and restoration times.

Pressure: New Technology

PowerStream is finding that in general, customers have increased expectations. They want to communicate with us around the clock and in new ways, such as through social media. Some customers are seeking a detailed understanding of their electricity consumption, and how their bill is calculated. PowerStream information systems must support these customer needs.

The delivery model of the distribution system is changing. Renewable or other forms of generation have changed power flow from unidirectional to multidirectional. To manage this fundamental change requires increased technological investments.

Challenges	Solutions
The requirement to develop and support smart grid technology to meet the high reliability demands of today's electricity consumers.	• Improvements to the **distribution system** to support growing numbers of Electric Vehicles. • Improvements to the distribution system to support increased renewable **generation** and **energy storage** initiatives. • Develop and promote consumer energy management initiatives to reduce energy demand.
An outdated billing system, over 35 years old, that cannot support a growing number of customers, has limited ability for interactive features, and no longer has vendor support.	• A new modern **billing system**, expandable in the future as required, to provide a more efficient platform for customers with increased interactive support and customer information security. A new modern billing system will also provide increased efficiencies by integrating with other systems, and produce long-term cost savings.
The replacement of end-of-life remote-controlled switches to ensure rapid and automatic transfer of loads in emergencies and reduce restoration times.	• Installation of new smart remote-controlled power line **switches** and **reclosers**. • A formal decision-making process for determining the most cost effective quantity of **switches**, and the optimal locations, for providing the maximum benefit to the largest number of customers.
The need to replace old and difficult to operate "mini-rupter" (high capacity isolating) switches in commercial/ industrial locations.	• Installation of new high-capacity isolating **switches** that increase operational efficiencies and reduce the need for costly power interruptions when performing routine maintenance.
New OEB regulations that require higher intelligence metering equipment for all commercial/industrial customers over 50kW by 2020.	• Replace 4400 meters with new **smart technology** meters in a pre-planned efficient multi-year program.

Pressure: Security

As technology continues to be utilized in every aspect of the utility's business, there is an increasing risk of cyber security attacks that could potentially affect confidential customer or corporate information, customer privacy, power delivery, and even the safety of employees or customers through the unauthorized use of PowerStream technology. One incident could do serious damage to the corporation and to its corporate image. In addition, there is the on-going risk of physical security; the physical protection of buildings and stations, and the monitoring of critical equipment to protect from impending failure.

Challenges	Solutions
Evolving risks to cyber security of customer information and grid due to aging and unsecure IT equipment.	• Firewall/Intrusion Detection System/Intrusion Protection System—this is a security checkpoint between the trusted and untrusted network/device/users and is also used to continuously monitor for any malicious activity and can automatically take action in certain instances. • Network Access Control—this dynamically monitors and controls devices, applications and users to deny unauthorized external access to the network. • Identity and Access Management—this manages user access and privileges granted throughout the PowerStream environment • Security Information and Event Management—this is real-time logging and analysis of security alerts. • Vulnerability Assessment Tool—this scans, identifies, quantifies and prioritizes vulnerabilities in the PowerStream environment and suggests remediation solutions. • Mobile Device Management—this controls mobile devices connected to our network and can authorize, wipe, secure and encrypt corporate information as required. • Enterprise Change Management—this process and associated technology allows PowerStream to effectively deal with constant change through a structured approach to transitioning systems, applications and technologies from current to desired future states.
Risk of vandalism to substation buildings and equipment.	• Install equipment monitoring Infrared cameras at 16 additional stations over the next 6 years. • Install perimeter video surveillance cameras at 17 additional stations over the next 6 years.

Pressure: Obsolescence

Despite an ever increasing number of weather-related interruptions each year, PowerStream has worked hard to stay within the boundary of its average historical reliability performance targets of one outage totalling 60 minutes per customer, per year.

While PowerStream continues to demonstrate strong reliability performance in the operation of its distribution network, it is not without its challenges. There are areas and pockets within the PowerStream distribution system that suffer poor reliability due to the type of legacy construction that was once considered acceptable or even preferable. An example of this would be older houses connected to overhead power lines located in the back lot (rear lot) of those properties.

The reliability of rear lot supply connections is worse under severe weather conditions than the current standard front lot connections. In addition, the cost to maintain these rear-lot connections is much higher than the cost to maintain front lot connections.

Challenges	Solutions
Rear Lot Conversion program: Capital work required to address reliability, safety, operations and customer service concerns on rear lot supply connections.	• There are 49 areas of rear lot construction scattered among eight of the municipalities of PowerStream. Most of those areas were constructed in the 1950's, 1960's and 1970's. The oldest dates back to 1948. • PowerStream proposes to replace the worst areas of rear lot connections on an annual basis over many years until all areas are converted. • The average cost of this conversion work is estimated to be $1.2M per rear lot area. • Elimination of rear lot supply connections will result in long-term operational efficiencies and reduced maintenance costs.

Pressure: Major Events

PowerStream's system is built to quickly restore power after the loss of one or two key elements in the electricity grid. But what happens when there is a major disruption to the system?

PowerStream has been severely impacted by weather–related events over the past year. The December 2013 ice storm, microbursts in York region and tornados in the North service area have all highlighted the risk to the grid from major events. Major events are rare events that have a major impact. The Insurance Bureau of Canada reports that severe weather is likely to increase over the next 40 years.

The December 2013 Ice Storm in Ontario severely tested the emergency preparedness of electrical utilities in Southern Ontario including the Greater Toronto Area where hundreds of thousands of customers were left without power, some for as long as a week, or even longer. An independent assessment of PowerStream's response to that storm highlighted a number of areas where improvements are required at PowerStream to be better prepared for future severe storms and emergency events. Key areas identified for improvement include:

1. Improve external communications with customers.
2. Improvements to Customer Care systems and staffing.
3. Improve Outage Management Systems and utilize outage reporting via existing Smart Meters.
4. Improve vegetation management.
5. Elimination of rear lot services, and convert to front lot.
6. Upgrade our underground key distribution lines.

Challenges	Solutions
The need for emergency preparedness during unplanned events and expenses.	• Prepare contingency plans for the immediate replacement of assets (i.e.: **poles, transformers**, etc.) due to unanticipated failure, storms, motor vehicle accidents, vandalism, etc. • Ensure adequate levels of spare equipment and materials that are available for emergencies.
The need to improve the supply to those customers who are more vulnerable to outages and duration of outages, specifically rear lot supply.	• Plan to replace rear lot supplies on an annual basis until all are remediated.
The need to make changes to key distribution lines to withstand increased severity of weather events.	• Plan to increase structural integrity of key assets (i.e. tension cables designed to add stability to poles). • Upgrade or underground key wires.

The investments discussed earlier in the primer are focused on minimizing the day-to-day outages and increasing the speed by which electricity is restored. Additional investments could help "harden" the system and speed up power restoration during a major event. There is no practical limit to potential ways of making the system more resilient in a major event, it is fundamentally a question of money.

13. A significant amount of PowerStream's distribution system equipment was installed in the 1970s, 1960s or even earlier, and is still in-service today. PowerStream works hard to extend the life of our existing equipment because it helps to keep rates down, but as equipment gets older it becomes more likely to fail. PowerStream has two approaches to older equipment.

- If the failure of a piece of equipment will impact a large number of people, result in a long outage or if an inspection shows the equipment is in poor condition, PowerStream does initiate equipment replacement before failure.
- When an equipment failure has only a limited impact and can be quickly replaced, PowerStream's policy is to leave the equipment in place until it breaks down to get all the value possible from that equipment.

What do you think of this policy?

- ☐ I am willing to pay more to replace all equipment before it fails
- ☐ I support the current approach of allowing equipment to run to failure when that failure impacts only a few customers for a limited period of time.
- ☐ Don't Know

14. When it comes to replacing aging equipment, which of the following points of view is closest to your own?

- ☐ PowerStream should invest what it takes to replace the system's aging infrastructure to reduce the risk of power outages; even if that means my electricity bill will increase by a few dollars per month.
- ☐ PowerStream should scale back their investment in renewing the system's aging infrastructure to reduce the size of any bill increase; even if that means more or longer power service interruptions.
- ☐ Don't Know

15. When it comes to investing in new technology, which of the following points of view is closest to your own?

- ☐ Investments in new technologies are more a luxury than a necessity and should be a low priority for PowerStream.
- ☐ I think the benefits of new technology are important and investments in new technology should be a priority for PowerStream.
- ☐ Don't know

16. Currently, the average general service customer pays $61 a month to PowerStream to operate and maintain the local distribution system. How much more are you willing to pay each month for investments that would help the system better withstand major events such as extreme weather?

$

What this Plan Means for You

It all comes down to what you pay and what you receive in return.

What will you get? PowerStream's plan for 2016 to 2020 deals with the challenges outlines in this primer to deliver a system that will maintain or achieve modest improvements in reliability and service.

What will it cost? General service customers with an average monthly consumption of 2000 kWh may see an average annual increase of **$5.25** per month or **8.2 per cent** on the distribution portion of their bill over the next five years. As such by 2020, the average general service customer will be paying an estimated **$26.24** more per month on the distribution portion of their electricity bill. It is important to note that other increases on the bill by other entities are also possible.

There are two main elements in that increase:

- An increase of approximately **2.5 per cent** or **1.60 cents** per month per year in operating costs which reflects inflation and new costs which are offset in part by efficiency savings;
- An increase of approximately **5.7 per cent** or **$3.65** per month per year new capital investments to deal with the issues discussed earlier such as growth, aging infrastructure and new technology.

In addition, in the first year of the plan there is a "catch-up" increase to deal with expenses that were not properly covered under the existing formula. The next section explains the need for that catch-up.

Current Revenue Shortfall

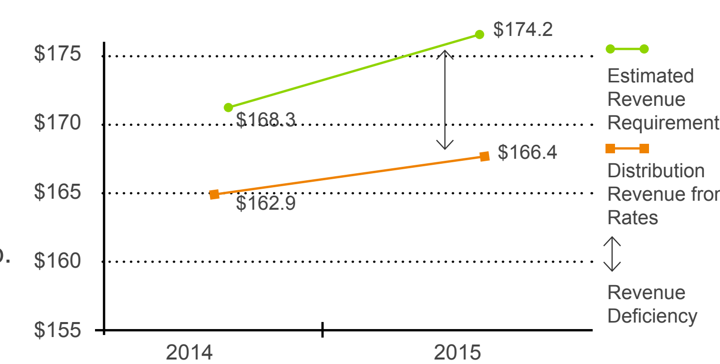
The formula setting PowerStream's rates in 2014 and 2015 is not keeping up with the need for new investment.

PowerStream's rates were set in 2013 using the cost of service method where the OEB sets rates at the level needed to fund the operation of the utility. That worked well in 2013.

However, in 2014 and 2015, rates were not based on actual costs. Instead, a formula was applied which adjusted rates for inflation less an adjustment for efficiency, referred to as a price cap index (PCI) adjustment. This formula does not provide enough revenue in rates to fund the actual capital investments being made in these years.

For instance, PowerStream made the second largest investment in its 10 year history when it brought in a new billing system. PowerStream is committed to providing customers with accurate billing information from meter to payment. However, the old system was implemented 30 years ago and just wasn't keep up with new demands such as mobile access and self-service options customers told us they expect today. Changing to a modern system required both a significant capital investment and an increased operating budget, but not only does it provides much better access for customers and staff, it does so with a much higher level of security for personal information, a key concern in these times.

Revenue Shortfall ($millions)



($ Millions)	2014	2015	Total
Estimated Revenue Requirement	$168.3	$174.2	$342.5
Distribution Revenue from Rates	$162.9	$166.4	329.3
Revenue Deficiency	($5.4)	($7.8)	($13.2)

The OEB recognized that problem and created the new Custom Incentive Rate rate setting method which PowerStream will be using in this rate filing. This method will alleviate this issue going forward but there is still a need to deal with 2014 and 2015 investments.

The chart on page 29 compares the revenue from rates using the PCI to the revenue needed to fund utility operations on a cost of service basis. Over 2014 and 2015, there will be a revenue shortfall of approximately $13.2 million. This shortfall is being funded by PowerStream's municipal shareholders from past earnings retained in the company. However, using savings to make up for the missing revenue will restrict PowerStream's ability to make the necessary future investments to maintain its system and the level of service provided to its customers. The catch-up will enable PowerStream to fund those needed investments.

Most of the rate increase in 2016 is to provide funding for capital investments in 2014 and 2015. This will result in an increase of $8.53 a month for the average general service customer consuming 2000 kWh a month.

Increased Capital Spending

PowerStream has developed a list of capital investment drivers and proposes capital investment programs based on these key drivers. The definitions of the key drivers are below.

Service Requests

PowerStream has an obligation to connect a customer to its distribution system. This includes both traditional demand customers and distributed generation customers. Requests also can include system modifications to support infrastructure development by government agencies, road authorities and developers. Normal connection costs are recouped through the revenue from new customers. Unusual connection costs are paid by the customer being connected.

Increased Delivery Capacity

As new customers are connected, PowerStream needs to expand the core elements of its distribution system, including expanded or new distribution stations and enhanced or new feeder lines. This is the fundamental infrastructure that allows new customers to be hooked up to the distribution system and is paid for by the extra revenue from new customers served over time.

System Efficiency

To provide customers with the best service possible, there is always a need to improve restoration capability. As the population in PowerStream's service territory continues to grow, the system also needs to grow in order to be able to handle new connections.

Mandated Compliance

Environmental, reliability and safety standards are updated on a regular basis and PowerStream's system must be updated to keep up with these standards. Agencies that impact PowerStream include the Ministry of Energy, Measurement Canada, the OEB, the IESO and/or other regulators.

Obsolescence

Improvements in technology can require PowerStream to replace equipment that is still functional but no longer meets current operating practices or current standards. Reasons for replacement include:

- the equipment is no longer manufactured;
- there are no spare parts;
- are unable to have maintenance performed on them;
- there are operational constraints or conflicts, which can result in increased reliability and/or safety-related risks.

Aging or Poor Performing Equipment

Where there is the imminent risk of failure due to age or condition deterioration, and these potential failures will result in severe reliability impacts to customers as well as potential safety risks to crew workers or to the public, refurbishment or replacement is required.

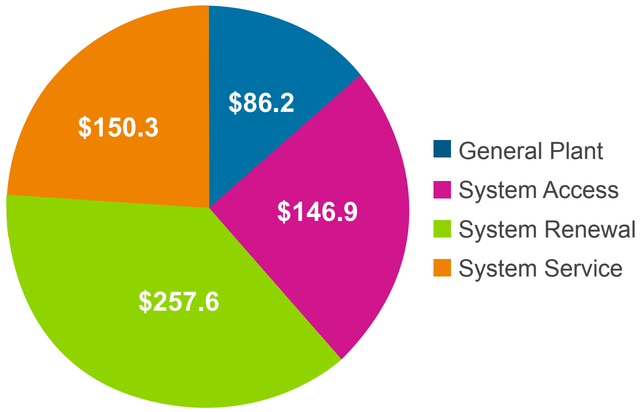
Business Support Costs

PowerStream is not just the local electricity grid itself, it is the business that operates that grid. The utility needs storage facilities for equipment, workshops to maintain and repair equipment and offices for people who manage your accounts and the electricity system. PowerStream needs vehicles for its crews, as well as computer systems to manage customer accounts, track equipment and operate the grid. While this is a relatively small slice of the capital spending over the next several years, it is just as critical to have IT systems identify where an outage is and where the needed parts are stored as to have the replacement parts themselves.

	Capital Investment Drivers	Primary Driver	Source
System Access	Subdivisions and New Connections Road Authority Metering Other Customer Initiated Work	Service Requests	Developers, Customers, Road Authorities
System Service	Reliability including Distribution Automation Additional Capacity - Lines Additional Capacity - Stations (TS and MS) Security Smart Grid Safety	Reliability Support Capacity Delivery System Efficiency Safety	PowerStream
System Renewal	Distribution Lines - Emergency/Reactive Replacement Overhead Lines and Assets Planned Replacement Underground Cable and Asset Planned Replacement Rear Lot Conversion Program Stations/Protection & Control Asset Replacement (Planned & Emergency)	Mandated Compliance Obsolescence Mitigate Failure Risks Safety	Regulator Safety Authority PowerStream
General Plant	Interest Capitalization Customer Service Information Service and Communication Systems Buildings/Facilities Fleet Tools	Capital investment Support Customer service	PowerStream

Looking ahead at the next five years and all the categories identified above, PowerStream is proposing to spend $641 million on new capital investments. This will result in an annual increase of about 6% on the distribution portion of your bill which is about three quarters of the proposed rate increase.

2016 - 2020 Forecasted Capital Expenditures ($ millions)



With the proposed levels of capital and operating budgets for 2016 to 2020, in 2020 PowerStream will continue to operate on less revenue per customer than the average Ontario local distribution company.

Feedback

17. Given what you know and what you have read so far, how well do you feel you understand the challenges facing the PowerStream system and what they are planning to do to meet those challenges?

- ☐ Very well
- ☐ Somewhat well
- ☐ Not very well
- ☐ I don't understand at all

18. From what you have read and what you may have heard elsewhere, does PowerStream's investment plan seem like it is going in the right direction or the wrong direction?

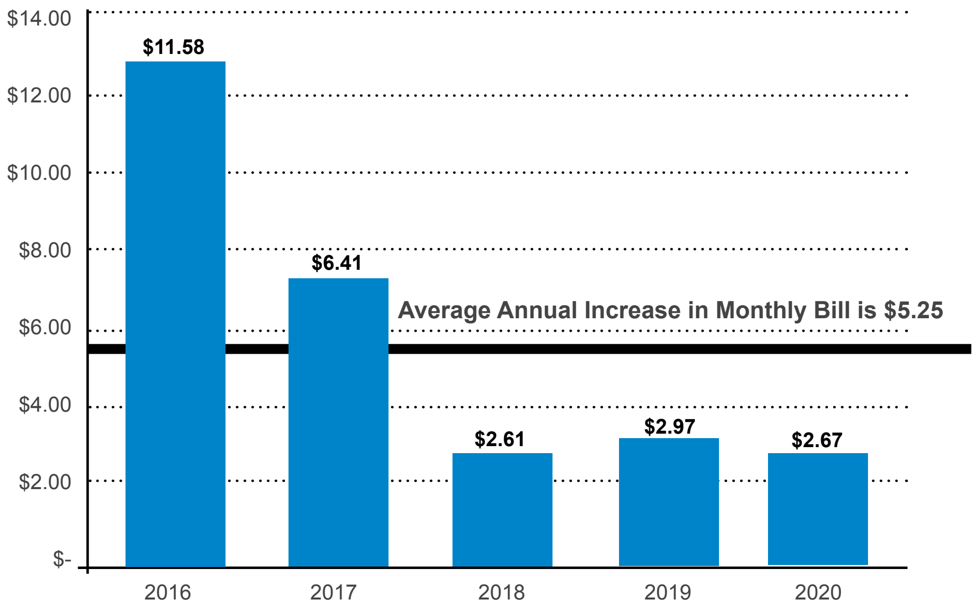
- ☐ Right direction
- ☐ Wrong direction
- ☐ Don't know

19. And why do you feel that way?

The Impact on Your Bill

General service customers with an average monthly consumption of 2000 kWh may see an average annual increase of **$5.25** per month or **8.2 per cent** on the distribution portion of their bill over the next five years. As such by 2020, the average general service customer will be paying an estimated **$26.24** more per month on the distribution portion of their electricity bill.

Estimated Typical GS<50 KW Annual Increase in Monthly Bill



Feedback

20. Considering what you know about the local distribution system, which of the following best represents your point of view:

- ☐ The rate increase is reasonable and I support it
- ☐ I don't like it, but I think the rate increase is necessary
- ☐ The rate increase is unreasonable and I oppose.
- ☐ Don't know

21. And why do you feel that way?

Final Thoughts

PowerStream values your feedback. This outreach is a new requirement, so this is the first time that the utility has conducted a review about its upcoming investment plan in this type of format.

General Impression - Overall, what did you think about this primer?

Volume of Information: Did PowerStream provide too much information, not enough, or just the right amount?

Content Covered: Was there any content missing that you would have liked to have seen included?

Outstanding Questions: Is there anything that you would still like answered?

Suggestions for Future Consultations: How would you prefer to participate in these consultations?

Glossary

Breakers: Devices that protect the distribution system by interrupting a circuit if a higher than normal amount on power flow is detected.

Feeder Circuit: Is a wire that connects stations to the broader distribution system in order to deliver electricity to customers.

Generation Station: A facility designed to produce electric energy from another form of energy, such as fossil fuel, nuclear, hydroelectric, geothermal, solar thermal, and wind.

Kilowatt (kW): 1000 watts.

Local Distribution Company (LDC): In Ontario, these are the companies that take electricity from the transmission grid and distribute it around a community.

OM&A: Operations, Maintenance and Administration

Stations: These include tranformer stations and distribution stations. They are used to switch generators, equipment, and circuits or lines in and out of a system. It also is used to change AC voltages from one level to another.

Switches: These control the flow of electricity—they direct which supply of electricity is used and which circuits are energized. Distribution systems have switches installed at strategic locations to redirect power flows for load balancing or sectionalizing.

System Access: Projects required to respond to customer requests for new connections or new infrastructure development. These are usually a regulatory requirement to complete.

System Renewal: Projects to replace aging infrastructure in poor condition.

System Service: Primarily projects that improve reliability.

General Plant: Investments in things like tools, vehicles, buildings and information technology (IT) equipment that are needed to support the distribution system.

Transmission lines: Transmit high-voltage electricity from the generation source or station to another station in the electricity grid.

Transformer: A piece of equipment that reduces the voltage of electricity from a high level to a level that can be safely distributed to your area or to your residence/business.

Underground Cable: A conductor with insulation, or a stranded conductor with or without insulation and other coverings (single-conductor cable), or a combination of conductors insulated from one another (multiple-conductor cable).

Volt (V): A unit of measure of the force, or 'push,' given the electrons in an electric circuit. One volt produces one ampere of current when acting on a resistance of one ohm.

Watt (W): The unit of electric power, or amount of work (J), done in a unit of time. One ampere of current flowing at a potential of one volt produces one watt of power.

Wire: A conductor wire or combination of wires not insulated from one another, suitable for carrying electric current.

If you have any additional questions or comments about PowerStream's Distribution System Plan Review please email:

CustomerFocus@powerstream.ca

or send your questions or comments to:

PowerStream
Attn: DSP Review
161 Cityview Boulevard,
Vaughan, Ontario
L4H 0A9

PowerStream

Appendix F

Customer Consultation Report

Delivered: February 24, 2015

Innovative Research Group, Inc.

Toronto • Vancouver

Customer Consultation Report

Distribution System Plan

February 2015

Prepared for:

PowerStream Inc.
161 Cityview Blvd,
Vaughan, ON L4H 0A9

Customer Consultation Report

Distribution System Plan

February 2015

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for PowerStream.

The conclusions drawn and opinions expressed are those of the authors.

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Introduction

About this Consultation

Innovative Research Group Inc. (INNOVATIVE) has been commission by PowerStream to help the utility design, collect feedback and document its customer engagement and consultation process as part of the development of PowerStream's Distribution System Plan (DSP).

PowerStream's Distribution System Plan is a key element of its next distribution rates application. The outcome of this application will determine PowerStream's electricity distribution rates for the next five years.

The OEB's new "consumer-centric" approach to rate applications contained in the *Renewed Regulatory Framework for Electricity (RRFE)* requires LDCs to demonstrate that services are provided in a manner that responds to identified customer needs and preferences[1]. Distributors are required to provide an overview of the customer engagement activities that that they have undertaken with respect to their plans and how customer needs and preferences have been reflected in their application. While PowerStream engages customers in a number of ways to explore their needs, it has not done so in the context of its capital plan or rate implications. This initiative sought to bring customers directly into the process of finding the right balance between cost and reliability in PowerStream's Distribution System Plan.

This process of identifying and reacting to customer needs and preferences as it pertains to their DSP development and execution is new to Ontario's LDCs. There are no established practices and there are a number of options available to engage with customers. The following section explains how INNOVATIVE approached this engagement.

Approach to Meaningful Customer Engagement

It is our experience at INNOVATIVE that engaging customers in meaningful consultation can be a challenge. The reality of most consultation processes is that they start out aiming to collect the views of the average person, but end up collecting the views of organized advocacy groups.

Many customers feel they don't know enough to contribute to a public consultation. Others fear the combative nature of some public processes or prefer not to risk offending friends and neighbours by taking firm positions on issues that are sometimes controversial. Moreover, many customers simply do not pay attention and remain unaware of particular consultations that they would participate in if they had been aware.

Running a consultation on a Distribution System Plan presents an additional challenge – the lack of awareness of the distribution system including how it is funded, regulated and the nature of its challenges. This is well documented in Ontario Energy Board research and in INNOVATIVE's own experience.

[1] OEB Renewed Regulatory Framework for Electricity Sections 2.4.2, 5.0, and 5.0.4.

Considering both the challenge of engaging a representative group of customers and a general lack of knowledge, we have created a process built on six key principles:

1. Ensure customers from across PowerStream's customer-base have an opportunity to be heard.
2. Use random-sampling research elements to ensure a representative sample of customers are engaged.
3. Create open voluntary processes to allow anyone who wants to be heard to be heard.
4. Focus on fundamental value choices. Look for questions that ask people to choose between key outcomes rather than focus on the technical questions of how to reach those outcomes.
5. Create an opportunity for the public to learn the basics of the distribution system so they can provide a more informed point of view.
6. Test the consultation material in advance for clarity of language, appropriateness of questions, ability to respond to questions, and the right balance between comprehensiveness and simplicity.

Since this was the first time PowerStream so explicitly engaged customers in the development of their DSP, a specific effort was made to collect participant comments on the process itself. While most customers felt this approach to engagement was effective at soliciting their feedback on PowerStream's DSP, other ideas on how to improve upon the process were collected throughout the consultation. This is discussed in detail throughout the body of this report.

Customer Consultation Overview

Based on the principles outlined above, INNOVATIVE worked with PowerStream staff to design a multifaceted customer engagement program which included a combination of traditional consultation services as well as qualitative and quantitative research elements. This comprehensive consultation was designed to engage various rate classes and collect feedback on preferences and priorities as they relate PowerStream's 5 Year DSP.

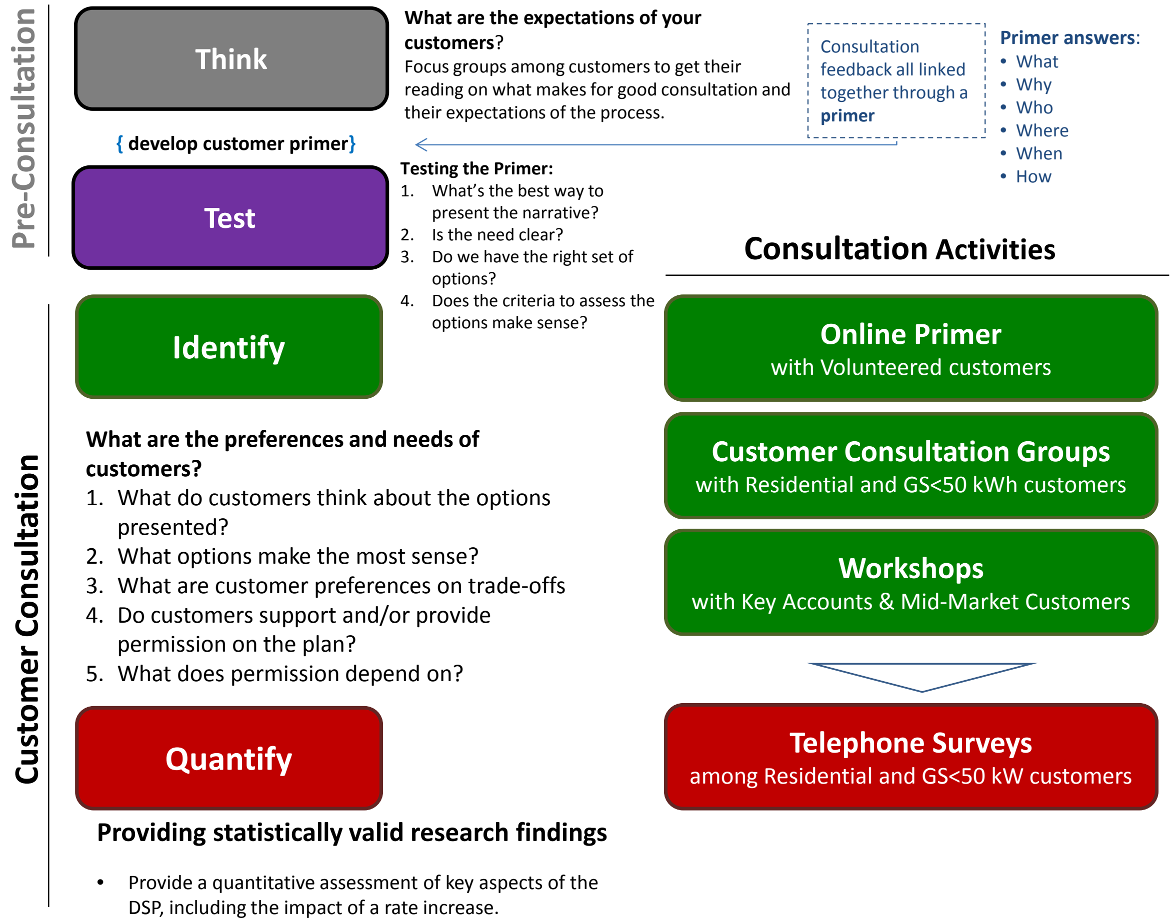
The consultation encompassed **five** core elements of customer engagement:

1. **Online Primer**: The online primer was promoted through traditional print advertising and social media as well as PowerStream's website. This first phase of the consultation was available to any PowerStream customer who wanted to participate.
2. **General Service and Residential Consultation Groups:** The General Service and Residential Customer phase of PowerStream's multi-faceted customer consultation was used as an engagement tool to educate customers, access customer preferences and priorities, gauge customer permission of rate increases, as well as to inform subsequent phases of the consultation. The groups were randomly recruited and held in different locations across PowerStream's service area. A primer was used to provide the participants with core information about Ontario's electricity system and PowerStream's Distribution System Plan. They were provided incentives in recognition of their time commitment.

3. **Mid-Market General Service Workshops**: General Service customers over 50 kW (GS > 50kW) were engaged through a series of randomly recruited workshops. They were provided incentives in recognition of their time commitment.
4. **Key Accounts Workshop:** Key Accounts customers were engaged in an interactive workshop, including a presentation from PowerStream staff, as well as a Focus Group component lead by INNOVATIVE. Key Accounts customers were randomly recruited from lists provided by PowerStream.
5. **Random Telephone Surveys**: INNOVATIVE conducted telephone surveys with residential and general service (GS < 50kW) customers to provide a quantitative assessment of key aspects of the plan. Customer lists for both respondent groups were provided by PowerStream and the sample was randomly-selected by INNOVATIVE.

There were **four** stages in developing and implementing this consultation:

- **Think**: The first step was developing the core background material and key questions for the primer. INNOVATIVE and PowerStream worked together to review the Distribution System Plan to identify potential questions that would allow customers to share their needs and preferences and then to develop a primer that would provide the information needed to allow customers with different levels of initial knowledge to find answers to those questions.
- **Test**: The second step was to refine the primer and determine what were the best ways to present the narrative. INNOVATIVE conducted Focus Groups to understand whether the primer was comprehensible and whether challenges, solutions and options were presented in as clear a manor as possible.
- **Identify:** The third step was to find out the range of views held by the public regarding the Distribution System Plan through the more qualitative elements of the process. This included an online primer using a voluntary sample and a series of customer discussion groups and workshops using randomly recruited samples of residential and GS customers, including PowerStream Key Accounts customers.
- **Quantify**: The final step was quantitative - randomly recruited telephone surveys of residential and GS customers. Randomly recruited surveys allow us to draw generalizable conclusions that can be applied to the broader population of PowerStream customers. The surveys were developed based on the feedback from the qualitative research.



The consultation was designed so that anyone who is interested would have an opportunity to participate in the process through the online primer. However, in our approach, we distinguish between responses from the opinion research discipline (random recruits and scientific polls) and responses from an "open invitation" consultation discipline.

The small group results are presented as numeric counts to help readers remember that qualitative research only identifies points of view, it does not project the incidence of that point of view in the broader public.

The results from the primer and random telephone surveys are presented as percentages due to the larger numbers involved.

- Readers are cautioned that the online primer results represent the views of volunteers. The online primer sample is not randomly selected and cannot be generalised to the broader public.
- The telephone surveys are based on random samples so we can reliably project the incidence to the broader population of PowerStream customers.
- In some instances, the quantitative total may be greater than 100% due to rounding. This is in keeping with standard research practice.

It is important to note that these consultations occurred as PowerStream was developing its plan.

Primer Development

As we noted earlier, a key challenge in getting public feedback on PowerStream's DSP is the lack of customer knowledge about the Ontario electricity system, PowerStream's role in the system and the local distribution system as a whole. The DSP itself is a very detailed and extensive document that uses technical language. Our challenge was to briefly cover these key issues and to frame meaningful questions to determine customer needs and preferences.

The process of developing the consultation primer began in the fall of 2014. INNOVATIVE and PowerStream staff began the process of reviewing PowerStream's Distribution System Plan while INNOVATIVE conducted three nights of exploratory groups on June 17th in Barrie, June 18th in Vaughan and June 19th in Markham with randomly selected Residential and General Service customers to determine what they were looking for in the consultation process and what they needed to know to determine if PowerStream's DSP was reasonable.

Based on the initial review of the plan, exploratory groups, and feedback from testing, the primer was divided into key sections that explained PowerStream's electric system, the challenges facing the system, and how PowerStream intended to meet those challenges over time.

The final consultation primer had six distinct chapters:

1. **Why Are We Here?**: the purpose of the discussion, where the discussion fits in the bigger picture.
2. **Electricity Grid 101**: how the overall system works and the players involved in operating and regulating the system.
3. **PowerStream's Grid Today**: a discussion of the structure and key elements of PowerStream's distribution system, including current and past reliability.
4. **Challenges and Solutions**: a discussion of the various challenges facing the grid and an overview of the initiatives being undertaken to manage these challenges.
5. **What this Plan Means for You**: how PowerStream customers will be affected by the proposed Distribution System Plan, including rate impacts.
6. **Final Thoughts**: an opportunity for customers to provide feedback on general aspects of the consultation process, including what they enjoyed and where improvements could be made.

Although the knowledge base of customers varied, the same basic primer was used in all qualitative customer engagements – the online primer, the residential and small GS discussion groups and the mid-sized GS and Key Accounts workshops. The key change in the material between audiences is that the bill references varied to reflect the details of that specific rate class. As the customer went through the consultation primer – either independently or through a facilitated session – they were prompted with questions related to system reliability, system challenges, and preferences on the direction of PowerStream's proposed Distribution System Plan.

The questions themselves were another key element of the primer. In developing them, we looked for questions that could also be applicable over the telephone, and without all the information in the primer.

The needs questions were the easiest to develop. We started with a basic satisfaction question and then asked an open-ended question about how PowerStream could improve its services. Without imposing boundaries, we let customers illustrate whatever topics they wanted to cover. Later in the primer we probed satisfaction with the number and duration of routine outages and probed the impacts of those outages. We also zeroed in on major events by asking customers if they had experienced an outage during the ice storm, microbursts or tornadoes, how satisfied they were with PowerStream's response, as well as how PowerStream could improve its services during those events.

Questions ascertaining preferences required more tact. We were looking for value choices rather than technical issues. Key topics for preferences included:

- What approach should be taken with regards to replacing aging infrastructure?
- Should the utility continue to follow a run-to-failure approach or implement a pro-active replacement strategy?
- Given the other major needs for investment, how important is it to invest in modernizing technology?
- How much more are you willing to pay for investments that would help the system better withstand major events such as extreme weather?
- Whether the overall Distribution System Plan was heading in the right or wrong direction and why?

The final substantive question asked about the cost of the DSP. Sometimes this question is asked with a simple *support or oppose* response scale, but we found that type of scale didn't effectively capture the scope of customer responses. Instead, we gave customers three options as well as a *not sure* opt out:

- The rate increase is reasonable and I support it.
- I don't like it, but I think the rate increase is necessary.
- The rate increase is unreasonable and I oppose.

The primer concluded with a final set of five questions to assess the primer and process itself.

The primers can be found in the **Appendix** of this report.

Executive Summary

The following section provides a detailed summary of the findings of PowerStream's Distribution System Plan Customer Consultation. In this section we provide a high level overview of PowerStream's Residential and General Service customers' needs and preferences as they relate to the DSP.

More than 1,600 customers participated in the qualitative stages of the consultation, which included both Focus Groups and an Online Primer. In these stages we explored the range of issues related to PowerStream's rate application. Another 1,202 customers participated in the quantitative stage where we documented the incidence of needs and preferences across the customer population.

Customer Needs

From the start of the consultation focus groups, and throughout the online primer and telephone survey, customers are extremely satisfied with the job PowerStream is doing running the electricity distribution system. The format of the consultation process is intended to build on ideas and questions from stage to stage, and satisfaction was positive throughout. Below is a chart indicating customers overall satisfaction with PowerStream and the services they provide.

Overall Satisfaction with PowerStream Service

Response	Directional (Focus Groups & Online Primer)				Generalizable (Telephone Surveys)	
	Residential Groups	GS under 50 kw Groups	Mid-Market Groups	Online Primer	General Service	Residential
Very satisfied	16	9	8	46%	25%	34%
Somewhat satisfied	6	13	8	45%	58%	52%
Somewhat dissatisfied	1	1	1	5%	6%	5%
Very dissatisfied	0	0	0	2%	4%	4%
Don't know / Refused	0	0	0	2%	6%	0%
TOTAL	**n=23**	**n=23**	**n=17**	**n=1,553**	**n=201**	**n=1,001**

While satisfaction is overwhelmingly positive, there are areas that customers believe PowerStream can improve upon. The main threads that ran throughout the stages were rate reductions and communication. When asked how PowerStream could improve service during both normal and usual weather outages, the overwhelming response in the telephone survey was tied to rate reductions. 33% of Residential and 32% of General Service customers saw reducing rates as key was PowerStream could improve service.

Improving communication was also seen as a priority in each stage of the consultation. Disseminating information regarding estimated recovery times was a key priority mentioned in each stage of the consultation. Business customers are affected by outages of any length, and improving communication can help them determine whether or not to remain open.

Generally, customers expect an increased online presence during outages and throughout the focus groups and online primer requested further online alerts through both social and television media.

Beyond rate reductions and communication, customers commonly asked that PowerStream provide clearer bill breakdowns. Upon gathering this feedback in the earlier consultation stages, customers in the telephone survey were asked about their familiarity with the amount of their electricity bill that went to PowerStream – of which, 67% of Residential and 55% of General Service customers were unfamiliar. These three responses were common through every stage of the consultation process. This paradox of *lower prices* while seeking *service improvements* is the key dilemma the consultation sought to explore and better understand.

All stages of the consultation focused deeply on the question of outages, both under normal circumstances and due to unusual weather. In both cases PowerStream customers were extremely satisfied with the utilities response. The tables below depict customer satisfaction with both types of outages across both the qualitative and quantitative stages of the consultation.

Satisfaction with Response to Unusual Weather Outages

Response	Directional (Focus Groups & Online Primer)				Generalizable (Telephone Surveys)	
	Residential Groups	GS under 50 kw Groups	Mid-Market Groups	Online Primer	General Service	Residential
Very satisfied	11	11	8	41%	25%	33%
Somewhat satisfied	7	13	8	41%	41%	40%
Somewhat dissatisfied	3	0	0	8%	4%	7%
Very dissatisfied	0	0	0	3%	3%	5%
Don't know / Refused	0	0	1	7%	25%	13%
TOTAL	**n=21**	**n=23**	**n=17**	**n=1,553**	**n=201**	**n=1,001**

Satisfaction with Response to Normal Outages

Response	Directional (Focus Groups & Online Primer)				Generalizable (Telephone Surveys)	
	Residential Groups	GS under 50 kw Groups	Mid-Market Groups	Online Primer	General Service	Residential
Very satisfied	11	12	5	42%	38%	42%
Somewhat satisfied	9	12	8	42%	43%	44%
Somewhat dissatisfied	0	0	1	8%	8%	5%
Very dissatisfied	0	0	0	3%	5%	4%
Don't know / Refused	1	1	2	5%	6%	6%
TOTAL	**n=21**	**n=25**	**n=16**	**n=1,012**	**n=81**	**n=462**

As with general satisfaction, PowerStream is seen extremely positively with regards to response to outages; yet improving communication during outages continues to be a central concern. If outages are going to be prolonged, customers want to know so they can plan accordingly. Customers understand that outages caused by usual weather are out of PowerStream's control, but they still request clear communication regarding recovery times.

Again, when asked how PowerStream could improve response to outages, customers in all stages pointed to recovery time and speed. In essence, they want faster response time from line crews, and the overall duration of outages to be reduced.

The customer needs feedback gathered in the qualitative stages of the consultation helped to shape the telephone survey and questions about customer preferences on the trade-off between cost and reliability. The feedback gathered in this phase of the consultation is summarized in the section below.

Customer Preferences

Outage Preferences

Building on the reliability performance feedback gathered in the qualitative stages of the consultation, the telephone survey asked customers to choose between three options with regards to how PowerStream should address the number of outages.

- 32% of Residential and 38% of General Service customers said PowerStream should spend what is needed to *reduce* the number of outages.
- 40% of Residential and 34% of General Service customers said PowerStream should spend what is needed to *maintain* the current level of outages.
- 13% of Residential and 14% of General Service customers said PowerStream accept more power outages in order to help keep customers costs from rising.

Similarly, when customers were asked about the length of time they were without power, both Residential and General Service customers gave almost the same responses to the previous question.

These findings from the telephone survey are consistent with much of the data and feedback gathered throughout the qualitative stages of the consultation. In fact, in the focus groups, many business customers said that reliability is often more important (and a cost savings) than the proposed rate increase. For these customers, any length of outage can be extremely costly and investment is seen to be the better option.

System Challenges and Priorities

There are a number of system challenges and priorities that PowerStream must address in the next five years, and customers voiced their preferences throughout the consultation process. With regards to replacing aging infrastructure, customers in all phases generally understand the need to invest in either improving or maintaining the current system. Below is a chart illustrating customer preference regarding investment in the infrastructure projects outlined in PowerStream's DSP.

Investment in Aging Infrastructure

Response	Directional (Focus Groups & Online Primer)				Generalizable (Telephone Surveys)	
	Residential Groups	GS under 50 kw Groups	Mid-Market Groups	Online Primer	General Service	Residential
PowerStream should invest what it takes to replace the system's aging infrastructure…	13	13	9	55%	54%	54%
PowerStream should lower its estimated investment in renewing the system's aging infrastructure	8	6	2	27%	32%	30%
Don't know	2	4	4	18%	8%	10%
TOTAL	**n=23**	**n=23**	**n=15**	**n=1,553**	**n=201**	**n=1,001**

Investments in new technology were seen as an important priority throughout the consultation stages. In the telephone survey, 61% of GS and 58% of residential customers think that the benefits of new technology are important and investments in new technology should be a priority for PowerStream.

Customer Reaction to Rate Impacts

Customers are generally conflicted when it comes to PowerStream's Distribution System Plan and the proposed rate impacts. While customers throughout the consultation understand that there is a need to invest in PowerStream's system, which they understand is facing numerous types of pressures, few customers welcome the idea of a rate increase.

Many customers, both business and residential are feeling a financial pinch. For residential customers, they feel as if they are continuously falling behind, and businesses are not able to charge more for products. In a sense, they have their hands tied.

Reliable electricity remains a priority for many customers; most do not *want* or *like* a rate increase, but are often not opposed. Referring to the results of the telephone survey, 63% of Residential and 43% of General Service customer support the proposed rate increase, numbers that fall slightly behind the direction observed in the qualitative phase of the consultation.

Customer Permission Regarding Proposed Rate Increase

Response	Directional (Focus Groups & Online Primer)				Generalizable (Telephone Surveys)	
	Residential Groups	GS under 50 kw Groups	Mid-Market Groups	Online Primer	General Service	Residential
The rate increase is reasonable and I support it	3	1	1	19%	15%	21%
I don't like it, but I think the rate increase is necessary	15	16	9	48%	28%	42%
The rate increase is unreasonable and I oppose it	5	4	6	26%	54%	33%
Don't know/ Refused	0	0	0	7%	1%	3%
TOTAL	**n=23**	**n=21**	**n=16**	**n=1,553**	**n=201**	**n=1,001**

After further analysis of the telephone survey data, financial strain is a determining factor in permission towards the proposed rate increase. Nearly 8-10 (76%) of Residential customers whose electricity bill does not majorly affect their finances accept the proposed rate increase. Almost 6-10 (58%) of General Service customers who electricity bill does not have a major impact on their organization's bottom line accept the proposed rate increase.

The majority (57%) of Residential customers whose bill majorly affects their finances also accept the proposed rate increase. 37% of General Service customers with the same financial strain accept the increase. That being said, in the directional stage of the consultation, many business customers expressed the financial strain that any length of outage causes their organization.

As seen throughout PowerStream's customer consultation, there is no simple answer to electricity utility spending and investing from the customer's perspective. Rate increases are undesirable, but lower reliability is unacceptable and the need to invest in renewal and spend on maintenance of the distribution system is understood and accepted.

As a result, PowerStream customers reluctantly accept the proposed Distribution System Plan and its accompanying rate increase as an unfortunate necessity.

Online Primer

Online Primer
with Volunteered customers

PURPOSE: To inform customers on the details of PowerStream's DSP and obtain feedback on the proposed options.

Summary

Satisfaction is extremely high, despite luke-warm familiarity with PowerStream.

- Consumers are quite happy with PowerStream: 91% (including 30 out of 32 business consumers) say they are satisfied with their service. Familiarity with the electricity system and PowerStream services is mixed (48% familiar vs. the same not familiar), but overall consumers feel they have a good understanding of the important parts of the system and PowerStream's responsibilities.
- Satisfaction with how PowerStream handled both unusual and normal weather outages is also extremely high: 82% are satisfied with PowerStream's response to unusual weather outages in the past year and 84% feel the same regarding normal weather outages.

Most have experienced outages, but consumers think current reliability is "good".

- Nearly seven-in-ten (70%) say they experienced an outage during unusual weather and six-in-ten (57%) say they experienced an outage not including extreme weather in the past year.
- That being said, the average outage described is quite short: six-in-ten (60%) outages in normal weather are less than an hour and three-in-ten (29%) are less than 15 minutes.
- Although a majority have experienced outages, two-thirds (57%) say that PowerStream's level of reliability is "good" and just 6% say "poor".

Communication during outages is a key concern.

- When asked how PowerStream can improve their service during both unusual and normal weather outages, "improved communication" is consistently a top mention.
- Consumers seem to appreciate an increased online presence during outages and asked for further online alerts through social media such as Twitter, the website, email and via apps or SMS on their phone.

Aurora, Markham and Richmond Hill self-report more issues with reliability.

- Respondents from Aurora, Markham and Richmond Hill generally report a bit less reliable service than the rest of the municipalities.
- They say they experienced more outages during unusual weather (Aurora (78%) and Richmond Hill (76%)) and in normal conditions (Aurora: just 25% "no outages; Markham: 29%; Richmond Hill, 41%).
- Outages are a bit longer in Aurora and Markham (55% and 54% "less than an hour").

- And all three, although still a majority, are less likely to say that PowerStream's level of reliability is "good" (Aurora: 65%; Markham 58%; Richmond Hill 66%).

Consumers support investment in infrastructure and new technologies.

- When asked which they prefer, ramping up infrastructure development to reduce outages or scaling back to reduce costs, consumers prefer "investing to reduce in power outages" by a two-to-one margin (55% to 27%).
- By a smaller margin, consumers also prefer investing in new technologies over the idea that new technologies are a "luxury, not a necessity" (48% to 34%).

Consumers understand challenges ahead, like the plan and are willing to pay.

- A strong majority (87%) feel they understand the challenges facing the PowerStream system.
- Six-in-ten (58%) think PowerStream's investment plan, from what they know so far, is on the right track.
- Those that think PowerStream is on the right track think that the "proposed solutions are reasonable and balanced", (26%) they're satisfied overall with PowerStream (10%) and they value increased reliability (26%). A plurality of those who think PowerStream's plan is going in the wrong direction just "don't want to cover the cost" (n=22/64 for "wrong direction").
- Overall, across all municipalities, a majority of business respondents and all demographics, two-thirds (67%) of consumers support the rate increase.
- Those who think the increase is reasonable support it to "prevent future disruptions" in service (n=45) and think the amount is also reasonable (n=31). Of those who oppose it, a quarter (n=55 out of 220) say they would not accept any increase at all. "Oppose" verbatim also talk about the operating efficiencies of PowerStream (n=37) and executive accountability (n=31). Those who "don't like the increase, but think it's necessary" also cite reliability (n=31) and don't necessarily see an alternative (n=23).

Methodology

About the Online Primer

PowerStream commissioned INNOVATIVE in 2014 to help create an online consumer primer for its consumers. This 21-question primer would inform consumers of current challenges facing the distribution system and explore opinion on the plan to deal with it, including a potential rate increase.

The PowerStream Primer is divided into five key sections:

- "Why are we Here?"
- "Electricity Grid 101"
- "PowerStream's Grid Today"
- "Challenges and Solutions"
- "What this Plan Means for You"

The first section, "Why are we Here?" briefly explains the Ontario Energy Board (OEB)'s regulatory requirements to consumers and the importance of consumer's opinions, whatever their level of expertise, to the rate application process. Respondents are asked to rate their familiarity with both the electricity system and PowerStream's role. A detailed explanation is provided of consumer bills and how electricity rates are determined.

In the second section, "Electricity Grid 101", PowerStream outlines the three components of Ontario's electricity system –"generation, transmission and distribution"- as well as examples of some of the regional companies in each category. With visual aids, the primer further explains how Ontario's electricity system is regulated and the roles of the OEB, the Ontario Power Authority (OPA) and the Independent Electricity System Operator (IESO).

The third section outlines the key parts of PowerStream's distribution system and provides an in-depth analysis on outages and an outline of how PowerStream plans to reduce outages through capital expenditure. Respondents are asked about their understanding of the system, their satisfaction with PowerStream and a number of detailed questions on outages, both during usual and unusual weather events.

"Challenges and Solutions", the fourth section, is precisely that: an outline of the challenges PowerStream faces to providing reliable distribution with aging equipment and technology, potential security concerns and reaction times during major events such as the December 2013 ice storm. For each of these topics, specific solutions are given. Then consumer opinion is gaged on investing in new infrastructure and technology.

The final section, "What this Plan Means for You" explains the current revenue shortfall to meet these challenges, forecasted capital expenditures from 2016-2020 and specifically how consumers' bills will be impacted. The final questions ask the consumer whether they think this investment plan is on the right track and whether they would be willing to support a rate increase to meet the challenges ahead.

Field Dates:

The Online Primer was accessible to PowerStream consumers from November, 17th 2014 to December, 29th 2014.

Promoting the Online Primer:

PowerStream promoted the Distribution System Plan primer in a number of ways:

- The PowerStream Call Centre and other Front line staff
- A two week digital advertising campaign that included ads on radio station websites (JewelRadio.com and 1059TheRegion.com) and three newspaper websites: TheBarrieExaminer.com (leaderboard ad, 100,000 impressions/week), Simcoe.com (run of site, 25,000 impressions/week) and YorkRegion.com (run of site, 40,000 impressions/week)
- The PowerStream website which included a survey "pop-up" modal with options to take the survey as well as reminders. Promotion on the website also included a home-page carousel banner.
- Social media such as Twitter, including a carousel banner image and link to the survey.

Publishing the Primer Online

INNOVATIVE hosted the primer at the following URL: powerstreamcustomerfocus.ca

The website prevented consumers from completing questions repeatedly and saved their progress as they answered each question. They could therefore complete the primer in more than one sitting. Upon completion, the site was no longer accessible at the web address given. After the website was taken down, consumers could still access an "offline" version of the primer.

Note that INNOVATIVE does not ever link to the personal information submitted on the website. All responses were kept anonymous and confidential.

Validating Consumer Responses:

Consumers who filled out the primer were tagged with an identification number based on their postal code and their response as a residential or business consumer of PowerStream. Postal codes were checked against a list provided by PowerStream for validity and those deemed invalid were removed from the final sample.

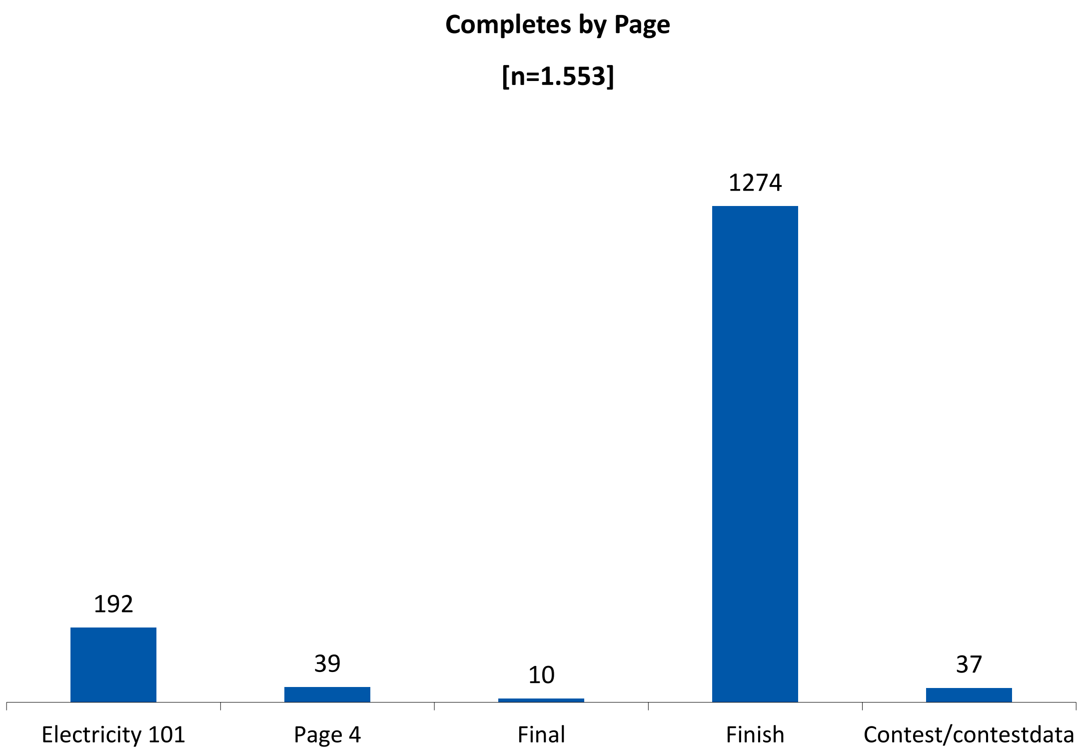
Sample Characteristics:

The breakdown of Online Primer responses are as follows:

- 5,130 unique visitors came to the landing page.
- 2,643 unique visitors answered at least a few questions.
- 1,553 consumers (including 32 business respondents) completed the entire Online Primer.

The information provided by consumers were grouped together anonymously and used only for exploratory analysis in this report.

Figure A: Online Primer Progress Rates



Business Respondents:

Since only 32 business consumers finished the primer out of a total of 1,553 respondents, the focus of this report will primarily be on the total sample with a close look at municipality and household size.

Responses provided by business consumers are included in most of the following charts as footnotes and for key questions on satisfaction and permission.

Respondent Profile

The following charts display a breakdown of the residential respondents by gender, age, responsibility for electricity bill, type of residence, living situation, and number of people in household. The sample is also divided up geographically in two ways: by region into York and Simcoe County; and by municipality, including Aurora, Barrie, Markham, Richmond, Vaughan and "Other". (This last category includes respondents from Bradford as well as respondents from 18 other FSAs that did not fit precisely into the other 5 regions).

Figure B1: Residential Consumer Profile

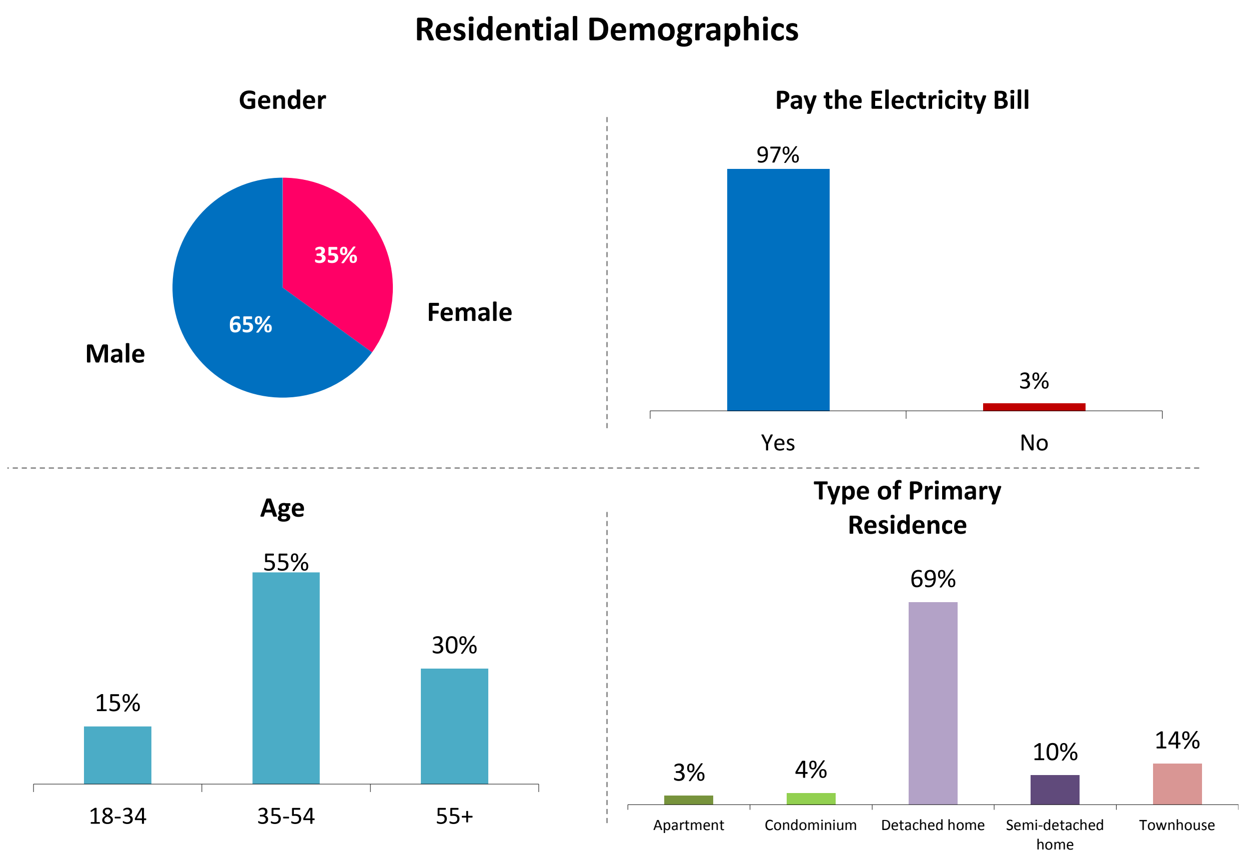
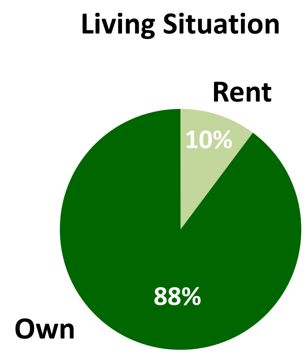


Figure B2: Residential Consumer Profile

Residential Demographics



Note: "Other" (2%) such as "living with parents" not shown.

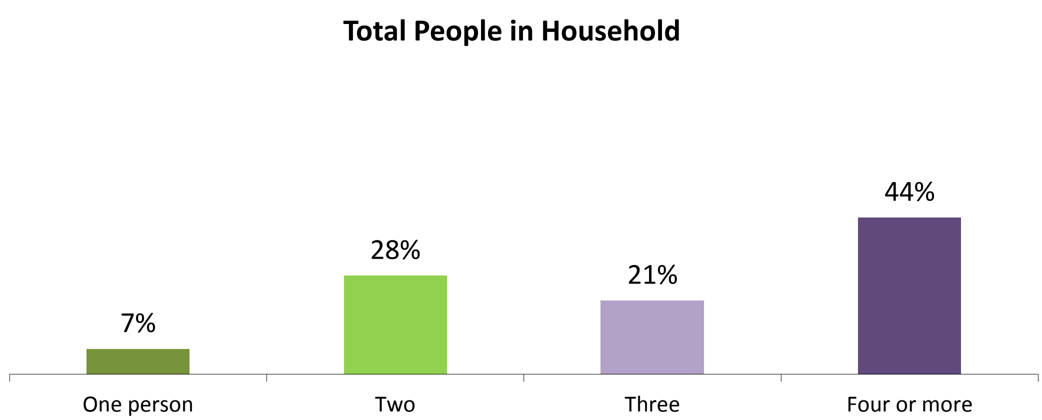
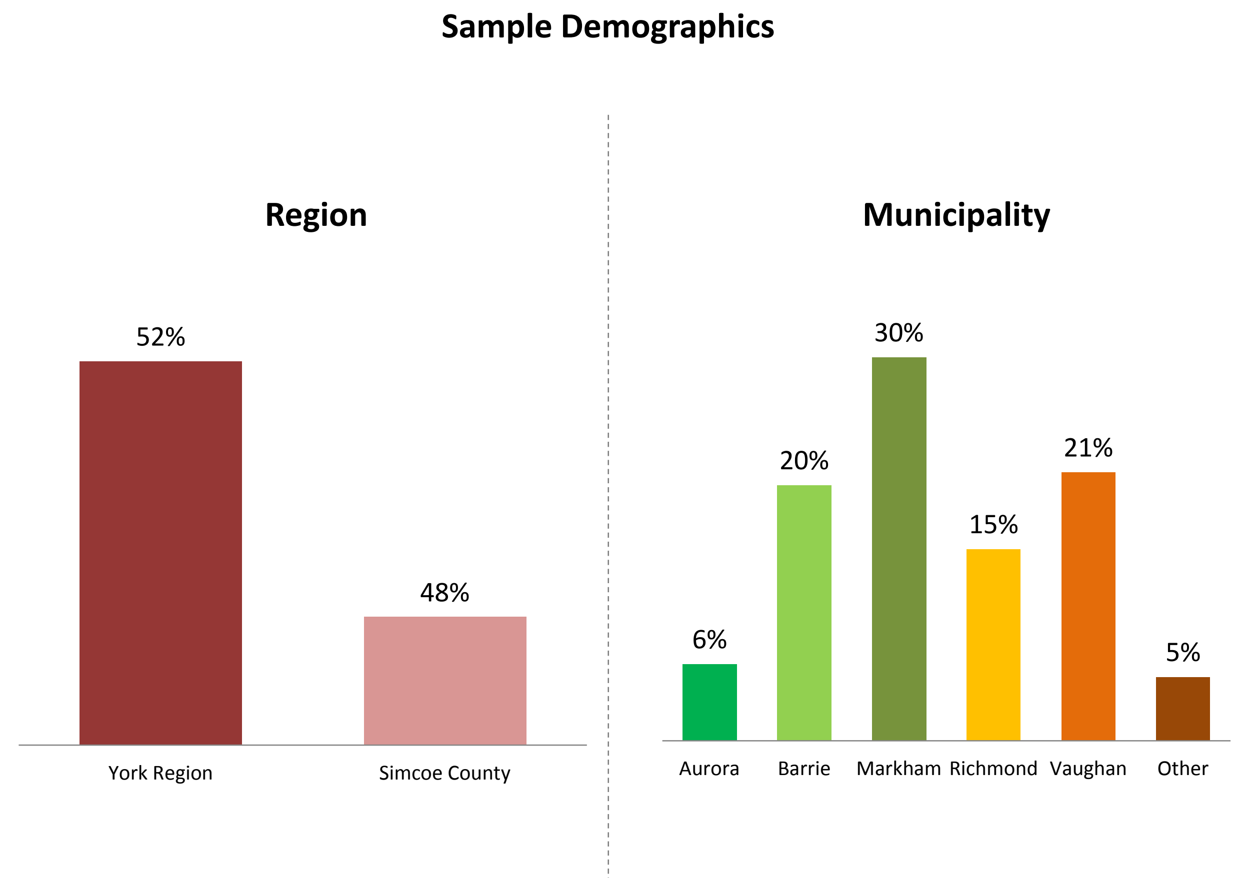


Figure C: Sample Regional Profile



Respondent Feedback

In total, 1,553 respondents answered questions to the end of the primer (including 32 business respondents). Note that the number of responses will vary from question to question, particularly on the open-ended questions.

Familiarity, Satisfaction and System Reliability

The first section of respondent feedback focuses on familiarity with the system and PowerStream, satisfaction with their level of service in the past year and perceived system reliability in both unusual and normal weather.

Familiarity and Understanding of the System

- PowerStream consumers say they have a good understanding of the electricity system and PowerStream's role (80% well vs. 20% not well). There's room to grow though on familiarity: half of consumers are not familiar with the system or where PowerStream fits in (49% familiar vs. 49% not familiar).

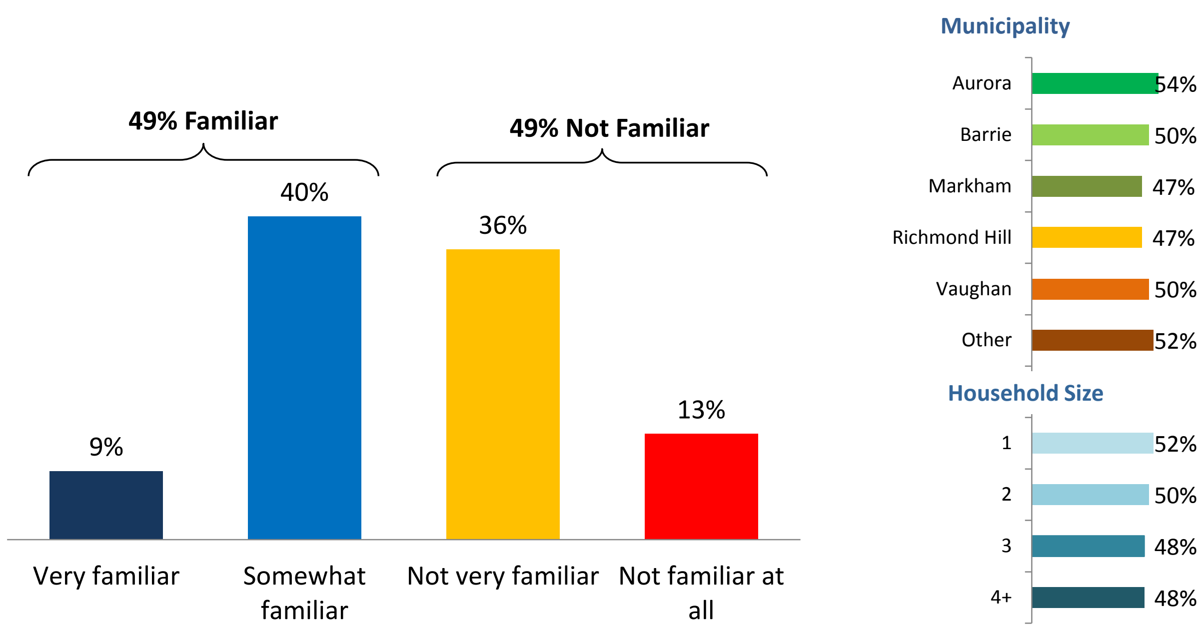
Satisfaction and System Reliability

- While consumers might not be the most familiar with the day-to-day track record of PowerStream, they sure are happy about what they've heard. Nearly all (91%) of the respondents say they are satisfied with PowerStream service. Similarly, 30 out of 32 of the business consumers who responded are satisfied with PowerStream.
- The best way consumers feel PowerStream could improve its service is to reduce rates (26%). Reliable service (9%) and improved communication (8%) are also key concerns. Still, even when asked for constructive criticism nearly two-in-ten (17%) say there's nothing wrong with their PowerStream service.
- Nearly seven-in-ten (70%) say they experienced an outage during unusual weather with the municipalities of Richmond Hill (78%) and Aurora (76%) and larger households (3+: 70-71% vs. 1 person: 57%) the hardest hit. Even so, a strong majority of consumers feel satisfied with PowerStream's response (82% satisfied).
- When asked how to deliver better service during both extreme weather and normal outages, "improved communication" (23%) is voiced as a key topic of concern.
- Not including unusual weather events, nearly six-in-ten (57%) respondents say they experienced an outage in the past year. Three-in-ten (29%) experienced at least two. The volume of outages varies across municipalities- Aurora (25% no outages), Markham (29%) and Richmond Hill (41%) were the hardest hit. And larger households experienced far more outages during normal weather than one-person households (42% to 58% no outages).
- These normal weather outages tended to be quite short: six-in-ten (60%) are less than hour. Aurora (55% less than an hour) and Markham (54%) experienced outages a bit longer.
- Consumers are just as happy with PowerStream's response during "normal" weather outages (84% satisfied).
- Two-thirds (67%) of consumers think PowerStream's level of reliability is "good". Aurora (65%), Markham (58%) and Richmond Hill (66%), the three municipalities who claim the most outages, are a bit less inclined to agree.

Figure 1: Familiarity with Electricity Distribution System

Q How familiar are you with the electricity system in Ontario and the services PowerStream is responsible for?
[n=1,553]

Sample Breakdown ▸▸
Those who say "familiar"



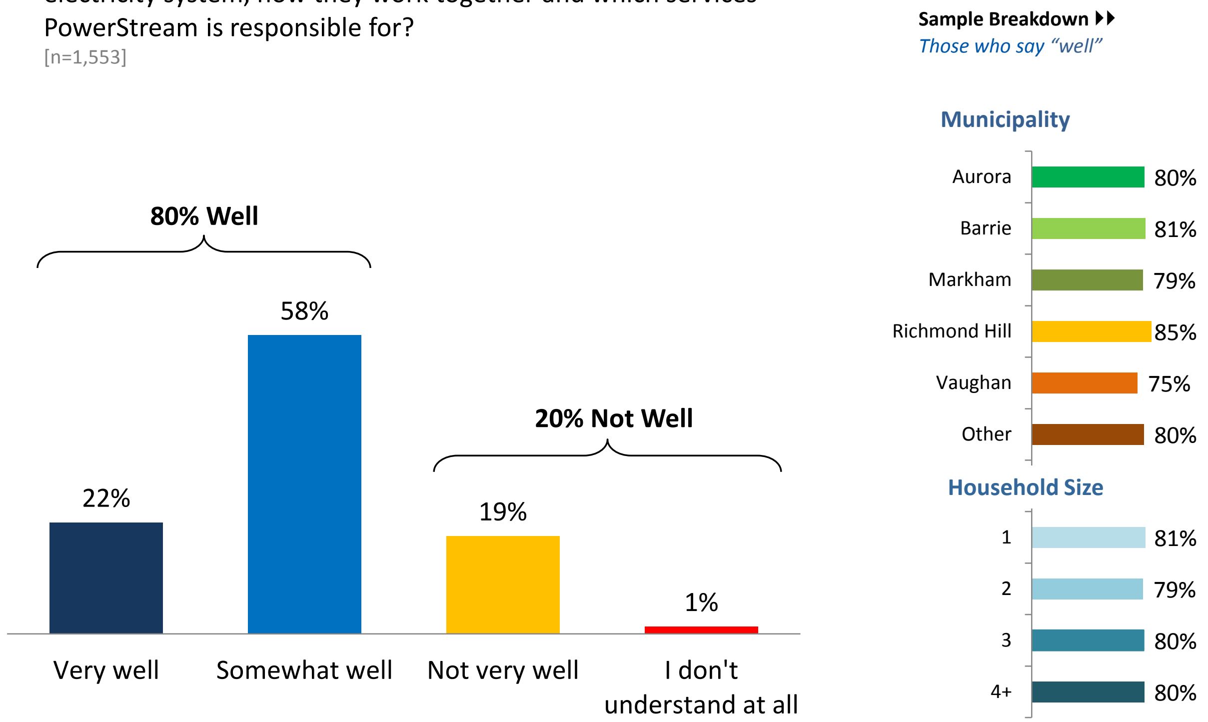
Note: "Don't know" (2%) not shown.
Business respondents included in chart.

About half (49%) of PowerStream consumers are familiar with the electricity system in Ontario. One-in-ten (9%) are "very familiar" with the system and four-in-ten (40%) are "somewhat familiar". Roughly the same number are not familiar with the Ontario system: nearly four-in-ten (36%) are "not very familiar" and 13% are "not familiar at all".

- In the region, Aurora (54%) is just a bit more aware than other municipalities of the electricity system.
- Men (55%) say they are much more familiar with the system than women (37%).
- Older consumers are more familiar with the system than younger ones (55+: 55% vs. 18-34: 42%).

Figure 2: Understanding of How Electricity System Works

Q How well do you feel you understand the important parts of the electricity system, how they work together and which services PowerStream is responsible for?
[n=1,553]



Business respondents included in chart.

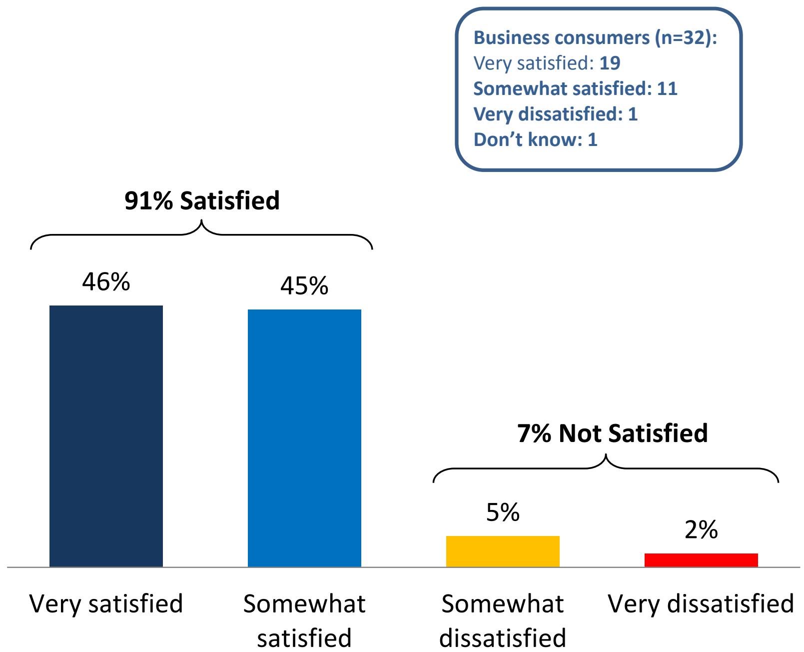
Eight-in-ten (80%) consumers say that they have a good understanding for both how the electricity system works and PowerStream's role in that system. More than two-in-ten (22%) think that they understand the system "very well" while almost six-in-ten (58%) understand it "somewhat well". Just two-in-ten (20%) do not understand the system (19%: "not very well"; 1%: "don't understand at all").

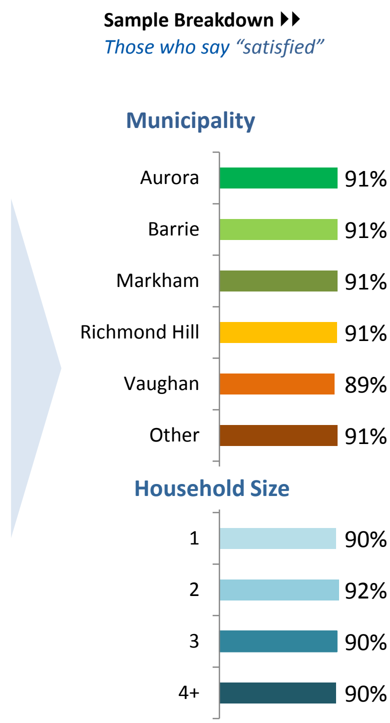
- Respondents in Richmond Hill (85%) feel that they have the greatest understanding of the electricity system, while just three-in-four (75%) consumers in Vaughan feel the same.
- Men are much more likely than women to say they understand the important parts of the electricity system, how they work together and PowerStream's role (84% vs. 71%).

Figure 3: General Satisfaction with PowerStream

Q Generally speaking, how satisfied are you with the service you are receiving from PowerStream? Would you say …

[n=1,553]



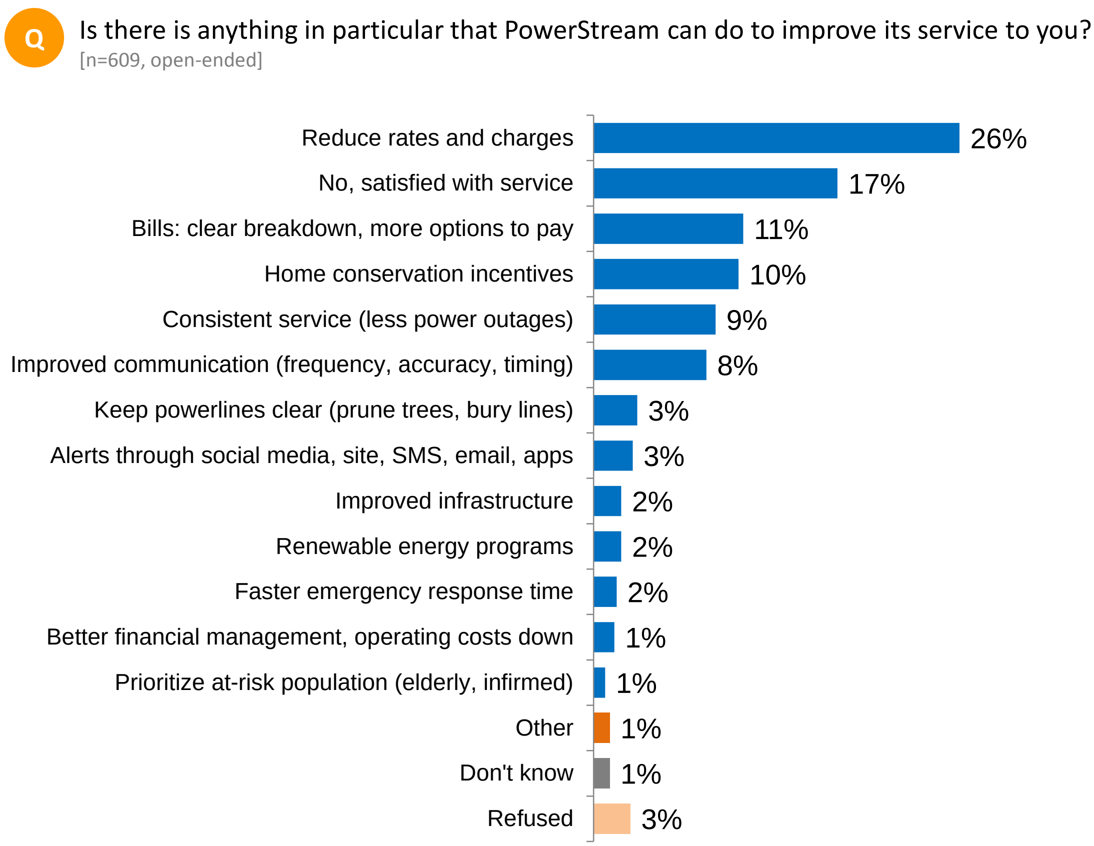


Note: Don't know (2%) not shown.
Business respondents included in chart.

From the northern tip of Simcoe County to the Markham-Toronto county line, consumers are pleased with their PowerStream service. Nine out of every ten (91%) consumers say they are satisfied with their service and nearly half (46%) are "very satisfied". Just seven percent of PowerStream consumers say they are dissatisfied with current service.

Over a very small sample of business consumers (n=32), nearly all say they are satisfied with their PowerStream service (n=19: "very satisfied"; n=11: "somewhat satisfied").

Figure 4: Open-ended on How to Improve Service



Business respondents included in chart.

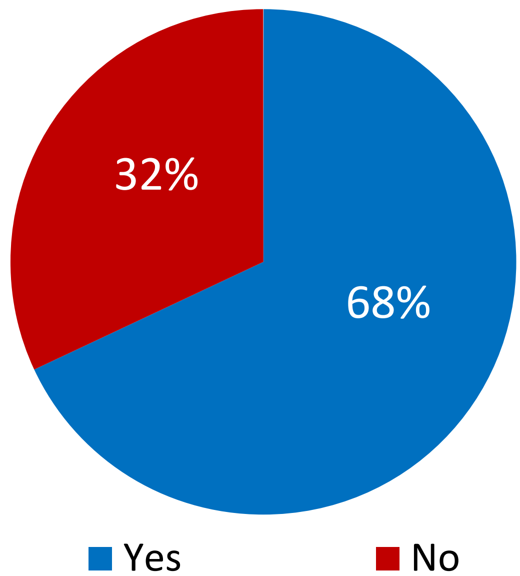
Cost appears to be a major concern for PowerStream consumers. When asked precisely how PowerStream could improve its service, a quarter of respondents said “reduce rates and charges” (26%).

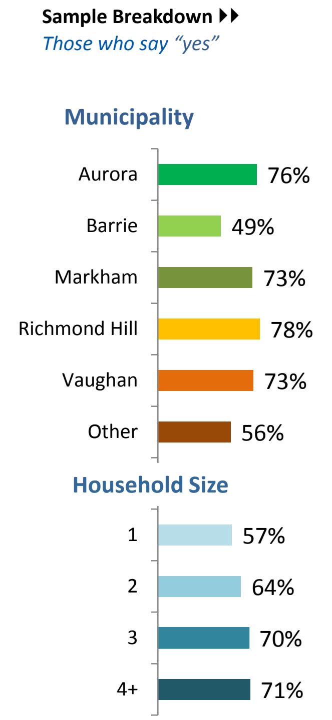
Still, satisfaction is clear among consumers even when asking for constructive criticism: nearly two-in-ten say “no improvements needed”- they are satisfied with the service.

Improvements to billing (“clear breakdown, more options to pay” (11%)), “home conservation incentives” (10%), “more consistent service, less power outages” (9%) and “improved communication” (8%) are also key issues that concern PowerStream consumers. Some issues brought up by a handful of consumers include “keeping the powerlines clear” (3%), “alerts through social media, site, SMS, email and apps” (3%), “improved infrastructure” (2%), “renewable energy programs” (2%), “faster emergency response time” (2%), “better financial management” (1%) and “prioritize the at-risk population such as elderly and infirmed consumers” (1%).

Figure 5: Outages in the Past Year during Unusual Weather

Q As far as you know, in the past year, did you experience any outages due to unusual weather such as the ice storm, microbursts or tornados?
[n=1,553]



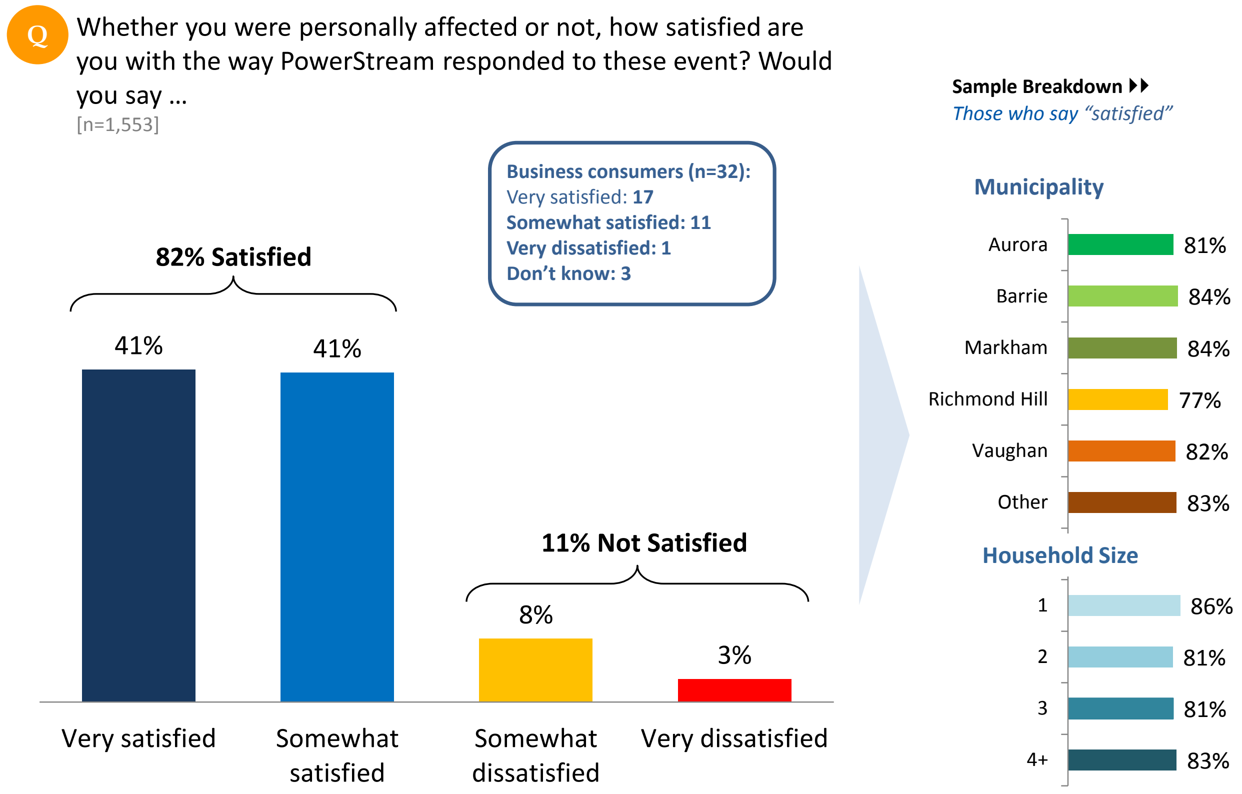


Business respondents included in chart.

In the previous question "consistent service" (9%) was a leading mention. Here, one can see why: in the past year, nearly seven-in-ten (70%) respondents experienced a power outage during unusual weather. Just a third (32%) did not experience any power outage during weather "such as the ice storm, microbursts or tornados".

- Some striking differences emerge in the regional breakdown: roughly three quarters of respondents in Richmond Hill (78%), Aurora (76%), Markham and Vaughan (73%) experienced a power outage during this unusual weather. Barrie, on the other hand, appears to have avoided the brunt of the unusual weather: less than half (49%) of respondents in that area say they experienced such an outage.
- The larger households seem to have the worst luck on outages: just 57% of single-person households and less than two-thirds (64%) of two-person households experienced an outage during unusual weather, whereas seven-in-ten (70%-71%) households with three-or-more people experienced the same. This could be explained by a spurious factor: the age and type of residence. Respondents with large families may be more likely to live in large, old homes vulnerable to the elements, whereas single respondents and couples might more likely live in smaller, more modern condo or apartment units with greater protection against unusual weather.

Figure 6: Satisfaction with Response to Unusual Weather Outages



Note: Don't know (7%) not shown.
Business respondents included in chart.

Despite the fact that 70% of respondents suffered outages in the past year, consumers are extremely satisfied with PowerStream's response to these unusual weather events. (Note that all consumers were asked, "whether they were personally affected or not".)

More than eight-in-ten (82%) consumers say they are satisfied with PowerStream's response to the outages and four-in-ten (41%) are "very satisfied". Just one-in-ten (11%) consumers are not satisfied with how PowerStream handled these events.

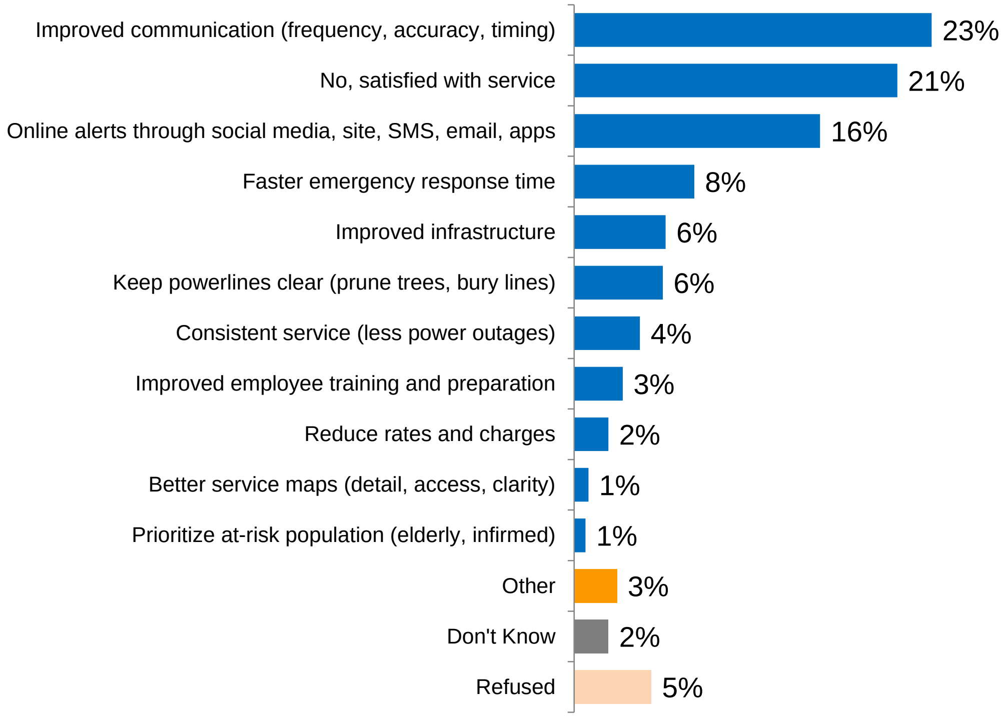
Of the 32 business consumers who responded, nearly all say they are satisfied with PowerStream's handling of the outages during unusual weather (n=17: "very satisfied"; n=11: "somewhat satisfied").

- Although satisfaction is high across municipalities, Richmond Hill (77%) is a bit less satisfied than the rest.
- Single-person households (86%) are the most satisfied with PowerStream's response in the past year to power outages.

Figure 6: Open-ended on How to Improve Service in Unusual Weather

Q Is there is anything in particular that PowerStream can do to improve its service to you during these extreme weather events?

[n=544, open-ended]



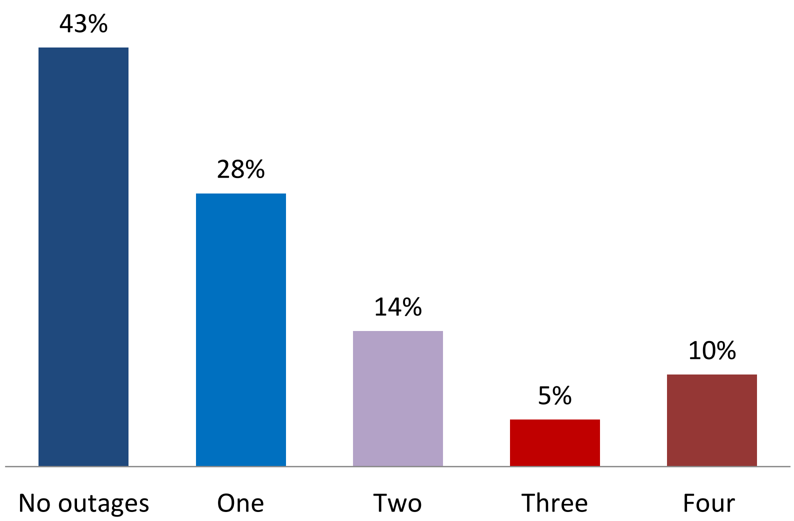
Business respondents included in chart.

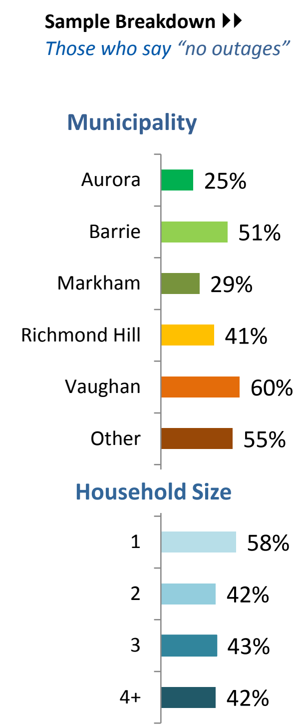
Communication during an outage is paramount to consumers. About a quarter (23%) of the 544 respondents say “improved communication” is needed and almost two-in-ten (16%) say “online alerts through social media, site, SMS, email or apps”. Even when prompted to provide criticism though, about two-in-ten say “no, they are satisfied” (21%).

Other mentions on how to improve service during extreme weather outages include “faster emergency response time” (8%), “improved infrastructure” (6%), “keep powerlines clear” (6%), “consistent service” (4%), “improved employee training and preparation” (3%), “reduce rates and changes” (2%), “better service maps” (1%) and “prioritize at-risk population” (1%).

Figure 7: Number of Outages in Past Year other than Unusual Weather

Q Other than outages during unusual weather events, how many outages did you experience in the past year?
[n=1,220]



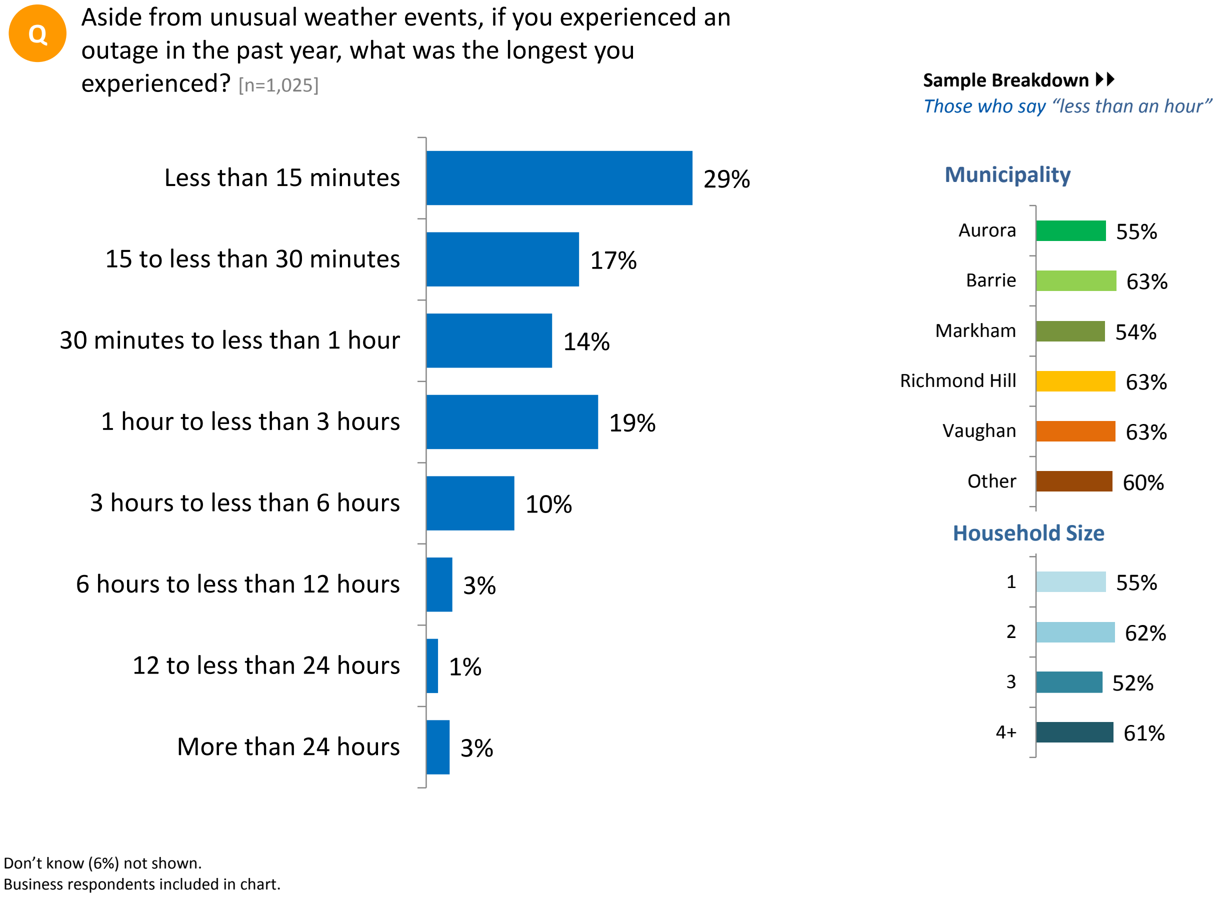


Business respondents included in chart.

Not including unusual weather events, nearly six-in-ten (57%) respondents experienced an outage in the past year. Of those, almost three-in-ten (28%) experienced just one outage, 14% experienced two and 15% experienced 3-4 outages. A large minority (43%) of respondents did not experience an outage.

- Looking at municipalities, some major differences emerge on number of outages. Aurora and Markham are much more likely to have been hit by power outages during normal weather than other PowerStream municipalities (No outages: Aurora, 25%; Markham, 29% vs. Vaughan, 60%).
- One-person households (No outages: 58%) are far less likely –by a fifteen point margin- to have suffered power outages in the last year compared with larger households (No outages: 2+, 42-43%).

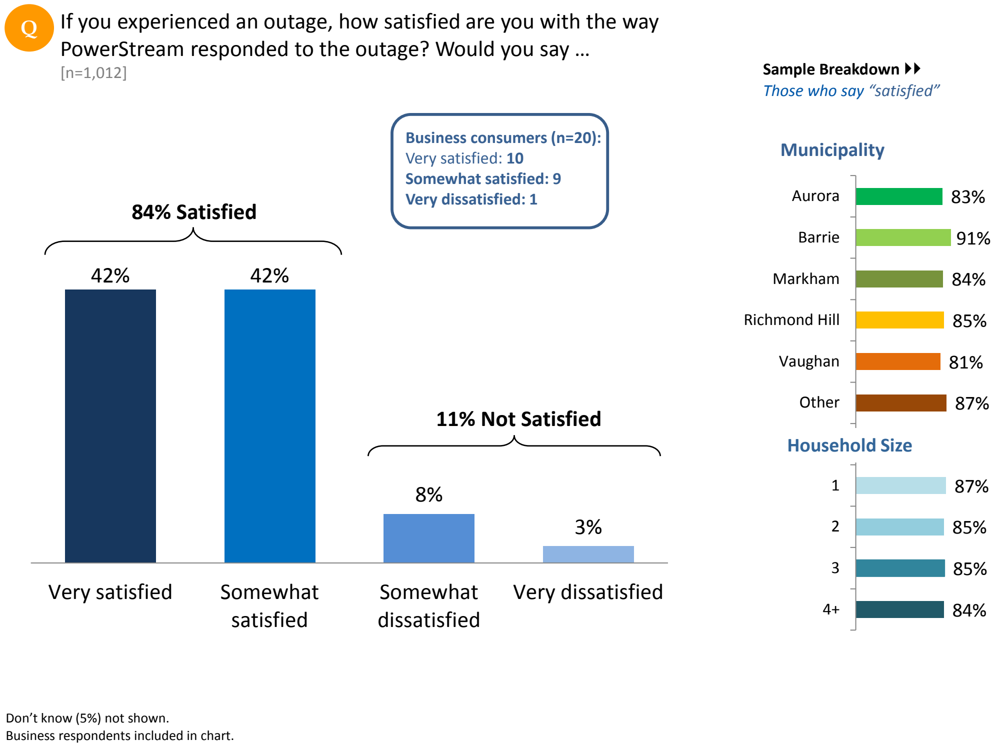
Figure 8: Outage Length in Past Year during Normal Weather



During normal weather, most outages for consumers are quite short. Six-in-ten (60%) outages for respondents are less than an hour; a third (29%) are less than fifteen minutes. Just three percent of outages for respondents are more than twenty four hours.

- Breaking it down by municipality, respondents Barrie, Richmond Hill and Vaughan (63%) experienced the shortest outages, with more than six-in-ten outages less than an hour. Consumers in Aurora (55%) and Markham (54%) are a bit more likely to say they experience longer outages.

Figure 9: Satisfaction with Response to Normal Weather Outages



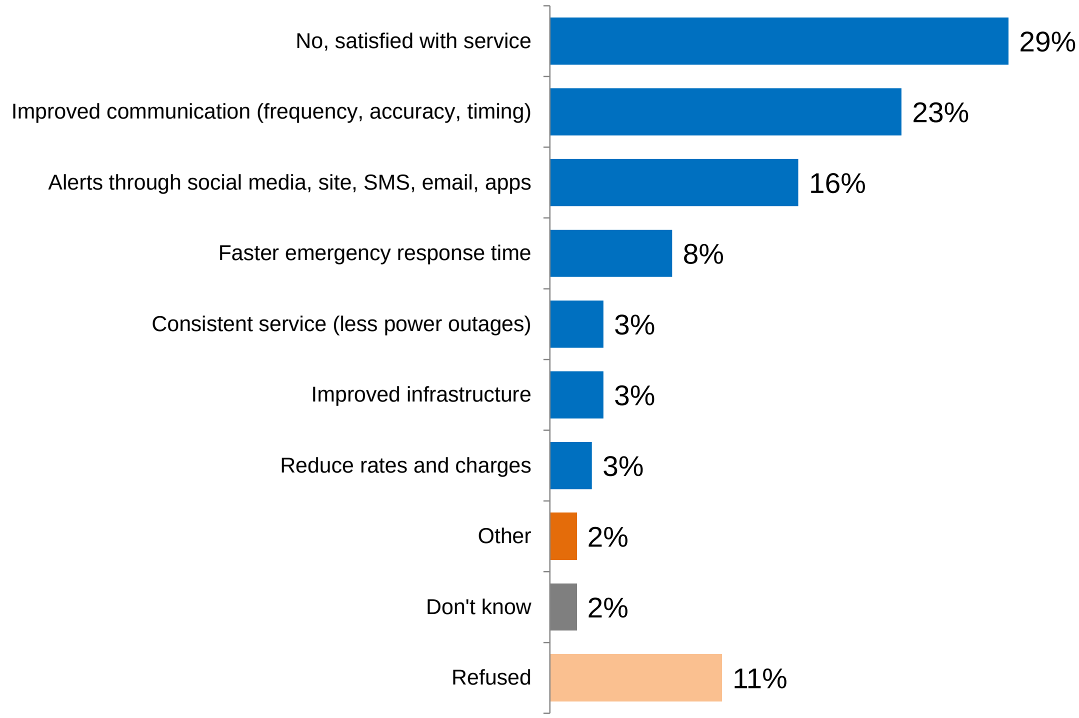
Again, even though a majority (57%) of respondents experienced an outage in normal weather, they are happy with how PowerStream handled it. Of those who had such an outage, more than eight-in-ten (84%) are satisfied with PowerStream's response to the outage and four-in-ten (42%) are "very satisfied". Only one-in-ten (11%) consumers who experienced an outage are dissatisfied with how PowerStream response to the power loss.

Almost all of the 20 business consumers left are satisfied with the way PowerStream responded to normal weather outages (n=10, very satisfied; n=9, somewhat satisfied).

- In the municipalities, satisfaction during normal weather outages is high across the board; Barrie (91%) appears the most satisfied.

Figure 10: Open-ended on How to Improve Service during Outages

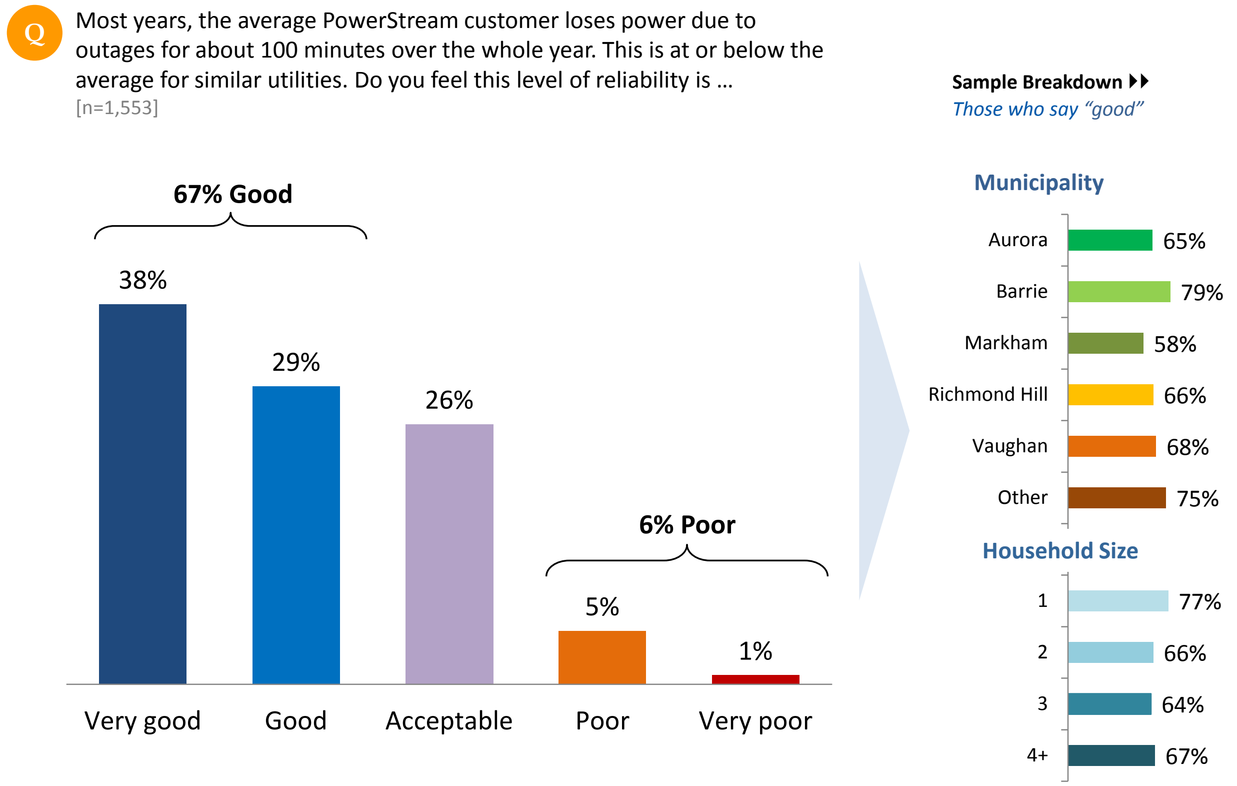
Q Is there is anything in particular that PowerStream can do to improve its service to you during outages?
[n=407, open-ended]



Business respondents included in chart.

When asked for an open-ended response to how PowerStream can improve their service during these outages, three-in-ten (29%) respondents said “nothing, they were satisfied” with how PowerStream handled it. Communication surfaces again as a major issue: nearly four-in-ten (39%) say PowerStream needs “improved communication” (23%) –such as faster and more accurate updates- and “alters through social media, site, SMS, email and apps” (16%).
Other key mentions include “faster emergency response time” (8%), “consistent service” (3%), “improved infrastructure” (3%) and “reduced rate and charges” (3%).

Figure 11: Level of Reliability



Don't know (1%) not shown.
Business respondents included in chart.

Respondents think PowerStream is reliable. When told that PowerStream consumers lose about 100 minutes of power a year due to outages and that this is at or below the industry average, more than two-thirds (67%) see that as a good level of reliability. About a quarter (26%) think it is "acceptable" and only 6% think the level of reliability is "poor".

- Of all the municipalities, Barrie (79%) is the most likely to say PowerStream is at a "good" level of reliability. There is a twenty-one point gap between Barrie and Markham (58%) on the level of reliability.
- One-person households (77%) are more likely than larger ones (64-67%) to say that the company is operating at a "good" level of reliability.

Long-term Challenges and Investment Solutions

The second and final section examines consumer opinion on aging infrastructure and investment in new technology and gages consumer “permission” to increase rates to address these challenges.

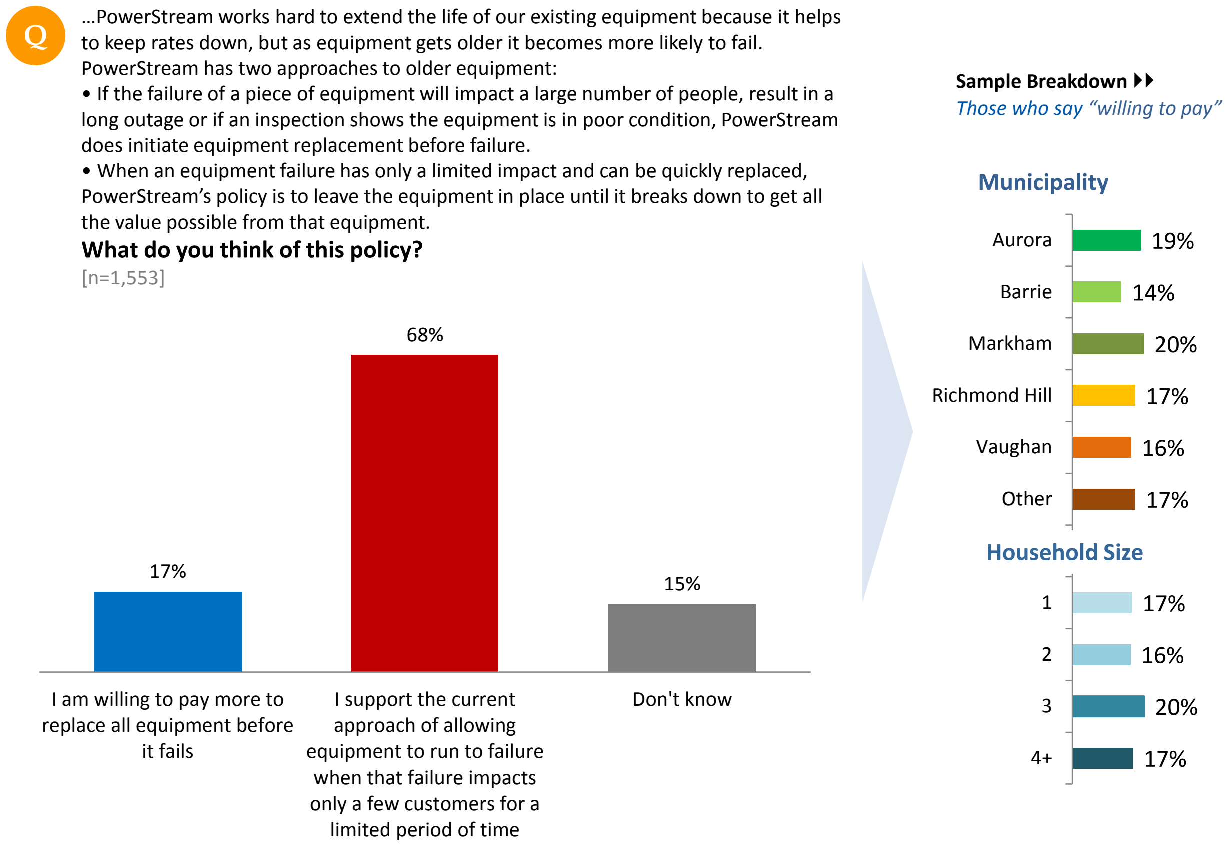
Aging Infrastructure and Investment in New Technology

- When asked if they are willing to pay for infrastructure, first respondents say instead "we should stay the course” of running equipment to failure if it impacts only a few consumers. However, when compared with scaling back on investments, respondents are mostly supportive: "investing to reduce in power outages" beats "scale back infrastructure investment" by a two-to-one margin (55% to 27%).
- Respondents also agree PowerStream should invest in new technologies (48%); just a third (34%) say these new technologies are a "luxury, not a necessity".

The Investment Plan, Consumer “Permission” for Increase

- In the open-ended question on how much more they would be willing to pay each month to support infrastructure investment, about forty percent said less than $10. There's a hard opposition here: 23% say they would not be willing to pay any additional fees.
- A strong majority (87%) feel they understand the challenges facing the PowerStream system.
- Six-in-ten (58%) think PowerStream's investment plan, from what they know so far, is on the right track. Those that think PowerStream is on the right track think that the "proposed solutions are reasonable and balanced", (26%) they're satisfied overall with PowerStream (10%) and they value increased reliability (26%). Those who aren't quite sure what to think of the investment plan and those who think PowerStream's plan is going in the wrong direction are likely to say "consumers shouldn't cover the additional cost" (31% not sure, n=22/64 for "wrong direction).
- Overall, two-thirds of consumers support the rate increase (19% "reasonable"; 48% "necessary"). Support is consistently high across the municipalities and for the 32 business consumers (n=21 support).
- Those who think the increase is reasonable support it to "prevent future disruptions" in service (n=45) and think the amount is also reasonable (n=31). Those who oppose it include the “hard opposition” mentioned above: 55 out of 220 say they would not accept any increase at all. "Oppose" verbatim also talk about the operating efficiencies of PowerStream (n=37) and executive accountability (n=31). Those who "don't like the increase, but think it's necessary" also cite reliability (n=31) and don't necessarily see an alternative (n=23).

Figure 12: Willingness to Pay for Infrastructure Development



Business respondents included in chart.

The next question, a measure of how willing consumers are to invest in infrastructure, includes the following pre-amble:

> *A significant amount of PowerStream's distribution system equipment was installed in the 1970s, 1960s or even earlier, and is still in service today. PowerStream works hard to extend the life of existing equipment because it helps to keep rates down, but as equipment gets older it becomes more likely to fail. PowerStream has two approaches to older equipment.*
>
> - *If the failure of a piece of equipment will impact a large number of people, result in a long outage or if an inspection shows the equipment is in poor condition, PowerStream does its best to replace the equipment before it fails.*
> - *When an equipment failure has only a limited impact and can be quickly replaced, PowerStream's policy is to leave the equipment in place until it breaks down to get all of the value possible from that equipment.*

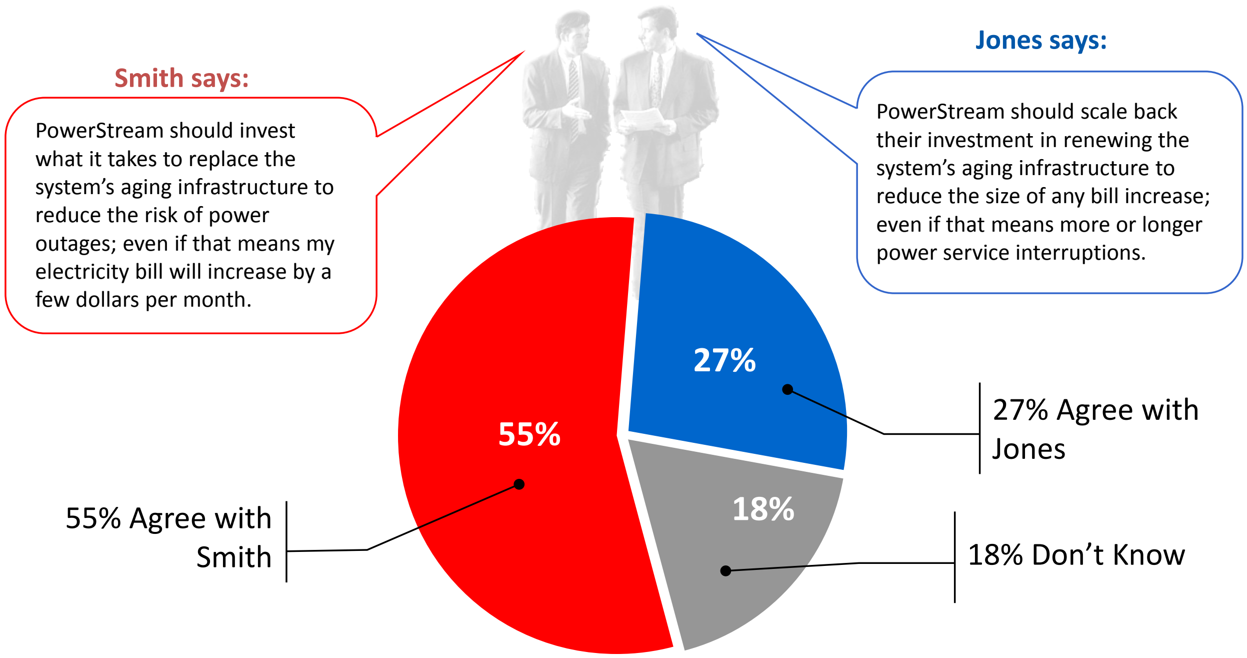
When asked what they think of this policy, just 17% of respondents say they are willing to pay more to replace equipment before it fails. Nearly seven-in-ten (68%) respondents "support the current approach" of running equipment to failure when it impacts "only a few consumers for a limited amount of time".

- No municipality in particular is more willing to pay to improve their infrastructure, despite the fact that some municipalities are far more likely to report outages this year than others (Aurora and Markham: 75% and 71% experienced an outage this year, respectively compared with just 40% in Vaughan).

Figure 12a: Smith and Jones on Investment in Infrastructure

Q Another planning issue is the pace of replacing aging equipment. This can have an impact on both the cost and the reliability of system. Replacing equipment sooner rather than later will result in higher rates but also should provide fewer outages due to equipment failures.

When it comes to replacing aging equipment, which of the following points of view is closest to your own?
[n=1,553]



Business respondents included in chart.

The previous question compared increased infrastructure investment to "the current approach" of running equipment until it fails. This next question asks: how does added infrastructure investment fare vs. *reduced* investment, considering the cost to consumers?

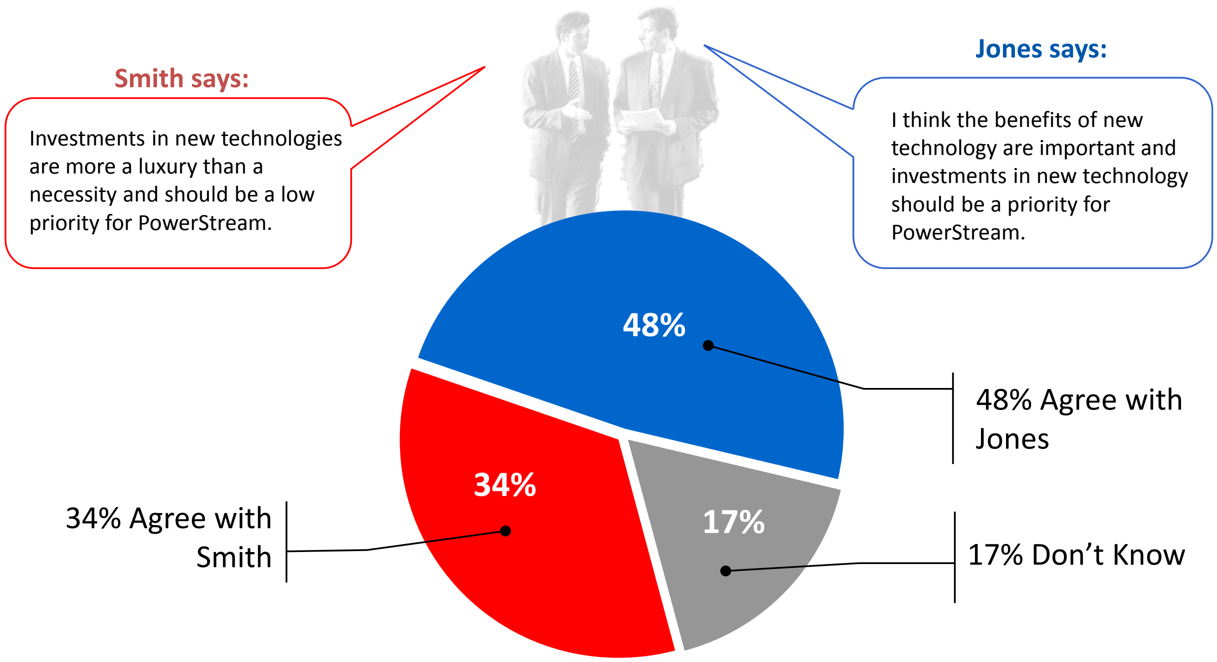
Consumers favor infrastructure investment a lot more in this comparison. More than half (55%) agree that PowerStream should invest in aging infrastructure whereas more than a quarter (27%) say PowerStream should "scale back" its investment to "reduce the size of any bill increase". Less than two-in-ten (18%) do not know the answer.

- Men are a bit more likely than women to want PowerStream to invest in infrastructure (58% vs. 50%).

Figure 12b: Smith and Jones on Investment in New Technologies

Q Of course, while there are clear benefits from new technology, there are also costs. The system functions well on the old technology. Do we want to pay more to secure the benefits new technology can deliver?

When it comes to investing in new technology, which of the following points of view is closest to your own?
[n=1,553]



Business respondents included in chart.

When asked about investment in new *technology*, almost half (48%) agree that "the benefits of new technology are important" and investing in it should be a priority. Just over a third (34%) agree with the opposite view, that investing in new technology is a "luxury" and should be a "low priority for PowerStream". Again, less than two-in-ten (17%), do not know the answer.

- Men are also more likely than women to think the benefits of new technology are important and investments in it should be a priority (51% vs. 43%).

Figure 12c: Municipalities on Investment in Infrastructure and Technology

	Aurora	Barrie	Markham	Richmond Hill	Vaughan	Other
Invest in Infrastructure	56%	55%	59%	55%	51%	58%
Scale back investment	22%	29%	25%	27%	28%	26%
Invest in technology	45%	47%	54%	48%	46%	42%
Technology luxury, not necessity	36%	37%	30%	35%	35%	40%

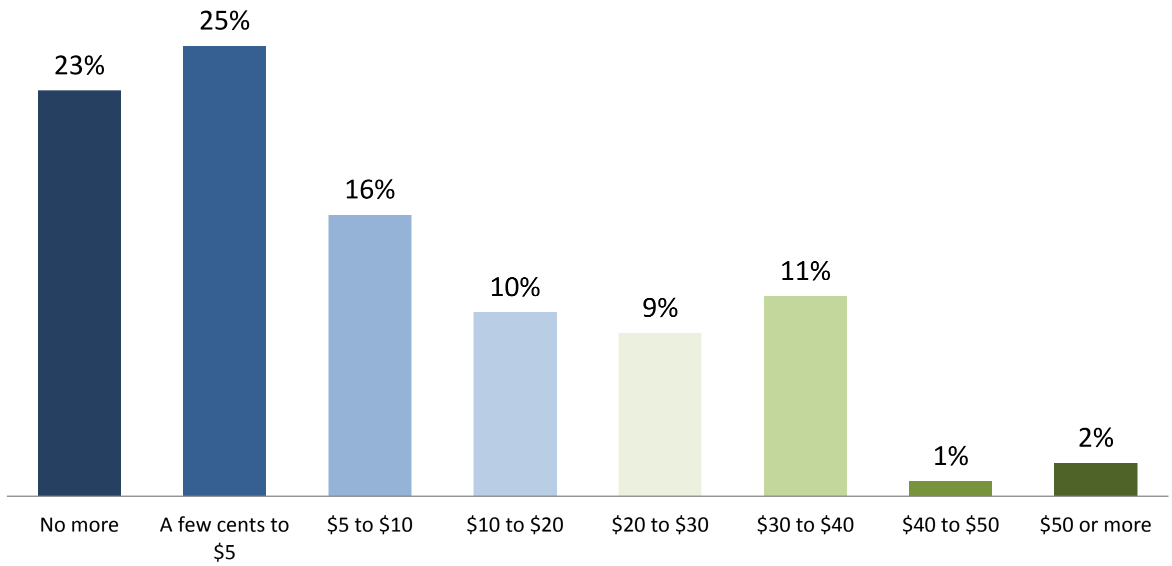
A majority of all the municipalities favor an investment in aging infrastructure over scaling back on investment with respondents from Markham (59%) the most likely to prefer investment.

Markham is also a bit more likely to want to invest in technology than other municipalities (54% vs. 42-48%) and also a bit less likely to say that technology investment is a luxury, not a necessity (30% vs. 35-40%).

Figure 13: Open-ended on Amount Willing to Pay for Infrastructure Investment

Q The investments discussed earlier in the primer are focused on minimizing the day-to-day outages and increasing the speed by which electricity is restored. There are additional investments that could help "harden" the system and speed up power restoration during a major event. There is no practical limit to potential ways of making the system more resilient in a major event, it is fundamentally a question of money.

Currently, the average residential customer pays $27 a month to PowerStream to operate and maintain the local distribution system. **How much more are you willing to pay each month for investments that would help the system better withstand major events such as extreme weather?**
[n=1542, open-ended]



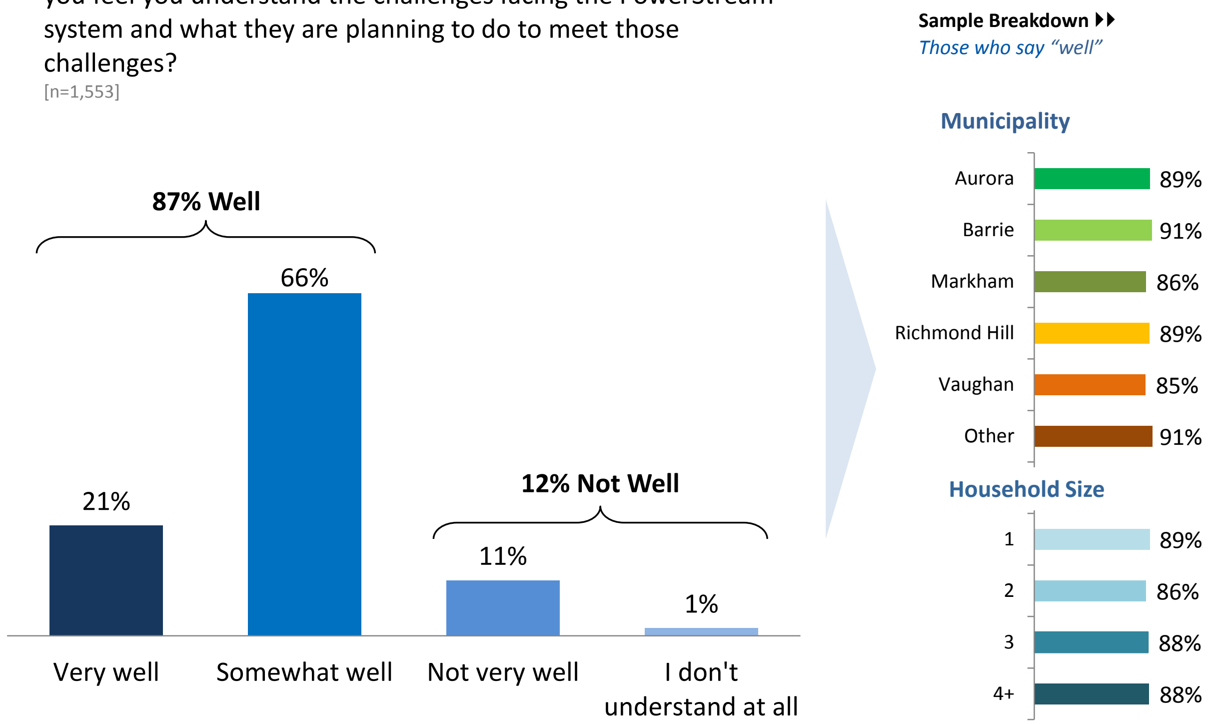
"Don't know" (1%), "Refused" (1%) not shown.
Business respondents included in open-ends.

This next open-ended question informs consumers that the "average residential consumer pays $27 a month to PowerStream" and asks them how much more they are willing to pay each month.

Around a quarter (23%) of consumers would not pay any more each month to invest in system improvement. Another quarter (25%) would pay less than $5 and 16% would pay between 5 and 10 dollars. About one-in-ten would pay $10 to $20 (10%), $20 to $30 (9%) or $30 to $40 (11%) and almost no respondents would pay more than that (3%).

Figure 14: Consumer Understanding of Challenges

Q Given what you know and what you have read so far, how well do you feel you understand the challenges facing the PowerStream system and what they are planning to do to meet those challenges?
[n=1,553]

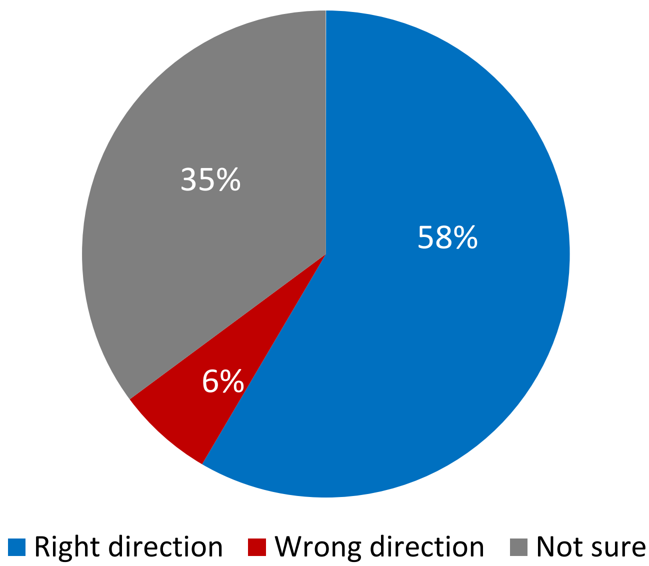


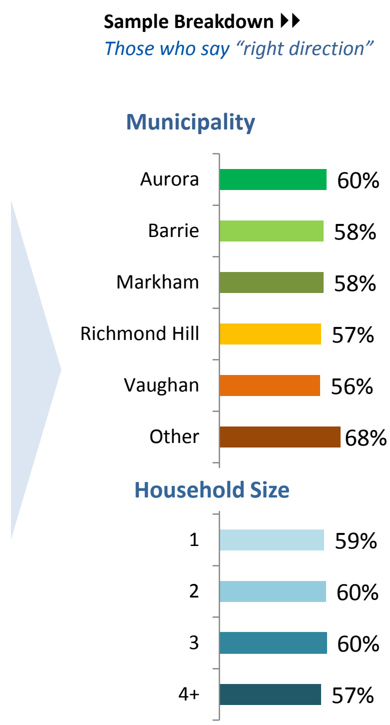
Business respondents included in chart.

A very strong majority of consumers (87%) feel that they understand the system challenges and also how PowerStream is addressing those challenges. Just 12% say they do not understand these system challenges and how PowerStream plans to address those problems.

Figure 16: Direction of Investment Plan

Q From what you have read and what you may have heard elsewhere, does PowerStream's investment plan seem like it is going in the right direction or the wrong direction?
[n=1,553]



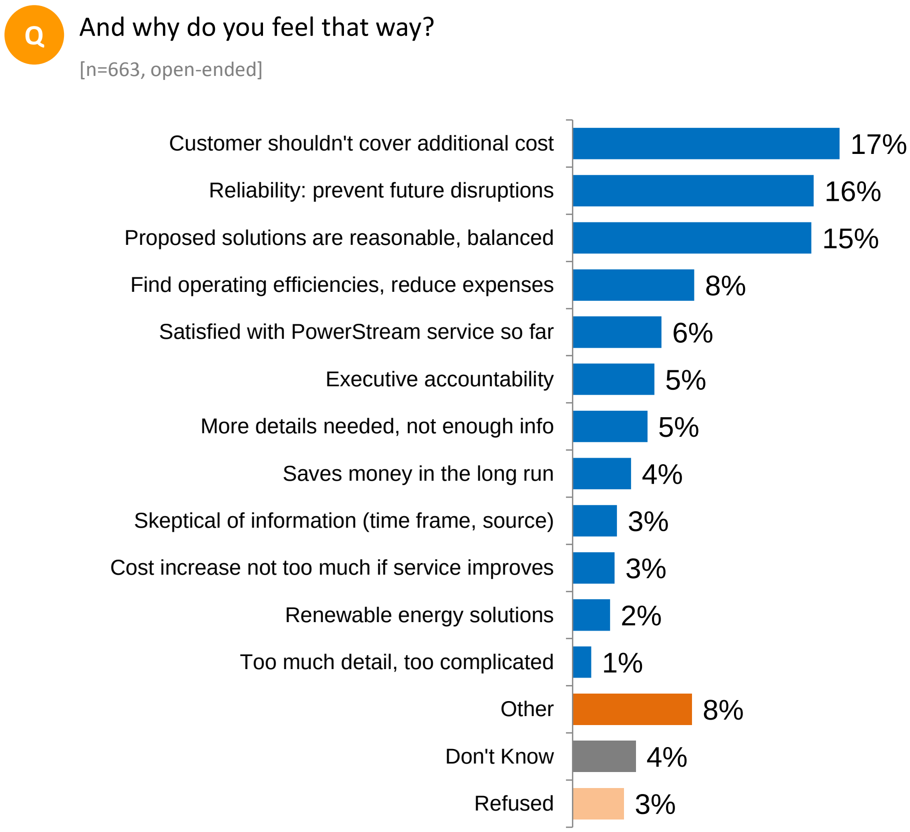


Business respondents included in chart.

PowerStream's investment strategy is on the right track, according to consumers. Nearly six-in-ten (58%) respondents feel that PowerStream's investment plan is moving in the right direction with just six percent who feel the opposite. There is a lot of uncertainty here: more than a third (35%) are "not sure".

- Other municipalities (including Bradford) are the most likely to think that PowerStream's investment plan is going in the right direction (68%). That being said, there is strong majority support across all municipalities.
- Men are slightly more likely than women to think PowerStream's investment plan is going in the right direction (61% vs. 53%).

Figure 17a: Open-ended on Direction of Investment Plan



Business respondents included in chart.

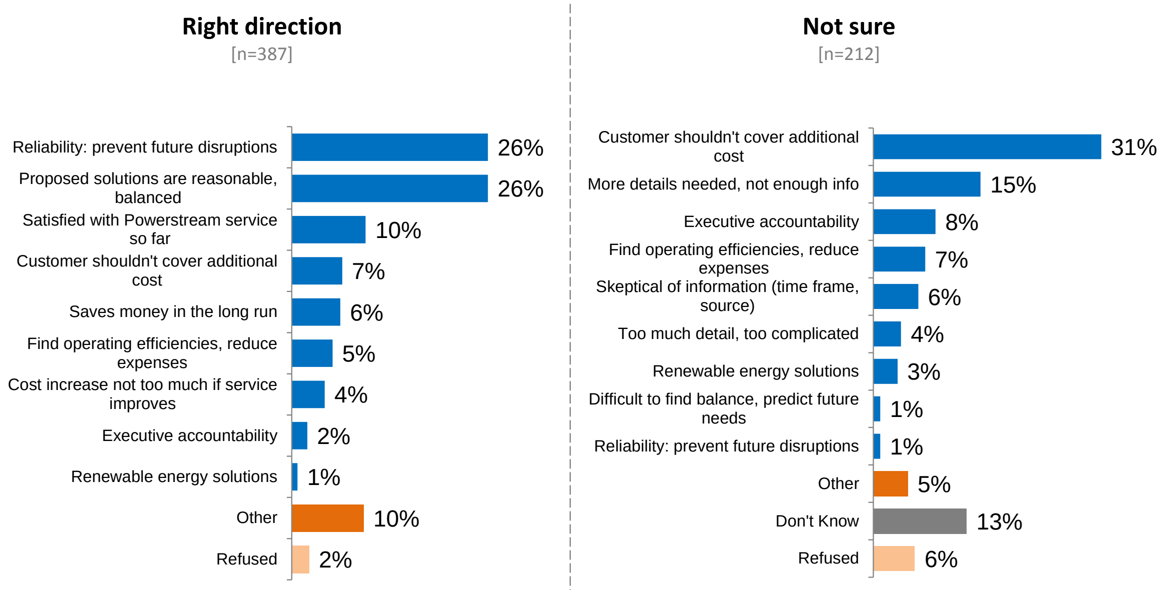
In this follow-up open-ended question, responses are categorized in two ways: the overall sample, and a breakdown of those who think PowerStream's investment plan is moving in the right direction vs. those who are unsure how to answer. (With only 64 responses, "Wrong direction" is only included as a footnote on the following chart.)

Out of the 663 total respondents, the main reasons respondents the key reasons are cost ("the consumers shouldn't cover the additional cost", 17%), reliability ("prevent future disruptions", 16%) and "proposed solutions are reasonable and balanced" (15%). Other key mentions include "find operating efficiencies, reduce expenses" (8%), "satisfied with PowerStream service so far" (6%), "executive accountability" (5%), "more details needed, not enough info" (5%), "saves money in the long run" (4%), "skeptical of information" (3%), "cost increase not too much if service improves" (3%), "renewable energy solutions" (2%) and "too much detail, too complicated" (1%).

Figure 17b: Open-ended on Direction of Investment Plan

Q And why do you feel that way?

[n=664, open-ended]



Wrong direction not shown [n=64].
Top mentions are "customers shouldn't cover additional costs" [n=22], "find operating efficiencies, reduce expenses" [n=16] and "executive accountability" [n=9]

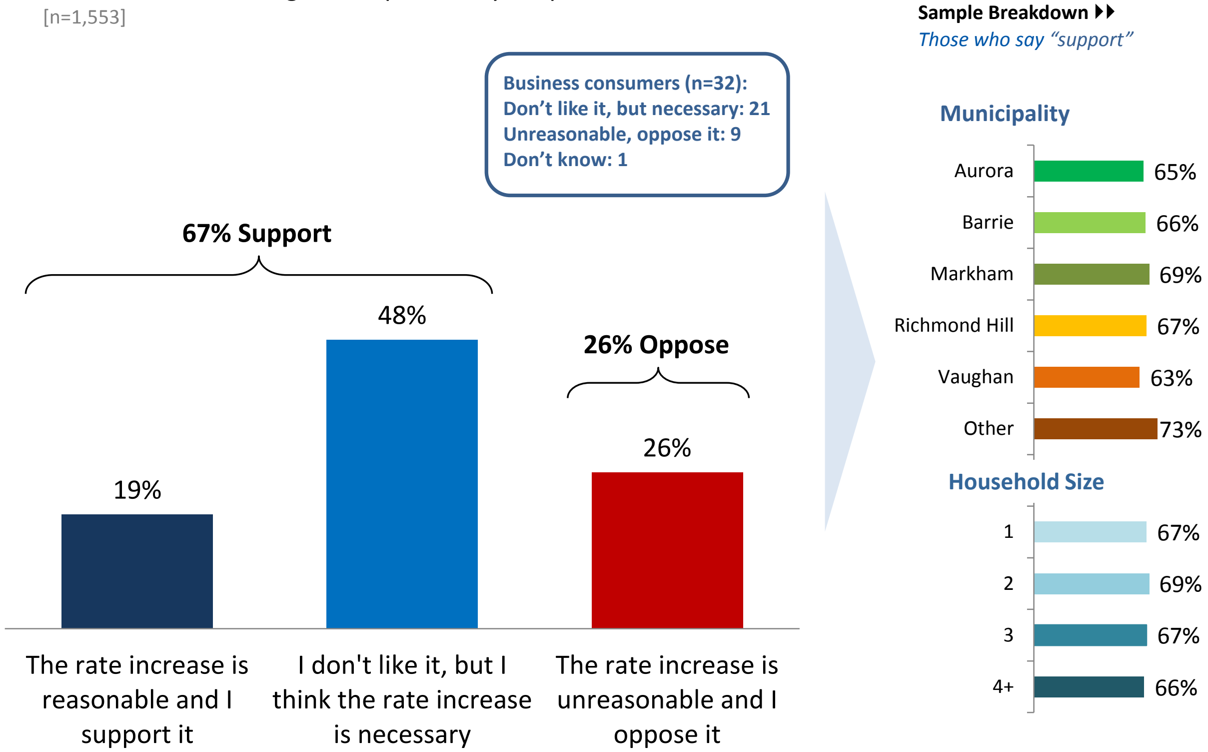
For those 387 respondents who feel PowerStream's investment plan is moving in the right direction, "reliability" (26%) and "proposed solutions are reasonable and balanced" (26%) are the key reasons for their support. Other reasons include "satisfied with PowerStream service so far" (10%), "consumers shouldn't cover additional cost" (7%), "saves money in the long run" (6%), "find operating efficiencies, reduce expenses" (5%), "cost increase not too much if service improves" (4%), "executive accountability" (2%) and "renewable energy solutions".

For the 212 PowerStream consumers who "aren't sure" about the company's direction, roughly three-in-ten (31%) say "consumers shouldn't cover the additional cost" (31%). These unsure consumers feel the details of what's going on are either not sufficient ("need more info" (15%)), not reliable ("skeptical of information", 6%) or too complicated (4%). Some other mentions for the unsure consumers are "executive accountability" (8%), "find operating efficiencies" (7%), "renewable energy solutions" (3%), "difficult to predict future needs" (1%) or reliability (1%). Not surprisingly for this group, 13% of them "don't know".

(Top mentions for "wrong direction" consumers are also cost ("consumers shouldn't cover additional costs", n=22), "find operating efficiencies, reduce expenses" (n=16) and "executive accountability" (n=9)).

Figure 18a: Permission Question

Q Considering what you know about the local distribution system, which of the following best represents your point of view:
[n=1,553]



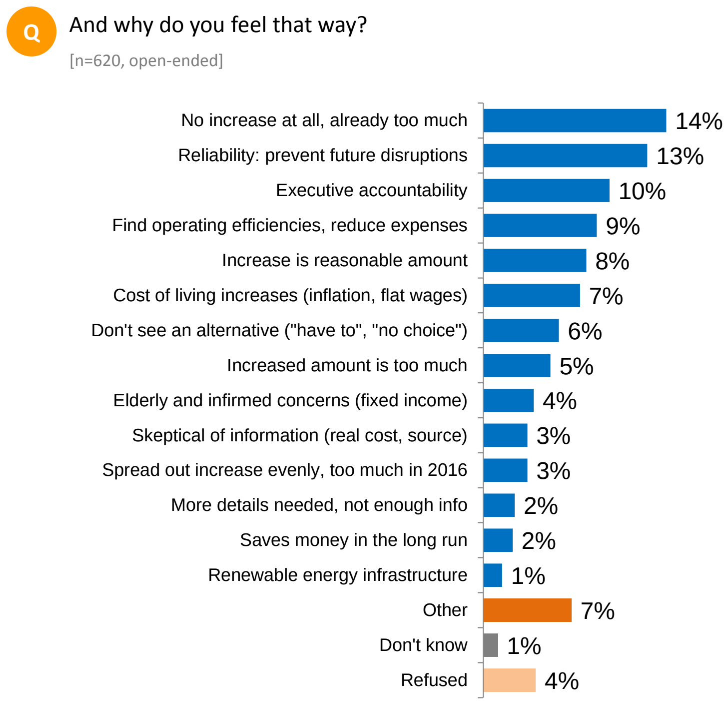
Don't know (7%) not included.

Two out of every three PowerStream consumers support the rate increase (67% support). Around two-in-ten think it is "reasonable and support it" while almost half (48%) say they "don't like it", but understand the rate increase is necessary. A quarter (26%) of respondents oppose it, saying the rate increase is "unreasonable".

- In the region, support is high across the board for the rate increase. Vaughan (63%) is slightly less supportive of it than the rest of the municipalities.
- Older Canadians (72%) are a bit more likely than younger ones to give permission (18-34: 67%; 35-54: 64%).

Of the 32 business consumers who responded to this question, 21 "don't like it, but think it's necessary" and nine think it is "unreasonable" and oppose it.

Figure 18b: Explanation of Permission Response

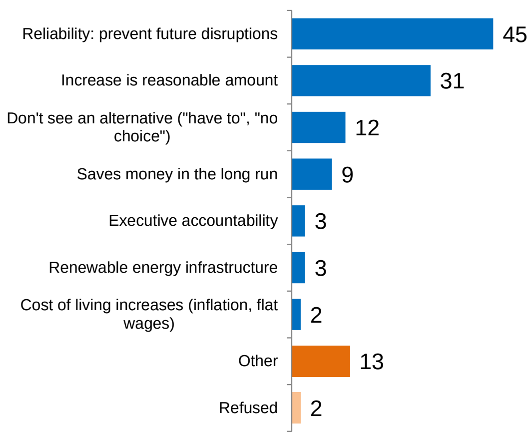


Business respondents included in chart.

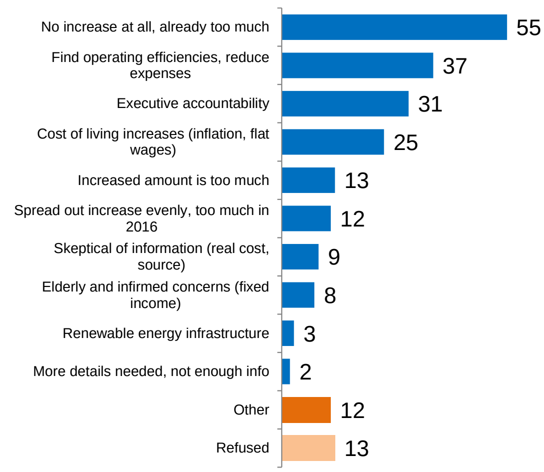
Q And why do you feel that way?

[n=620, open-ended]

Reasonable, support it
(n-sizes only) [n=120]



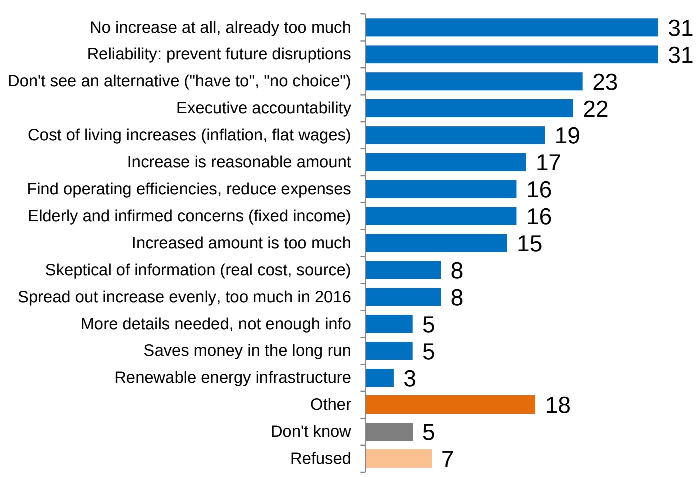
Unreasonable, oppose it
(n-sizes only) [n=220]



Q And why do you feel that way?

[n=620, open-ended]

Don't like it, but necessary
(n-sizes only) [n=249]



The final question of the primer asks consumers to explain their opinion on the rate increase. Responses are divided into those who support it, those who "don't like it, but think it's necessary", and those who oppose it.

Respondents who support the rate increase do so because they want reliable service (n=45 out of 120). They also think the increase is a reasonable amount (n=31). Other reasons include “don’t see an alternative” (n=12), “saves money in the long run” (n=9), “executive accountability” (n=3), “renewable energy infrastructure” (n=3), and “cost of living increases” (n=2).

A quarter (n=55 out of 220) of consumers who oppose the rate increase would not accept any increase at all, no matter the size: it already “costs too much”. Some think that PowerStream should look from within first to reduce expenses (n=37) while others mention “executive accountability” (n=31) or the rising cost of living (n=25) as their key concern. Other reasons by consumers who oppose the rate increase are “increased amount is too much” (n=13), “spread it out more evenly” (12), “skeptical of information (9), “elderly and infirmed concerns” (8), “renewable energy infrastructure” (3) and “not enough info” to decide (2).

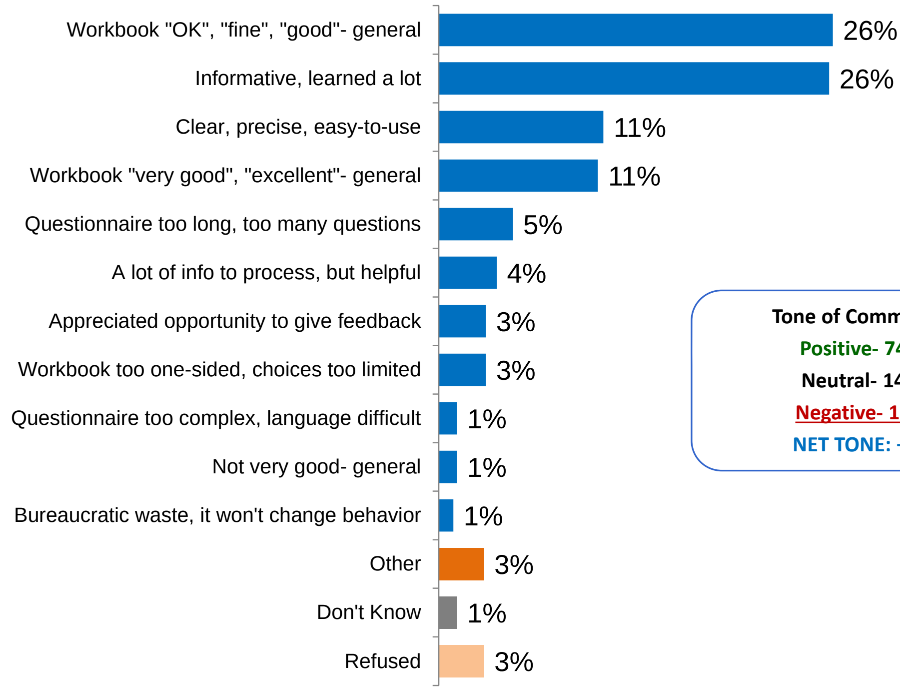
For those who don’t like the increase but think it’s necessary, “cost” and “reliability” are the top concerns (n=31). The cost is already too much, but, if it prevents future disruptions, they consider it worth it. Other top mentions include “they don’t see an alternative” (n=23), “executive accountability” (n=22), “cost of living increases” (n=19), “the increase is a reasonable amount” (n=17), “find operating efficiencies, reduce expenses” (n=16), “elderly and infirmed concerns” (n=16) and “the amount is too much” (n=15).

Appendix: Feedback on the Primer

In the appendix, respondents were asked a series of questions to give feedback on the primer; their impression of the primer itself, the volume of information, the depth of coverage, and suggestions for future consultations.

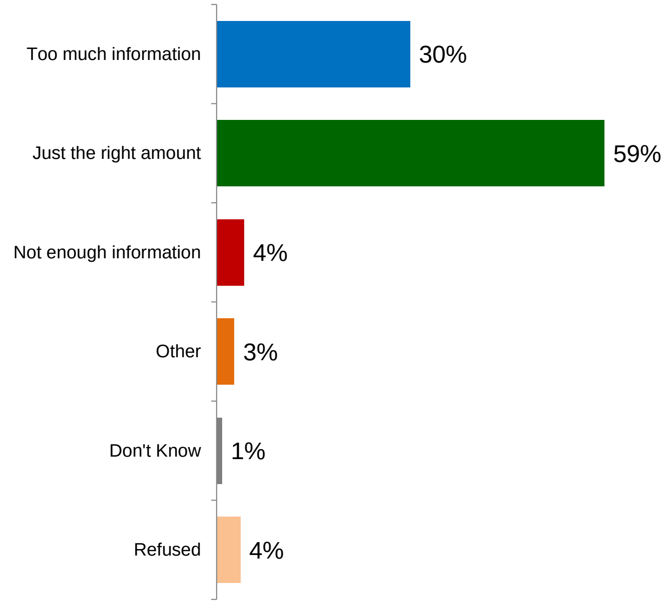
- General impression of the primer overall was quite positive (+62): overall respondents found it “very good” or “good (37%), informative (26%) and clear and easy to use (11%).
- The primer had just the right amount of information according to a majority of respondents (60% “just the right amount”; 30% “too much”; “4% not enough”).
- For a majority, the primer covered everything relevant and did not leave anything out (57% “no, didn’t miss anything”; 62% “no, no other questions to answer”).
- A strong minority (43%) would prefer to participate in a similar format, online, in the future.

General Impression - Overall, what did you think about this primer?
[n=826, open-ended]

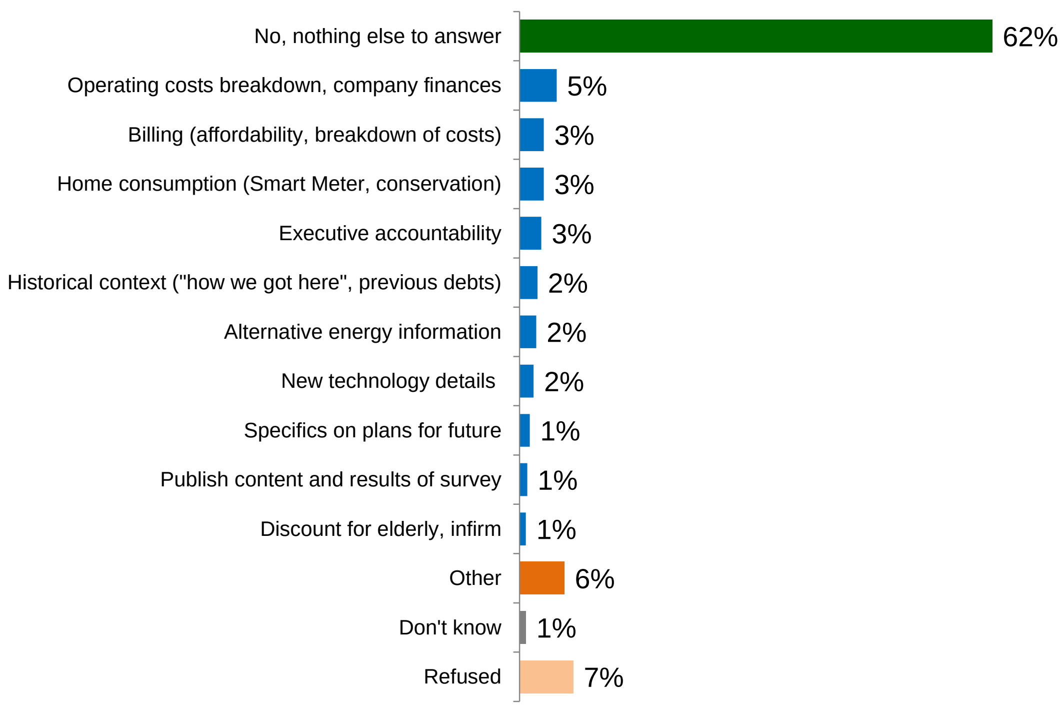


Tone of Comments:
Positive- 74%
Neutral- 14%
Negative- 12%
NET TONE: +62

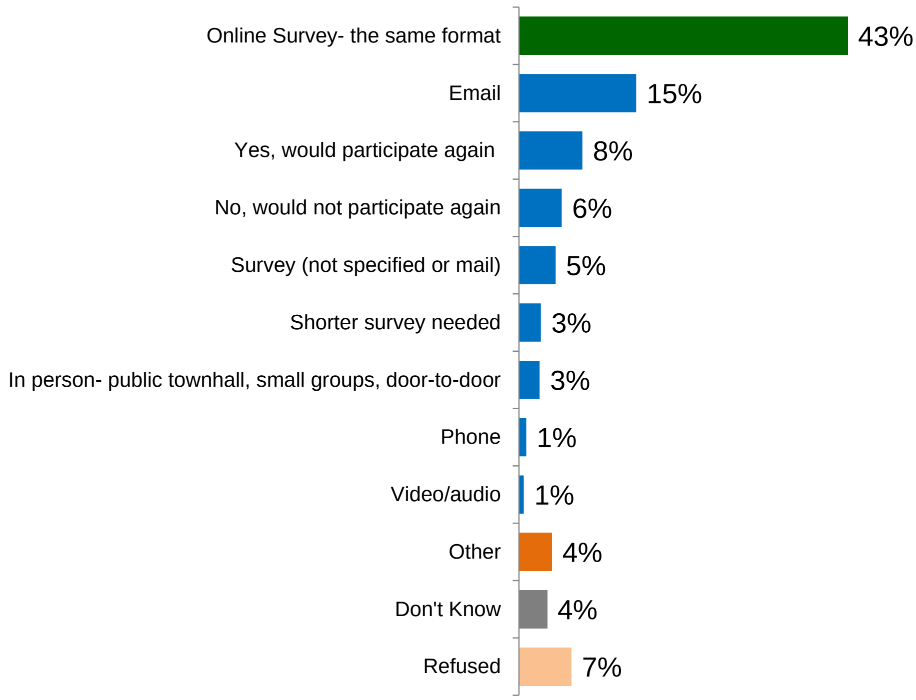
Volume of Information: Did PowerStream provide too much information, not enough, or just the right amount?
[n=857, open-ended]



Outstanding Questions: is there anything that you would still like answered?
[n=592, open-ended]



Suggestions for Future Consultations: how would you prefer to participate in these consultations?
[n=620, open-ended]



General Service and Residential Consultations

Customer Consultation Groups
with Residential and General Service customers

PURPOSE: To gain qualitative input on PowerStream's DSP from residential and GS < 50 kW customers and to obtain feedback into survey design.

Summary

The following summary highlights key findings from the General Service and Residential consultation sessions held in Barrie, Markham, and Vaughan.

PowerStream's service is seen positively by both General Service and Residential customers.

Both rate classes are generally satisfied with the service they receive from PowerStream. Residential customers see the utility as being well run and visible in the community and General Service customers see PowerStream as helpful and responsive. PowerStream is also generally held in high regard when compared to other utilities, including Toronto Hydro.

Improved communication would help increase customer satisfaction.

Both General Service and Residential customers generally believe that communications could be improved, especially during outages. Communicating the estimated length of outages is important for both rate classes, primarily General Service customers, as prolonged outages can effect productivity and therefore, profitability.

Given high reliability, certain investments are seen as unnecessary.

The majority of customers feel PowerStream is highly reliable. They generally buy into the argument on pro-active replacement, but look to that as a business case, and want to know that the investment will yield not only reliability benefits, but also cost savings for customers down the line.

Both General Service and Residential customers often focused on the billing system as a point of disconnect. Many participants questioned the need for such an expenditure, and also the benefit to them as they saw no issue in their experience.

Preparing for extreme weather is not seen as a priority for many customers.

Because reliability is generally seen positively, many participants, both General Service and Residential, did not see preparing for extreme weather as a priority. These types of events are seen as 'unpredictable' and do not provide value to the overall system's reliability.

There is a desire to know that both internal and external cost savings have been considered.

Before agreeing to a rate increase, many customers, both General Service and Residential, felt that every possible avenue of cost savings needs to be looked at. They felt that the magnitude of the rate increase would require significant sacrifice on the part of customers – they wanted to see that the sacrifices were shared by PowerStream, even among management.

General Service customers were particularly interested in internal efficiencies related to employee salaries and managing assets. Many GS customers argued that they could not increase costs so dramatically at their own businesses, and PowerStream shouldn't either.

Opinions are formed at a higher level, in the context of overall energy bills.

Both General Service and Residential customers look at this proposed rate increase in terms of their overall energy bill. Again, both groups believe increases to other elements are also on the horizon, bringing the net customer 'ask' on bills much higher. Many customers point out that the 'stacking' of rate increases is making it increasingly difficult to afford electricity. While for many, this proposed rate increase is manageable, there is a general uncertainty as to what will happen in the future should these increases continue.

The rate increase is seen as symptomatic of a broader disconnect between public and private economies.

Many business customers point out that they have faced increasing costs, technology shifts, and other pressures for several years that they are unable to pass on to customers. They ask why PowerStream is unable to operate under the same conditions that they face.

Residential customers point out that they have for the most part not been receiving raises or bonuses for several years, while their costs continue to escalate. They ask why PowerStream is unable to operate in the same economic world they are forced to operate in.

The Primer was informative, but was seen to have gaps that created 'push back'.

Many customers zeroed in on the rate increase. They generally did not find the information they needed to justify it, and although they understood the plan and the underlying needs, they could not find the information to truly validate it. This caused the Primer to invoke some 'push back' as to motive, most feeling it was simply a tool to get a rate increase across.

Some customers, both General Service and Residential, wanted a business case that included full financial information, presented in a simple, clear manner. They specifically wanted financial information that showed costs on a comparative basis, particularly salary costs and overheads. They wanted information on what many called "profit", or any surpluses.

Permission was obtained, but somewhat grudgingly.

Ultimately, participants in the customer consultation sessions give PowerStream social permission for a rate increase (35 of 47), although, somewhat grudgingly. Many customers want to be sure that all alternative avenues have been explored and that PowerStream is making the prudent spending and investment decisions. While most customers feel that PowerStream's rate increase is necessary, many want to be reassured that rates do not continue to increase indefinitely at such a significant level.

Response	Sum Total
The rate increase is reasonable and I support it	**4**
I don't like it, but I think the rate increase is necessary	**31**
The rate increase is unreasonable and I oppose	**9**
Don't know	**0**
Total	**47**

Methodology

About the General Service and Residential Customer Consultation

Innovative Research Group (INNOVATIVE) was engaged by PowerStream to conduct a series of General Service and residential customer consultation sessions designed to identify the needs and preferences of consumers as they relate to the Distribution System Plan.

The consultation sessions were held in Barrie on November 17, 2014, Markham on November 17, 2014, and Vaughan on November 19, 2014. A total of 49 General service and residential customers participated in these consultation sessions.

Barrie: November 17, 2014

General Service under 50 kW Rate Class	10 participants
Residential Rate Class	7 participants

Markham: November 18, 2014

General Service under 50 kW Rate Class	10 participants
Residential Rate Class	10 participants

Vaughan: November 19, 2014

General Service under 50 kW Rate Class	6 participants
Residential Rate Class	6 participants

Recruiting Consultation Participants:

General Service customers in the under 50 kW rate class were randomly selected by telephone from customer lists and screened for appropriateness as session participants. General Service customers qualified for the consultation if they managed or oversaw their businesses' electricity bill. This was to ensure they were at least somewhat knowledgeable of their electricity costs and could have an informed discussion on the impact of the proposed rate increases.

Customer recruitment lists were randomly generated and provided to INNOVATIVE by PowerStream.

An incentive of $100 was provided to General Service customers, while residential customers received $80 to participate in the consultation sessions.

All consultation sessions were video recorded to verify participant feedback and quotes.

Consultation Session Structure:

The consultation sessions were structured around the themes contained in the primer, which was developed by INNOVATIVE and PowerStream in Fall 2014.

The primer themes included the following:

1. Why Are We Here?
2. Electricity Grid 101
3. PowerStream's Grid Today
4. Challenges and Solutions
5. What This Plan Means for You
6. Final Thoughts

At the start of the sessions, the facilitator gave an overview explaining the purpose of the consultation and why PowerStream is seeking feedback from General Service and residential customers.

After explaining the purpose of the consultation, hardcopy primers were distributed to act as a session guide for participants to record their answers to the question contained within.

Participants were then provided roughly 45-minutes to read and complete the questions within the primer. When it came to the questions within the primer, participants were asked to fill in their answers independently.

The facilitator then went through the primer section by section and facilitated a discussion on what the details meant for the individual or their business.

Hardcopy primers were collected from the participants at the conclusion of each consultation session.

Each consultation sessions ran for approximately two hours.

Informing the Consultation Process:

In addition to identifying customer needs and preferences as they relate to the proposed Distribution System Plan, feedback collected from this phase of the consultation was used to inform the next phases of the process.

NOTE: Results contained within this report are based on a limited sample and should be interpreted as directional only.

Participant Feedback

The following section highlights the general feedback from General Service and Residential customers.

General Service under 50kW Rate Class (Barrie)

Customers were generally satisfied with PowerStream's service.

Overall, General Service customers were happy with the service they were receiving from PowerStream. That being said, many participants noted a high (and increasing) bills as a reason for displeasure with the service they are receiving.

> *What can they improve on? For me, nothing.*
>
> *Been in business for 6 years and never had a power outage.*
>
> *The cost could come down.*
>
> *PowerStream does a really good job, but I think we pay for it.*

Some participants provided 'push back' to this process and PowerStream in general.

There was some 'push back' regarding where PowerStream fits in to the larger energy sector. Discussion focused on the rate increase being passed regardless of customer opinions. For several participants, PowerStream was seen as a bureaucratic monopoly that can just about do whatever it pleases.

> *Part of a Hydro bureaucracy.*
>
> *Looks like this is just to justify rate increases.*
>
> *They don't talk about the profit portion of it.*
>
> *We don't have an option, we're in a monopoly.*

System reliability was generally seen positively by participants.

Overall, participants in this group were pleased with the reliability they received. Outside of outages caused by extreme weather, participants noted very few power interruptions.

> *From a customer point of view, you can't complain, the power works.*
>
> *Our system's pretty reliable. We're competing on a global basis.*
>
> ` *I'm very satisfied, they can't do anything better.*

Some participants reported varying consequences during shorter outages.

Smaller outages that do not register in formal statistics were a concern for some participants. The consequences of these minor outages varied within the group, however, can be seen as a substantial problem for some businesses. For instance, one participant noted the machinery recovery time following these types of outages. Again, equipment damage is a concern for some businesses.

> *It's flickering, maybe there's a surge. I'm worried about my equipment.*
>
> *We had a padmount blow up and they were on it like white on rice.*
>
> *Just a flicker. Not a huge issue.*
>
> *We had five incidents. I can't afford battery backups for machines.*

An overarching concern in this group was related to improving communication during outages.

The central concern in this group was related to improved communication during outages. Many participants in this group found that communication during outages, particularly during the Ice Storm, could be improved. For many small businesses, understanding the duration of an outage affects how they will respond, including; sending employees home and closing their business altogether. Many participants pointed to using media, both paid and unpaid, to disseminate information to the general public. While some participants pointed to using social media, others said radio and television would be more effective.

> *Is there any way to communicate a timeline [for restoration]?*
>
> *Most people have smartphones, there's always Twitter and Facebook.*
>
> *Sometimes I'm informing [PowerStream] of the outage.*
>
> *When the power goes out, people are thinking; what, what? The best way now would be through a smartphone.*
>
> *Go through the media and give out information [during outages].*
>
> *I don't see why the utilities can't be more proactive in media.*
>
> *They need to use something to show that everything is good. Maybe Twitter?*

Despite a desire for improved communication, several participants do not believe investing in a new billing system is important.

While proactive communication during outages was seen as important, improvements to the billing system were generally not seen as a priority for many. Many participants had a difficult time seeing why a new billing system would be a priority. It is not seen as helping to increase reliability or offset bill increases, and therefore, not a priority for many. Some participants noted receiving this bills on time, and not wanting to pay more to receive a bill they already get.

> *If they were doing something completely new that was saving money, that's a different story.*
>
> *I think they should invest what's necessary.*
>
> *Billing system doesn't support reliability.*

Several participants suggested coordinating future infrastructure projects with city plans.

Several participants in this group believe that there should be more effort made to coordinate infrastructure projects with other city projects. These participants believe that efficiencies could be found if this coordination occurs, as roads would not need to be 'torn up' more than once to accommodate for these projects.

> *These companies need to be more forward-thinking. Integrate [infrastructure projects] with construction.*
>
> *When they decide they're going to tear up the road, plan it together.*

Many participants believe that PowerStream should find internal efficiencies to reduce the proposed rate increase.

Internal efficiencies are seen to be an important factor in reducing the proposed rate increase. Again, these participants point to how PowerStream operates as an area that requires further attention.

Find [the money] in the company.

Find it from within.

If it's being run really efficiently inside. Are there a lot of efficiencies at PowerStream?

Participants were generally split regarding preparing for extreme weather, however, most do not believe it should be a priority.

The majority of participants in this group do not believe it is necessary to invest in preparing for extreme weather. Because future weather is seen as unpredictable, and past experience is generally positive, this is seen as an area of investment that is not necessary, and does not directly affect day-to-day reliability.

What happens is going to happen, I don't buy that as a reason to raise rates.

It's like planning for shit happening when you can't.

This company should be planning a systematic upgrade.

There is a general desire for further information and education regarding the plan and PowerStream billing in general.

Many customers in this group believe that the public needs further information regarding the rate increase. That being said, several participants point to not fully understanding the bills, and this being a barrier to understanding the plan in its entirety. A few participants had a difficult time understanding where PowerStream fit in the larger energy market.

I get three bills. I pay for those three meters, send me one bill.

As consumers, we know little about this, it's just PowerStream on the letterhead. This is information that the public needs.

Explain to me what the benefit is.

In order for me to approve something I need to understand it completely.

Although the rate increase is generally seen negatively, the majority of participants believe it is necessary.

Seven participants support the rate increase, while only one are opposed to it. Despite receiving support in the primer, further clarity was seen as an important factor. There are some gaps in trust that left some participants feeling uneasy about the increase. Some participants pointed to small businesses being unable to shoulder the proposed increase. Despite this pushback, the majority of participants understood why is was necessary.

This plan shoes a lack of foresight.

Based on the last 5 years of government I don't trust them.

How are small businesses going to cope [with this increase]?

No attempt to address waste and inefficiencies.

What will the [new] system do? Why is it such a big priority?

Residential Rate Class (Barrie)

While several participants were overwhelmingly positive about the consultation process, some provided more 'push back'.

Some participants were positive regarding the consultation process. These participants were specifically satisfied with the opportunity to voice their opinions, as well as getting educated on the broader energy sector. Prior to reading the primer, few participants in this group were very familiar with PowerStream's responsibility. Despite this positivity, some participants felt that the rate increase was inevitable and that the primers intention was to persuade and not to consult.

> *We get to voice our opinions directly.*
>
> *I feel more educated, I like it.*
>
> *It was driven in one direction to get you to agree.*
>
> *No matter what we say, the rates are going to go up.*
>
> *Corporations should pay more for the delivery costs – they can afford it.*

Several participants believe that PowerStream could improve communication, especially during outages.

While the consequences of outages were not seen as being severe, several participants requested increased communication during outages. Short-term outages were less problematic, however, some more prolonged outages presented more problematic concerns.

> *If it's going to be out for 16 days, tell us.*
>
> *Communication would be nice.*

Many participants say that the proposed investments can be justified by long-term savings.

Many participants in this group believed that these proposed infrastructure investments should provide long-term savings on bills. Many in this group found it difficult to justify the investment without savings in the long-term.

> *If it's an investment in the long-term*
>
> *They should be making decisions based on what's profitable*
>
> *Efficiencies can be found by modernizing the system*

The same long-term savings were also expressed for investments in new technology.

Again, investments in new technology are seen to generate long-term savings. These investments are generally seen to be positive only when providing some long-term benefit, mainly cost savings.

> *If there's a cost benefits to technology, go for it.*
>
> *If it increase the system's capacity, go for it.*

Several participants believe that planning for extreme weather will not only increase safety, but also help offset bills.

Some participants saw investing in planning for extreme weather as a potential savings, should the system be hit again (like the Ice Storm).

> *I don't like to see major amount of people without what they need to survive [electricity].*

> *Maybe this will help decrease bills in the long-run.*

Some also see these investments as unnecessary due to the unpredictability of weather.

With regards to extreme weather, the opposite view was also expressed in this group. For a few participants, these investments should not be made because weather is seen as unpreventable, and investments might turn out to be unused and redundant.

> *We don't know, it's way up in the air.*

All participants approved the rate increase, however, with some reluctance.

Seven out of seven participants supported the proposed rate increase. However, many participants suggested that further information would help solidify their support for the plan. Specifically, several participants expressed interest in further information regarding how the business portion of PowerStream operates, including employee salaries.

> *I'm never sure [PowerStream] is running effectively on the business side.*

> *You question if the [money] is actually being well spent.*

> *I would rather see a gradual increase.*

General Service under 50kW Rate Class (Markham)

Participants were generally satisfied with the service being provided by PowerStream.

Generally, participants in this group were satisfied with the service they were receiving from PowerStream. In particular, one participant pointed to the relatively young age of the company as being an 'impressive' factor in their positive service experience.

> *I think their doing a pretty good job. They're only a ten year old company.*

> *My [service] is exceptional.*

Some participants expressed difficulty in understanding how certain investments would help improve productivity.

Several participants in this group found it difficult to understand how these investments would improve their own reliability. For instance, how will certain investments affect the recovery time during outages? In addition to this, some participants wanted to know how these investments would increase productivity and operations costs as a whole. Specifically, what would be the cost difference between replacing infrastructure proactively versus replacing at time of failure?

> Everything that is given is black and white, they should have some middle ground.

> If I were to have everything that is proposed, will I have less downtime? We don't have that number.

Know the price difference between sending the crews out and using remote technology.

This is how quickly we'll be able to get power to a number of people, this scenario compared to the other.

Several participants questioned why there was no information regarding internal efficiencies and PowerStream salaries.

Several participants in this group questioned why the primer and PowerStream's plan in general did not feature any savings or internal efficiencies. PowerStream was generally seen as placing the burden on the customer without looking within to find savings. Specifically, participants pointed to employee salaries as an area that could be examined to find savings and therefore reduce overall bill impacts.

I didn't see one word on spending less money on anything.

How much does an executive at PowerStream make?

If they want to, [PowerStream] can find out things they can reduce.

They don't talk about wage increases.

Although the majority of participants accept the proposed rate increase, some believe that further savings can be found to reduce rate impacts.

Similarly to the prior point, several participants in this group believe that further efficiencies can be found to reduce the rate impact, including stretching equipment life. The general sentiment in this group was that some rate increase was acceptable, however, the percentage was difficult to justify. Many of these business customers express not being able to pass this rate increase off to their own customers without "a damn good explanation".

I believe they can use the older equipment a bit longer, if they're not broke don't fix them.

8.2 per cent, and I'm assuming that's going to be compounded. I have public companies and I can't tell them were going to have an 8.2 per cent increase without a really damn good explanation.

They want to be proactive, and there's nothing wrong with that.

When asked about the balance between investment and rate increases, participants were generally divided.

At the end of the session, participants were asked to write down what they thought the appropriate balance was between investments and rate increases. The following are transcribed responses from that question:

The right balance between a rate increase and providing consistent, reliable power needs to be based on the power distributor's ability to maintain as well as improve electricity distribution while still breaking even and being revenue positive one year to the next.

Try not to spend more than you make, but repair (replace) what is needed.

The correct balance for rate inflation should be gradual enough for the consumer to comprehend. 2%. More information should be provided to keep costs low!

Identify the hazard of failing equipment and prioritize. Charge sufficient development fees to cover future needs plus refurbish old equipment. Reasonable, increase 5%

Increase the rate based on the most urgent needs. To start with, increase the efficiency of operations (overhead), have a longer plan.

Inform the consumers what kinds of plan the PowerStream has at the present time so that consumers can use this plan so that they can reduce the bill.

Replacement needs to be ongoing for aging equipment. Utility needs to be proactive in information supplied to end consumer.

Residential Rate Class (Markham)

PowerStream's service is generally seen positively, including their response during the 2013 Ice Storm.

Residential customers in Markham were generally very positive about PowerStream's service. In fact, in this group, very little time was spent on this subject, because participants generally had nothing negative to say about PowerStream, nor the services it offers.

> *During the ice storm I think they did a wonderful job communicating with customers when the power was going to be back.*

In addition to service, most participants do not see PowerStream's reliability as an issue.

Similarly to overall service, customers in this group did not see reliability as a major concern. In fact, 6 of 7 participants who responded in the primer express having two or fewer outages in the past year. Again, for these individuals, reliability was of little concern.

> *There's no reliability problem in my opinion. In the last 12 months I've had no outages.*

Several participants do not believe the PowerStream is effectively managed.

Despite a general positive perception of PowerStream in this group, there were several participants who believe its financials are not being effectively managed. In fact, a few of these people believe that the current proposed rate increase is a result of mismanagement.

> *I think they need to justify more why they need an increase.*
>
> *I believe that they money is not managed properly.*
>
> *It doesn't strike to the heart of the matter, when you look at the sunshine list in Ontario, how many hundreds of people are working for PowerStream.*

A number of participants believe that further information is needed to make an informed decision regarding the rate increase.

There were certain gaps in the primer that created skepticism regarding the proposed rate increase. For instance, one participant pointed to a lack of information regarding labour costs. This participant believed that there was a lack of information regarding a specific cost breakdown of various proposed infrastructure projects. In addition to this, a few participants requested information regarding current costs compared to proposed costs.

> *This whole book did not mention labour costs. They're just not mentioned.*
>
> *In order to make an informed decision on the rates, we need to know what they are doing now.*

Many participants note using less electricity, however, not seeing a bill decrease.

In a discussion regarding electricity usage, most participants noted using substantially less electricity, yet bills continued to rise. Many of these participants found it difficult to understand how decreasing usage didn't result in savings.

> *My usage has gone down, my bill has gone up dramatically.*

Most participants questioned what would happen following the five year rate increase.

There was an overarching concern in this group that bill increases would go beyond the proposed five year plan. The general feeling was that the current proposed plan was reasonable, however, not if the same increases occur indefinitely.

> *It's still not clear. In the five years are they fixing everything?*
>
> *My expectation is what's going to happen after five years? Is there any promise to the consumer that because all the infrastructure has been repaired we won't see any more rate increases?*
>
> *I agree with five years. What's going to happen after five years?*

For many participants, the proposed rate increase is seen as unreasonable.

> *I think that with proper planning, why would they need more than an inflation increase.*
>
> *I agree to a rate increase but not at these rates.*

That being said, seven of ten participants accepted the rate increase, despite not 'liking it'.

> *If you don't invest in the future today, at some point you hit a brick wall and have a huge expense and have to catch up.*
>
> *Why get opinions from us if they're going to make the changes anyways.*

General Service under 50kW Rate Class (Vaughan)

Participants were generally satisfied with PowerStream's service.

Many participants stated their satisfaction with PowerStream's service, particularly when compared to other similar utilities. In fact, a few participants who managed multiple properties noted that PowerStream's service was far superior to that of Toronto Hydro.

> *Compare PowerStream to Toronto, it's like night and day. PowerStream is way better.*

Most participants were also generally satisfied with the reliability they receive.

In addition to service, most participants were satisfied with the service reliability they received. Very few had experienced many substantial outages, and this left them feeling positive about the system reliability.

> *My office is in Woodbridge and I haven't seen an outage once.*
>
> *The reliability is way better then where I live in Albion.*

Some participants were unclear as to how this plan will directly affect their businesses.

There was a general desire in this group to understand how exactly this plan would affect their own business' service and reliability. For instance, some participants wanted to know how these investments would help guarantee less outages or the time required to regain power. Many participants found these questions to be missing in the primer.

> *I don't know what I'm gaining in terms of downtime.*

Many participants questioned PowerStream's plan from a business perspective.

Some participants questioned the validity of the plan as they believe it does not make a "strong business case". Again, some participants wanted more details on PowerStream operations and a more detailed understanding of how the business was run. Until this information was provided, several participants believed that the plan was unreasonable.

> *It doesn't tell me what their overhead is.*
>
> *It's all vague, there's no specifics. This is a very generalized document.*
>
> *Line wages, management wages.*
>
> *I don't know how they manage their resources.*

Some participants also believe that alternative sources of funding should be found to help pay for the proposed investments.

A few participants raised the idea of alternative sources of funding, particularly by finding internal efficiencies and government assistance.

> *This is what we're contributing, what are they contributing?*
>
> *What funding does PowerStream get from the different levels of government?*

According to some participants, prolonged outages can be financially costly to small businesses.

For many participants in this group, short outages were not overly concerning, however, prolonged outages are costly.

> *If I have to close for a whole day, that's a problem.*

A few participants did not understand the need to invest in a new billing system.

A new billing system was seen to not benefit the customer whatsoever. Generally, participants in this group consistently received a bill, and did not see how this investment would improve system reliability.

> *I love my bills, I can read by bills.*

While the majority approved the proposed rate increase, they did so with certain provisions.

Generally speaking, most participants in this group wanted certain guarantees when approving the proposed rate increase. For instance, they wanted assurance that all efficiencies have been found and that the money would be spent effectively. That being said, most participants understood that these investments are necessary.

> *It's a burden but we have to do it. I would like to see if they can look internally.*
>
> *I don't want to see in a year from now that we're doing this again.*
>
> *There's no option because they have to start doing this.*
>
> *Are they going to spend the money in the right way?*

Residential Rate Class (Markham)

Many participants found the consultation to be a valuable education in electricity.

> *Before I just paid the bill. Now I have a better understanding of what I'm paying, and why I'm paying.*
>
> *I learned a little more detail on all the different parts and how much the local utility. It's a smaller part than what I thought.*

Generally, participants had a positive perception of PowerStream as a well-run company.

The general sense in this group was that PowerStream was doing an excellent job managing their electricity. Several participants had recently had positive interactions with PowerStream, whether during the Ice Storm or with general Customer Service. Overall, PowerStream was seen to be doing a good job managing the distribution portion of bills.

> *I really feel PowerStream is a respected utility in many ways. I think the public feels like they're managing well. And they've been manning with the rate increases they've been giving us.*
>
> *I see the trucks on the street, I see the efficiency of the ground crews. They're better – their trucks. They spend money on the essential on-street equipment and they're doing a better job.*

Most participants found that system reliability was a strength for PowerStream.

Very few participants in this group were at all concerned with the reliability they were currently experiencing. In fact, the only real instances were outages were noticeable was during the Ice Storm in 2013. Even then, customers in this group experienced outages that were seen to be 'manageable'.

> *Personally, I think it is very reliable. During last year's ice storm I was sleeping and four hours later - so during the time the power was out - by the time I got up and running it was restored. For me that was great.*
>
> *I'm satisfied with how we get hydro. The interruptions are minimal. Other than during the ice storm, we were I think three days without power. What was nice in our particular case - we had power maybe for an hour at one point and then it went off or maybe 10 hours. But then we would get it for a little bit so we could recharge.*

Some participants pushed back as to why they had to fund a rate increase.

In large part, because reliability was seen positively by most, participants in this group did not understand why they were being asked to fund these investments. It was generally believed that PowerStream should be able to find internal and external efficiencies to help mitigate the rate impact.

> *The question is why are they asking us to pay for it.*
>
> *We're paying distribution then replacement, new equipment. It's like my business. I don't charge my customers when I have to replace an oven. You know, it's part of my costs. So my question is why do they keep passing it on to us.*

The proposed rate increase was generally seen as unrealistic.

Some participants in this group found that PowerStream might be asking for too much. Although perceptions of PowerStream were still positive, it was said that this level of investment might not be needed.

> *I think they might be overreacting a little bit, in terms of this plan – but it's in the right direction. And in my opinion PowerStream is doing a good job.*

Several participants agreed that average households would not be able to afford the proposed rate increase.

When tied to the overall cost of living, many participants believe that this rate increase is too high. All aspects of energy continue to rise, while the average household income stays the same, making it increasingly difficult to 'keep up'. Overall, this increase is seen as too much for the average household.

> *I don't want to go 7.7%, I think that's too much. I disagree with that, but I also am positive about the future. But the ordinary household can't afford that because everything is going up. Taxes are going up.*

> *A lot of people are working for minimum wage and they're stretching their budget already. They're doing their part and buying these homes. They're mortgaging and stretching a dollar and I think for the average household it's too much.*

Questionnaire Results

The following tables are the tabulations of participant feedback to questions in the hardcopy primers which were returned at the end of each consultation session.

Reponses to *open-ended* questions have been coded and examples of those codes are included below the question.

1. How familiar are you with the electricity system in Ontario, and the services PowerStream is responsible for?

Response	Barrie			Markham			Vaughan			Grand Total
	GS	Res	Total	GS	Res	Total	GS	Res	Total	
Very familiar	1	0	1	1	1	2	1	0	1	**4**
Somewhat familiar	2	2	4	5	2	7	1	2	3	**14**
Not very familiar	4	2	6	2	4	6	3	3	6	**18**
Not at all familiar	2	1	3	0	2	2	0	1	1	**6**
Don't know	1	0	1	0	0	0	0	0	0	**1**
TOTAL	**10**	**5**	**15**	**8**	**9**	**17**	**5**	**6**	**11**	**43**

2. How well do you feel you understand the important parts of the electricity system, how they work together, and which services PowerStream is responsible for?

Response	Barrie			Markham			Vaughan			Grand Total
	GS	Res	Total	GS	Res	Total	GS	Res	Total	
Very well	1	1	2	3	4	7	2	1	3	**12**
Somewhat well	8	4	12	6	5	11	3	4	7	**30**
Not very well	1	2	3	0	1	1	0	1	1	**5**
I don't understand	0	0	0	0	0	0	0	0	0	**0**
TOTAL	**10**	**7**	**17**	**9**	**10**	**19**	**5**	**6**	**11**	**47**

3. Generally speaking, how satisfied are you with the service you are receiving from PowerStream? Would you say…

Response	Barrie			Markham			Vaughan			Grand Total
	GS	Res	Total	GS	Res	Total	GS	Res	Total	
Very satisfied	4	4	8	4	7	11	1	5	6	**25**
Somewhat satisfied	6	2	8	3	3	6	4	1	5	**19**
Somewhat dissatisfied	0	1	1	1	0	1	0	0	0	**2**
Very dissatisfied	0	0	0	0	0	0	0	0	0	**0**
Don't know	0	0	0	0	0	0	0	0	0	**0**
TOTAL	**10**	**7**	**17**	**8**	**10**	**18**	**5**	**6**	**11**	**46**

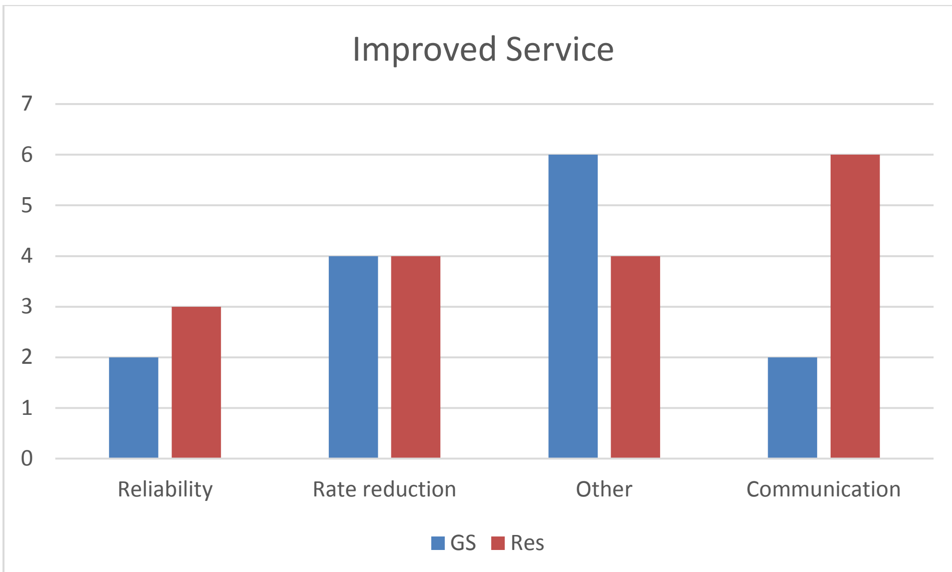
4. Is there anything in particular that PowerStream can do to improve its service to you? [OPEN-ENDED]

Reliability – *Improve the reliability in the area north of Highway 7 and west of Woodbine Ave. Blackouts seem to occur at least 1-2 times a year in all or part of this area*

Rate Reduction – *Lower bills, eliminate the GEA and reduce the hydro bureaucracy. Capitalize on efficiencies in the system. Promote/ encourage more power reductions and streamline the system*

Communication – *when undertaking major projects informing customers about the phases of the project would be appreciated*

Other - *not a big fan of the peak mid peak and off peak usage. I think electrical costs should not be based on peak demand*



5. As far as you know, in the past year, did you experience any outages due to unusual weather such as the ice storm, microbursts or tornados?

Response	Barrie			Markham			Vaughan			Grand Total
	GS	Res	Total	GS	Res	Total	GS	Res	Total	
Yes	8	2	10	7	8	15	5	6	11	**36**
No	1	5	6	3	2	5	0	0	0	**11**
Don't know	1	0	1	0	0	0	0	0	0	**1**
TOTAL	**10**	**7**	**17**	**10**	**10**	**20**	**5**	**6**	**11**	**48**

6. Whether you were personally affected or not, how satisfied are you with the way PowerStream responded to these events? Would you say…

Response	Barrie			Markham			Vaughan			Grand Total
	GS	Res	Total	GS	Res	Total	GS	Res	Total	
Very satisfied	6	4	10	3	5	8	2	2	4	**22**
Somewhat satisfied	3	1	4	7	3	10	3	3	6	**20**
Somewhat dissatisfied	0	0	0	0	2	2	0	1	1	**3**
Very dissatistied	0	0	0	0	0	0	0	0	0	**0**
Don't know	0	0	0	0	0	0	0	0	0	**0**
TOTAL	**9**	**5**	**14**	**10**	**10**	**20**	**5**	**6**	**11**	**45**

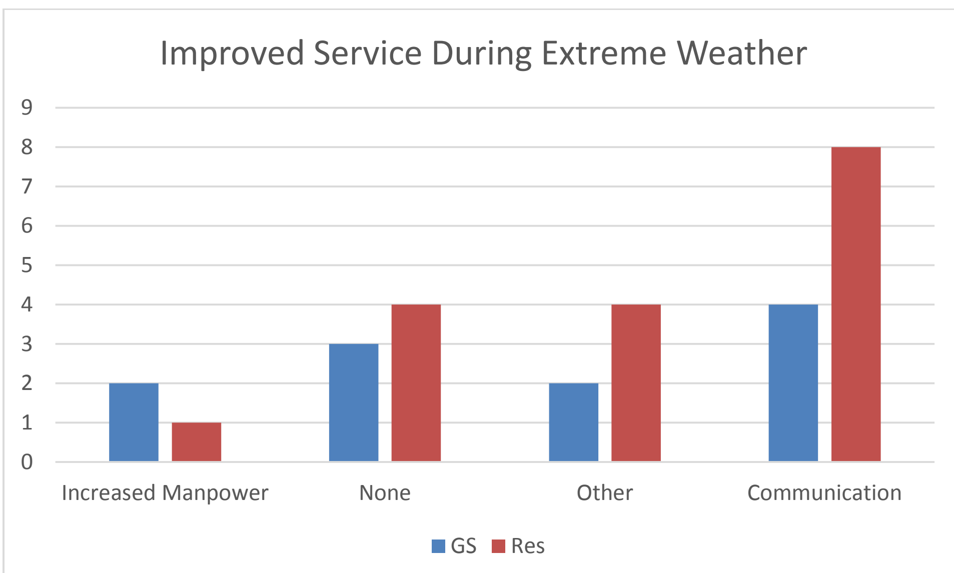
7. Is there anything in particular that PowerStream can do to improve its service to you during these extreme weather events?

Increased Manpower – *have on call staff list to increase man power during bad weather.*

None – *No I find PS to be very proactive they act fast during outages*

Communication – *it would be great if an email blast would be sent out updating us on the status of the outage. Most of us have email service on our phone and PDA*

Other - *ensure power outages are dealt with as quickly as possible, with as short a duration as possible*



8. Other than outages during unusual events, how many outages did you experience in the past year?

Response	Barrie			Markham			Vaughan			Grand Total
	GS	Res	Total	GS	Res	Total	GS	Res	Total	
Zero	1	4	5	1	3	4	0	0	0	**9**
One	2	0	2	4	2	6	3	2	5	**13**
Two	4	0	4	1	1	2	1	3	4	**10**
Three	0	0	0	0	0	0	0	0	0	**0**
Four	0	0	0	0	0	0	0	0	0	**0**
Five or more	2	2	4	1	1	2	0	0	0	**6**
TOTAL	**9**	**6**	**15**	**7**	**7**	**14**	**4**	**5**	**9**	**38**

9. Aside from unusual weather events, if you experienced an outage in the past year, what was the longest you experienced?

Response	Barrie			Markham			Vaughan			Grand Total
	GS	Res	Total	GS	Res	Total	GS	Res	Total	
Less than 15 min	1	2	3	4	4	8	1	1	2	**13**
15 to less than 30 min	3	1	4	0	0	0	0	1	1	**5**
30 min to less than 1 hr	0	1	1	1	1	2	0	1	1	**4**
1 hr to less than 3 hrs	0	0	0	0	0	0	0	0	0	**0**
3 hrs to less than 6 hrs	0	0	0	0	0	0	0	0	0	**0**
6 hrs to less than 12 hrs	0	0	0	0	0	0	0	0	0	**0**
12 to less than 24 hrs	0	0	0	0	0	0	1	1	2	**2**
More than 24 hrs	0	0	0	0	0	0	0	0	0	**0**
Don't know	1	0	1	0	2	2	2	0	2	**5**
TOTAL	**5**	**4**	**9**	**5**	**7**	**12**	**4**	**4**	**8**	**29**

10. If you experienced an outage, how satisfied are you with the way PowerStream responded to the outage? Would you say…

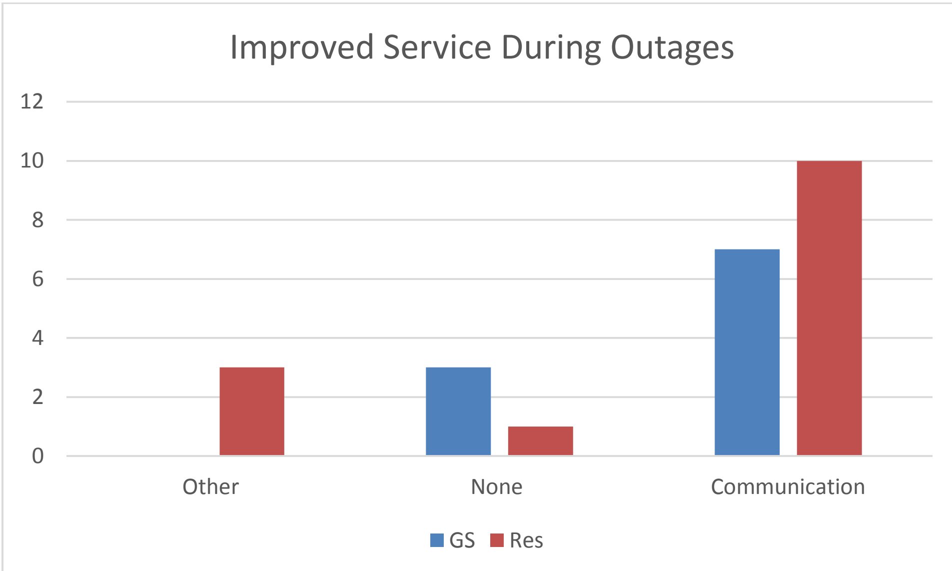
Response	Barrie			Markham			Vaughan			Grand Total
	GS	Res	Total	GS	Res	Total	GS	Res	Total	
Very satisfied	6	4	10	4	5	9	2	2	4	**23**
Somewhat satisfied	4	1	5	5	4	9	3	4	7	**21**
Somewhat dissatisfied	0	0	0	0	0	0	0	0	0	**0**
Very dissatistied	0	0	0	0	0	0	0	0	0	**0**
Don't know	0	0	0	1	1	2	0	0	0	**2**
TOTAL	**10**	**5**	**15**	**10**	**10**	**20**	**5**	**6**	**11**	**46**

11. Is there anything in particular that PowerStream can do to improve its service to you during outages? [OPEN-ENDED]

None – *no - speed in my area is adequate*

Communication - *communicate to the customer via email, message or 1800 number*

Other - *maybe design backup power packs. Use text to customers re outages*



12. Most years, the average PowerStream customer loses power due to outages for about 100 minutes over the whole year. This is at or below the average for similar utilities. Do you feel this level of reliability is…

Response	Barrie			Markham			Vaughan			Grand Total
	GS	Res	Total	GS	Res	Total	GS	Res	Total	
Very good	4	2	6	4	3	7	3	3	6	**19**
Good	5	5	10	4	3	7	1	1	2	**19**
Acceptable	0	0	0	2	2	4	1	2	3	**7**
Poor	0	0	0	0	0	0	0	0	0	**0**
Very poor	0	0	0	0	0	0	0	0	0	**0**
Don't know	0	0	0	0	1	1	0	0	0	**1**
TOTAL	**9**	**7**	**16**	**10**	**9**	**19**	**5**	**6**	**11**	**46**

13. What do you think of this policy?

Response	Barrie			Markham			Vaughan			Grand Total
	GS	Res	Total	GS	Res	Total	GS	Res	Total	
I am willing to pay more	1	2	3	1	2	3	2	0	2	**8**
Support current approach	9	5	14	5	7	12	3	6	9	**35**
Don't know	0	0	0	2	0	2	0	0	0	**2**
TOTAL	**10**	**7**	**17**	**8**	**9**	**17**	**5**	**6**	**11**	**45**

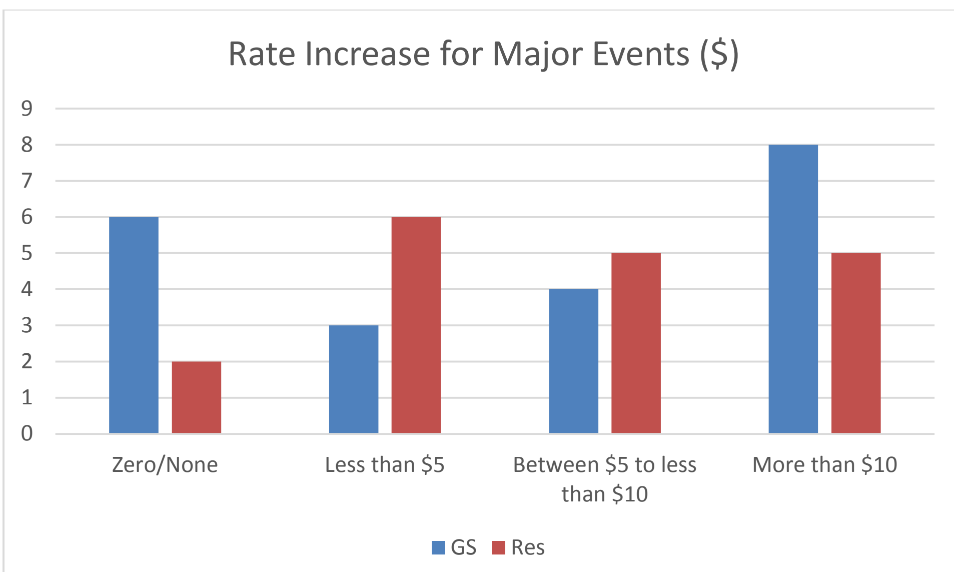
14. When it comes to replacing aging equipment, which of the following points of view is closest to your own?

Response	Barrie			Markham			Vaughan			Grand Total
	GS	Res	Total	GS	Res	Total	GS	Res	Total	
PowerStream should invest	4	3	7	6	7	13	3	3	6	**26**
PowerSteam should scale back	4	4	8	1	2	3	1	2	3	**14**
Don't know	2	0	2	1	1	2	1	1	2	**6**
TOTAL	**10**	**7**	**17**	**8**	**10**	**18**	**5**	**6**	**11**	**46**

15. While there are clear benefits from new technology, there are also costs. The system functions well on the old technology. Do we want to pay more to secure the benefits new technology can deliver?

Response	Barrie			Markham			Vaughan			Grand Total
	GS	Res	Total	GS	Res	Total	GS	Res	Total	
Investments in new technology…	5	3	8	4	3	7	2	0	2	**17**
I think the benfits of new techology…	2	4	6	3	6	9	3	6	9	**24**
Don't know	3	0	3	1	1	2	0	0	0	**5**
TOTAL	**10**	**7**	**17**	**8**	**10**	**18**	**5**	**6**	**11**	**46**

16. Currently, the average residential customer pays $27 a month to PowerStream to operate and maintain the local distribution system. How much more are you willing to pay each month for investments that would help the system better withstand major events such as extreme weather? [OPEN-ENDED]



17. Given what you know and what you have read so far, how well do you feel you understand the challenges facing the PowerStream system and what they are planning to do to meet those challenges?

Response	Barrie			Markham			Vaughan			Grand Total
	GS	Res	Total	GS	Res	Total	GS	Res	Total	
Very well	2	3	5	4	3	7	1	1	2	**14**
Somewhat well	8	4	12	4	6	10	4	3	7	**29**
Not very well	0	0	0	0	0	0	1	2	3	**3**
Don't understand at all	0	0	0	0	0	0	0	0	0	**0**
TOTAL	**10**	**7**	**17**	**8**	**9**	**17**	**6**	**6**	**12**	**46**

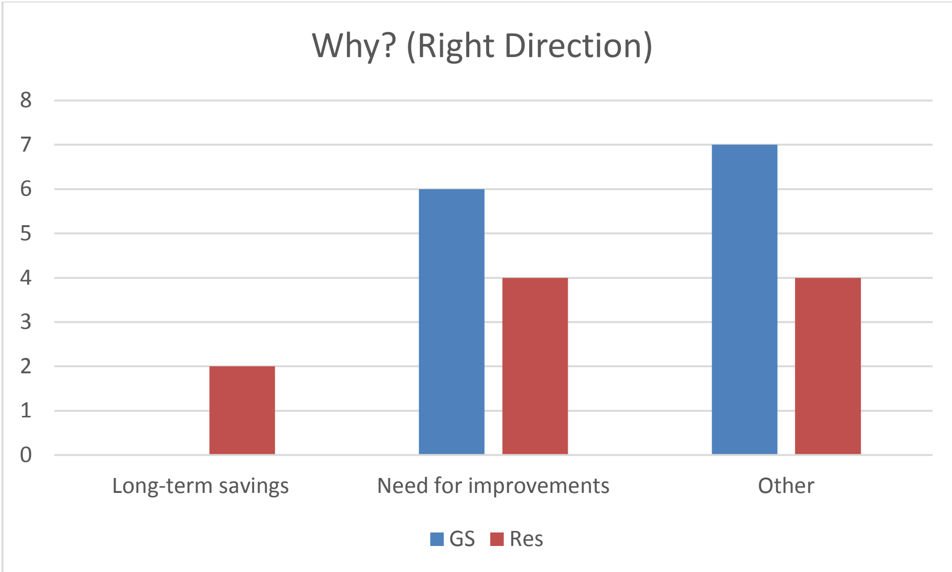
18. From what you have read and what you may have heard elsewhere, does PowerStream's investment plan seem like it is going in the right direction or the wrong direction?

Response	Barrie			Markham			Vaughan			Grand Total
	GS	Res	Total	GS	Res	Total	GS	Res	Total	
Right direction	6	5	11	5	5	10	5	2	7	**28**
Wrong direction	3	0	3	2	0	2	0	1	1	**6**
Don't know	1	2	3	0	3	3	1	2	3	**9**
TOTAL	**10**	**7**	**17**	**7**	**8**	**15**	**6**	**5**	**11**	**43**

19. And why do you feel that way? [OPEN-ENDED]

Respondents who answered **"right direction"** to Q18 provided the following responses:

> **Long-term savings –** *improvements in reliability and efficiency appear to pay returns in the long term*
>
> **Need for improvements –** *I see a need for continual system and infrastructure upgrades in the area. Particularly for hardware. Not sure that I agree that a major investment should be identified as a new billing system are consumers expected to pay for investments in order for PS to take our money*
>
> **Other -** *overall I feel PowerStream is a respectful utility managing rate increases while investing prudently in infrastructure but prioritize and focus on essential changes in infrastructure and manage better*



19. And why do you feel that way? [OPEN-ENDED]

Respondents who answered **“wrong direction”** to Q18 provided the following responses:

Only 1 Residential and 5 General Service participants found that PowerStream was moving in the “wrong direction”. The general theme of “finding money elsewhere” could be found amongst these responses. Specific responses include the following:

> *Has PS identified any efficiencies within their system? What waste needs to be addressed/ trimmed. Is PS overstaffed what are they doing to address these?*
>
> *the investment plan is being funded by the taxpayer or consumer - why aren’t taxpayers given incentives and builders to assist in reducing costs by participating in electrical generation i.e. solar panels or new roofing design and technology*
>
> *Expect us to pay for the repairs. We pay enough the repairs should come out of their profits not put the burden on us. We pay for a service. We are not owners in the company, government needs to be more responsible. Stop building new subdivisions until we can maintain the homes we have now. Use modern technology, solar panels, waterless hot water tanks, etc.*
>
> *Making "major capital investments" on a new billing system? Come on! The old system is just fine. Focus on the field and not on ancillary aspects*
>
> *As small businesses will not be able to afford the increase. Developers should be charged for a large portion of providing energy to new areas*

20. Considering what you know about the local distribution system, which of the following best represents your point of view?

Response	Barrie			Markham			Vaughan			Grand Total
	GS	Res	Total	GS	Res	Total	GS	Res	Total	
The rate increase is reasonable and I support it	0	2	2	1	1	2	0	0	0	**4**
I don't like it, but I think the rate increase is necessary	7	5	12	4	6	10	5	4	9	**31**
The rate increase is unreasonable and I oppose	2	0	2	2	3	5	0	2	2	**9**
Don't know	0	0	0	0	0	0	0	0	0	**0**
TOTAL	**9**	**7**	**16**	**7**	**10**	**17**	**5**	**6**	**11**	**44**

Mid-Market General Service Workshops

Workshop Presentations and Discussion Groups
with Mid-Market Customers

PURPOSE: To gain qualitative input on PowerStream's DSP from Mid-Market customers and to obtain feedback into survey design.

Summary

The following summary highlights key findings from the mid-market workshop sessions held in Simcoe County (Barrie) on December 9th, 2014 and York Region (Richmond Hill) on December 10th, 2014.

Satisfaction with service is high in both Simcoe County and York Region.

Customers in Simcoe County were overwhelmingly positive about the service they receive from PowerStream. In both groups, PowerStream was often compared to other utilities, and in all cases fared positively. Overall, PowerStream has provided excellent service and is perceived as a well-run business by its customers.

When asked where improvements could be made, customers in both groups pointed to reducing bills. Otherwise, PowerStream is doing an excellent job at being visible in the community.

Since satisfaction with reliability is high, customers find it difficult to justify the proposed investment plan.

In both regions, customers have experienced very few outages in recent years, including those due to extreme weather. As such, they found it difficult to justify the need for the proposed investments. Customers in both groups provided consistent push-back on infrastructure projects because reliability was not seen as a pressing concern.

In Simcoe County specifically, customers found both customer service and reliability to be adequate, and therefore, could not understand why money was needed to invest in these areas.

Certain aspects of communication were seen as a weakness in York Region, but customers believe that investments in new technology should provide cost savings.

Customers in York Region found that PowerStream could improve its communications, especially when outages were planned and could be prepared for. Receiving information regarding projected outage durations helps small businesses decide whether they should shut down, or stay open – a decision that affects them financially.

Many customers believe that any investments in new technology, including communications systems should provide long-term cost savings. Using their own businesses as a point of reference, many participants thought that investments in new technology should reduce bills rather than increase them.

Planning for extreme weather is not seen as a priority for most.

Neither group saw investments in planning for extreme weather as a priority. Since overall system reliability was seen positively, most customers did not believe it was necessary to plan for events that would 'happen regardless'. While most, especially in Simcoe County understood that these investments would act as an 'insurance policy' very few were willing to spend the extra money required to harden the system.

Instead of hardening the system as a whole, many customers in both groups, have already or plan to invest in backup generation in case of prolonged outages caused by extreme weather. In fact, some participants in Simcoe County wanted more information on how they could become less reliant on PowerStream.

Depending on the region, short outages and interruptions can be costly for small businesses.

Short interruptions, including brown-outs and 'blips' are a concern for customers in York Region. While the consequences of outages vary based on sector, most customers in this region report having experienced loss caused by outages. Safety and lost productivity are real concerns for customers. In some cases they have to clear buildings that contain vulnerable populations, notably the elderly. These short outages, which often do not register in formal statistics, can cause serious problems to equipment and electronics.

In Simcoe County, however, customers reported minor inconveniences when outages occurred, even when exceeding a few hours. In most cases, they simply shut down or operated without power. Again, for many of these customers, if the projected duration of these outages are effectively communicated, they are manageable.

The proposed rate increase generated push-back and was seen as being 'over ambitious'.

Customers in Simcoe County provided a great deal of push-back towards the proposed rate increase. This is seen as an overly ambitious plan. That being said, they realized that these investments are necessary, and most would be willing to agree to some increase, but not at this level. In order to offset the proposed rate increase, the majority believe that PowerStream can find efficiencies.

In York Region, customers were more receptive to the plan and provided less push-back. Although they might not like it, they understand that the pressures to the system require action and the cost of increased outages would most likely outweigh the cost of the proposed rate increase.

Methodology

About the Mid-Market GS Workshop Consultation

Innovative Research Group (INNOVATIVE) was engaged by PowerStream to conduct a series of mid-market customer consultation sessions designed to identify the needs and preferences of consumers as they relate to the proposed Distribution System Plan.

The consultation sessions were held in Simcoe County (Barrie) on December 9th, 2014 and York Region (Richmond Hill) on December 10th, 2014. A total of 18 mid-market customers participated in these consultation sessions.

Simcoe County: December 9th, 2014

Simcoe County (Barrie) 6 participants

York Region: December 10th, 2014

York Region (Richmond Hill) 12 participants

Recruiting Consultation Participants:

Mid-market (GS over 50 kWh) customers were randomly selected by telephone from customer lists and screened for appropriateness as session participants. Users qualified for the consultation if they managed or oversaw their businesses' electricity bill. This was to ensure they were at least somewhat knowledgeable of their electricity costs and could have an informed discussion on the impact of the proposed rate increases.

Mid-market customer lists were randomly generated and provided to INNOVATIVE by PowerStream.

An incentive of $150 was provided to all mid-market customers who participated in the consultation sessions.

All consultation sessions were video recorded to verify participant feedback and quotes.

Consultation Session Structure:

The consultation sessions were structured around the themes contained in the primer, which was developed by INNOVATIVE and PowerStream staff in Fall 2014.

The primer themes included the following:

1. Why Are We Here?
2. Electricity Grid 101
3. PowerStream's Grid Today
4. Challenges and Solutions
5. What this Plan Means for You
6. Final Thoughts

All consultation participants were sent electronic copies of the primer via email as part of a pre-read package in advance of the sessions.

At the start of the sessions, the facilitator gave an overview explaining the purpose of consultation and why PowerStream is seeking feedback from mid-market customers.

After explaining the purpose of the consultation, PowerStream staff delivered a detailed presentation outlining key aspects of the DSP, including the challenges faced by the grid, as well as the proposed solutions.

Following the presentation, consultation participants were able to ask PowerStream staff questions. Overall, this portion of the session lasted roughly one and a half hours.

PowerStream staff then left and participants were separated into two “breakout” groups. Two facilitators then lead the two groups of participants through the primer section by section to ensure they understood the information and to answer any questions they had about the content.

When it came to the questions within the primer, participants were asked to fill in their answers independently. The facilitator then led a group discussion on the answers participants provided and what this meant for their own businesses.

Hardcopy primers were collected from the participants at the conclusion of each consultation session.

Each consultation sessions ran for approximately 3 hours.

NOTE: Results contained within this report are based on a limited sample and should be interpreted as directional only.

Participant Feedback

The following section highlights the general feedback from each Mid-Market General Service consultation group.

Simcoe County Consultation Session (Tuesday December 9th, 2014)

Participants were generally very satisfied with PowerStream’s services.

Participants had unanimously positive things to say about PowerStream’s current level of service. PowerStream was often compared to other Local Distribution Companies, and is seen very positively. Other than outages occurring during extreme events, participants expressed very few power outages at their businesses. In fact, several participants in the Barrie area did not suffer an outage during the ice storm in 2013.

> *I’m very satisfied. As I said, from the School Board, we have buildings all across the county and we are in many different utility companies, and PowerStream is the easiest. You can actually talk to real people and answer your questions.*
>
> *We have regular power, even with the ice storm last year, we didn’t have any loss of power, we’re satisfied, obviously like to see rates lower.*
>
> *Very satisfied. We rarely have outages.*

For many respondents, a rate reduction is the sole way PowerStream can improve service.

When probed regarding how PowerStream can improve overall service, many respondents pointed to a rate reduction as a key driver. Again, perceptions were overwhelmingly positive, however, rates were a point of dissatisfaction for many.

> *Just rates, otherwise, just fine.*

In terms of average reliability, participants were also very satisfied with PowerStream.

> *Somewhat satisfied, because in the last two weeks we probably had 4 outages. .Good for us, I think we've had one in the last two years, like a half hour or something like that.*
>
> *Reliability is fine.*
>
> *Since I've been where I am, 2007, we lost it for two days, that's the only significant power loss in that time.*
>
> *Compared to Angus they get outages all the time.*
>
> *Right now the restoration time is not that high.*

Several participants had a difficult time comprehending the difference in cost between replacing and repairing aging infrastructure.

Participants had a difficult time digesting the need to replace aging infrastructure, rather than simply making repairs on an ongoing basis. Several participants wanted further details regarding the cost differential of replacing versus repairing said infrastructure. Generally, participants chose to support the most cost-effective measures that kept rate impacts low.

> *I'm not sure you need to replace everything before it fails.*
>
> *What percentage of those totals that they show you is actually aged, and has to be replaced, versus what percent they want to replace as a prevention type thing.*
>
> *We don't know their priorities. At the school board we have 140 buildings that we manage, we have a system like they do that shows us, we have all of our equipment itemized, based on age, brand and model, it tells us the estimated replacement date and if we followed that we would be spending $150 million a year replacing equipment, the reality is we've spending $10 million because it's not always accurate, we can fix it or patch it and make it last another 10 years.*
>
> *What is the cost of replacing a pole when it fails, as opposed to proactively?*
>
> *I agree that they need to replace as they go along, I just don't want to spend more money on it.*

Because reliability was generally considered "good" in the area, participants found it difficult to justify further investments.

Since most participants considered PowerStream's reliability to be "good", they found it difficult to understand why large infrastructure investments were needed. Since reliability and customer service are both considered to be adequate, many did not see the need for investments in these areas. Again, some participants compared PowerStream's system reliably to other LDC's where it was often seen as far superior.

> *My concern is, going around the room, none of us have really experienced many power outages. If we were in a different area, maybe Hydro One, where we had more outages, my answer would be different.*
>
> *My power is really reliable so I have a hard time justifying why they need these huge infrastructure increases.*

Several participants saw planning for extreme weather as an insurance policy that wasn't always necessary.

Overall, since system reliability was positive, participants did not see planning for extreme weather as a priority.

> *I have to look at and say, the risk of going down is a day of sales which I just have to determine if that's a risk I'm willing to take.*
>
> *If it was three days, I could probably live with that.*
>
> *Zero insurance. I've run my business for 20 years and we lost power for two days, we survived, no big loss and the reliability of the product we're getting now is right up there.*
>
> *If I'm willing to pay 5 per cent, what do you get for that?*
>
> *If something happens, you shut down your business and go home.*
>
> *When we have had power outages, we just send the kids home. Big picture, it's not really that big of a deal.*
>
> *The weather man's never right, their models never right, so it could be we have ten years of great weather, or ten years of bad weather.*
>
> *I put zero [percent]. We have a backup generator already.*

Many saw new technology as a cost-saver, rather than an additional cost on bills.

Using their own businesses as a point of reference, many participants thought that investments in new technology should reduce bills rather than increase them. Ultimately, several participants doubted whether new technology should be a priority if, in the end, it doesn't help to reduce the impact of their bills.

> *New tech should be priority?*
>
> *It makes it more efficient, so it should be cheaper in the long run for them, so the bills shouldn't be reflected.*
>
> *I don't think there's enough information on the new technology available.*
>
> *I find it interesting that costs continue to grow, when typically, you would think, a lot of new technology when you're putting it into plants and manufacturing it's supposed to reduce your costs.*

Some participants saw new technology as an opportunity to invest in reliability outside of PowerStream.

A few participants saw improvements in technology as an opportunity to invest in their businesses own electricity system, and ultimately as a way to separate from PowerStream. Several businesses currently operate generators and are looking to reduce bills by investing in sustainable energy.

> *I'm looking at it as: How do I get off the grid?*

Many participants saw this increase as part of a broader series of increases.

> *This just seems like you've got a lot of cost increases and I see five years from now being in same boat where they're going to do it again.*
>
> *There's so much pressure, and then to add and say, do we want to spend the money to do this infrastructure?*

That's a big hit. For us, our electricity bill is pretty big and we're looking at a 6 percent increase on the commodity, were not getting a 6 percent increase in funding.

Several participants saw the proposed rate increase as difficult to afford for small businesses and not-for-profits.

We certainly can't increase our capital expenditures by 150%, I don't know who does that. I don't get where that makes sense.

Looking at the type of funding we're given to pay our electricity bill, the rate of inflation is sort of the line I was looking at, I get that they would like to do some big things in years one and two, but maybe they have to look at some other ways to fund it.

Everything is higher, but our margins aren't any higher, so it's coming out of our bottom line.

When you're operating your own business, you have to look at your profitability and what can you afford to do, so it's a different decision when you can just go charge everyone.

Most participants believe that the proposed increase is "too ambitious".

I think they're going in the right direction, I just question if they're too aggressive.

I think the increase is very high, and they just need to scale it back.

I think the scale of it is a little too ambitious and what they're asking for from customers.

Again, the majority of participants do not support the proposed rate increase; however, they would consider a smaller amount.

Four of the five participants who responded to the question found the rate increase to be unreasonable. That being said, they were not generally opposed to *any* rate increase, however, the current proposal was seen as too severe. Finding efficiencies and alternate funding were seen as potential solutions to offset the proposed rate increase.

I understand why they have to do the rate increase and I think it's reasonable that they're asking for a rate increase, but there should be a blend of the rate increase.

They should try to mitigate the rate increase, it's a big punch.

I don't like it, but I think it's necessary. I think it's inevitable. We're going to have to pay for it now or later.

I think the rate increase is unreasonable, I think it's too high.

I think the cost increase they're proposing is too high. I think some increase is reasonable, but not this much because we're a not-for-profit, there's no profit for us to cover this kind of an increase.

Look at if our own business is efficient and could we reduce our own costs internally to offset some of these costs.

I completely understand. They fell behind on their maintenance program, it's really what it comes down to.

Some participants were outright unwilling to see any rate increase on their bills.

> *I don't think there should be any increases.*
>
> *I understand it. I don't agree with it. Fundamentally [don't agree] with the concept of money, that's the issue.*
>
> *They [PowerStream] just stick it the guys paying the bill*.

York Region Consultation Session (Wednesday December 10th, 2014)

Participants were generally very satisfied with PowerStream's services.

Overall, the participants in this group were satisfied with PowerStream's current services. PowerStream was held in particularly high regard when compared to other urban utilities, including Toronto Hydro.

> *You're doing an excellent and you're doing very well with the money we give you now.*
>
> *That's something that surprised me that we're charged exactly what PowerStream pays for the commodity. I would assume that they would mark it up a certain amount.*

Overall, most participants thought the response to extreme weather was adequate.

With regards to extreme weather, almost all participants found that PowerStream effectively responded to requests and was efficient at restoring power. In fact, many participants have not experienced outages due to extreme weather, and those that have, had power quickly restored.

> *I was really impressed with how quickly they responded to most of the problematic areas of the ice storm.*
>
> *They we're better than Toronto.*
>
> *I thought the communication was good, and the response was great. That really showed me a lot.*
>
> *Toronto was bad, and they weren't as good as PowerStream at getting it up again.*

Several participants believe that PowerStream could improve certain aspects of communications.

Several participants, including many in the second 'breakout group' found that communication was often lacking. Particularly, participants requested better communication regarding planned outages. These are seen as outages that can be prepared for, however, they are often in adequately informed or entirely unaware.

> *I think that the communication and coordination with the clients is an area that can be improved.*
>
> *Lack of notification is the problem.*
>
> *They don't always tell us they're going to do the work in advance.*
>
> *They need to improve reaction time from customer calls.*
>
> *When we put in a request, it goes into a black hole and we don't get a response back.*
>
> *Mostly you can't get through to anybody, it's an automated voicemail. Nobody actually picks up.*

I think our regular meetings with key account reps would be helpful, I know with Entersource we have meetings every two months and it's an opportunity just to talk.

If it's something more than a half an hour up to an hour, it comes down to communication, when will the power come back on?

For most participants, short outages, including brown-outs and blips can be very costly.

Particularly in manufacturing, any short outage, which is not registered in formal statistics, can force equipment to shut down. Several participants expressed that certain equipment can take several minutes, or even hours, to restart.

Power outages are expensive for us.

At my business, we've had some power surges where it just goes off for a second or two and the impact to us was we had metal-halide fixtures and they take 10 or 15 minutes to re-illuminate.

We have a large number of blips on our feeders, it's a nuisance for us and it happens quite routinely.

Sometimes an outage of a minute requires restarting machinery.

Any sort of power outage requires re-setting equipment, bringing it back on line. Usually we can have stuff back up and running in 15 minutes.

Safety and lost productivity are serious concerns for many participants during outages.

If the rental we have for 1 hour and the lights are out for 15 minutes, they want their money back or they complain, and it's not our fault.

Last time we went out with the ice storm, a lot of trouble. The reason being, most of our systems are automated, some of the doors failed to close or lock, some systems went down. Because of the time of the year we couldn't even get technicians to look at the systems. So we had a really bad period where we had to get security guards in place. We had to start investing in staff to stay overnight. For 10-15 days it was crazy.

There's a health and safety issue for us. Different times of the day we might have 400-500 people in the building and when the lights are out, especially in the evening, it's a serious issue. Clearing the building, making sure people get out safely.

There's also the impact on revenue, our rentals are typically 55 minutes, so if we lose 10 or 15 minutes because the power went out, it's a significant issue for us.

All the equipment goes off, damage for our refrigerators and computers and the whole facility.

We have to send everyone home, with pay of course.

More of a human resources matter than machines. People go outside and have a fun time and then it's difficult to get them back to work.

It's dangerous in the dark, because we have huge bins all over the warehouse, people can get hurt and fall.

According to some participants, outages to certain businesses and at certain times of day are not costly.

Participants in the restaurant industry express not suffering significant losses when outages occur during the day. Additionally, certain small trades could operate certain equipment without electricity, or simply resume a project when the outage ends. Ultimately, where outages were not costly, increasing rates were a particular concern.

> *I have no problem with power, if it's off and we're making a monument, it's not a big rush.*
>
> *If the outage is during the day, it's not a big problem, nothing stops. When it's dark outside it's a disaster.*
>
> *We haven't had any complaints other than the rates.*

Many participants have invested in backup generators, which are costly to run during prolonged outages.

> *It costs us money because we have to run our diesel generators and pay for fuel, plus it effects productivity.*
>
> *Quite often, a 30 minute outage is longer for us, because once we've transferred to our generators, you have to get a change window to retransfer. That 30 minutes could easily become 12 hours of diesel run time.*

Generally, participants see the ability to plan for outages as more important than the actual number of outages.

> *We couldn't plan anything. We didn't know if we should close down or cancel events and 90 per cent of our events start after 7, we need everything working.*
>
> *In our case it makes no difference if it's five minutes or three hours, we get just as many calls.*

Participants generally did not like it, but supported the proposed rate increase.

9 out of 11 respondents who answered the question in the primer supported the proposed rate increase. Additionally, most participants find that PowerStream's plan is on the right path.

> *Loss of power costs more than the rate increase.*

Questionnaire Results

The following tables are the tabulations of participant feedback to questions in the hardcopy primers which were returned at the end of each consultation session.

1. How familiar are you with the electricity system in Ontario, and the services PowerStream is responsible for?

Response	York Region	Simcoe County	Total
Very familiar	3	2	5
Somewhat familiar	4	3	7
Not very familiar	3	0	3
Not at all familiar	1	0	1
Don’t know	1	0	1
TOTAL	**12**	**5**	**17**

2. How well do you feel you understand the important parts of the electricity system, how they work together, and which services PowerStream is responsible for?

Response	York Region	Simcoe County	Total
Very well	5	2	7
Somewhat well	6	4	10
Not very well	0	0	0
I don’t understand	0	0	0
TOTAL	**11**	**6**	**17**

3. Generally speaking, how satisfied are you with the service you are receiving from PowerStream? Would you say…

Response	York Region	Simcoe County	Total
Very satisfied	5	3	8
Somewhat satisfied	5	3	8
Somewhat dissatisfied	1	0	1
Very dissatistied	0	0	0
Don't know	0	0	0
TOTAL	**11**	**6**	**17**

5. As far as you know, in the past year, did you experience any outages due to unusual weather such as the ice storm, microbursts or tornados?

Response	York Region	Simcoe County	Total
Yes	10	4	14
No	1	2	3
Don't know	0	0	0
TOTAL	**11**	**6**	**17**

6. Whether you were personally affected or not, how satisfied are you with the way PowerStream responded to these events? Would you say…

Response	York Region	Simcoe County	Total
Very satisfied	5	3	**8**
Somewhat satisfied	5	3	**8**
Somewhat dissatisfied	0	0	**0**
Very dissatistied	0	0	**0**
Don't know	1	0	**1**
TOTAL	**11**	**6**	**17**

8. Other than outages during unusual events, how many outages did you experience in the past year?

Response	York Region	Simcoe County	Total
Zero	1	2	**3**
One	2	0	**2**
Two	2	2	**4**
Three	3	0	**3**
Four	1	0	**1**
Five or more	2	2	**4**
TOTAL	**11**	**6**	**17**

9. Aside from unusual weather events, if you experienced an outage in the past year, what was the longest you experienced?

Response	York Region	Simcoe County	Total
Less than 15 min	3	2	**5**
15 to less than 30 min	1	1	**2**
30 min to less than 1 hr	3	0	**3**
1 hr to less than 3 hrs	1	0	**1**
3 hrs to less than 6 hrs	1	1	**2**
6 hrs to less than 12 hrs	0	0	**0**
12 to less than 24 hrs	1	0	**1**
More than 24 hrs	0	0	**0**
Don't know	0	1	**1**
TOTAL	**10**	**5**	**15**

10. If you experienced an outage, how satisfied are you with the way PowerStream responded to the outage? Would you say…

Response	York Region	Simcoe County	Total
Very satisfied	3	2	**5**
Somewhat satisfied	5	3	**8**
Somewhat dissatisfied	1	0	**1**
Very dissatistied	0	0	**0**
Don't know	1	1	**2**
TOTAL	**10**	**6**	**16**

12. Most years, the average PowerStream customer loses power due to outages for about 100 minutes over the whole year. This is at or below the average for similar utilities. Do you feel this level of reliability is…

Response	York Region	Simcoe County	Total
Very good	2	3	**5**
Good	6	3	**9**
Acceptable	2	0	**2**
Poor	1	0	**1**
Very poor	0	0	**0**
Don't know	0	0	**0**
TOTAL	**11**	**6**	**17**

13. What do you think of this policy?

Response	York Region	Simcoe County	Total
I am willing to pay more	1	0	**1**
Support current approach	9	6	**15**
Don't know	1	0	**1**
TOTAL	**11**	**6**	**17**

14. When it comes to replacing aging equipment, which of the following points of view is closest to your own?

Response	York Region	Simcoe County	Total
PowerStream should invest	6	3	**9**
PowerSteam should scale back	2	0	**2**
Don't know	3	1	**4**
TOTAL	**11**	**4**	**15**

15. While there are clear benefits from new technology, there are also costs. The system functions well on the old technology. Do we want to pay more to secure the benefits new technology can deliver?

Response	York Region	Simcoe County	Total
Investments in new technology…	2	1	**3**
I think the benfits of new techology…	7	3	**10**
Don’t know	2	2	**4**
TOTAL	**11**	**6**	**17**

17. Given what you know and what you have read so far, how well do you feel you understand the challenges facing the PowerStream system and what they are planning to do to meet those challenges?

Response	York Region	Simcoe County	Total
Very well	3	2	**5**
Somewhat well	8	4	**12**
Not very well	0	0	**0**
Don’t understand at all	0	0	**0**
TOTAL	**11**	**6**	**17**

18. From what you have read and what you may have heard elsewhere, does PowerStream’s investment plan seem like it is going in the right direction or the wrong direction?

Response	York Region	Simcoe County	Total
Right direction	8	3	**11**
Wrong direction	0	2	**2**
Don’t know	3	0	**3**
TOTAL	**11**	**5**	**16**

20. Considering what you know about the local distribution system, which of the following best represents your point of view?

Response	York Region	Simcoe County	Total
The rate increase is reasonable and I support it	1	0	**1**
I don't like it, but I think the rate increase is necessary	8	1	**9**
The rate increase is unreasonable and I oppose	2	4	**6**
Don't know	0	0	**0**
TOTAL	**11**	**5**	**16**

Key Accounts Consultations

Workshop Presentations and Discussion Groups
with Key Accounts

PURPOSE: To gain qualitative input on PowerStream's DSP from Key Accounts customers and to obtain feedback into survey design.

Summary

The following summary highlights key findings from the key accounts workshop session held in the Richmond Hill area on December 10th, 2014.

Participants want to know how this plan will affect their businesses as generally, reliability is more important than cost.

Reliability and cost are closely connected for this group. Participants want to clearly understand how the proposed plan will affect their own reliability and not just the system as a whole. Many participants are willing to spend more if they can be assured that their own reliability will improve.

It was repeated multiple times that the costs related to poor reliability outweigh the costs associated with the proposed rate increase. It is important to demonstrate how individual, case-by-case reliability will improve, rather than the system as a whole.

When viable, businesses are looking beyond PowerStream to improve individual reliability.

For those who cannot afford *any* outage, customers are turning to alternative sources of energy to help harden their own systems. Although reliability is generally seen positively, many companies are investing in backup systems in order to avoid relying on PowerStream's system.

However, in other cases, where these investments are not possible, customers want to see improvements to the overall system in order to see better reliability.

Communication is seen as a concern that can be improved through investments in technology.

Communication is generally seen as an area that needs improvement. Participants often found that there was not often a clear stream of information being shared between PowerStream and themselves. A key area of improvement could be seen in projecting outage lengths, particularly for customers with tenants.

Investments in new technology were seen as a potential bridge to help with communication. Again, projecting outage durations was a key driver in this discussion.

No matter the length, power interruptions can be very costly.

Short power interruptions, which do not register in system reliability statistics, can cause serious headaches for large customers. These interruptions, which can last from seconds to minutes, cause robotics to malfunction and force computer systems to reboot, which affects productivity and creates lost production.

For many of these customers, any length of interruption can shut them down; it can take anywhere from minutes to hours to return to working order.

Investing in extreme weather preparedness is seen as a valuable 'insurance policy'.

As reliability is of such importance for these customers, investing in extreme weather preparedness is seen as a valuable insurance policy that could ultimately pay for itself. For many customers, the costs related to prolonged outages are far greater than that of making these investments.

On the other hand, some customers do not see these investments as a priority, as these weather events will happen regardless and the system cannot be made 'invincible'.

While the rate increase is understood, efficiencies should be found to reduce overall impact.

While customers generally granted permission for PowerStream's proposed Distribution System Plan, they did so under certain circumstances. The plan as a whole was seen to be overly ambitious and overall rate impact was far too high. Many customers pointed to finding internal efficiencies to help reduce the proposed rate increase.

Generally, there is concern that these rate increases will continue for the foreseeable future (beyond five years), and this is alarming for many customers. When combined with other rising costs, the increases become too much for many businesses to handle, especially for those who own multiple buildings with tenants. While this proposed increase may be manageable, if they continue for 20 years, it becomes unrealistic for many.

Methodology

About the Key Accounts Workshop Consultation

Innovative Research Group (INNOVATIVE) was engaged by PowerStream to conduct a series of mid-market customer consultation sessions designed to identify the needs and preferences of consumers as they relate to the proposed Distribution System Plan

The consultation session was held in York Region (Richmond Hill) on December 10th, 2014. A total of 8 key accounts customers participated in this consultation session.

York Region: December 10th, 2014

York Region (Richmond Hill)	8 participants

Recruiting Consultation Participants:

Key Accounts customers were selected by telephone from a list generated and provided to INNOVATIVE by PowerStream.

All consultation sessions were video recorded to verify participant feedback and quotes.

Consultation Session Structure:

The consultation sessions were structured around the themes contained in the primer, which was developed by INNOVATIVE and PowerStream staff in Fall 2014.

The primer themes included the following:

1. Why Are We Here?
2. Electricity Grid 101
3. PowerStream's Grid Today
4. Challenges and Solutions
5. What this Plan Means for You
6. Final Thoughts

All consultation participants were sent electronic copies of the primer via email as part of a pre-read package in advance of the sessions.

At the start of the sessions, the facilitator gave an overview explaining the purpose of consultation and why PowerStream is seeking feedback from mid-market customers.

After explaining the purpose of the consultation, PowerStream staff delivered a detailed presentation outlining key aspects of the DSP, including the challenges faced by the grid, as well as the proposed solutions.

Following the presentation, consultation participants were able to ask PowerStream staff questions. Overall, this portion of the session lasted roughly two hours.

PowerStream staff then left and the facilitator began to lead the participants through the primer section by section to ensure they understood the information and to answer any questions they had about the content.

When it came to the questions within the primer, participants were asked to fill in their answers independently. The facilitator then led a group discussion on the answers participants provided and what this meant for their own businesses.

Hardcopy primers were collected from the participants at the conclusion of each consultation session.

The consultation session ran for approximately four hours.

NOTE: Results contained within this report are based on a limited sample and should be interpreted as directional only.

Participant Feedback

The following section highlights the general feedback from the Key Accounts consultation group.

Key Accounts Consultation Session (Wednesday December 10th, 2014)

Customers want to know how this plan will affect their business.

Many participants want to know how the proposed DSP will directly affect their business' reliability. Many participants are willing to accept the rate increase, however, they want to be assured that their reliability will be improved, otherwise it is difficult to justify the proposed rate increase.

> *For us, in manufacturing, reliability is more important than cost, if costs are going to go up a little bit but it's going to give us better reliability, we're okay with it.*
>
> *We don't know if these capital investments are going to directly affect our area or our production, or our feed or anything like that, so if I'm going to answer, yeah, let's pay more money so we can be more reliable, I don't know if that's going to actually affect my plant.*
>
> *If you're in an area that won't receive any benefit for 5 years…*
>
> *We don't know what that asset allocation is. We don't know where we're on the list.*

For large users, reliability is generally more important than cost.

Participants generally saw reliability as being directly connected to cost. For these customers, the cost of poor reliability greatly outweighs potential rate increases.

> *For me, reliability is more important than cost.*
>
> *For us, reliability is a bigger factor than cost.*

Several participants believe that PowerStream should find efficiencies to help reduce the overall rate impact.

Customers are generally satisfied with PowerStream's service, despite wanting to see bills decrease.

PowerStream is generally positively perceived, however, common complaints were tied to bills. When asked how PowerStream could improve service, most customers pointed to finding ways to help decrease overall bills.

> *I'm somewhat satisfied. [They can make it better] by reducing the bills.*
>
> *It's been good, they have been quite accommodating, because in the past we've asked them to adjust some switches.*
>
> *Things fail, and to be honest with you, they haven't failed very much. We've had two outages in the last 20 years.*

There are, however, isolated incidences of dissatisfaction with PowerStream's service.

Despite the general satisfaction with PowerStream's service, a few customers pointed to poor reliability as a serious concern. As several customers had multiple tenants, poor reliability affected them on multiple levels. In fact, tenants had threatened to deduct costs based on poor reliability and frequent outages.

> *The tenant has come to us and said, we're going to clock some time and deduct that from our rent, and if you don't like that we'll move out.*
>
> *Probably have [outages] two or three times a year.*
>
> *They haven't been doing that well. We had six brown-outs just last year. These are just cutting right into our profitability.*

Many customers are looking beyond PowerStream to improve their company's electricity reliability.

Several participants expressed not being in a position to allow any outages to occur. Reasons varied from loss of business to potential fines. In such cases, most participants have invested in alternative systems to protect against issues related to PowerStream reliability. Again, while outages may be infrequent, these 'backup' systems are seen as an insurance policy that will pay for itself over time.

> *PowerStream says "We provide you will as reliable power as we can, and what you need is above standard expectation."*
>
> *We use UPS [electronics], the motor will go down, but the brain still works and knows where it is and where it left off. Everything is UPS with 20 minute backup.*
>
> *I can't afford to have any outage, that's why I have 12 megawatts of backup power on top of UPS backup, transfer switches.*

However, in some instances where this is not viable, there is a desire to improve the overall system.

Some participants noted that regardless of the investments they make, the overall system's reliability has to be improved in order to reduce the effect of an outage.

> *If there were different classes for different needs of reliability, that's something we would discuss with them.*
>
> *Not everything is [protected by surge], key equipment and key components are, but if you get a hit, your presses will go down.*

Improving communication is a concern for these customers, however, only at the right cost.

A prominent theme that emerged in this discussion group was related to a lack of communication. Several participants found that there was not a clear stream of information between PowerStream and themselves. Projected outage durations were a particular concern for many of the participants who managed several properties or buildings.

We've had numerous concerns with reliability, being complete blackouts, brown-outs, switchovers, for any length of time. In many cases later on finding out that many of these switchovers could be communicated but actually were not.

One of our concerns other than rates and reliability would be communication. I'm getting numerous calls and tenants are wanting to know if they should close up shop.

Telephone, they should have a line that gives you a continuous update. A website that you can click on that says this was just updated 15 minutes ago. Is [increased communication] going to cost me $100,000 or $1000? If it's $100,000 I don't want it, but for $1000, okay.

When it comes to communication, they haven't been that helpful telling us what can they do and what can we do, and how can we work together to get rid of these issues.

It wouldn't bother me if PowerStream contacted me and said it was going to be an hour [to restore an outage].

Investment in new technology is generally seen as an important step for PowerStream and will also help with communication.

Beyond general reliability, many participants saw technology as the key to improving communications. Potential improvements in communications technology included telephone services and 'smart phone' accessibility.

We want to have more communication, we want to have more knowledge and be more involved in what's going on and I think new technology would help.

I think the benefits of the new technology, in my particular case, is keeping my customers informed, I think it's an important component. When you let it get too old, we're going to be in this position again.

It's a priority in terms of knowing what is happening at that particular time When is the recovery time?

Several participants believe that new technology should bring a positive return.

Cost reductions were often tied to improvements in technology. Participants generally believed that these investments would increase efficiency and ultimately reduce bills.

If there's a productivity improvement, that should be able to recover some of the costs.

Depending on what the investment is, there should be some type of return.

There could be added value to some of the technology, whether it's timer sensors, there could be some benefits to that.

As a general statement, technology has helped us become more effective, more efficient. I would push definitely for that.

Some participants noted extended wait times while attempting to gather information on outages.

Frustrating. It can take a couple of hours, and with tenants calling me it's just a continuous frustrating experience. Once we get a hold of them they give us an estimated time, and we give that to the client, and when that's not met, you try to contact them again.

Any power disruption can be very costly.

In terms of both productivity and lost product, any duration of outage can cost large users greatly. While many minor outages do not register in system reliability statistics, they can cause robotics to malfunction and force computer systems to reboot. It can take anywhere from minutes to hours to return to working order.

> *In certain instances we've had a flicker, and in that process we have something rebooting. You can't just shut it down again, we've lost CPUs, and sensitive equipment, and we've lost multiple items that are our assets.*
>
> *We have 145 electric robots and when they're in motion, the least power flicker, it stops. You have to recover.*
>
> *Recovery is the big thing. It's the recovery all the way down the line, and that hurts.*
>
> *Sometimes we have to scrap the product out - a lot of times we have to scrap it.*
>
> *Probably [costs] about $5,000 or $6,000 each time [there's an outage].*
>
> *Complete or 50 percent loss of production and our lines take five or six hours to start back up.*
>
> *Our machinery is expensive- each piece of equipment. The PLCs are designed to be sensitive.*
>
> *Three outages is worth our total bill for the year.*

Overall, there is general dissatisfaction with energy policy in Ontario.

PowerStream's DSP was often tied to broader energy policies in Ontario. Many participants saw this rate increase as part of a system that was inherently flawed. One participant pointed to PowerStream not being permitted to save money for future investments as a key policy concern.

> *I'm upset because of the government. The stupid people become ministers.*
>
> *They're creating a system that's gauging, and [PowerStream] is part of it.*
>
> *The process needs to be addressed.*

Some participants believe that in order to keep rates down, the depreciation model should be changed.

The depreciation model of PowerStream assets was seen as a potential weakness by some participants. These participants believed that further efficiencies could be found by making changes to the model.

> *If they want to keep this rate down, that means they're going to depreciate it over a longer period of time?*

There is a general concern that these increases will continue beyond five years.

Most participants are concerned that these rate increases will continue beyond the scope of the DSP. Additionally, when combined with other increases in energy costs, participants believe that overall costs are getting 'out of control'.

> *This 6.7 is being ramped up and will likely continue for longer than that five year period, but then in a couple of years they are going to look at some more stuff, which will make the increases even more.*
>
> *Is the five years the end, or does it go on for another five, another five, another five?*

Many participants said that their businesses could not afford sustained rate increases, nor could their tenants.

Beyond being unable to afford the increasing rates themselves, several participants were concerned that their tenants would be forced to vacate their properties. Again, several participants noted they could afford this increase, however, not if they continue for the next 20 years and beyond.

> *No business can afford these kind of increases over the next 20 years.*
>
> *There's only so much a business can afford, there has to be a median.*

Most participants generally support the current 'run to failure' approach, however, they asked for more information on the policy.

In principal, most participants supported this policy; however, they were unclear as to whether the equipment supporting their buildings were covered. Concerns with this policy occur on an individual basis, not on the system as a whole.

> *The way I read this, is it a major impact or a minor impact? If it's a minor impact, let it fail because it's not going to affect so much.*
>
> *It's a tough question because there's one extreme and the other extreme, there's nothing in between.*
>
> *It all depends on if I'm on that 'run to fail' list.*
>
> *From our point of view, I don't want them to repair anything in the system; I want everything to go to failure.*

Participants were generally divided regarding investing for extreme weather, however several saw it as a valuable insurance policy.

> *It's a matter of importance- importance to the system, to the security and the functionality of the system.*
>
> *You can only design to a certain point. At the end of the day, if an act of god happens, it doesn't matter what you've got in place, you'll go down. It doesn't matter how much money you throw at it.*
>
> *Up until 3 percent would be a realistic insurance policy.*
>
> *I do think there needs to be some sort of upgrade to the system, you're going to lose money anyway in a different way.*
>
> *If you can't predict it, don't spend any money.*
>
> *A very small percentage increase.*
>
> *You have to spend something to make sure; the potential costs of a disaster are substantial.*

Participants generally don't like the increase, but think it's necessary; however, they do wish to see the overall bill impact reduced.

While permission was generally granted, many participants expressed a desire for further information and for efficiencies to be found in the plan. The general feeling was that this plan, and rate increase, were unrealistic and further internal efficiencies could be found to reduce the overall percentage.

I challenge them to revisit it. We always put our wish list out first and I'm wondering if there's an opportunity for it to be challenged

Overall, I would challenge it.

It's a big increase, I would like to see a bit more planning.

6.7 per cent I would say automatically no.

If it's necessary, spend it. But I would say that the whole process needs to be looked at to even it out in such a way that you don't get hit by 6.7 per cent.

It's the difference between what I'd like to have and what I need to have.

My first impression of the budget is that it was padded. They know they're not going to get it, so if they wanted X they made Y because they know the government is going to cut them down a bit.

You've got all these big fat cats in all these different industries, and they're all making money out of it with no competition.

What's your staff, what's in the office, what's on the road? How many people do you have in your staff?

My point is productivity, what are they doing about productivity?

Residential and General Service Telephone Survey

Telephone Surveys
among Residential and GS customers

PURPOSE: To obtain statistically significant quantitative customer feedback on PowerStream's Distribution System Plan and assess reaction to customer opinions obtained from the previous research phases.

Summary

This section summarizes the findings from the two telephone surveys of 1,001 PowerStream residential customers and 201 General Service customers:

Familiarity, Satisfaction and Bill Knowledge

Nearly half of customers are familiar with their local distribution systems, Residents more familiar than GS on PowerStream ownership.

- Just under half of both Residential (45%) and General Service (45%) respondents are familiar with their local distribution system while a majority (54% Residential; 55% General Service) in both groups are unfamiliar.
- "High consumption" residential customers are much more familiar with the system than "low consumption ones (50% vs. 37%).
- When asked if they knew that PowerStream was owned by the cities of Vaughan, Markham and Barrie, less than six-in-ten Residential (57%) respondents confirmed they already knew this information before the survey.
- Less than four-in-ten (36%) GS respondents confirmed they already knew PowerStream's owners before the survey.

Strong majority of Residential and General Service customers are satisfied with PowerStream's service.

- Nearly nine-in-ten residential customers (87%) are satisfied with PowerStream's service; just one-in-ten say they are "dissatisfied".
- General Service customers are also quite pleased with PowerStream; more than eight-in-ten (83%) say they are satisfied with how PowerStream is running their local distribution system.

"Lower rates" is by far the leading concern for PowerStream customers, "communication" and "reduced outages also key mentions.

- For both Residential and General Service customers, a plurality say "lowering rates" is the biggest improvement PowerStream could make to improve service.
- "Better communication" (4% Residential, 3% General Service), "reduced outages" (2%, 2%) and "improved billing" (2%, 4%) are also key ways that, according to respondents, PowerStream could better service its customers.

Customers are not familiar with the breakdown of their electricity bill.

- Before the details provided in the survey just a third (33%) of Residential customers say they are familiar with the amount of their electricity bill that went to PowerStream.
- Nearly half (45%) of Residential customers say they are "not familiar at all".
- As for General Service customers, only three-in-ten (29%) are familiar with the amount of their bill owed to PowerStream. More than half (53%) of GS customers are "not familiar at all" with the breakdown of their bill.

System Reliability

Almost half of customers experienced outage during extreme weather, most are satisfied with PowerStream's response.

- This past year, almost half of both Residential (45%) and General Service (44%) customers experienced an outage due to extreme weather. "High consumption" customers were the hardest hit (41% vs. Low: 56% "no, did not experience outage").
- That being said, customers are quite satisfied with PowerStream's response. Nearly three-quarters (73%) of Residential and two-thirds (66%) of General Service say they are satisfied with how PowerStream handled the extreme weather service issues.
- When asked in the open-ended question to list something PowerStream could do to improve its services during extreme weather outages, a plurality of both Residential and General Service customers said they did not see anything else PowerStream could do to improve service (49% Residential, 30% GS).

Again, about half experienced an outage during normal weather, high levels of satisfaction with PowerStream response.

- In the last year, not including extreme weather, almost half (47%) of Residential and four-in-ten (39%) GS customers have experienced an outage.
- A quarter (24%) of Residential customers have experienced one or two outages and also about a quarter (23%) have experienced three or more outages.
- Again, a quarter (25%) of GS customers have experienced one or two outages and roughly the same number (23%) have experienced three or more outages.
- A strong majority (86%) of Residential and GS customers (81%) are satisfied with PowerStream's response to these outages.

Customers want "better communication" and "improved response time" during outages.

- The two leading improvements during outages mentioned by PowerStream Residential customers are "better communication" (13%) and "improved response and recovery" (8%). Other specific mentions include "reduced outages" (4%), "reduced short outages" (2%) and "reduce rates" (1%).
- General Service customers also bring up "improved communication" and "improved recovery time" as their top two concerns. There is some uncertainty among GS customers: three-in-ten (31%) don't know how to improve PowerStream's response to outages.

Customers divided on whether to spend to maintain current number of outages or spend more to reduce the number.

- Four-in-ten (40%) Residential customers say PowerStream should "spend what is needed to maintain the current level of outage". Roughly a third (32%) say PowerStream should "spend what is needed to reduce the current length of time customers are without power." Only 13% say PowerStream should "accept longer time without power in order to help minimize customer costs from rising".
- General Service customers are also evenly divided on how PowerStream should approach the number of outages. Nearly four-in-ten (38%) say PowerStream should spend to maintain the current levels while a third (34%) say that it should spend to reduce the number. Again just 14% say they would accept more outages to keep costs from rising.
- Additional knowledge, that the average PowerStream customer loses power "for about 100 minutes per year", does not change the results much for either Residential or GS customers. Still a large minority (43%) of Residential and GS (38%) say "spend to maintain". Nearly the same amount say "spend to reduce" (31% Residential and GS).

System Challenges & Priorities

Generally, both RS and GS customers support increased investment in aging infrastructure despite additional cost.

- A majority (54%) of both Residential and General Service customers choose to maintain the system despite an increase in cost for them personally.
- Three-in-ten (30%) Residential and a third (32%) of General Service customers prefer a reduced investment strategy to minimize any impact on their bill.

When asked to put a specific dollar amount on it to deal with unusual weather though, roughly half would not pay a dime more.

- A strong minority, nearly half (46%) of Residential customers say they would not pay anything more to strengthen the system to deal with unusual weather. A quarter (24%) would pay less than $5 and 15% would pay between $5 and $10 more. Very few people, just 11% would pay more than $10 on their monthly bill to prevent outages in unusual weather.
- As for General Service customers, six-in-ten (59%) say they would not pay any more on their monthly bill when asked the same question. Those that would pay are willing to pay slightly more than the Residential customers: roughly a quarter (26%) would pay less than $10 and 15% would pay more than $10 a month to help prevent outages during unusual weather.

Both "new technology" and "buildings, equipment and IT systems" should be an investment priority.

- Most Residential and GS customers think investment in new technology should be a priority for PowerStream. Nearly six-in-ten (58%) Residential and just over six-in-ten (61%) GS feel that investment in new technology should be a priority for PowerStream, while just a third of Residential (33%) and a quarter (24%) of GS customers feel that investment in new technology is a luxury, not a necessity.
- A majority of both Residential and GS customers also think PowerStream should invest in "buildings, equipment and IT systems". Two-thirds (64%) of Residential and over half (51%) OF GS customers prefer to manage the system efficiently with the right equipment and tools

despite the cost, while around three-in-ten (29%) Residential and nearly four-in-ten (37%) GS customers think PowerStream should make do with its current buildings and equipment.

Overall Assessment of Plan

Residential customers give permission, General Service oppose the increase.

Residential

Q: Considering the cost of PowerStream's plan, would you say…?

The rate increase is reasonable and I support it	**21%**
I don't like it, but I think the rate increase is necessary	**42%**
The rate increase is unreasonable and I oppose it	**33%**

- A majority (63%) of PowerStream Residential customers, when given additional context on the five-year plan, permit PowerStream to increase its rates.
- Two-in-ten (21%) think "the rate increase is reasonable and support it"; more than four-in-ten (42%) say they "don't like it, but think it's necessary"; and a third (33%) say "the rate increase is unreasonable and oppose it".

General Service

Q: Considering the cost of PowerStream's plan, would you say…?

The rate increase is reasonable and I support it	**15%**
I don't like it, but I think the rate increase is necessary	**28%**
The rate increase is unreasonable and I oppose it	**54%**

- General Service customers generally oppose it with a majority (54%) who say "the rate increase is unreasonable". Just 15% say "the rate increase is reasonable and support it" and less than three-in-ten (28%) say they "don't like it, but think the increase is necessary".

Cost is main permission concern for both Residential and General Service.

- When Residential customers were asked an open-ended follow-up on the permission question, the leading concern was cost. Specifically, the increase was "already too high" or "they pay too much currently" (35%).
- For General Service customers, the leading mention is also cost-related. More than a quarter (27%) say that "the rate increase is too much" and "they're paying enough already". Others think PowerStream or the government should shoulder the cost burden (11%).

Methodology

About the Residential and General Service Telephone Survey

PowerStream commissioned two surveys by telephone: the "Residential Rate Payer Customer Consultation" for 1,001 Residential customers of PowerStream and 201 organization customers, both conducted between January 14th and January 29th. The sample of Residential customers this size is considered accurate to within ±3.1 percentage points, 19 times out of 20 and the General Service sample is considered accurate to within ±6.9 percentage points 19 times out of 20. Margin of error will vary widely within each sub-grouping of the sample.

Questionnaire Design

This questionnaire is a direct result of the previously-mentioned Online Primer and Primer-led Consultation Sessions conducted in 2014. Feedback, both positive and negative, from these two previous phases helped guide PowerStream and Innovative in the initial question design phase.

The primary goal of this survey was to both consult and inform the customer on their personal (or organizational) experience with the distribution system and gage their opinions on familiarity, satisfaction, bill knowledge, system reliability, the system challenges and priorities and, finally, the assessment of the plan to raise rates to help pay for necessary infrastructure investment.

Note that wording of questions changed slightly between Residential and General Service questions- such as the amount paid in a bill per month- but otherwise are readily comparable.

The average survey ran approximately 10 minutes. For further information on exact question wording and order, see Appendices A and B at the end of the Telephone Survey Report.

Fielding the Survey

In order to field both surveys, PowerStream provided INNOVATIV E with a confidential list containing the contact information of 316,066 Residential and 315,861 GS customers. PowerStream built this list through randomly selecting among the approximately 312,000 Residential customers and 37,000General Service customers on file in its customer database. The list consisted of customers with a landline contact on file who had been customers of PowerStream since at least December 31st, 2012. Information included in this file included customer name, home telephone number, home address, service area, and total annual usage between January 1st and December 31st, 2013.

Only one customer per household was eligible to complete the residential survey and this member was screened to ensure that they were the resident primarily responsible for paying their PowerStream bill. This screen was used to ensure the customer was the most qualified to answer the questions regarding billing and the proposed rate increase.

Before retiring a randomly selected phone number, 12 attempts were made to reach the customer for each unique telephone number, or until a hard refusal from the customer. Each number was called twice a day for the first half of field and once a day for the remaining half. Each night, INNOVATIVE added new sample to the contact list to replace completed or retired calls.

PowerStream Residential customers were contacted at home by telephone between 4pm and 8pm on weekdays; 10am and 8pm on Saturdays; and 11am to 8pm on Sundays.

General Service customers were contacted during standard work hours: weekdays 9am to 4pm. These customers were also screened to ensure they were the person in-charge of managing the electricity bill at their organization. Only 50kW or less organizations were used in this survey.

All fieldwork was conducted using INNOVATIVE's CATI system.

Sample Design

The survey followed a stratified random sampling methodology. This is a method of sampling that divides the population into smaller groups known as strata. In stratified random sampling, the strata are formed based on members' shared attributes or characteristics (in this case, customer service area or electricity consumption). A random sample from each stratum is taken in a number proportional to the stratum's size when compared to the customer population. These subsets of the strata are then pooled to form a random sample.

In this survey, residential customers were divided into strata based on service area populations and then again into quartiles based on annual electricity usage to ensure the sample has a proportionate mix of customers from low, medium-low, medium-high, and high electricity usage households.

The table below illustrates the strata divisions for the Residential customer survey:

Residential Customers	Count	% Dist	Sample	Quartile 1	Quartile 2	Quartile 3	Quartile 4
Aurora	16,673	5%	53	13	13	13	13
Barrie	47,194	15%	151	38	38	38	38
Bradford	7,896	3%	25	6	6	6	6
Markham	87,074	28%	279	70	70	70	70
Richmond Hill	54,006	17%	173	43	43	43	43
Vaughan	81,528	26%	262	65	65	65	65
Other	17,285	6%	55	14	14	14	14
Total	**311,656**	**100%**	**1,000**	**250**	**250**	**250**	**250**

A similar stratified random sample was used for the General Service customers, broken down in the following table:

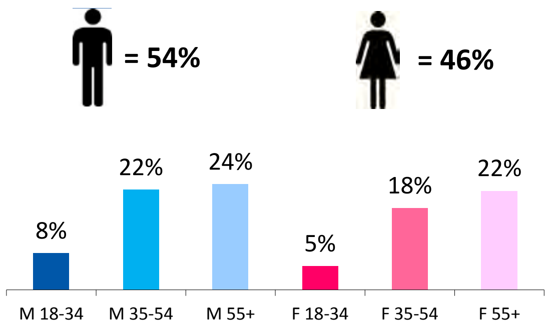
GS Customers	Count	% Dist	Sample	Quartile 1	Quartile 2	Quartile 3	Quartile 4
Barrie	5,051	14%	28	7	7	7	7
Markham	8,580	23%	47	12	12	12	12
Richmond Hill	4,931	13%	27	7	7	7	7
Vaughan	12,224	33%	67	17	17	17	17
Other	5,836	16%	32	8	8	8	8
Total	**36,622**	**100%**	**200**	**50**	**50**	**50**	**50**

Both samples were weighted according to the Region and Quartiles breakdown in the two previous tables.

Demographic Profile

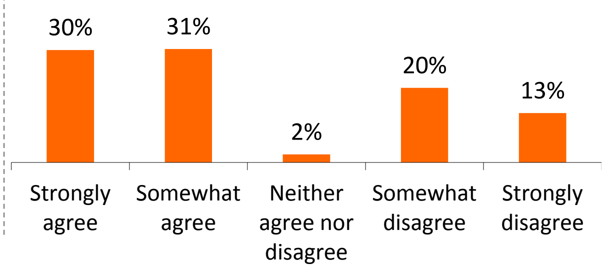
The following details the demographic characteristics of respondents who completed the Residential Ratepayer Survey [n=1,001].

Age-Gender

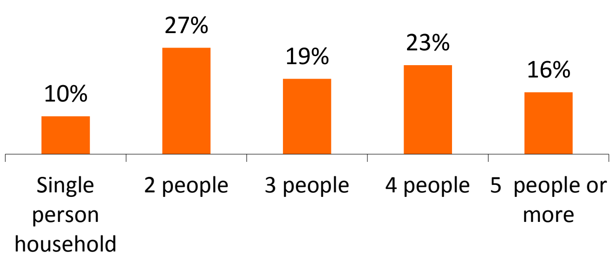


Financial Strain

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

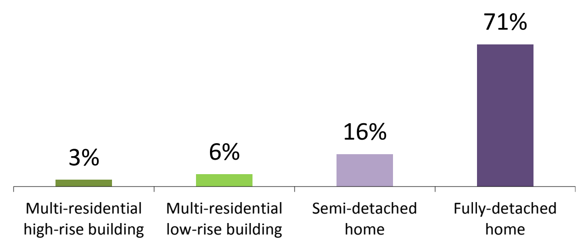


Household Size



Note: Refused (5%) not shown

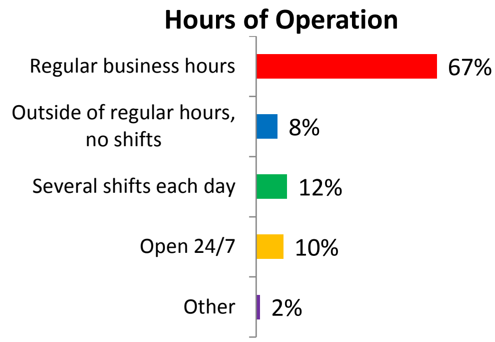
Type of Primary Residence



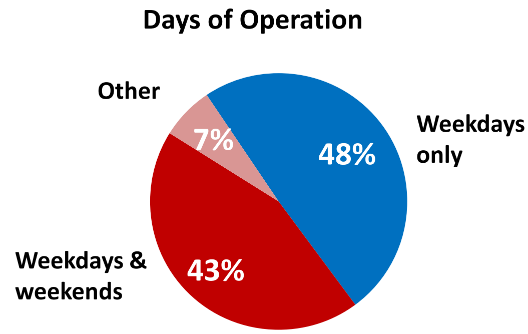
Note: Refused (4%) not shown

The residential ratepayers tend to be older (44% “55+”; 40% “35-54”; 13% “18-34”) home-owners (87% own vs. 9% rent) living in fully- (71%) or semi-(16%) detached homes.

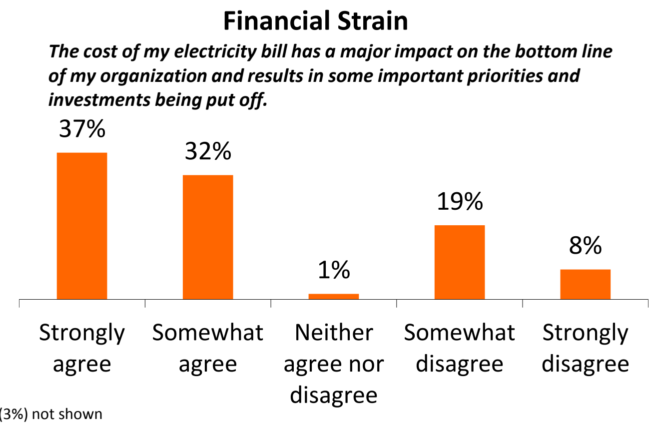
Below are the firmographics of respondents who completed the General Service Ratepayer Survey [n=200]:



Note: Refused (2%) not shown



Note: Refused (2%) not shown



Note: Refused (3%) not shown

Respondent Feedback

Familiarity and Satisfaction: Residential and General Service Customers

The first section of respondent feedback examines how familiar both Residential and General Service customers are with the local distribution system and their satisfaction with PowerStream's stewardship of that system.

Familiarity, Satisfaction Summary

Nearly half of customers are familiar with their local distribution systems, Residents more familiar with GS on PowerStream ownership.

- Just under half of both Residential (45%) and General Service (45%) respondents are familiar with their local distribution system while a majority (54% Residential; 55% General Service) in both groups are unfamiliar.
- "High consumption" residential customers are much more familiar with the system than "low consumption ones (50% vs. 37%).
- When asked if they knew that PowerStream was owned by the cities of Vaughan, Markham and Barrie, less than six-in-ten Residential (57%) respondents confirmed they already knew this information before the survey.
- Less than four-in-ten (36%) respondents confirmed they already knew PowerStream's owners before the survey.

Strong majority of Residential and General Service customers are satisfied with PowerStream's service.

- Nearly nine-in-ten residential customers (87%) are satisfied with PowerStream's service; just one-in-ten say they are "dissatisfied".
- General Service customers are also quite pleased with PowerStream; more than eight-in-ten (83%) say they are satisfied with how PowerStream is running their local distribution system.

"Lower rates" is by far the leading concern for PowerStream customers, "communication" and "reduced outages also key mentions.

- For both Residential and General Service customers, a plurality say "lowering rates" is the biggest improvement PowerStream could make to improve service.
- "Better communication" (4% Residential, 3% General Service), "reduced outages" (2%, 2%) and "improved billing" (2%, 4%) are also key ways that, according to respondents, PowerStream could better service its customers.
- Still, about a quarter of both Residential and General Service customers have no complaints, even when prompted to give one (26% Residential, 22% General Service).

Preamble for Familiarity and Satisfaction Section

Before respondents are asked the first question on familiarity, the following preamble describes the components of Ontario's electricity system:

"To start, I'd like to ask you a few questions about the electricity system…

*As you may know, Ontario's electricity system has three key components: **generation**, **transmission** and **distribution**.*

- ***Generating stations** convert various forms of energy into electric power;*
- ***Transmission lines** connect the power produced at generating stations to where it is needed across the province; and*
- ***Distribution lines** carry electricity to the homes and businesses in our communities.*

*Today we're going to talk about your **local distribution system** which is maintained and operated by PowerStream in your community."*

Figure 1.0 RS: Familiarity with the Local Distribution System

Q How familiar are you with the **local distribution system** which it maintained and operated by PowerStream?
[asked of all respondents; n= 1001]

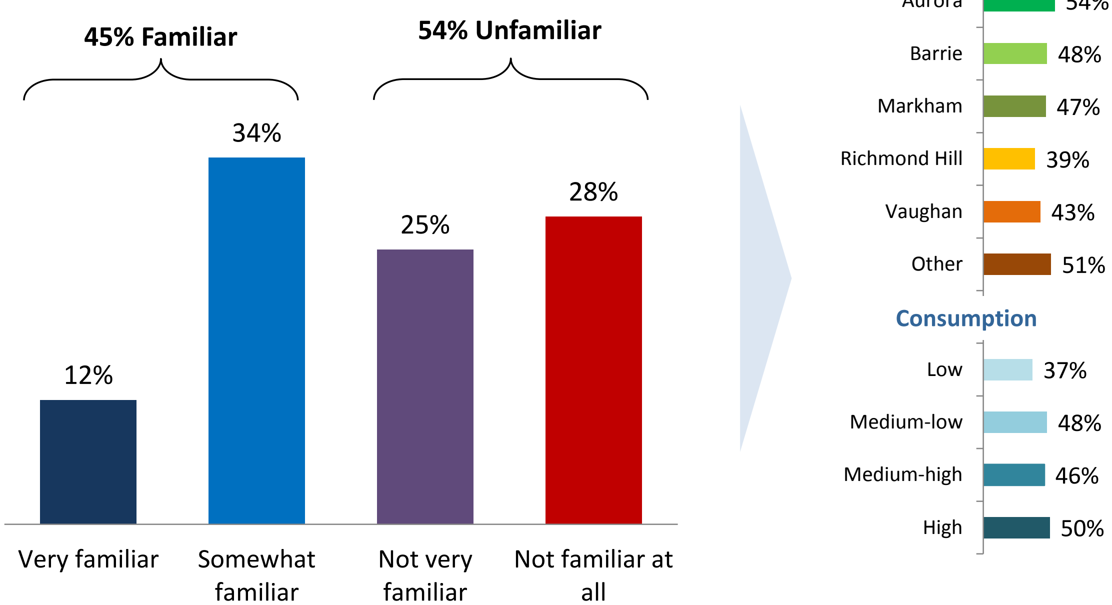
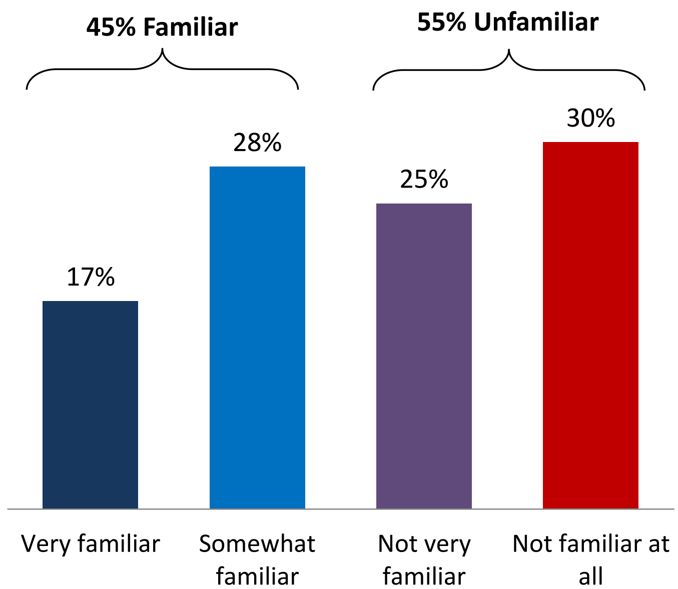
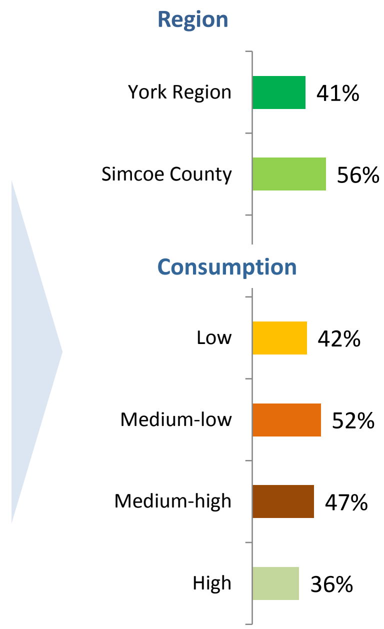


Figure 1.1 GS: Familiarity with the Local Distribution System

Q How familiar are you with the **local distribution system** which it maintained and operated by PowerStream?
[asked of all respondents; n= 201]



Sample Breakdown
Those who say "familiar"



Note: 'Refused' (>1%) not shown

Almost half of both Residential (45%) and General Service (45%) respondents are familiar with their local distribution system while a majority (54% Residential; 55% General Service) in both groups are unfamiliar.

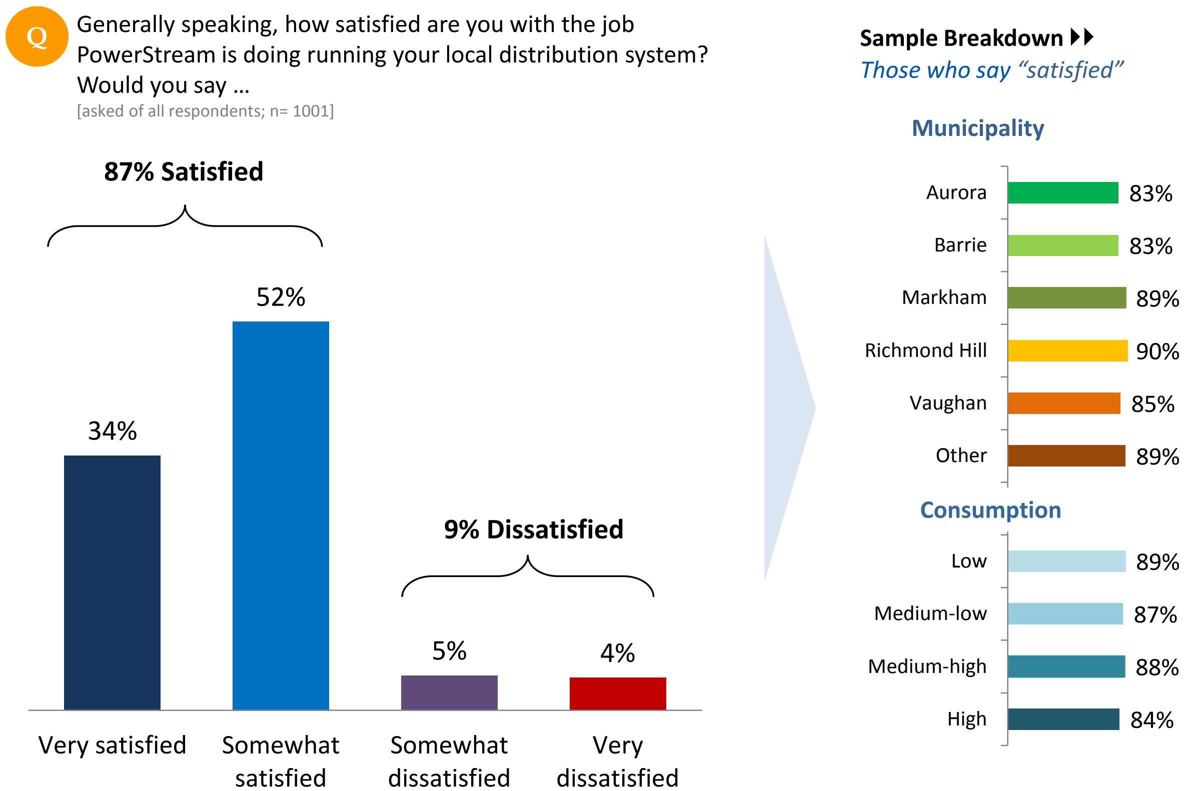
Residential

- Richmond Hill (39%) and Vaughan (43%) have the lowest level of familiarity with the local system.
- Differences in consumption level are also related to familiarity. High (50%) levels of consumption are associated with more familiarity than low (37%) level consumption.
- Consumers "55+" are more familiar with the system (52%) than consumers age 18-34 (31%).

General Service

- More than half (56%) of General Service customers in Simcoe County are familiar, while only 41% of York Region say the same.
- High (36%) consumption organizations are the least familiar with their local distribution system.

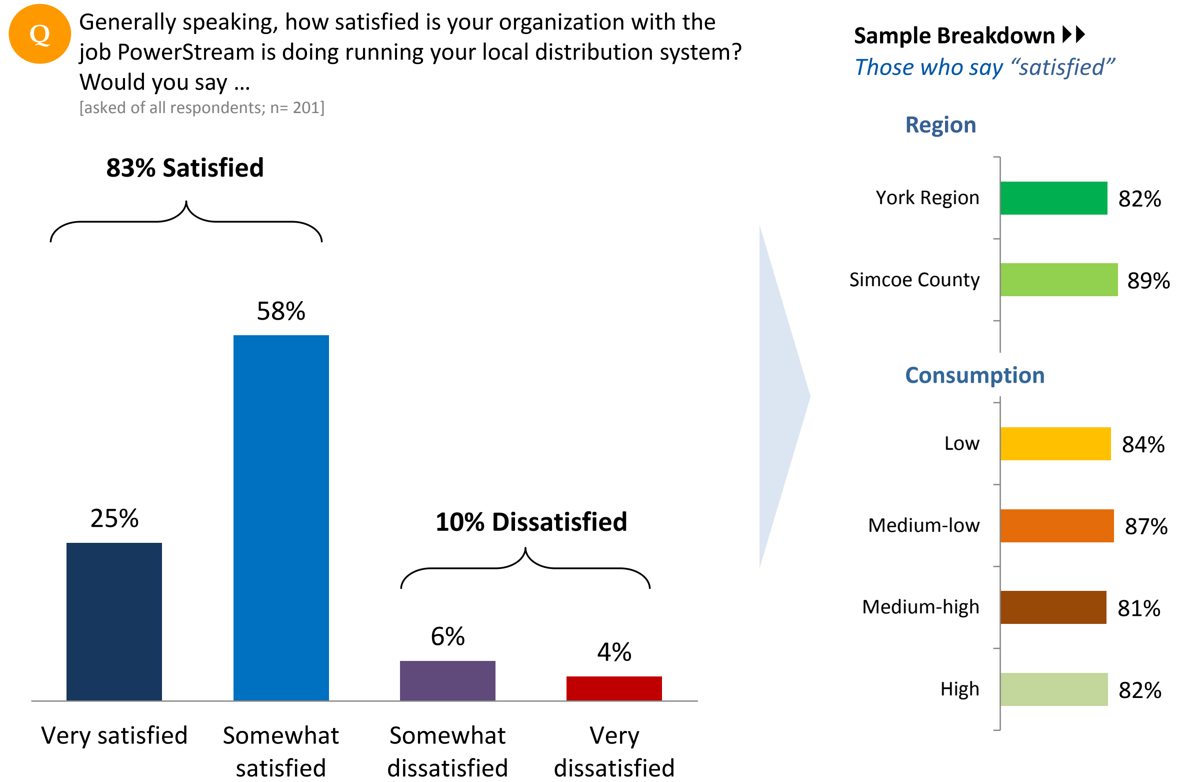
Figure 1.2 RS: Satisfaction with PowerStream



Nearly nine-in-ten residential customers (87%) are satisfied with PowerStream's service; just one-in-ten say they are "dissatisfied".

- Richmond Hill (90%) and Markham (89%) are a bit more likely to be satisfied with their service than the rest of the region.

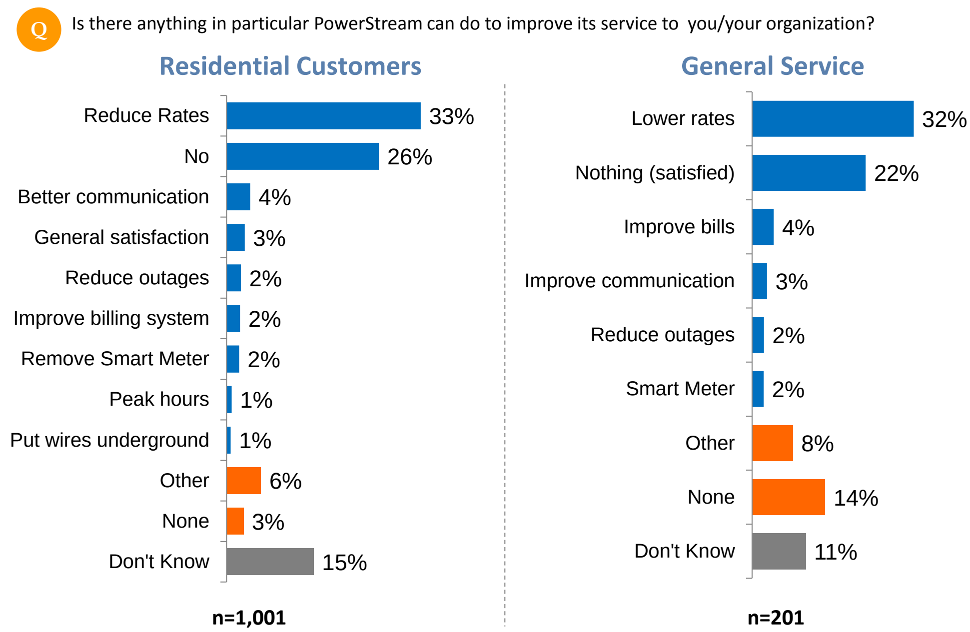
Figure 1.3 GS: Satisfaction with PowerStream



Note: 'Don't know' (6%) not shown

General Service customers are also quite pleased with PowerStream; more than eight-in-ten (83%) say they are satisfied with how PowerStream is running their local distribution system.

Figure 1.4 RS/GS: How to Improve Service

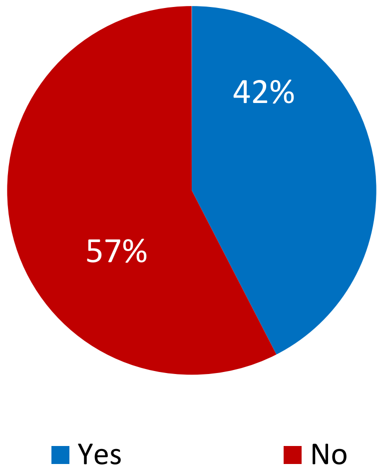


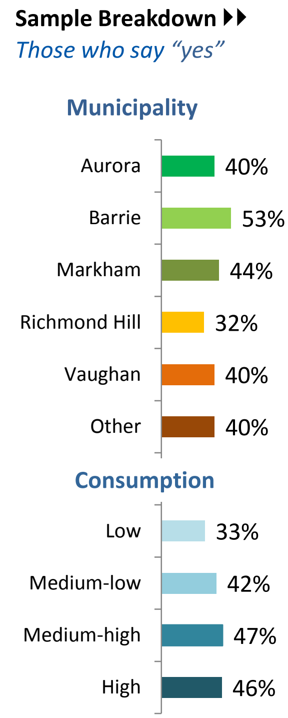
For both Residential and General Service customers, the biggest improvement PowerStream could make is to "lower rates" (33% residential; 32% General Service). "Better communication" (4% Residential, 3% General Service), "reduced outages" (2%, 2%) and "improved billing" (2%, 4%) are also key ways that, according to respondents, PowerStream could better service its customers. Still, about a quarter of both Residential and General Service customers have no complaints, even when prompted to give one (26% Residential, 22% General Service).

Figure 1.5 RS: Knowledge of PowerStream ownership

Q PowerStream is 100% owned by the cities of Vaughan, Markham and Barrie and is overseen by a board of directors. This board is made up of members of the respective city councils and the community and is responsible for overseeing the operations and management of the utility.

Before this survey did you know that PowerStream was owned by the cities of Vaughan, Markham and Barrie?
[asked of all respondents; n =1001]





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

When asked if they knew that PowerStream was owned by the cities of Vaughan, Markham and Barrie, less than six-in-ten Residential (57%) respondents confirmed they already knew this information before the survey.

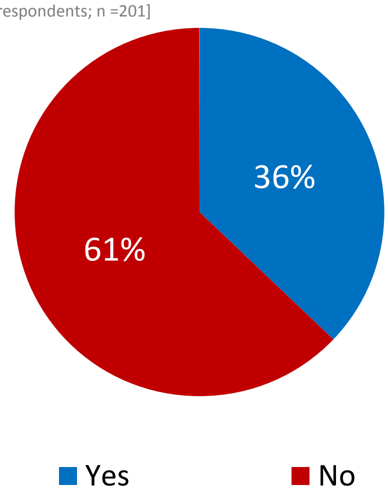
- Barrie (53%) Residential customers are the most likely to claim knowledge of PowerStream ownership while Residential customers in Richmond Hill (32%) are the least likely.
- Higher consumption customers (46-47%) claim to be a bit more knowledgeable than lower consumption residential customers (Low: 33%; Medium-low: 42%).

Figure 1.6 GS: Knowledge of PowerStream ownership

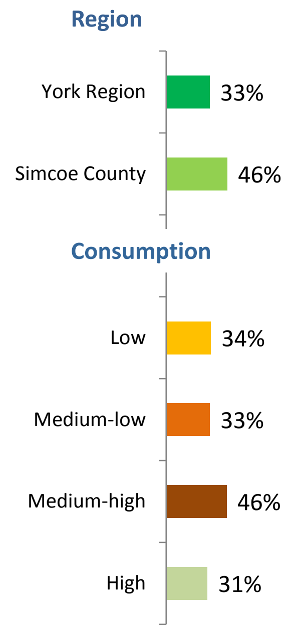
Q

PowerStream is 100% owned by the cities of Vaughan, Markham and Barrie and is overseen by a board of directors. This board is made up of members of the respective city councils and the community and is responsible for overseeing the operations and management of the utility.

Before this survey did you know that PowerStream was owned by the cities of Vaughan, Markham and Barrie?
[asked of all respondents; n =201]



Sample Breakdown ▸▸
Those who say "yes"



Note: 'Don't know/refused' (3%) not shown

Less than four-in-ten (36%) respondents confirmed they already knew PowerStream's owners before the survey.

- Simcoe County is a bit more likely than York Region General Service customers to know PowerStream is owned by the cities of Vaughan, Markham and Barrie (46 vs. 33%).

Electricity Bill Knowledge

This section explores Residential and General Service respondent perceptions and knowledge of their electricity bill. It specifically focuses on the breakdown of the bill and what portion respondents estimate goes to PowerStream.

Electricity Bill Knowledge Summary

Customers are not familiar with the breakdown of their electricity bill

- Before the details provided in the survey just a third (33%) of Residential customers say they are familiar with the amount of their electricity bill that went to PowerStream.
- Nearly half (45%) of Residential customers say they are "not familiar at all".
- As for General Service customers, only three-in-ten (29%) are familiar with the amount of their bill owed to PowerStream. More than half (53%) of GS customers are "not familiar at all" with the breakdown of their bill.

Preamble for Bill Knowledge Section

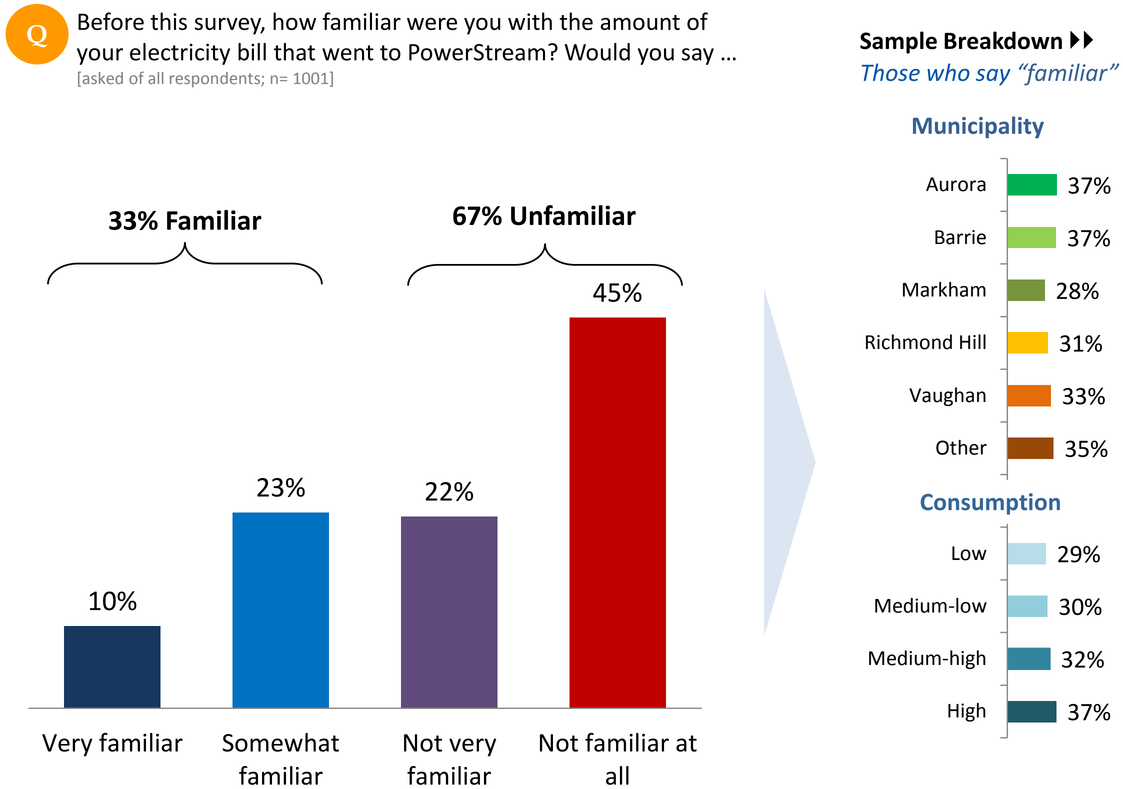
The question on electricity bill knowledge begins with this preamble:

"I'd now like to talk with you about your electricity bill …

*While some customers pay more and other pay less, the **average residential customer pays about $135 a month** for electricity of **which $27 or approximately 20% goes to PowerStream**. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies."*

(Note that in the GS survey, the bolded text is replaced with the following: ***"the average General Service customer pays about $305 a month for electricity of which $61 or approximately 20% goes to PowerStream"***.)

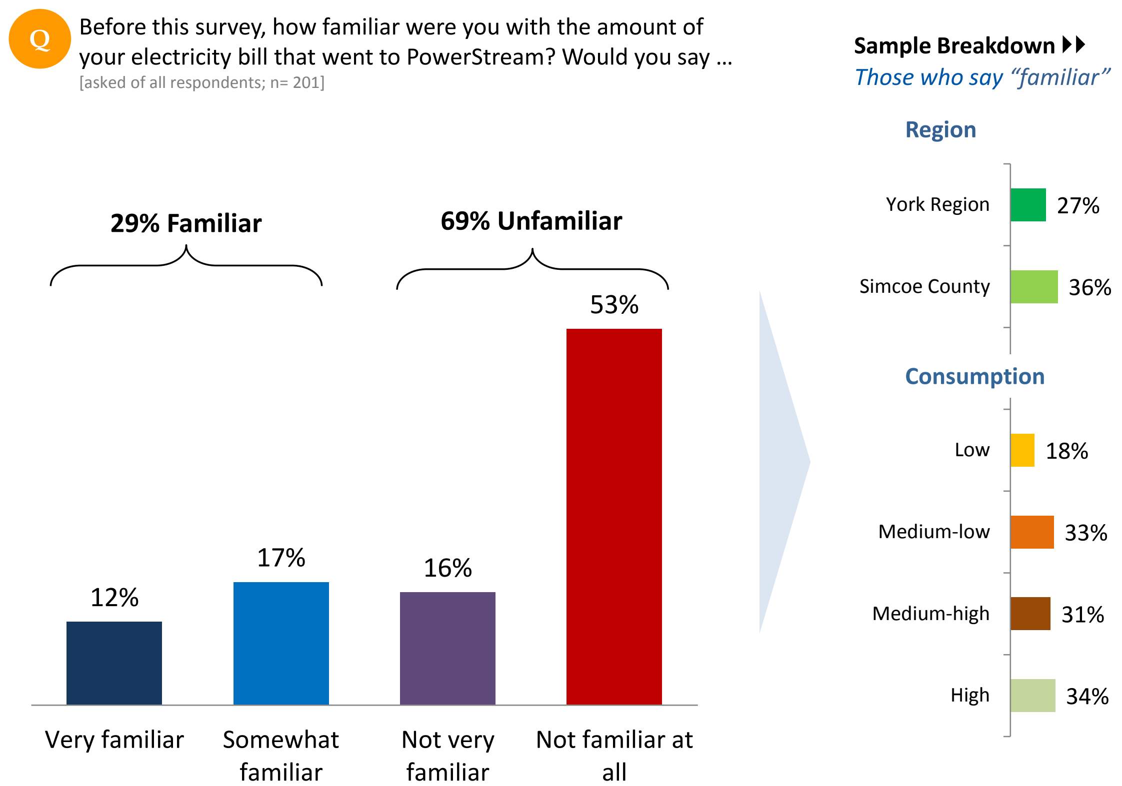
Figure 2.0 RS: Familiarity with Share of Bill Going to PowerStream



The details of billing are fuzzy to Residential consumers: just a third (33%) say they are familiar with the amount of their electricity bill that went to PowerStream. Nearly half (45%) say they are "not familiar at all"

- "High consumption" respondents (37%) are a bit more familiar with the breakdown of their bills than "Low consumption" ones (29%).

Figure 2.1 GS: Familiarity with Share of Bill Going to PowerStream



Note: 'Don't know/refused' (3%) not shown

Just three-in-ten (29%) General Service customers are familiar with the amount of their bill owed to PowerStream. More than half (53%) say they are "not familiar at all".

- Again, "High consumption" General Service customers (34%) are more familiar than "Low consumption" ones (18%).

System Reliability

This next section analyzes feedback on power service interruptions in the last 12 months, due to either extreme weather or normal conditions, as well as customer satisfaction with PowerStream's responses to these outages. Then customers were asked to describe in the open-ends specifically how PowerStream could improve its service during these two types of interruptions and also.

System Reliability Summary

Almost half of customers experienced outage during extreme weather, most are satisfied with PowerStream's response

- This past year, almost half of both Residential (45%) and General Service (44%) customers experienced an outage due to extreme weather. "High consumption" customers were the hardest hit (41% vs. Low: 56% "no, did not experience outage").
- That being said, customers are quite satisfied with PowerStream's response. Nearly three-quarters (73%) of Residential and two-thirds (66%) of General Service say they are satisfied with how PowerStream handled the extreme weather service issues.
- When asked in the open-ended question to list something PowerStream could do to improve its services during extreme weather outages, a plurality of both Residential and General Service customers said they did not see anything else PowerStream could do to improve service (49% Residential, 30% GS).

Again, about half experienced an outage during normal weather, high levels of satisfaction with PowerStream response

- In the last year, not including extreme weather, almost half (47%) of Residential and four-in-ten (39%) GS customers have experienced an outage.
- A quarter (24%) of Residential customers have experienced one or two outages and also about a quarter (23%) have experienced three or more outages.
- Again, a quarter (25%) of GS customers have experienced one or two outages and roughly the same number (23%) have experienced three or more outages.
- A strong majority (86%) of Residential and GS customers (81%) are satisfied with PowerStream's response to these outages.

Customers want "better communication" and "improved response time" during outages

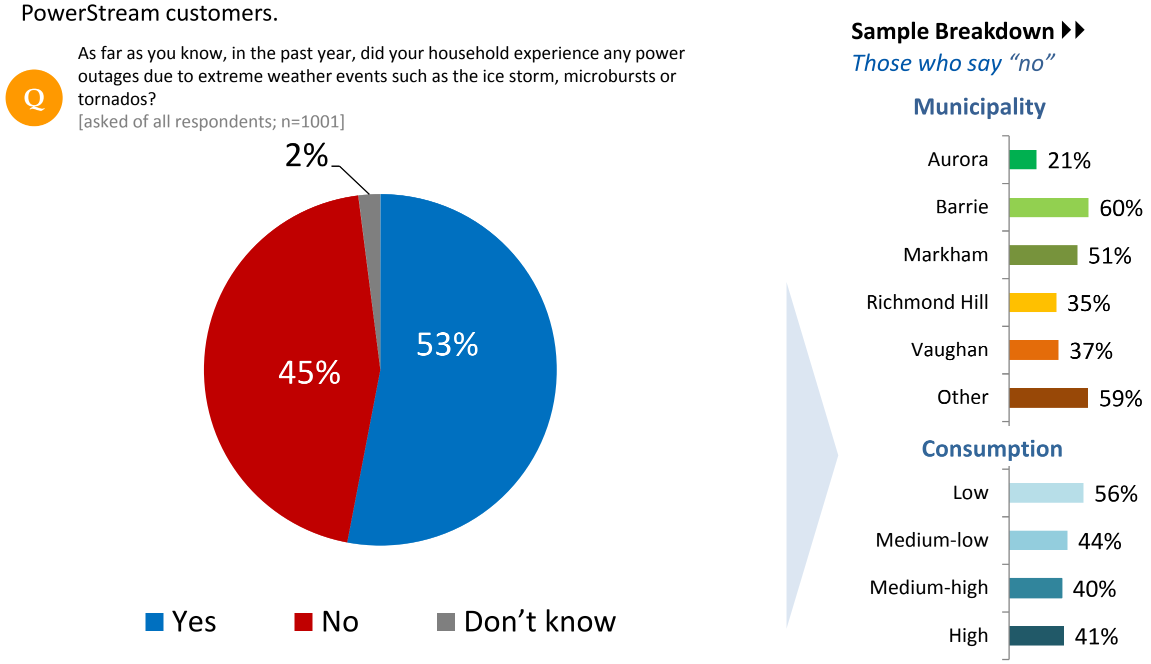
- The two leading improvements during outages mentioned by PowerStream Residential customers are "better communication" (13%) and "improved response and recovery" (8%). Other specific mentions include "reduced outages" (4%), "reduced short outages" (2%) and "reduce rates" (1%).
- General Service customers also bring up "improved communication" and "improved recovery time" as their top two concerns. There is some uncertainty among GS customers: three-in-ten (31%) don't know how to improve PowerStream's response to outages.

Customers divided on whether to spend to maintain current number of outages or spend more to reduce the number

- Four-in-ten (40%) Residential customers say PowerStream should “spend what is needed to maintain the current level of outage”. Roughly a third (32%) say PowerStream should “spend what is needed to reduce the current length of time customers are without power.” Only 13% say PowerStream should “accept longer time without power in order to help minimize customer costs from rising”.
- General Service customers are also evenly divided on how PowerStream should approach the number of outages. Nearly four-in-ten (38%) say PowerStream should spend to maintain the current levels while a third (34%) say that it should spend to reduce the number. Again just 14% say they would accept more outages to keep costs from rising.
- Additional knowledge, that the average PowerStream customer loses power “for about 100 minutes per year”, does not change the results much for either Residential or GS customers. Still a large minority (43%) of Residential and GS (38%) say “spend to maintain”. Nearly the same amount say “spend to reduce” (31% Residential and GS).

Figure 3.0 RS: Extreme Weather Outages

In the past year or so, PowerStream customers experienced unusually extreme weather – *microburst and tornados this past summer* and an *ice storm in December 2013*. These major weather events caused power outages for many PowerStream customers.



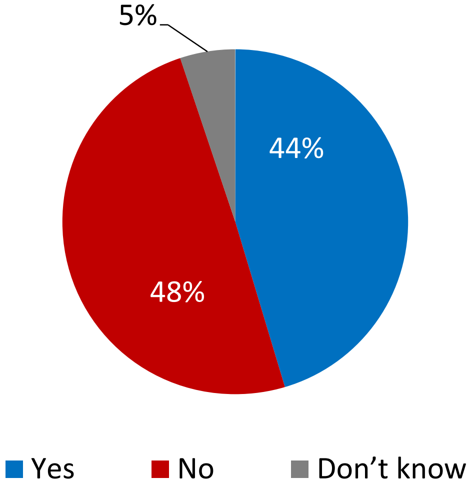
In the past year, nearly half (45%) of Residential PowerStream customers experienced an outage during an extreme weather event.

- "High consumption" Residential customers are the most likely to have experienced an outage (41% vs. Low: 56% "no").
- Older Residential customers are more likely than younger ones to have experienced an outage due to extreme weather (35+: 42-44% "no"; 18-34: 56% "no).

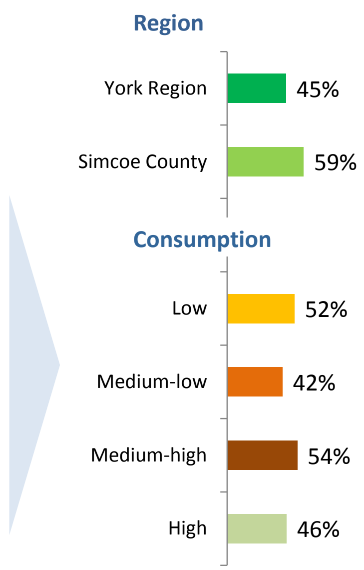
Figure 3.1 GS: Extreme Weather Outages

In the past year or so, PowerStream customers experienced unusually extreme weather – *microburst and tornados this past summer* and an *ice storm in December 2013*. These major weather events caused power outages for many PowerStream customers.

Q As far as you know, in the past year, did your organization experience any power outages due to extreme weather events such as the ice storm, microbursts or tornados?
[asked of all respondents; n=201]



Sample Breakdown ▸▸
Those who say "no"

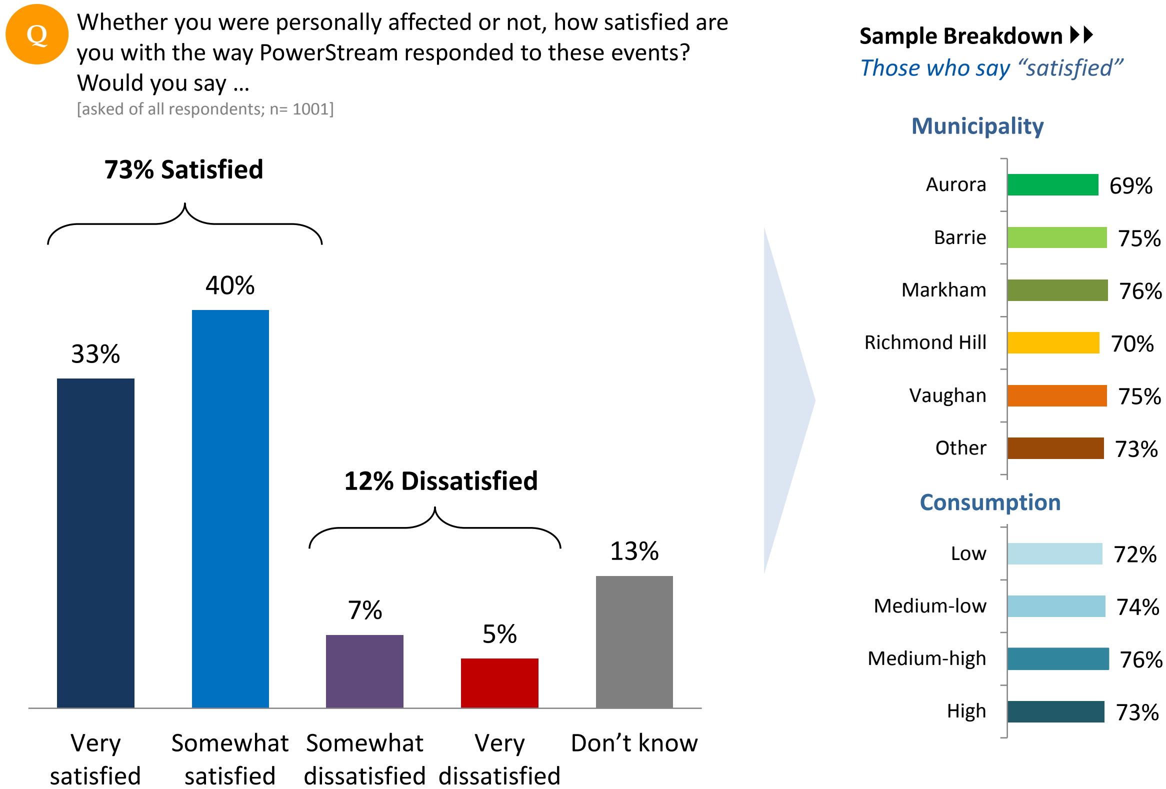


Note: 'Refused' (2%) not shown

Nearly half (44%) of General Service customers, over the past year, experienced an outage.

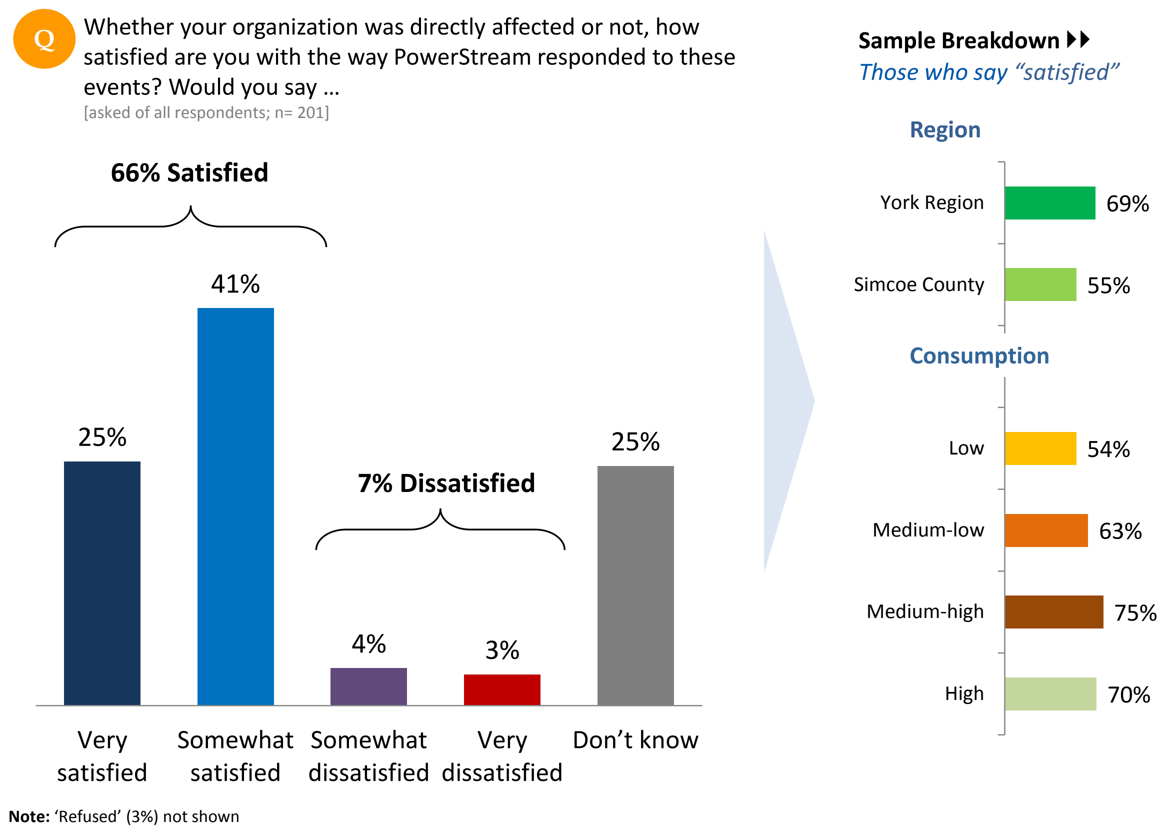
- General Service customers in York Region are more likely to have experienced an outage than those in Simcoe County (59% vs. 45%: "no").

Figure 3.2 RS: Satisfaction with Response to Events



Nearly three-quarters (73%) of Residential customers are satisfied with PowerStream's response to extreme weather events. Just 12% say they are dissatisfied with the service.

Figure 3.3 GS: Satisfaction with Response to Events

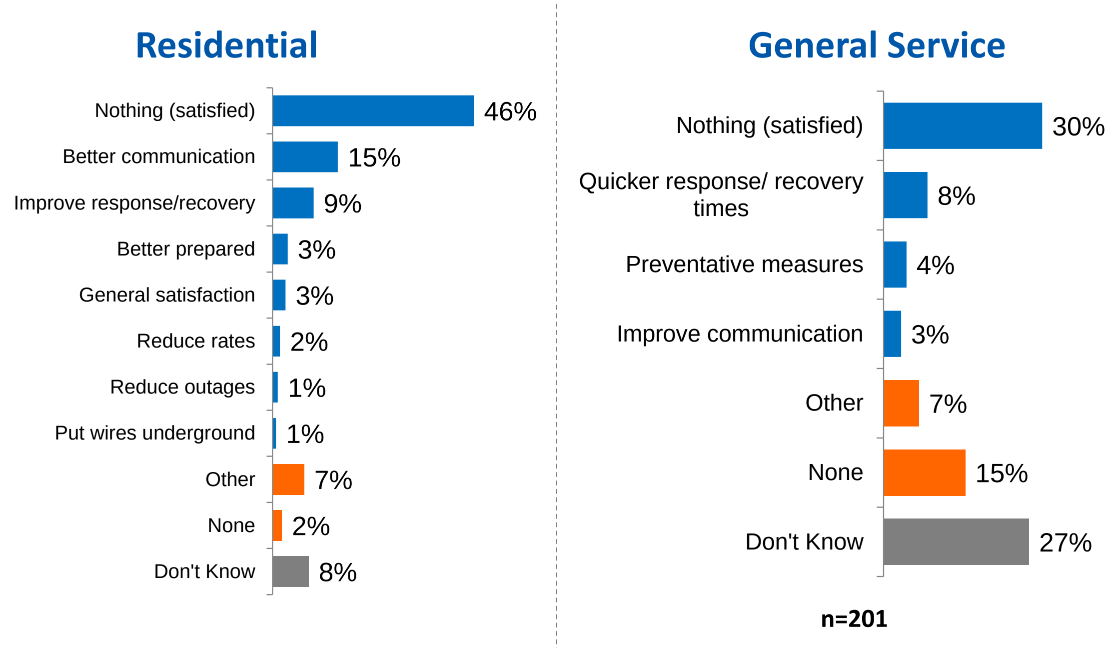


General Service customers are a bit less positive, but still two-thirds (66%) say they are "satisfied" overall with how PowerStream responded.

- "High consumption" General Service customers are more likely than "Low consumption" ones to feel satisfied with PowerStream's response (55% vs. 36%).

Figure 3.4 RS/GS: How to improve service during Extreme Weather

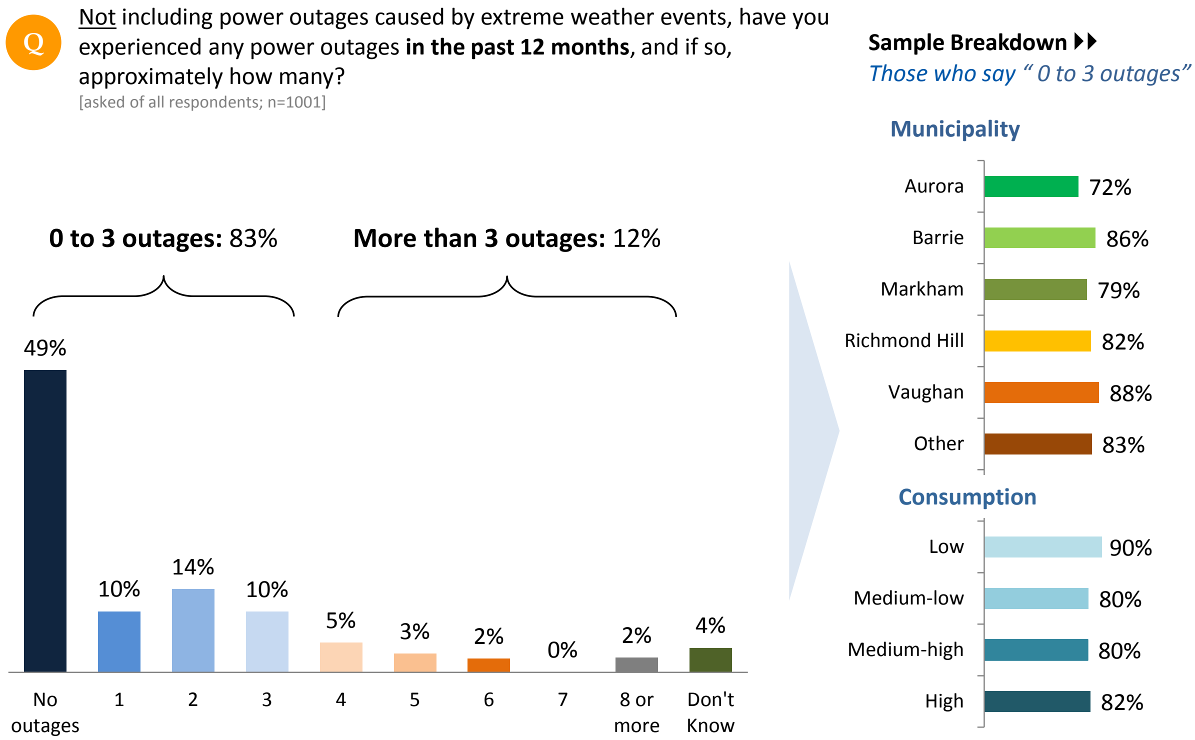
Q Is there is anything in particular that PowerStream can do to improve its service to your organization during these extreme weather events?



Generally, both Residential and General Service customers appear satisfied with PowerStream's response to extreme weather events. Half (49%, includes "general satisfaction") of Residential and three-in-ten (30%) General Service say that there is nothing the organization could do to improve its service during this time.

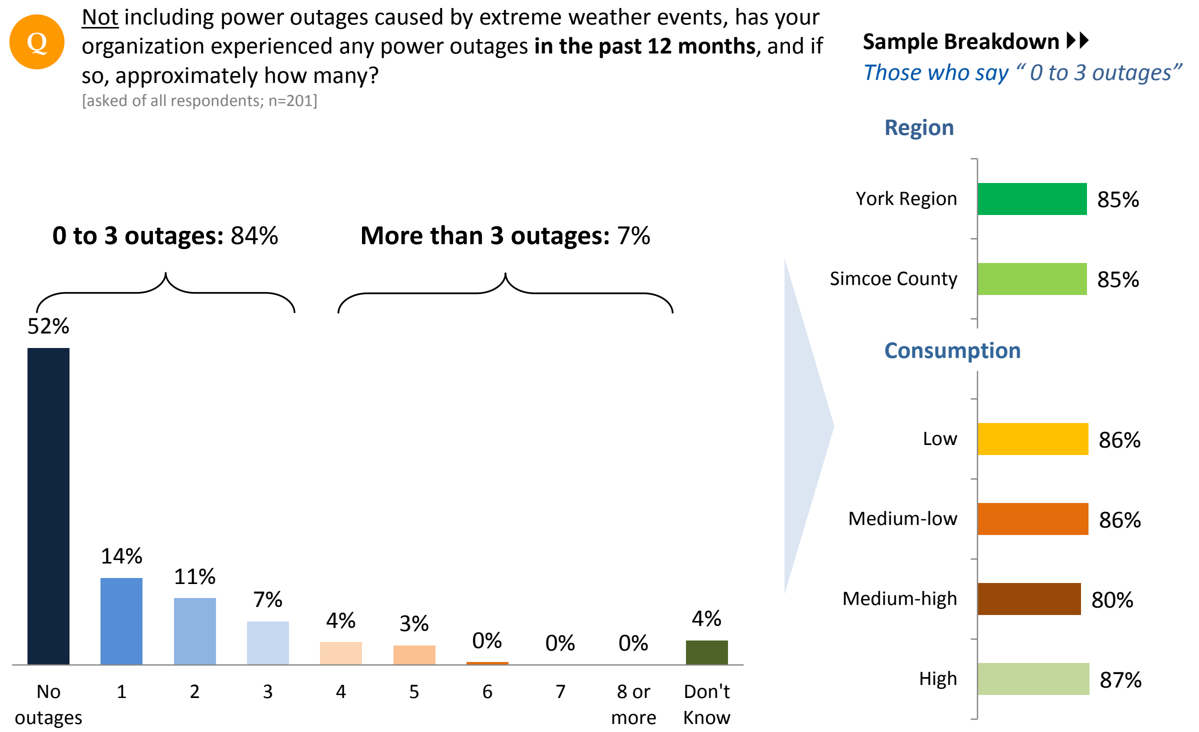
Criticism focused more on "better communication" (15% Residential, 3% GS) and "improved response and recovery times" (9% Residential, 8% GS). Other specific ways to improve include "better preparation and prevention measures" (3% Residential, 4% GS), "reduce rates" (2%), "reduce outages" (1%) and "move wires underground" (1%).

Figure 3.5 RS: Number of Outages during Extreme Weather Events



In the past twelve months, excluding extreme weather, nearly half (47%) of Residential customers have experienced an outage. About a quarter of Residential customers have experienced one or two outages (24%), and nearly the same amount (23%) have experienced three or more outages.

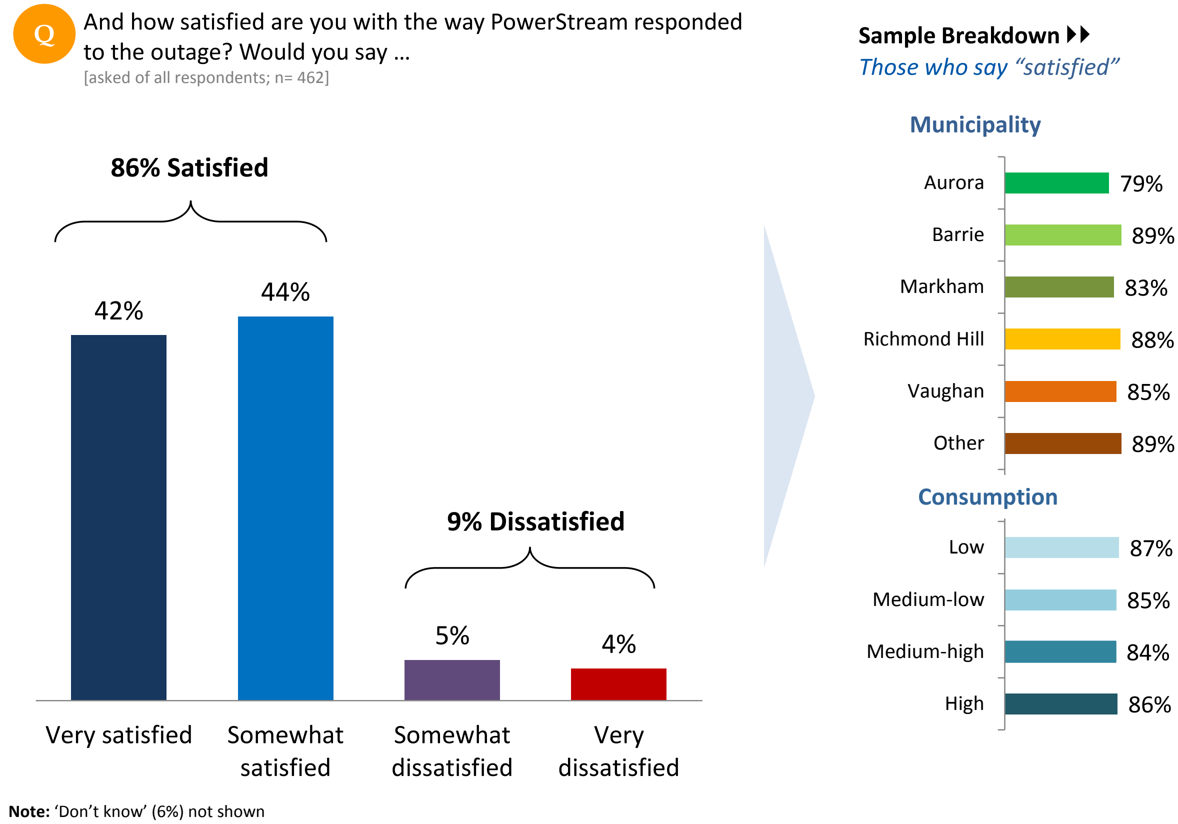
Figure 3.6 GS: Number of Outages during Extreme Weather Events



Note:'Refused' (3%) not shown

As for General Service customers, nearly four-in-ten (39%) have experienced an outage at their organization in the past year. One-in-four (25%) experienced one or two outages and 14% experienced three or more outages. A slight majority (52%) of General Service customers experienced no outages during normal weather.

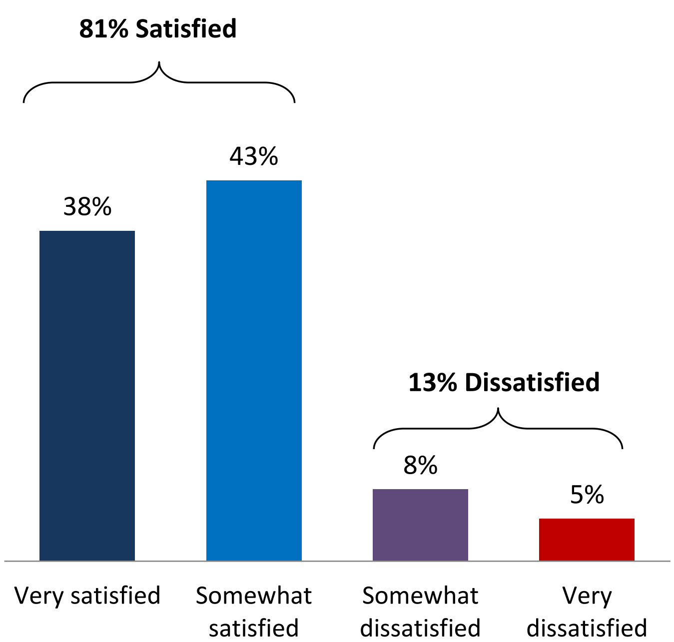
Figure 3.7 RS: Satisfaction with PowerStream Response



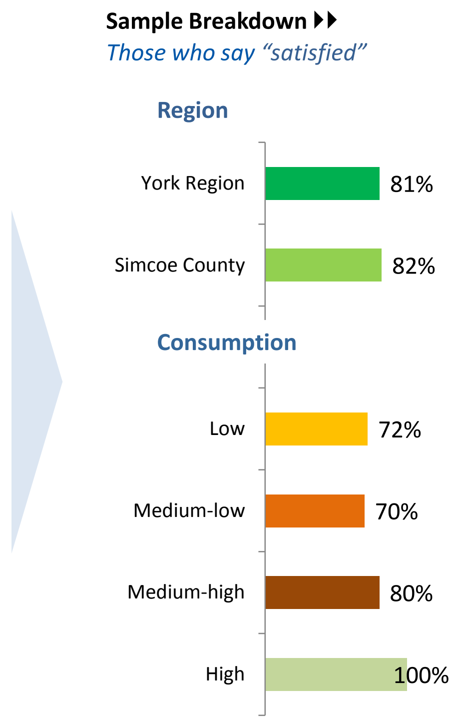
A strong majority (86%) of Residential customers are satisfied with PowerStream's response to the outages. Just 9% say they are dissatisfied.

Figure 3.8 GS: Satisfaction with PowerStream Response

Q And how satisfied is your organization with the way PowerStream responded to the outage? Would you say …
[asked of all respondents who experienced an outage; n= 81]



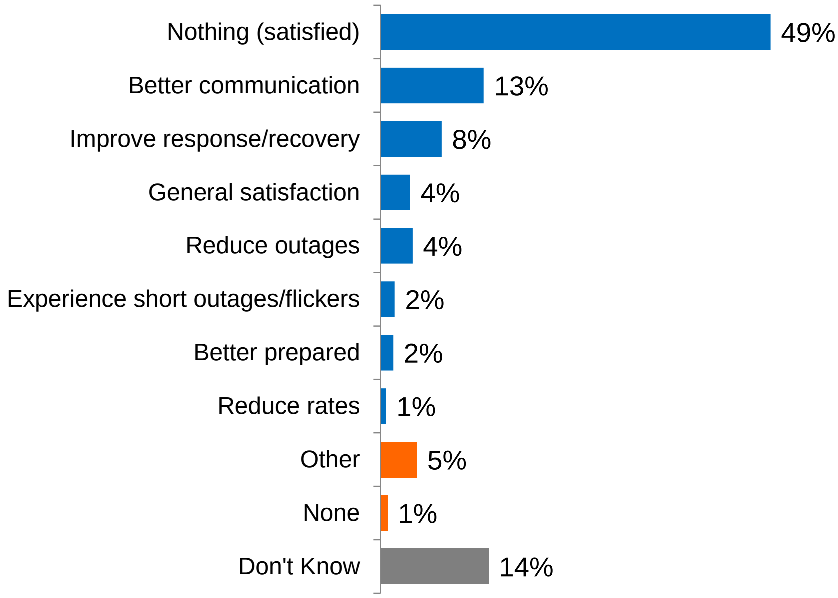
Note: 'Don't know' (6%) not shown



As for the 81 General Service customers who responded, eight-in-ten (81%) say they are satisfied with the way PowerStream handled the outage.

Figure 3.9 RS: Open-ended on Improvement to Service

Q Is there is anything in particular that PowerStream could do to improve its service to you during your most recent power outages?

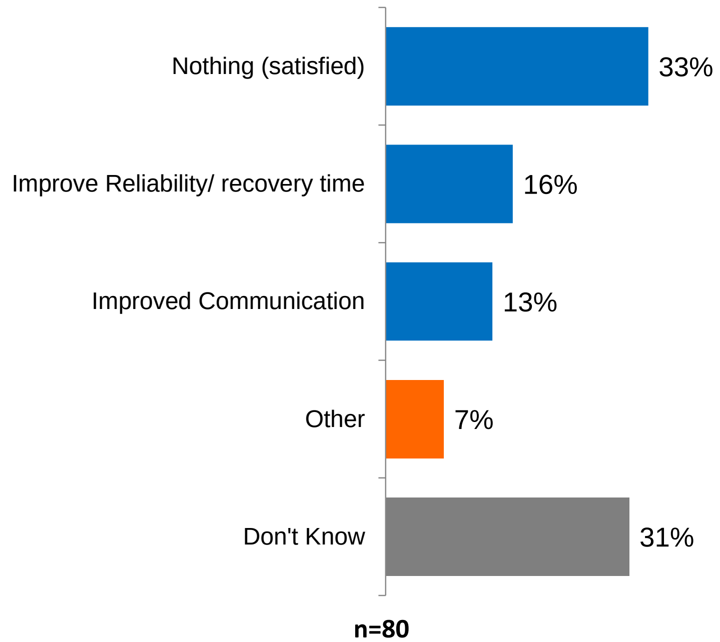


n=460

When asked an open-ended question on how PowerStream could improve its service during outages, half (49%) of Residential customers say there are no improvements needed- they are satisfied with the response. The two leading improvements mentioned by respondents are “better communication” (13%) and “improved response and recovery” (8%). Other specific mentions include “reduced outages” (4%), “reduced short outages” (2%) and “reduce rates” (1%).

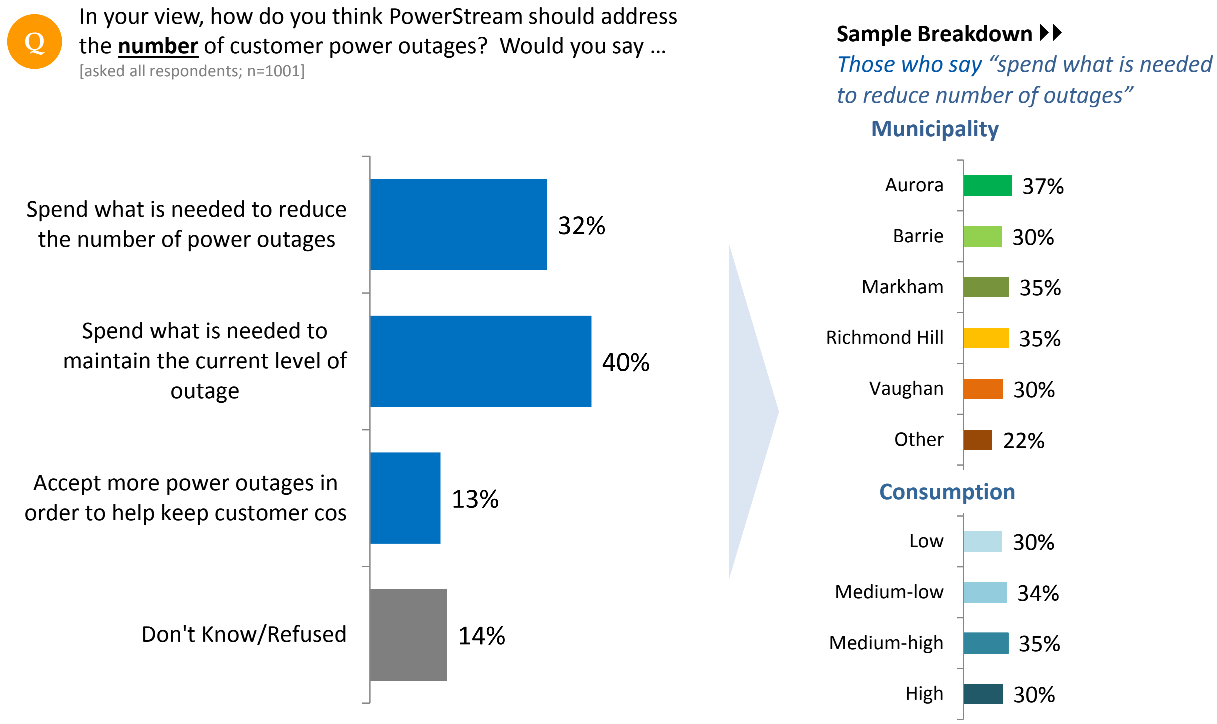
Figure 3.10 GS: Open-ended on Improvement to Service

Q Is there is anything in particular that PowerStream could do to improve its service to your organization during your most recent power outages?



Turning to the General Service customers, one-in-three (33%) in the open-ended question said they were satisfied and nothing could improve PowerStream service. Again, concerns about communication (13%) and recovery time (16%) top the list. Three-in-ten (31%) are unsure of how to improve PowerStream's response to outages.

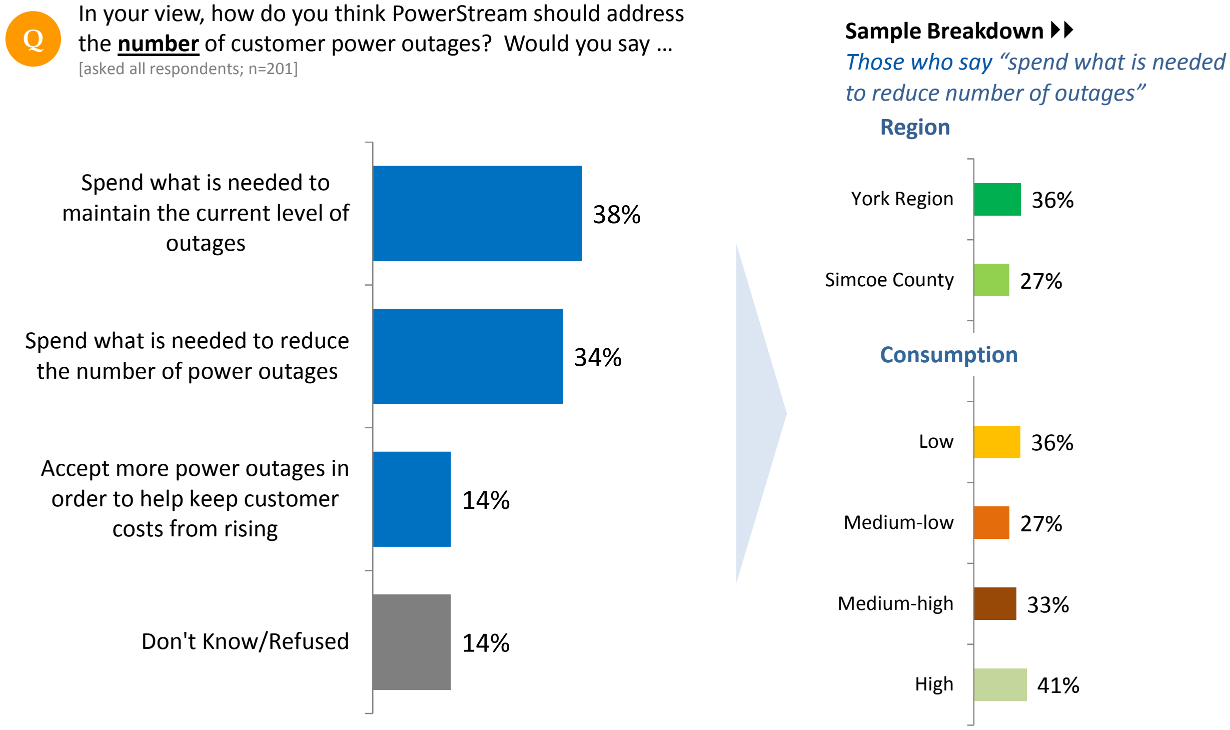
Figure 3.11 RS: Number of Power Outages



When offered a choice between spending what is needed to maintaining the number of outages vs. spending more to reduce them, customers prefer "maintain" by a hair. Four-in-ten (40%) Residential customers say PowerStream should "spend what is needed to maintain the current level of outage". Roughly a third (32%) say PowerStream should "spend what is needed to reduce the current length of time customers are without power" and just 13% say PowerStream should "accept longer time without power in order to help minimize customer costs from rising".

- Aurora (37%) is a bit more likely to say "spend what is needed" than the rest of the municipalities (22-35%).

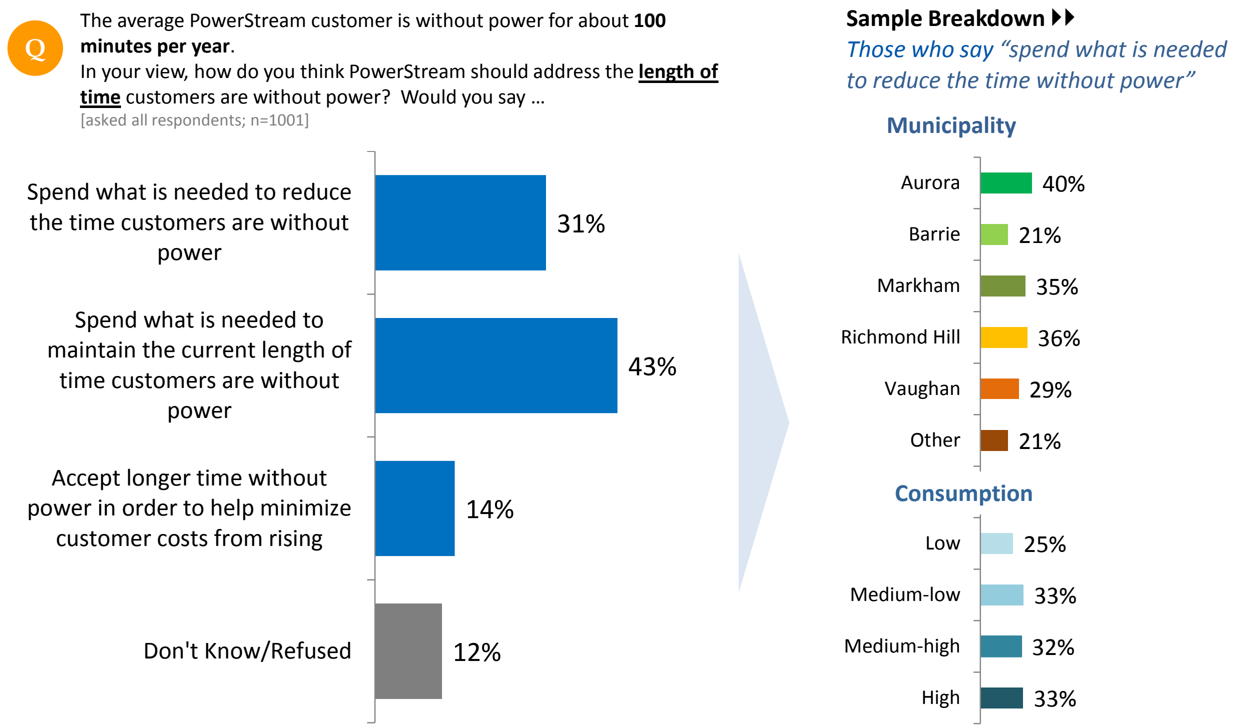
Figure 3.12 GS: Number of Power Outages



General Service customers are about evenly divided regarding *number* of outages. Nearly four-in-ten (38%) say PowerStream should spend to maintain the current levels while a third (34%) say that it should spend to reduce the number. Only 14% say they would accept more outages to keep costs from rising.

- York Region is slightly more likely than Simcoe County to say PowerStream should spend what is needed to reduce the number of outages (36% vs. 27% "spend what is needed").

Figure 3.13 RS: Aided Number of Power Outages

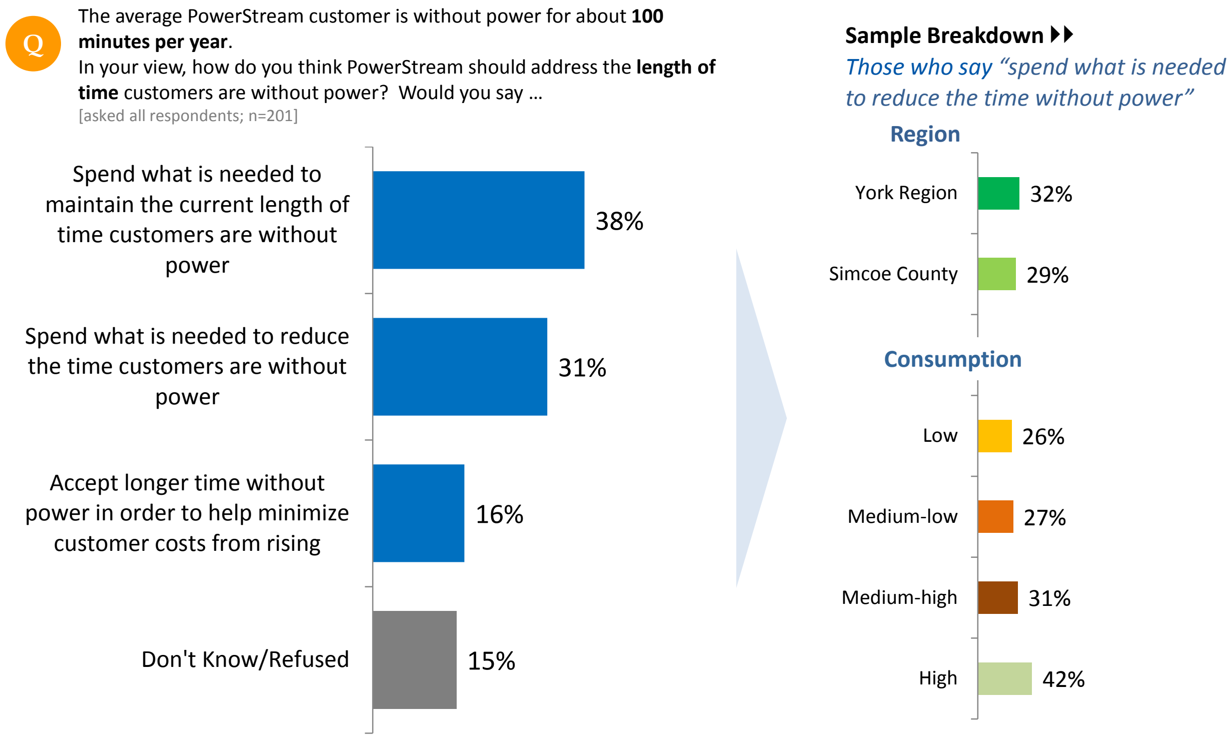


The follow-up question explains to customers that the average PowerStream customer loses power "for about 100 minutes per year" and, with this new piece of information, asks them to answer the previous question again.

This new piece of information does not move the dial. Roughly the same breakdown occurs as the previous question: around three-in-ten (31%) say PowerStream should spend to reduce time and a large minority (43%) say to spend what is needed to maintain the length of outages. Again, 14% say they would accept longer times without power if it prevented rising costs.

- High consumption (33%) customers are a bit more likely to prefer "spending to reduce the number of outages" than low consumption ones (25%)

Figure 3.14 GS: Aided Number of Power Outages



The General Service customers do not, with this new piece of information, change their opinion much. A plurality prefer "spending to maintain" (38%) over "spending to reduce time" (31%) and still the distant third is to "accept longer times to minimize rising costs" (16%).

- "High consumption" (42%) customers are more likely to prefer "spending to reduce the number of outages" than "Low consumption" customers (26%)

System Challenges & Priorities

The next section outlines challenges to the system -aging infrastructure, outdated technology and older buildings, equipment and IT systems- and gages customer preference on infrastructure investment.

System Challenges & Priorities Summary

Generally, both RS and GS customers support increased investment in aging infrastructure despite additional cost

- A majority (54%) of both Residential and General Service customers choose to maintain the system despite an increase in cost for them personally.
- Three-in-ten (30%) Residential and a third (32%) of General Service customers prefer a reduced investment strategy to minimize any impact on their bill.

When asked to put a specific dollar amount on it to deal with unusual weather though, roughly half would not pay a dime more

- A strong minority, nearly half (46%) of Residential customers say they would not pay anything more to strengthen the system to deal with unusual weather. A quarter (24%) would pay less than $5 and 15% would pay between $5 and $10 more. Very few people, just 11% would pay more than $10 on their monthly bill to prevent outages in unusual weather.
- As for General Service customers, six-in-ten (59%) say they would not pay any more on their monthly bill when asked the same question. Those that would pay are willing to pay slightly more than the Residential customers: roughly a quarter (26%) would pay less than $10 and 15% would pay more than $10 a month to help prevent outages during unusual weather.

Both "new technology" and "buildings, equipment and IT systems" should be an investment priority

- Most Residential and GS customers think investment in new technology should be a priority for PowerStream. Nearly six-in-ten (58%) Residential and just over six-in-ten (61%) GS feel that investment in new technology should be a priority for PowerStream, while just a third of Residential (33%) and a quarter (24%) of GS customers feel that investment in new technology is a luxury, not a necessity.
- A majority of both Residential and GS customers also think PowerStream should invest in "buildings, equipment and IT systems". Two-thirds (64%) of Residential and over half (51%) OF GS customers prefer to manage the system efficiently with the right equipment and tools despite the cost, while around three-in-ten (29%) Residential and nearly four-in-ten (37%) GS customers think PowerStream should make do with its current buildings and equipment.

Preamble for System Challenges & Priorities Section

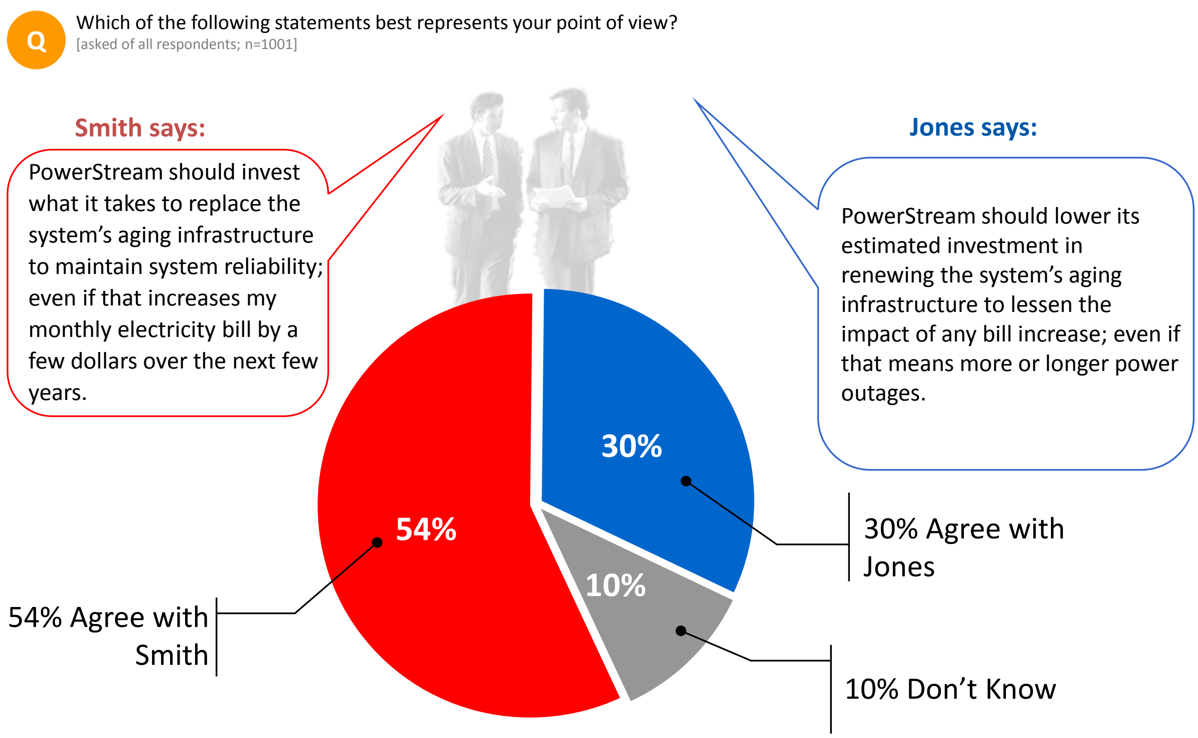
The following pre-amble was read to respondents before they were asked the first question on system challenges and priorities:

"As significant amount of PowerStream's electrical infrastructure was built in the 1960s and 70s, and is still in-service today. While PowerStream believes it has done its best to prolong the life of these assets, today many of these assets are now approaching the end of their useful life and are beginning to pose a threat to system reliability.

As part of its investment plan, PowerStream is proposing a significant infrastructure renewal program. The estimated cost of this system renewal program is $258 million over the next 5 years.

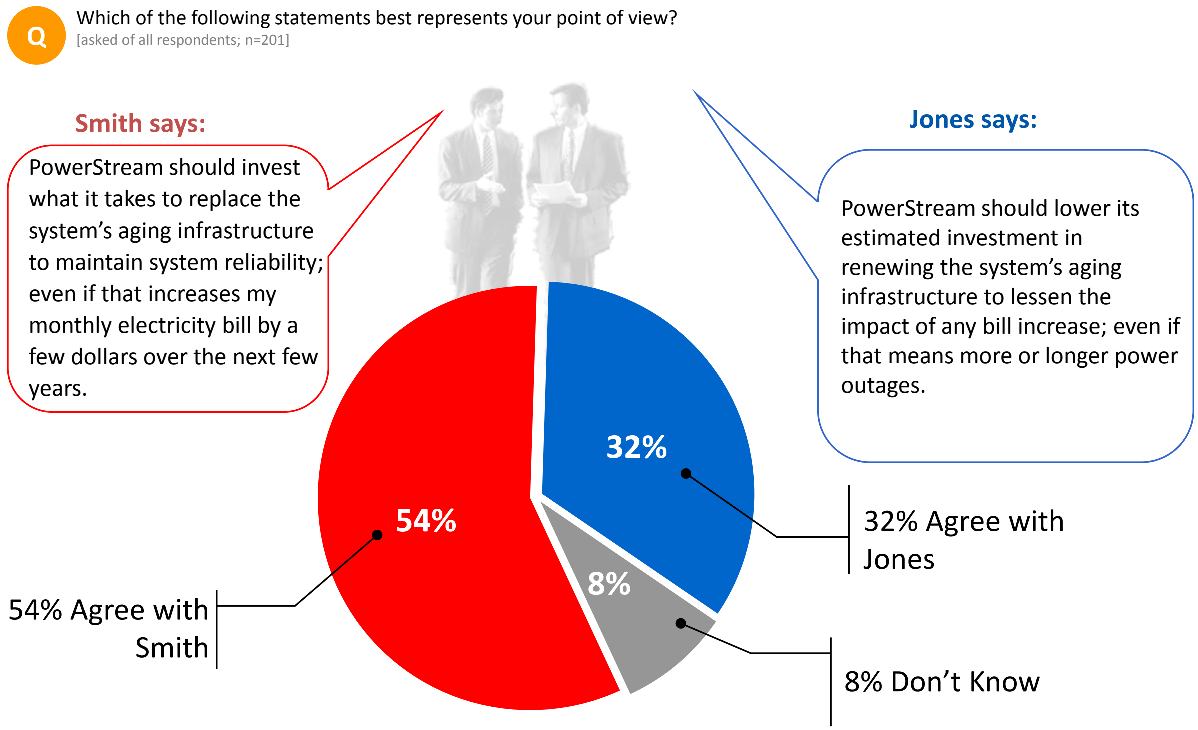
Although this plan will allow PowerStream to make, what independent studies suggest are, the necessary investments to maintain system reliability, it will have an impact on customer bills."

Figure 4.0 RS: Investment in Aging Infrastructure



Note: Statements randomized

Figure 4.1 GS: Investment in Aging Infrastructure



Note: Statements randomized (Refused (6%) not shown)

Customers were asked to choose between two opposing statements on infrastructure: either to "invest what it takes to replace aging infrastructure and maintain reliability even if it means a bill increase" or "lower its investment in aging infrastructure to lessen the impact of a bill increase".

A majority (54%) of both Residential and General Service customers choose to maintain the system despite an increase in cost for them personally. Three-in-ten (30%) Residential and a third (32%) of General Service customers prefer a reduced investment strategy to minimize any impact on their bill.

Residential

- Male residential customers (58%) are a bit more likely than women (50%) to support investment in aging infrastructure despite the cost.

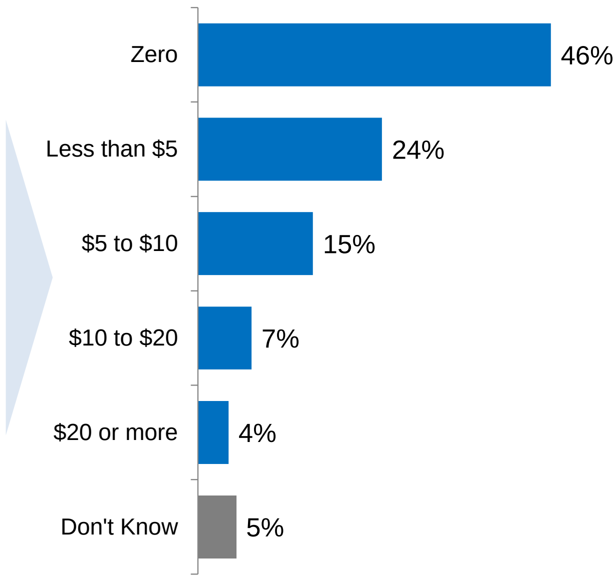
General Service

- Among the General Service customers, those in the York Region (56%) are more likely to support aging infrastructure investment than organizations in Simcoe County (46%)

Figure 4.2 RS: Open-ended on Extreme Weather Infrastructure Investment

Q The investments discussed earlier are focused on day-to-day reliability. There are additional investments that could help "harden" the electrical system and speed up power restoration during **rare weather events that have an unusually large impact on the system** – *such as tornados or ice storms*. There is no practical limit to potential ways of making the system more resilient in a major event, it is fundamentally a question of money.

Currently, the average residential customer pays $27 a month to PowerStream to operate and maintain the local distribution system. How much are you willing to pay each month for investments that would help the system better withstand major events such as extreme weather?



n=1,001

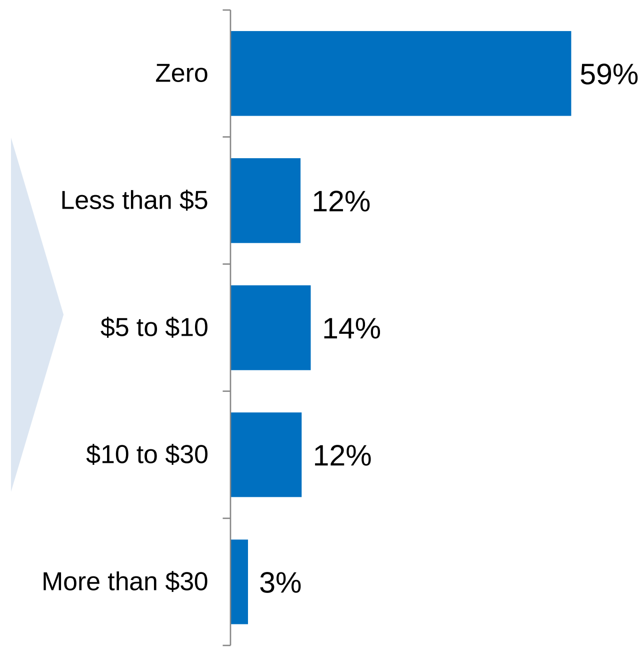
A brief pre-amble to the next question outlines the need for additional infrastructure to deal with unusual weather issues such as ice storms and also reminds them how much they pay PowerStream on their monthly bill. With all this in mind, customers are asked how much more they are willing to pay towards infrastructure to deal with major weather events.

A strong minority, nearly half (46%) say they would not pay one cent more to strengthen the system to deal with unusual weather. A quarter (24%) would pay less than $5 and 15% would pay between $5 and $10 more. Very few people, just 11% would pay more than $10 on their monthly bill to prevent outages in unusual weather.

Figure 4.3 GS: Open-ended on Extreme Weather Infrastructure Investment

Q The investments discussed earlier are focused on day-to-day reliability. There are additional investments that could help “harden” the electrical system and speed up power restoration during **rare weather events that have an unusually large impact on the system** – *such as tornados or ice storms*. There is no practical limit to potential ways of making the system more resilient in a major event, it is fundamentally a question of money.

Currently, the average General Service customers pays $61 a month to PowerStream to operate and maintain the local distribution system. How much more are you willing to pay each month for investments that would help the system better withstand major events such as extreme weather?



n=201

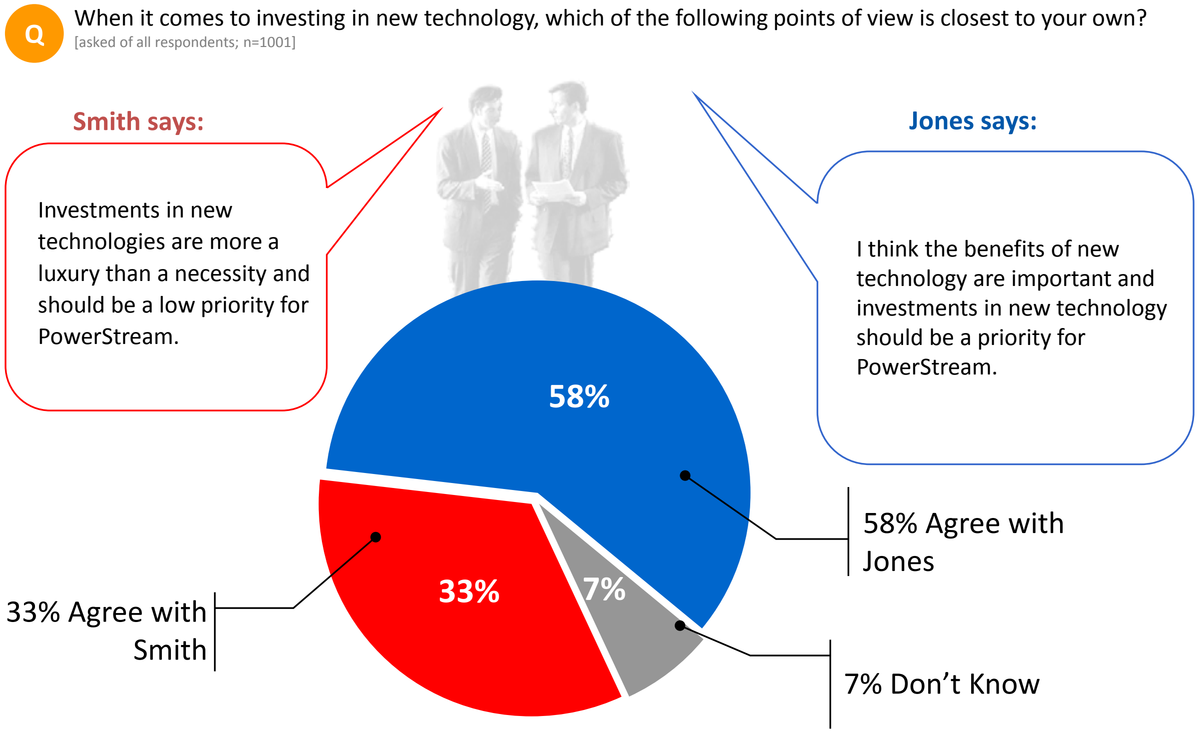
As for General Service customers, six-in-ten (59%) say they would not pay any more on their monthly bill when asked the same question. Those that would pay are willing to pay slightly more than the Residential customers: roughly a quarter (26%) would pay less than $10 and 15% would pay more than $10 a month to help prevent outages during unusual weather.

Preamble for Investment in Equipment and Tools

On the next question regarding investment in equipment, tools and IT systems, customers were read the following short pre-amble:

“PowerStream is not just the local electricity distribution system itself, but a company that operates the system. As a company, PowerStream needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the electrical system and customer information.

Figure 4.4 RS: Investment in New Technology



Note: Statements randomized

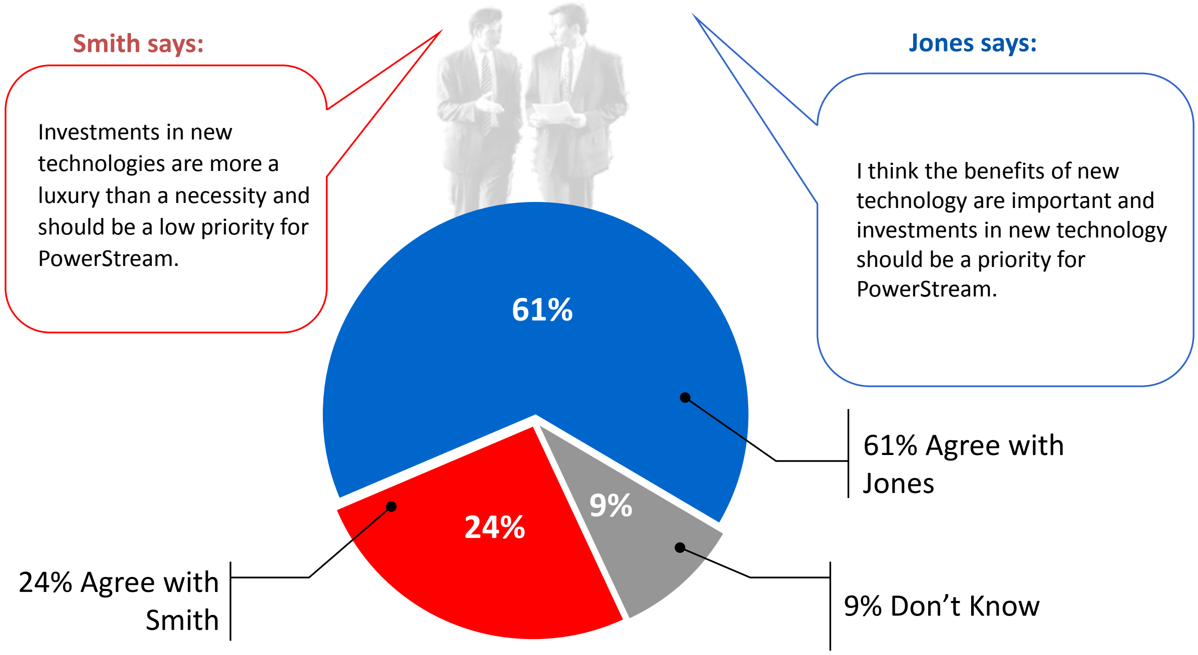
Most customers think investment in new technology should be a priority for PowerStream.

When asked to choose between two competing viewpoints on "new technology investment", nearly six-in-ten (58%) Residential customers agree that "the benefits of new technology are important and investment in new technology should be a priority for PowerStream." One-third (33%) of customers agree with the contrary view, that "investments in new technologies are more a luxury than a necessity and should be a low priority for PowerStream."

- Aurora (63%) is a bit more likely to think investment in new technology should be a priority than other municipalities (56-60%).

Figure 4.5 GS: Investment in New Technology

Q When it comes to investing in new technology, which of the following points of view is closest to your own?
[asked of all respondents; n=201]



Note: Statements randomized (Refused (7%) not shown)

General Service customers feel roughly the same on new technology investment: six-in-ten (61%) say that new technology should be a priority compared with a quarter (24%) who feel it is more of "a luxury than a necessity".

Preamble for Investment in New Technology

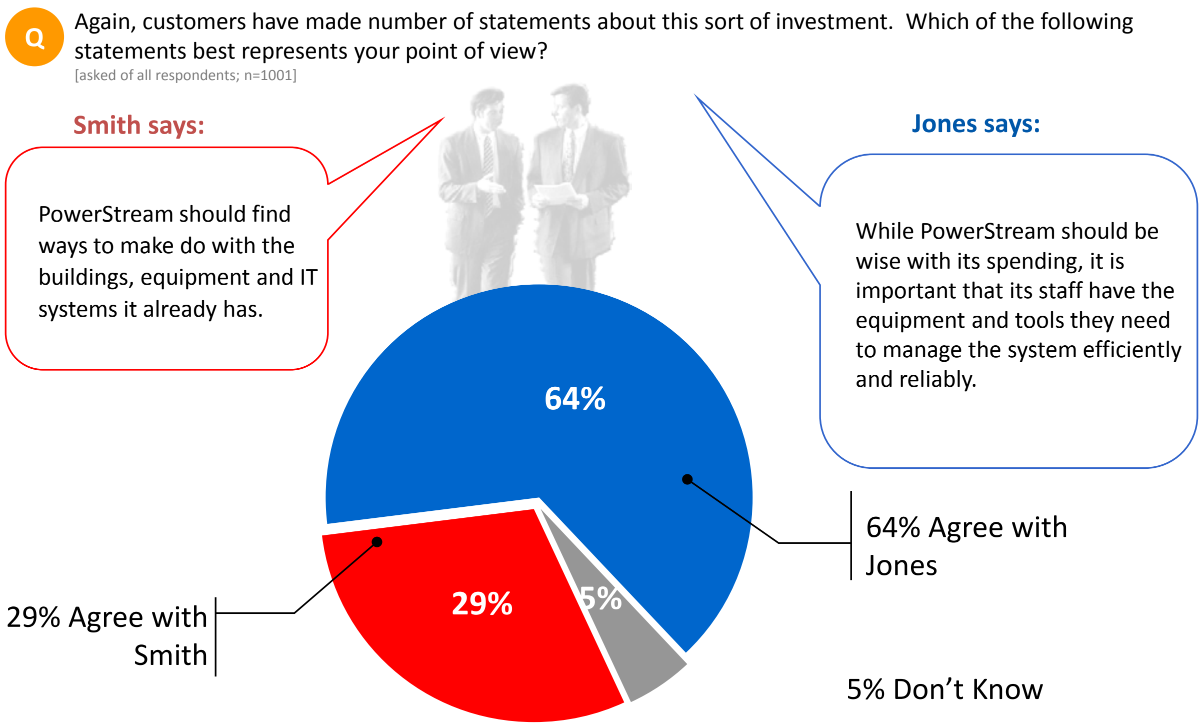
Before asking customers for their opinion on investment in new technology, callers read respondents this brief pre-amble:

"New technology can have many impacts on electricity distribution systems:

- *New computer systems and GPS systems provide pinpointed information about outages to both system controllers and customer in real time.*
- *Remote monitors and switches allow power to be restored to many customers much more quickly than in the past.*

While there are benefits from new technology, there are also costs."

Figure 4.6 RS: Investment in New Buildings, Equipment and IT



Note: Statements randomized

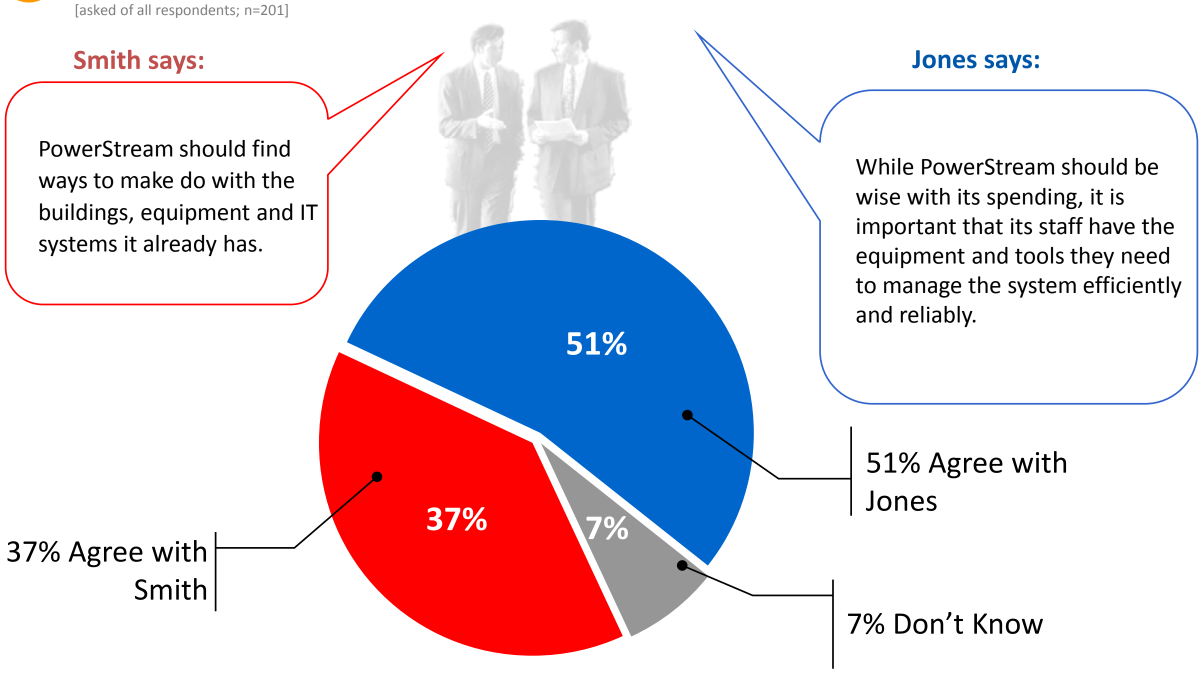
The final "Smith and Jones" question compared viewpoints on investment in buildings, equipment and IT: on the one hand, customers could agree that "PowerStream should find ways to make do with the buildings, equipment and IT systems it already has"; or instead, they could choose "while PowerStream should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably."

Two-thirds (64%) of customers agree with the latter, that it is important to have the right equipment and tools despite the cost. Less than three-in-ten (29%) say that PowerStream should make do with its current buildings, equipment and IT systems.

- "High consumption" Residential customers (71%) are more likely than "Low consumption" (61%) to feel PowerStream should spend as it needs on equipment and tools to manage the system efficiently.

Figure 4.7 GS: Investment in New Buildings, Equipment and IT

Q Again, customers have made number of statements about this sort of investment. Which of the following statements best represents your point of view?
[asked of all respondents; n=201]



Note: Statements randomized (Refused (5%) not shown)

General Service customers also favor investment in new equipment and tools. Just over half (51%) prefer the option to manage the system efficiently with the right equipment and tools despite cost while nearly four-in-ten (37%) think that PowerStream should make do with its current building, equipment and IT systems.

Assessment of Plan

In this last section, customers were given additional context on the five-year plan and asked for permission on a possible rate increase. A follow-up open-ended question asked customers to explain their decision to support or oppose the increase.

Assessment of Plan Summary

Residential customers give permission, General Service oppose the increase.

- A majority (63%) of PowerStream Residential customers, when given additional context on the five-year plan, permit PowerStream to increase its rates.
- Two-in-ten (21%) think “the rate increase is reasonable and support it”; more than four-in-ten (42%) say they “don’t like it, but think it’s necessary”; and a third (33%) say “the rate increase is unreasonable and oppose it”.
- General Service customers generally oppose it with a majority (54%) who say “the rate increase is unreasonable”. Just 15% say “the rate increase is reasonable and support it” and less than three-in-ten (28%) say they “don’t like it, but think the increase is necessary”.

Cost is main permission concern for both Residential and General Service.

- When Residential customers were asked an open-ended follow-up on the permission question, the leading concern was cost. Specifically, the increase was “already too high” or “they pay too much currently” (35%).
- Other reasons for not supporting the increase include “PowerStream should find efficiencies or the money from other sources” (10%), “it’s not necessary” (1%), “cost of everything is going up” (1%), “it will happen anyways” (1%) and “need more information” (1%).
- For General Service customers, the leading mention is also cost-related. More than a quarter (27%) say that “the rate increase is too much” and “they’re paying enough already”. Others think PowerStream or the government should shoulder the cost burden (11%).
- Some other reasons to oppose it mentioned include “they don’t like the rate increase or decisions made at PowerStream” (8%), “businesses can’t afford it” (5%) and “it’s a waste of money and unnecessary” (3%).

RS/GS- Preamble for Assessment of Plan Section

Before customers were asked for permission, a brief explanation of the investment plan was included in the preamble:

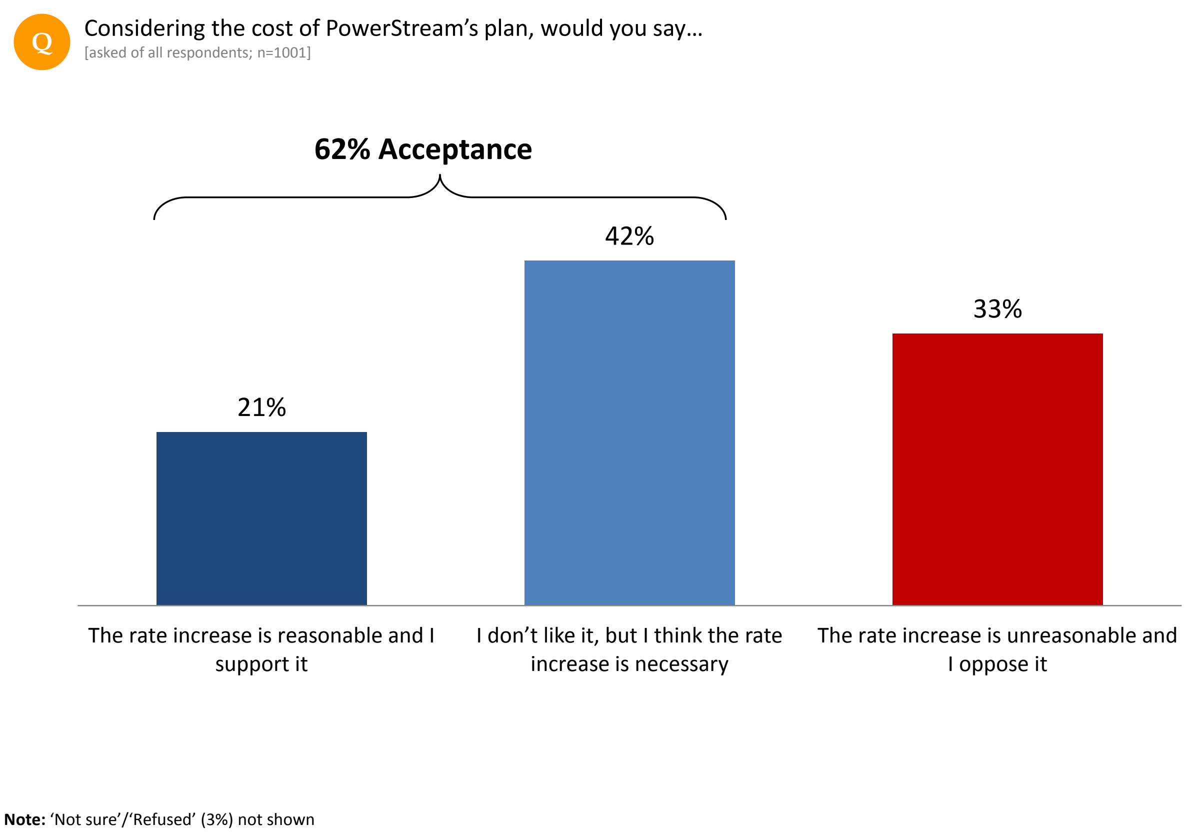
“To maintain the reliability of the local electricity system, PowerStream’s proposed 5 year plan will spend an estimated **$641 million** on new capital investments. This includes …

- **$258 million** to replace aging infrastructure;
- **$150 million** for new technologies to make the system more efficient, reliable, safe and to expand system capacity to accommodate future growth;
- **$147 million** to maintain metering and connect new customers to the electricity system;
- **$86 million** to invest in tools, computers and software systems, vehicles and facilities needed to manage the electricity system;

To fund this plan, PowerStream is proposing the **average residential customers' rate increase by $2.14 per month** on the distribution portion of their bill over the next five years. So, by 2020, the average residential household will be paying an **estimated $10.72 <u>more</u> per month** on the distribution portion of its electricity bill."

(In the General Service survey, the last two bolded phrases were replaced with "**average General Service customers' rate increase by $5.25 per month"** and "**estimated $26.24 <u>more</u> per month"**, respectively. Other than the difference in rate impact, the pre-amble is identical in both surveys).

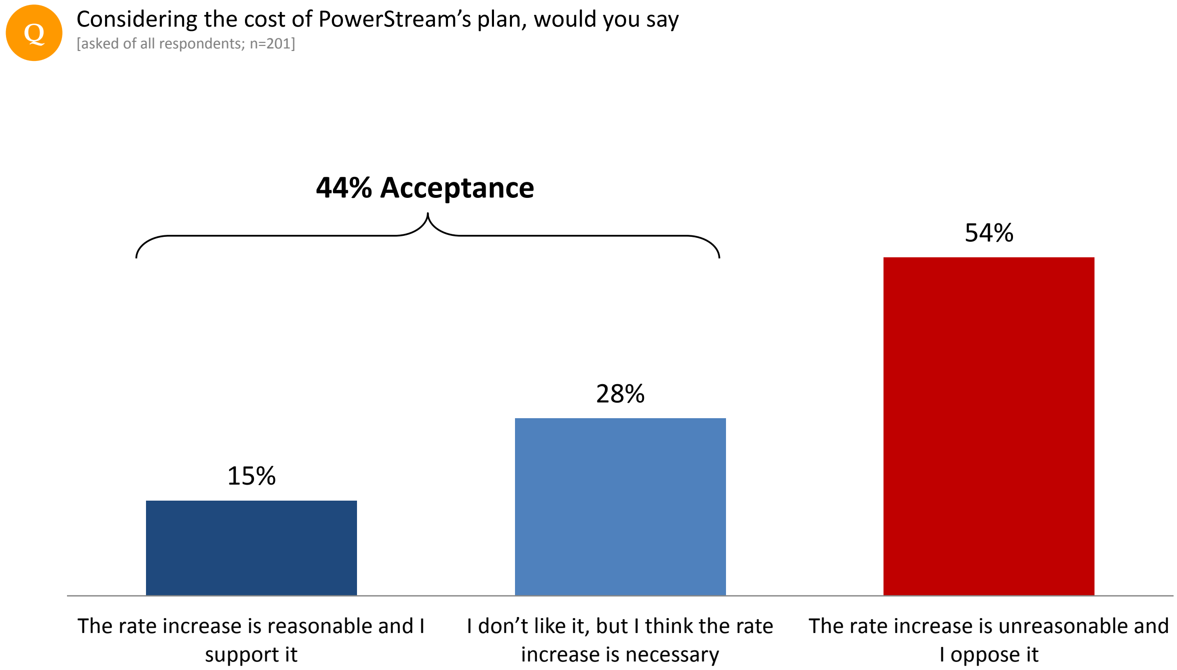
Figure 5.0 RS - Permission for Rate Increase



A majority (63%) of PowerStream Residential customers, when the breakdown of pricing is explained, permit a rate increase. Two-in-ten (21%) think "the rate increase is reasonable and support it"; more than four-in-ten (42%) say they "don't like it, but think it's necessary"; and a third (33%) say "the rate increase is unreasonable and oppose it".

- Opposition is a bit higher in Aurora (39%) and Vaughan (37%) and lowest in Richmond Hill (27%).
- Residential customers aged 18-34 are a bit more likely to support the rate increase (28% "oppose" vs. 31-38%).

Figure 5.1 GS - Permission for Rate Increase



Note: 'Not sure'/'Refused' (1%) not shown

Conversely, a majority (54%) of General Service customers *oppose* the rate increase. Just 15% say "the rate increase is reasonable and support it" and less than three-in-ten (28%) say they "don't like it, but think the increase is necessary".

Financial Strain on Level of Acceptance

It is expected that PowerStream's proposed rate increase will have a greater financial impact on some customers more than others, depending on their level of financial strain. As such, all respondents were asked the extent to which the cost of their electricity bill has on the respondents' personal finances or business' bottom line.

For residential respondents whose electricity bill has major impact on their finances and requires them do without some other important priorities, the level of their acceptance for the proposed rate increase (57%) is lower than those whose finances are less impacted by their electricity bill (76%).

Figure 5.2 RS – Residential Financial Strain

	Financially Strained Households	Not Financially Strained Households
The rate increase is reasonable and I support it	16%	32%
I don't like it, but I think the rate increase is necessary	41%	44%
The rate increase is unreasonable and I oppose it	40%	21%
Overall Permission	**57%**	**76%**

For GS respondents whose electricity bill has major impact on their organizations' bottom line and requires them to put off some important priorities and investments, the level of their acceptance for the proposed rate increase (37%) is lower than those whose bottom line are less impacted by their electricity bill (58%).

Figure 5.3 GS – General Service Financial Strain

	Financially Strained Business'	Not Financially Strained Business'
The rate increase is reasonable and I support it	14%	16%
I don't like it, but I think the rate increase is necessary	22%	42%
The rate increase is unreasonable and I oppose it	61%	40%
Overall Permission	**37%**	**58%**

Open-Ended Opinions Based on PowerStream's Proposed Rate Increase

When Residential customers were asked an open-ended follow-up on the permission question, 36% of those who chose "the rate increase is reasonable and I support it" did so because they believe the proposed rate increase is "not a lot". Other reasons for this group include "system upgrade needed" (19%) and "it's important/needed" (13%).

For Residential customers who chose "I don't like it, but I think the rate increase is necessary", nearly 1-3 (32%) held this position because the rate increase is seen as too high and "already pay too much".

For Residential customers who chose "the rate increase is unreasonable and I oppose it", a large majority (61%) hold this position because they think the increase is too high and that they "already pay too much". Additionally, 22% of the same group believe that PowerStream can "find efficiencies" or other sources to reduce the rate impact.

Figure 5.4 RS – Opinion on Proposed Rate Increase

Q And why do you say that? (Asked of Residential respondents who had an opinion of PowerStreams's proposed rate increase)

ACCEPTANCE: INCREASE REASONABLE	% RS
It's not a lot	36%
System upgrade needed	19%
It's important/needed	13%
Improve/maintain reliability	10%
New technology	7%
Other	13%
Don't Know	1%

n=210

NO ACCEPTANCE: INCREASE UNREASONABLE	% RS
Increase too high/ already pay too much	61%
Find efficiencies/ other sources	22%
Not necessary	3%
Other	12%
Don't Know	2%

n=328

ACCEPTANCE: DON'T LIKE BUT NECESSARY	% RS
Increase too high/ already pay too much	32%
It's important/needed	21%
System upgrade needed	10%
Find efficiencies/ other sources	6%
Improve/maintain reliability	3%
New technology	3%
It's not a lot	2%
Cost of everything is going up	2%
Will happen anyways	2%
Need more information	1%
Not necessary	1%
Other	10%
None	1%
Don't Know	5%
Refused	1%

n=416

For General Service customers who chose “the rate increase is reasonable and I support it”, 35% hold that position because the rate increase is seen as “small/ reasonable”. The same amount (35%) think it’s “the smart thing to do”.

For General Service customers who chose “I don’t like it, but I think the rate increase is necessary”, almost half (43%) hold that position because they think the investments are “necessary”.

Almost half (48%) of General Service customers who chose “the rate increase is unreasonable and I oppose it” did so because they believe they “already paying enough” for electricity. 1-5 (20%) of this group hold that position because they believe that PowerStream should find savings elsewhere.

Figure 5.5 GS – Opinion on Proposed Rate Increase

Q And why do you say that? (Asked of General Service respondents who had an opinion of PowerStreams's proposed rate increase)

ACCEPTANCE: INCREASE REASONABLE	% GS
The rate increase is small/reasonable	35%
It's the smart thing to do	35%
Investments are necessary	10%
Business depends on reliable electricity	6%
Other	3%
Don't Know	3%
Refused	6%

n=31

NO ACCEPTANCE: INCREASE UNREASONABLE	% GS
Already paying enough	48%
Cost savings should be found elsewhere	20%
Businesses can't afford a rate increase	9%
Waste of money/unnecessary	5%
Don't like rate increases	4%
Other	13%
Don't Know	3%

n=111

ACCEPTANCE: DON'T LIKE BUT NECESSARY	% GS
Investments are necessary	43%
Don't like rate increases	19%
Business depends on reliable electricity	16%
If it saves money in the long run	5%
Waste of money/unnecessary	3%
The rate increase is small/reasonable	2%
Cost savings should be found elsewhere	2%
Other	7%
Don't Know	3%

n=58

Survey Instruments

Residential Survey Instrument

A. Introduction

Hello, my name is ________________ and I'm calling from **Innovative Research Group** on behalf of **PowerStream**, your electricity distributor.

Innovative Research Group is a national public opinion research firm. We have been commissioned by **PowerStream** to help them better understand the needs and preferences of customers who are responsible for paying their household's electricity bill.

PowerStream – which distributes electricity to homes and businesses in your community – is preparing to submit its 5-year investment plan to the Ontario Energy Board for regulatory review. Since this plan will impact your bill, PowerStream wants to hear from you, so your views can help shape its plan.

A1. Would you mind if I had ten minutes of your time to ask you some questions? All your responses will be kept strictly confidential.

Yes	1	[**continue**]
No – NOT PRIMARY BILL PAYER	2	[**go to TRANSFER-1**]
No – BAD TIME	3	**ARRANGE CALLBACK**
No – HARD REFUSAL	4	[**Terminate**]

MONIT

This call may be monitored or audio taped for quality control and evaluation purposes.

PRESS TO CONTINUE	1

A2. Have I reached you at your home phone number?

INTERVIEWER NOTE; IF "NO" ASK: May I speak to someone who does live there?

Yes - SPEAKING, CONTINUE	1	[**continue to A3**]
YES - TRANSFERRED – **(GO BACK TO INTRODUCTION)**	2	[**back to INTRO**]
No - NOT AVAILABLE – **(ARRANGE CALLBACK)**	3	[**ARRANGE CALLBACK]**
Refused – LOG **(THANK AND TERMINATE)**	9	[**Terminate**]

A3. Are you the person primarily responsible for paying the electricity bill in your household?

Yes – I pay the bill	1	[**continue to A4**]
Yes – shared responsibility	2	[**continue to A4**]
No	3	[**go to TRANSFER-1**]
Don't know (**DNR**)	98	[**Terminate**]

TRANSFER-1

Can I speak with the person in your household who usually pays the electricity bill?

Yes	1	[**BACK TO** ***INTRO***]

No – NOT AVAILABLE/BAD TIME – **(ARRANGE CALLBACK)**	2	[**ARRANGE CALLBACK]**
No – HARD REFUSAL	3	[**Terminate**]
Don't know (**DNR**)	98	[**Terminate**]

A4. And can you confirm that your household receives an electricity bill from **PowerStream**?

Yes	1	[**continue**]
No	2	[**Terminate**]
Don't know (**DNR**)	98	[**Terminate**]

GENDER	Note gender by observation:
Male	1
Female	2

B. General Satisfaction

We need to prime respondents to start thinking about electricity and the part of the system that PowerStream operates.

PREAMBLE-1

To start, I'd like to ask you a few questions about the electricity system …

As you may know, Ontario's electricity system has three key components: **generation, transmission** and **distribution**.

- **Generating stations** convert various forms of energy into electric power;
- **Transmission lines** connect the power produced at generating stations to where it is needed across the province; and
- **Distribution lines** carry electricity to the homes and businesses in our communities.

Today we're going to talk about your **local distribution system** which is maintained and operated by **PowerStream** in your community.

How familiar are you with the **local electricity distribution system**? Would you say … [READ LIST]

Very familiar	1
Somewhat familiar	2
Not very familiar	3
Not familiar at all	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

B6. Generally speaking, how satisfied are you with the job **PowerStream** is doing running your local distribution system? Would you say … [**READ LIST**]

Very satisfied	1
Somewhat satisfied	2
Somewhat dissatisfied	3
Very dissatisfied	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

B7. Is there anything in particular **PowerStream** can do to improve its service to you? [**OPEN**]

Don't know (**DNR**)	98
Refused (**DNR**)	99

B8. **PowerStream** is 100% owned by the cities of Vaughan (***<u>pronounced as "Von"</u>***), Markham and Barrie and is overseen by a board of directors. This board is made up of members of the respective city councils and the community and is responsible for overseeing the operations and management of the utility.

Before this survey, did you know that PowerStream was owned by the cities of Vaughan, Markham and Barrie?
[**DO <u>NOT</u> READ LIST**]

Yes	1
No	2
Don't know (**DNR**)	98
Refused (**DNR**)	99

C. Bill Knowledge & Impact

I'd now like to talk with you about your electricity bill …

C9. While some customers pay more and other pay less, the **average residential customer pays about $135 a month** for electricity of **which $27 or approximately 20% goes to PowerStream**. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

Before this survey, how familiar were you with the amount of your electricity bill that went to **PowerStream**? Would you say … [**READ LIST**]

Very familiar	1
Somewhat familiar	2
Not very familiar	3
Not familiar	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

D. System Reliability

These questions are about priming the respondent to think about their experience with system reliability and separate adverse weather from failing equipment.

D10. In the past year or so, PowerStream customers experienced unusually extreme weather – *microburst and tornados this past summer* and an *ice storm in December 2013*. These major weather events caused power outages for many PowerStream customers.

As far as you know, in the past year, did your household experience any power outages due to extreme weather events such as the ice storm, microbursts or tornados?

Yes	1
No	2
Don't know (**DNR**)	98
Refused (**DNR**)	99

D11. Whether you were personally affected or not, how satisfied are you with the way PowerStream responded to these events? Would you say … [READ LIST]

Very satisfied	1
Somewhat satisfied	2
Somewhat dissatisfied	3
Very dissatisfied	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

D12. Is there is anything in particular that PowerStream can do to improve its service to you during these extreme weather events? [**OPEN**]

[Ask all respondents]

D13. <u>Not</u> including power outages caused by extreme weather events, have you experienced any power outages **in the past 12 months**, and if so, approximately how many?
[**DO NOT READ LIST**]

No outages	0 [**SKIP to D16**]
1 outage	1 [CONTINUE]
2 outages	2 [CONTINUE]
3 outages	3 [CONTINUE]
4 outages	4 [CONTINUE]
5 outages	5 [CONTINUE]
6 outages	6 [CONTINUE]
7 outages	7 [CONTINUE]
8 or more outages	8 [CONTINUE]
Don't know (**DNR**)	98 [**SKIP to D16**]
Refused (**DNR**)	99 [**SKIP to D16**]

D14. And how satisfied are you with the way PowerStream responded to the outage? Would you say … [READ LIST]

Very satisfied	1
Somewhat satisfied	2
Somewhat dissatisfied	3
Very dissatisfied	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

D15. Is there is anything in particular that PowerStream could do to improve its service to you during your most recent power outages? [**OPEN**]

D16. In your view, how do you think **PowerStream** should address the **number** of customer power outages? Would you say … [**READ LIST**]

[Rotate response codes 1 and 3]

Spend what is needed to reduce the number of power outages	1
Spend what is needed to maintain the current level of outages	2
Accept **more** power outages in order to help keep customer costs from rising	3
Don't Know (**DNR**)	98
Refused (**DNR**)	99

D17. The average **PowerStream** customer is without power for about **100 minutes per year**.

In your view, how do you think PowerStream should address the **length of time** customers are without power? Would you say … [READ LIST]

[Rotate response codes 1 and 3]

Spend what is needed to **reduce** the time customers are without power	1
Spend what is needed to **maintain** the current length of time customers are without power	2
Accept **longer** time without power in order to help minimize customer costs from rising	3
Don't Know (**DNR**)	98
Refused (**DNR**)	99

E. System Challenges & Priorities

System Renewal Question

E18. [PREAMBLE to E19] As significant amount of PowerStream's electrical infrastructure was built in the 1960s and 70s, and is still in-service today. While PowerStream believes it has done its best to prolong the life of these assets, today many of these assets are now approaching the end of their useful life and are beginning to pose a threat to system reliability.

As part of its investment plan, PowerStream is proposing a significant infrastructure renewal program. The estimated cost of this system renewal program is **$258 million** over the next 5 years.

Although this plan will allow PowerStream to make, what independent studies suggest are, the necessary investments to maintain system reliability, **it will have an impact on customer bills**.

E19. Which of the following statements best represents your point of view?
[Read and Rotate statements 1 and 2]
Some customers have said …

PowerStream should invest what it takes to replace the system's aging infrastructure to maintain system reliability; even if that increases my monthly electricity bill by a few dollars over the next few years. 1

Others have said …
PowerStream should lower its estimated investment in renewing the system's aging infrastructure to lessen the impact of any bill increase; even if that means more or longer power outages. 2

Don't know (**DNR**) 98
Refused (**DNR**) 99

E20. The investments discussed earlier are focused on day-to-day reliability. There are additional investments that could help "harden" the electrical system and speed up power restoration during **rare weather events that have an unusually large impact on the system** – *such as tornados or ice storms*. There is no practical limit to potential ways of making the system more resilient in a major event, it is fundamentally a question of money.

Currently, the average residential customer pays $27 a month to PowerStream to operate and maintain the local distribution system. How much more are you willing to pay each month for investments that would help the system better withstand major events such as extreme weather? $_____

System Service Questions

[PREAMBLE TO E22] New technology can have many impacts on electricity distribution systems:

- New computer systems and GPS systems provide pinpointed information about outages to both system controllers and customer in real time.
- Remote monitors and switches allow power to be restored to many customers much more quickly than in the past.

While there are benefits from new technology, there are also costs.

E22. When it comes to investing in new technology, which of the following points of view is closest to your own?

[Read and Rotate statements 1 and 2]

Some customers have said…

Investments in new technologies are more a luxury than a necessity and should be a low priority for PowerStream.	1

Others have said …

I think the benefits of new technology are important and investments in new technology should be a priority for PowerStream.	2
Don't know (**DNR**)	98
Refused (**DNR**)	99

General Plant Questions

E23. PowerStream is not just the local electricity distribution system itself, but a company that operates the system. As a company, PowerStream needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the electrical system and customer information.

Again, customers have made number of statements about this sort of investment. Which of the following statements best represents your point of view?
[Read and Rotate statements 1 and 2]

Some customers have said …

PowerStream should find ways to make do with the buildings, equipment and IT systems it already has.	1

Others have said …

While PowerStream should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably.	2
Don't know (**DNR**)	98
Refused (**DNR**)	99

F. Assessment of Plan

PREAMBLE

To maintain the reliability of the local electricity system, PowerStream's proposed 5 year plan will spend an estimated **$641 million** on new capital investments. This includes …

- **$258 million** to replace aging infrastructure;
- **$150 million** for new technologies to make the system more efficient, reliable, safe and to expand system capacity to accommodate future growth;
- **$147 million** to maintain metering and connect new customers to the electricity system;
- **$86 million** to invest in tools, computers and software systems, vehicles and facilities needed to manage the electricity system;

To fund this plan, PowerStream is proposing the **average residential customers' rate increase by $2.14 per month** on the distribution portion of their bill over the next five years. So, by 2020, the average residential household will be paying an **estimated $10.72 <u>more</u> per month** on the distribution portion of its electricity bill.

F25. Considering the cost of PowerStream's plan, would you say [**READ LIST**] …
Rotate response codes "1 "and "3"

The rate increase is reasonable and I support it	1
I don't like it, but I think the rate increase is necessary	2
The rate increase is unreasonable and I oppose it	3
Don't know (**DNR**)	98
Refused (**DNR**)	99

Ask only if F25 = 1, 2 or 3

F26. And why do you say that? [**OPEN**]

Don't know (**DNR**)	98
Refused (**DNR**)	99

G. Segmentation

These last few questions are for statistical purposes only and we remind you again that all of your responses are completely confidential.

G27. Please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree with the following statement:
The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.

Strongly agree	1
Somewhat agree	2
Neither agree nor disagree (**DNR**)	3
Somewhat disagree	4
Strongly disagree	5
Don't Know (**DNR**)	98
Refused (**DNR**)	99

G28. In which year were you born? [**Enter YEAR**]

INTERVIEWER NOTE: if REFUSE; ask "AGE".

AGE: Can you tell me what age category do you fall into? [**READ LIST**]

Less than 18	0
18-25	1
25-34	2
35-44	3
45-54	4
55-64	5
65 years or older	6
Refused (**DNR**)	99

G29. Do you own or rent your home?

Own	1
Rent	2
Refused (**DNR**)	99

G30. How would you describe your primary residence? Would you say you live in … [**READ LIST**]

A fully-detached home;	1
A semi-detached home;	2
An apartment or condo building **less than 5 stories**; or	3
An apartment or condo building **5 stories or higher**?	4
Refused (**DNR**)	99

G31. Counting yourself, how many people live in your household?

1 person	1
Enter number of people	2---7
8 or more	8
Refused (**DNR**)	99

THANK and END SURVEY

Thank you very much for taking the time to complete this survey.

General Service Survey Instrument

Introduction

INTRO

INTRO. Hello, my name is ________________ and I'm calling from **Innovative Research Group**, a national public opinion research firm. We have been hired by **PowerStream** to help them better understand the needs and preferences of its customers.

Can I please speak to the person who is in-charge of managing the electricity bill at your organization?

1) Yes, speaking <**contact on the line**>		[**skip to Q1]**
2) Yes <**transferred to contact**>		[**skip to Q1]**
3) No <**not the right contact person**>		**[GO to "NEW"]**
4) No <**busy**>	"When is a good time to callback?"	**[record callback time**
5) Maybe <**may I ask who is calling?**>		[**skip to GATE]**

NEW. And … can I have their …

First Name _____________

Last Name _____________

Title/Position ___________

Phone Number __________

ASK to be transferred …

- **if transferred → go to A1**
- **if not transferred → Thank & Add to Callback List**

GATE. My name is __________ and I'm calling on behalf of your local electricity distributor, **PowerStream**.

INTERVIEWER NOTE: If gatekeeper asks the purpose of call → I'd like to ask the person in-charge of managing the electricity bill at your organization a few questions concerning a **PowerStream** customer consultation.

1) Yes <**transferred to contact**>		**[skip to A1]**
2) No <**not available**>	"When is a good time to callback?	**[record callback time and GO to "NEW"]**
3) No <**not interested in talking**>		**[Thank & Terminate]**

A2 QUAL PREAMBLE:
Innovative Research Group is a national public opinion research firm. We have been commissioned by **PowerStream** to help them better understand the needs and preferences of customers who are responsible for paying their businesses' electricity bill.

PowerStream – which distributes electricity to homes and businesses in your area – is preparing to submit its 5-year investment plan to the Ontario Energy Board for regulatory review. Since this plan will impact your bill, PowerStream wants to hear from you, so your views can help shape its plan.

A2. Would you mind if I had ten minutes of your time to ask you some questions? All your responses will be kept strictly confidential.

Yes	1	[**continue**]
No – NOT PRIMARY BILL PAYER	2	[**go to TRANSFER-1**]
No – BAD TIME	3	**ARRANGE CALLBACK**
No – HARD REFUSAL	4	[**Terminate**]

MONIT
This call may be monitored or audio taped for quality control and evaluation purposes.

PRESS TO CONTINUE	1

A3. Just to confirm, does your organization receive an electricity bill from **PowerStream**?

YES	1	[**continue**]
NO	2	[**Terminate**]
DK (volunteered)	98	[**Terminate**]

A4. As part of your job, are you in-charge of <u>managing</u> or <u>overseeing</u> your organization's electricity bill?

Yes	1	[**Continue to B5]**
No	2	CAN I SPEAK TO THE PERSON WHO MANAGES YOUR ORGANIZATION'S **ELECTRICITY** BILL?**[Return to NEW]**
DK	3	CAN I SPEAK TO THE PERSON WHO MANAGES YOUR ORGANIZATION'S **ELECTRICITY** BILL? **[Return to NEW]**

TRANSFER-1
Can I speak with the person at your organization who usually pays the electricity bill?

Yes	1	[**BACK TO** *<u>INTRO</u>*]
No – NOT AVAILABLE/BAD TIME – **(ARRANGE CALLBACK)**	2	[**ARRANGE CALLBACK]**
No – HARD REFUSAL	3	[**Terminate**]
Don't know (**DNR**)	98	[**Terminate**]

B. General Satisfaction

We need to prime respondents to start thinking about electricity and the part of the system that PowerStream operates.

PREAMBLE-1

To start, I'd like to ask you a few questions about the electricity system …

As you may know, Ontario's electricity system has three key components: **generation, transmission** and **distribution**.

- **Generating stations** convert various forms of energy into electric power;
- **Transmission lines** connect the power produced at generating stations to where it is needed across the province; and
- **Distribution lines** carry electricity to the homes and businesses in our communities.

Today we're going to talk about your **local distribution system** which is maintained and operated by **PowerStream**.

How familiar are you with the **local electricity distribution system**? Would you say … [READ LIST]

Very familiar	1
Somewhat familiar	2
Not very familiar	3
Not familiar at all	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

B6. Generally speaking, how satisfied are your organization with the job **PowerStream** is doing running your local distribution system? Would you say … [**READ LIST**]

Very satisfied	1
Somewhat satisfied	2
Somewhat dissatisfied	3
Very dissatisfied	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

B7. Is there anything in particular **PowerStream** can do to improve its service to your organization? [**OPEN**]

Don't know (**DNR**)	98
Refused (**DNR**)	99

B8. **PowerStream** is 100% owned by the cities of Vaughan (***<u>pronounced as "Von"</u>***), Markham and Barrie and is overseen by a board of directors. This board is made up of members of the respective city councils and the community and is responsible for overseeing the operations and management of the utility.

Before this survey, did you know that PowerStream was owned by the cities of Vaughan, Markham and Barrie?
[**DO <u>NOT</u> READ LIST**]

Yes	1
No	2
Don't know (**DNR**)	98
Refused (**DNR**)	99

C. Bill Knowledge & Impact

I'd now like to talk with you about your electricity bill …

C9. While some customers pay more and other pay less, the average General Service customer pays about $305 a month for electricity of which $61 or approximately 20% goes to PowerStream. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

Before this survey, how familiar were you with the amount of your electricity bill that went to **PowerStream**? Would you say … [**READ LIST**]

Very familiar	1
Somewhat familiar	2
Not very familiar	3
Not familiar	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

D. System Reliability

These questions are about priming the respondent to think about their experience with system reliability and separate adverse weather from failing equipment.

D10. In the past year or so, PowerStream customers experienced unusually extreme weather – microburst and tornados this past summer and an ice storm in December 2013. These major weather events caused power outages for many PowerStream customers.

As far as you know, in the past year, did your organization experience any power outages due to extreme weather events such as the ice storm, microbursts or tornados?

Yes	1
No	2
Don't know (**DNR**)	98
Refused (**DNR**)	99

D11. Whether your organization was directly affected or not, how satisfied are you with the way PowerStream responded to these events? Would you say … [READ LIST]

Very satisfied	1
Somewhat satisfied	2
Somewhat dissatisfied	3
Very dissatisfied	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

D12. Is there is anything in particular that PowerStream can do to improve its service to your organization during these extreme weather events? [**OPEN**]

[Ask all respondents]

D13. Not including power outages caused by extreme weather events, has your organization experienced any power outages **in the past 12 months**, and if so, approximately how many? [**DO NOT READ LIST**]

No outages	0 [**SKIP to D16**]
1 outage	1 [CONTINUE]
2 outages	2 [CONTINUE]
3 outages	3 [CONTINUE]
4 outages	4 [CONTINUE]
5 outages	5 [CONTINUE]
6 outages	6 [CONTINUE]
7 outages	7 [CONTINUE]
8 or more outages	8 [CONTINUE]
Don't know (**DNR**)	98 [**SKIP to D16**]
Refused (**DNR**)	99 [**SKIP to D16**]

D14. And how satisfied is your organization with the way PowerStream responded to the outage? Would you say … [READ LIST]

Very satisfied	1
Somewhat satisfied	2
Somewhat dissatisfied	3
Very dissatisfied	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

D15. Is there is anything in particular that PowerStream could do to improve its service to your organization during your most recent power outages? [**OPEN**]

D16. In your view, how do you think **PowerStream** should address the **<u>number</u>** of customer power outages? Would you say … [**READ LIST**]

[Rotate response codes 1 and 3]

Spend what is needed to reduce the number of power outages	1
Spend what is needed to maintain the current level of outages	2
Accept **<u>more</u>** power outages in order to help keep customer costs from rising	3
Don't Know (**DNR**)	98
Refused (**DNR**)	99

D17. The average **PowerStream** customer is without power for about **100 minutes per year**.

In your view, how do you think PowerStream should address the **<u>length of time</u>** customers are without power? Would you say … [READ LIST]

[Rotate response codes 1 and 3]

Spend what is needed to **<u>reduce</u>** the time customers are without power	1
Spend what is needed to **<u>maintain</u>** the current length of time customers are without power	2
Accept **<u>longer</u>** time without power in order to help minimize customer costs from rising	3
Don't Know (**DNR**)	98
Refused (**DNR**)	99

E. System Challenges & Priorities

System Renewal Question

[PREAMBLE to E19] A significant amount of PowerStream's electrical infrastructure was built in the 1960s and 70s, and is still in-service today. While PowerStream believes it has done its best to prolong the life of these assets, today many of these assets are now approaching the end of their useful life and are beginning to pose a threat to system reliability.

As part of its investment plan, PowerStream is proposing a significant infrastructure renewal program. The estimated cost of this system renewal program is $258 million over the next 5 years.

Although this plan will allow PowerStream to make, what independent studies suggest are, the necessary investments to maintain system reliability, **it will have an impact on customer bills**.

E19. Which of the following statements best represents your point of view?
[Read and Rotate statements 1 and 2]
Some customers have said …

PowerStream should invest what it takes to replace the system's aging infrastructure to maintain system reliability; even if that increases my monthly electricity bill by a few dollars over the next few years. 1

Others have said …
PowerStream should lower its estimated investment in renewing the system's aging infrastructure to lessen the impact of any bill increase; even if that means more or longer power outages. 2

Don't know (**DNR**)	98
Refused (**DNR**)	99

E20. The investments discussed earlier are focused on day-to-day reliability. There are additional investments that could help "harden" the electrical system and speed up power restoration during **rare weather events that have an unusually large impact on the system** – *such as tornados or ice storms*. There is no practical limit to potential ways of making the system more resilient in a major event, it is fundamentally a question of money.

Currently, the average General Service customers pays $61 a month to PowerStream to operate and maintain the local distribution system. How much more are you willing to pay each month for investments that would help the system better withstand major events such as extreme weather? $_____

System Service Questions

[PREAMBLE TO E22] New technology can have many impacts on electricity distribution systems:

- New computer systems and GPS systems provide pinpointed information about outages to both system controllers and customer in real time.
- Remote monitors and switches allow power to be restored to many customers much more quickly than in the past.

While there are benefits from new technology, there are also costs.

E22. When it comes to investing in new technology, which of the following points of view is closest to your own?

[Read and Rotate statements 1 and 2]

Some customers have said…

Investments in new technologies are more a luxury than a necessity and should be a low priority for PowerStream.	1

Others have said …

I think the benefits of new technology are important and investments in new technology should be a priority for PowerStream.	2
Don't know (**DNR**)	98
Refused (**DNR**)	99

General Plant Questions

E23. PowerStream is not just the local electricity distribution system itself, but a company that operates the system. As a company, PowerStream needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the electrical system and customer information.

Again, customers have made number of statements about this sort of investment. Which of the following statements best represents your point of view?
[Read and Rotate statements 1 and 2]

Some customers have said …

PowerStream should find ways to make do with the buildings, equipment and IT systems it already has. 1

Others have said …

While PowerStream should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably. 2

Don't know (**DNR**) 98
Refused (**DNR**) 99

F. Assessment of Plan

PREAMBLE

To maintain the reliability of the local electricity system, PowerStream's proposed 5 year plan will spend an estimated **$641 million** on new capital investments. This includes …

- **$258 million** to replace aging infrastructure;
- **$150 million** for new technologies to make the system more efficient, reliable, safe and to expand system capacity to accommodate future growth;
- **$147 million** to maintain metering and connect new customers to the electricity system;
- **$86 million** to invest in tools, computers and software systems, vehicles and facilities needed to manage the electricity system;

To fund this plan, PowerStream is proposing the **average General Service customers' rate increase by $5.25 per month** on the distribution portion of their bill over the next five years. So, by 2020, the average General Service customer will be paying an **estimated $26.24 <u>more</u> per month** on the distribution portion of its electricity bill.

F25. Considering the cost of PowerStream's plan, would you say [READ LIST] …
Rotate response codes "1 "and "3"

The rate increase is reasonable and I support it	1
I don't like it, but I think the rate increase is necessary	2
The rate increase is unreasonable and I oppose it	3
Don't know (**DNR**)	98
Refused (**DNR**)	99

Ask only if F25 = 1, 2 or 3

F26. And why do you say that? [**OPEN**]

Don't know (**DNR**)	98
Refused (**DNR**)	99

G. Segmentation

These last few questions are for statistical purposes only and we remind you again that all of your responses are completely confidential.

G27. Please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree with the following statement:
The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important priorities and investments being put off.

Strongly agree	1
Somewhat agree	2
Neither agree nor disagree (**DNR**)	3
Somewhat disagree	4
Strongly disagree	5
Don't Know (**DNR**)	98
Refused (**DNR**)	99

G28. Which of the following best describes the **hours of operation** of your business? Would you say … [**READ LIST**]

We are open 24/7	1
We operate several shifts each day, but are not open 24/7	2
We operate during regular business hours only	3
We operate outside of regular business hours, but do not have shifts	4
Other (please specify): ____________________________	88

G29. And, which of the following best describes **when your business operates** through the week? Would you say … [**READ LIST**]

We operate on weekdays only	1
We operate on weekdays and weekends	2
Other (please specify): ____________________________	88

THANK and END SURVEY

Thank you very much for taking the time to complete this survey.

Primer Appendices:

PowerStream Distribution System Plan

Residential Primer

General Service Primer

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Appendix G-2a-1
Fixed Asset Continuity Schedule

Year **2012**

					COST (000's)				ACCUMULATIVE DEPRECIATION (000's)				
CCA Class	**GL account**	**Detail Asset Class**	**Depreciation Rate**	**Notes**	**Opening Balance**	**Additions (3)**	**Disposals/ Adjustments**	**Closing Balance**	**Opening Balance**	**Additions (3)**	**Disposals/ Adjustments**	**Closing Balance**	**Net Book Value (000's)**
Distribution Assets and Streetlighting													
47	1610	Hydro One TS - Contributed Capital	2.50%		609	4,363	0	4,972	29	288	0	317	4,655
n/a	1805	Land	0		10,968	7,117	0	18,085	0	0	0	0	18,085
CEC	1612	Land Rights	0		766	31	0	797	0	0	0	0	797
1	1808	Building & Fixtures	2.50%		6,120	188	0	6,308	191	197	0	388	5,920
47	1810	Major spare parts	0		9,184	(1,076)	0	8,108	0	0	0	0	8,108
47	1815	Transformer Stations	2.50%	1	94,982	838	0	95,820	4,974	4,280	0	9,254	86,566
47	1820	Distribution Stations	3.33%	1	21,527	219	0	21,746	2,051	1,162	0	3,213	18,533
47	1830	Poles, Towers & Fixtures	2.22%		100,913	13,031	(115)	113,829	2,327	2,606	(4)	4,929	108,900
47	1835	O/H Cond & Devices	2.50%		94,291	8,572	(187)	102,676	2,567	2,996	(10)	5,553	97,123
47	1840	U/G Conduit	1.67%		63,374	7,572	0	70,946	1,081	1,253	0	2,334	68,612
47	1845	U/G Cond & Devices	2.22%		185,286	30,099	(389)	214,996	5,296	5,462	(14)	10,744	204,252
47	1850	Line Transformers	2.92%	2	133,046	13,599	(1,665)	144,980	5,823	6,195	(101)	11,917	133,063
47	1855	Services (OH and UG)	3.25%	2	53,933	4,219	0	58,152	4,469	3,239	0	7,708	50,444
47	1860	Meters	5.33%	2	18,058	3,908	1,878	23,844	(777)	1,202	1,945	2,370	21,474
47	1860	Smart Meters	6.67%		46,536	471	(84)	46,923	3,735	3,413	(14)	7,134	39,789
47	1875	Streetlighting	4.00%		1,632	320	0	1,952	54	73	0	127	1,825
		Subtotal Distribution Assets	n/a		841,225	93,471	(562)	934,134	31,820	32,366	1,802	65,988	868,146
General Plant Assets													
1	1908	Building & Fixtures - Head office	2.00%	1	39,884	354	0	40,238	919	927	0	1,846	38,392
13	1910	Leasehold Improvements	30.00%		0	65	0	65	0	0	0	0	65
8	1915	Office Equipment	10.00%		3,654	1,223	0	4,877	460	556	0	1,016	3,861
10	1920	Computer hardware	20.42%	2	5,100	1,752	0	6,852	1,568	1,390	0	2,958	3,894
12	1611	Computer Software	22.78%	2	8,750	(1,556)	0	7,194	2,159	2,383	0	4,542	2,652
10	1930	Transportation	9.05%	2	9,581	1,947	0	11,528	1,165	1,396	(8)	2,553	8,975
8	1935	Stores Equipment	10.00%		(4)	7	0	3	(2)	0	0	(2)	5
8	1940	Tools, Shop & Garage	10.00%		2,528	715	0	3,243	379	419	0	798	2,445
8	1955	Communication Equipment	21.67%	2	1,618	257	0	1,875	398	377	0	775	1,100
8	1960	Miscellaneous equipment	10.00%		0	0	0	0	0	0	0	0	0
47	1980	System Supervisory Equip	7.78%	2	8,099	782	(7)	8,874	1,491	979	(2)	2,468	6,406
47	1990	Other Tangible property	n/a		0	0	0	0	0	0	0	0	0
		Subtotal General Plant Assets	n/a		79,210	5,546	(7)	84,749	8,537	8,427	(10)	16,954	67,795
Other Capital													
47	2005	Prop. Under Capital Lease-Addiscott	4.00%		17,549	0	0	17,549	731	733	0	1,464	16,085
47	2075	Non-utility property owned	4.00%		0	0	0	0	0	0			
		Subtotal Other Capital Assets	n/a		17,549	0	0	17,549	731	733	0	1,464	16,085
		Total Assets Before Contributed Capital	n/a		937,984	99,017	(569)	1,036,432	41,088	41,526	1,792	84,406	952,026
47	1995/1996	Contributed Capital	varies		(244,673)	(37,923)	885	(281,711)	(8,805)	(8,199)	45	(16,959)	(264,752)
		All PP& E ASSETS	n/a		693,311	61,094	316	754,721	32,282	33,327	1,837	67,447	687,274
		Less Socialized Renewable Energy Generation Investments (input as negative) (5)			(493)	(604)	0	(1,097)	(22)	(50)	0	(72)	(1,025)
		Less/plus: Other Non Rate-Regulated Utility Assets (4)			(45)	(37)	0	(82)	37	(14)	0	23	(105)
		Net Total PP&E Distribution Assets			692,773	60,453	316	753,542	32,297	33,263	1,837	67,398	686,144

10		Transportation
8		Stores Equipment
8		Tools, Shop & Garage

Less: *Fully Allocated Depreciation*	
Transportation	$ 1,396
Stores Equipment	$ -
Tools, Shop & Garage	$ 419
less - Non- distribution	-$ 14
Net Depreciation	$ 31,498

NOTES:

(1) This is the depreciation rate on the largest component within the asset class. Actual depreciation is calculated on the specific rate for each component within the class.
(2) This is the average depreciation rate of subclass of assets within the asset group
(3) Work in progress expenditures have been removed
(4) Non-distribution assets have been removed. In some years the net impact is adding cost because the removal of the contributed capital on streetlighting exceeded the cost
(5) Renewable Generation Connection Rate Potection (RGCRP} is not applicable to 2012 as the Renewable generation costs were in the Deferral account and not Board approved until a later year

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Appendix G-2a-1
Fixed Asset Continuity Schedule

Year 2013

					COST (000's)				ACCUMULATIVE DEPRECIATION (000's)				
CCA Class	**GL account**	**Detail Asset Class**	**Depreciation Rate**	**Notes**	**Opening Balance**	**Additions (3)**	**Disposals/ Adjustments**	**Closing Balance**	**Opening Balance**	**Additions (3)**	**Disposals/ Adjustments**	**Closing Balance**	**Net Book Value (000's**
Distribution Assets and Streetlighting													
47	1610	Hydro One TS - Contributed Capital	2.50%		4,972	0	0	4,972	317	288	0	605	4,367
n/a	1805	Land	0		18,085	146	0	18,231	0	0	0	0	18,231
CEC	1612	Land Rights	0		797	30	0	827	0	0	0	0	827
1	1808	Building & Fixtures	2.50%		6,308	340	0	6,648	388	202	0	590	6,058
47	1810	Major spare parts	0		8,108	649	0	8,757	0	0	0	0	8,757
47	1815	Transformer Stations	2.50%	1	95,820	4,185	0	100,005	9,254	4,154	0	13,408	86,597
47	1820	Distribution Stations	3.33%	1	21,746	1,365	0	23,111	3,213	1,154	0	4,367	18,744
47	1830	Poles, Towers & Fixtures	2.22%		113,829	15,751	(59)	129,521	4,929	2,858	(3)	7,784	121,737
47	1835	O/H Cond & Devices	2.50%		102,676	11,151	(74)	113,753	5,553	3,181	(6)	8,728	105,025
47	1840	U/G Conduit	1.67%		70,946	8,070	0	79,016	2,334	1,385	0	3,719	75,297
47	1845	U/G Cond & Devices	2.22%		214,996	31,247	(477)	245,766	10,744	6,097	(32)	16,809	228,957
47	1850	Line Transformers	2.92%	2	144,980	9,662	(2,136)	152,506	11,917	6,476	(231)	18,162	134,344
47	1855	Services (OH and UG)	3.25%	2	58,152	4,555	0	62,707	7,708	3,298	0	11,006	51,701
47	1860	Meters	5.33%	2	23,844	5,015	0	28,859	2,370	1,453	0	3,823	25,036
47	1860	Smart Meters	6.67%		46,923	1,448	0	48,371	7,134	3,453	0	10,587	37,784
47	1875	Streetlighting	4.00%		1,952	150	0	2,102	127	88	0	215	
		Subtotal Distribution Assets	n/a		934,134	93,764	(2,746)	1,025,152	65,988	34,087	(272)	99,803	923,462
General Plant Assets													
1	1908	Building & Fixtures - Head office	2.00%	1	40,238	889	0	41,127	1,846	936	0	2,782	38,345
13	1910	Leasehold Improvements	30.00%		65	151	0	216	0	8	0	8	208
8	1915	Office Equipment	10.00%		4,877	17	0	4,894	1,016	594	0	1,610	3,284
50	1920	Computer hardware	20.42%	2	6,852	2,138	0	8,990	2,958	1,194	0	4,152	4,838
12	1611	Computer Software	22.78%	2	7,194	8,097	0	15,291	4,542	2,821	0	7,363	7,928
10	1930	Transportation	9.05%	2	11,528	1,897	(10)	13,415	2,553	1,596	(10)	4,139	9,276
8	1935	Stores Equipment	10.00%		3	0	0	3	(2)	1	0	(1)	4
8	1940	Tools, Shop & Garage	10.00%		3,243	510	0	3,753	798	430	0	1,228	2,525
8	1955	Communication Equipment	21.67%	2	1,875	241	0	2,116	775	411	0	1,186	930
8	1960	Miscellaneous equipment	10.00%		0	0	0	0	0	0	0	0	0
47	1980	System Supervisory Equip	7.78%	2	8,874	1,310	(5)	10,179	2,468	984	(4)	3,448	6,731
47	1990	Other Tangible property	n/a		0	0	0	0	0	0	0	0	0
		Subtotal General Plant Assets	n/a		84,749	15,250	(15)	99,984	16,954	8,975	(14)	25,915	74,069
Other Capital													
47	2005	Prop. Under Capital Lease-Addiscott	4.00%		17,549	0	0	17,549	1,464	731	0	2,195	15,354
		Subtotal Other Capital Assets	n/a		17,549	0	0	17,549	1,464	731	0	2,195	15,354
		Total Assets Before Contributed Capital	n/a		1,036,432	109,014	(2,761)	1,142,685	84,406	43,793	(286)	127,913	1,014,772
47	1995/1996	Contributed Capital	varies		(281,711)	(24,442)	1,117	(305,036)	(16,959)	(8,873)	91	(25,741)	(279,295)
		NET DISTRIBUTION ASSETS	n/a		754,721	84,572	(1,644)	837,649	67,447	34,920	(195)	102,172	735,477
		Less Socialized Renewable Energy Generation Investments (input as negative) (5)			(1,097)	(740)	0	(1,837)	(72)	(73)	0	(145)	(1,692)
		Less Other Non Rate-Regulated Utility Assets *(input as negative) (4)*			(82)	194	0	112	23	(51)	0	(28)	140
		Total PP&E			753,542	84,026	(1,644)	835,924	67,398	34,796	(195)	101,999	733,926

10		Transportation
8		Stores Equipment
8		Tools, Shop & Garage

Less: *Fully Allocated Depreciation*	
Transportation	$ 1,596
Stores Equipment	$ 1
Tools, Shop & Garage	$ 430
less - Non- distribution	-$ 51
Net Depreciation	$ 32,842

NOTES:

(1) This is the depreciation rate on the largest component within the asset class. Actual depreciation is calculated on the specific rate for each component within the class.

(2) This is the average depreciation rate of subclass of assets within the asset group

(3) Work in progress expenditures have been removed

(4) Non-distribution assets have been removed. In some years the net impact is adding cost because the removal of the contributed capital on streetlighting exceeded the cost

(5) Renewable Generation ("RGEN") capital costs for 2010 and 2011 are included in the closing 2013 fixed assets balances above in the amount of $524k. In 2013 received Board approval for the renewable generation connection rate protection amount of $493k . This represents 94% of the total RGEN costs to be recovered from all provincial ratepayers through the IESO and not directly from PowerStream ratepayers. Accordingly this amount is removed from the fixed assets along with the associated depreciation as they are not included in revenue requirement. The residual 6%, otherwise known as the RGEN direct benefit, remain in rate base and are recovered from PowerStream rate payers as part of this Custom IR rate application

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Appendix G-2a-1
Fixed Asset Continuity Schedule

Year 2014

					COST (000's)				ACCUMULATIVE DEPRECIATION (000's)				
CCA Class	**GL account**	**Detail Asset Class**	**Depreciation Rate**	**Notes**	**Opening Balance**	**Additions (3)**	**Disposals/ Adjustments**	**Closing Balance**	**Opening Balance**	**Additions (3)**	**Disposals/ Adjustments**	**Closing Balance**	**Net Book Value (000's**
Distribution Assets													
47	1610	Hydro One TS - Contributed Capital	2.50%		4,972	0	(19)	4,953	605	288	0	893	4,060
n/a	1805	Land	0		18,231	4,191	0	22,422	0	0	0	0	22,422
CEC	1612	Land Rights	0		827	46	0	873	0	0	0	0	873
1	1808	Building & Fixtures	2.50%		6,648	70	0	6,718	590	211	0	801	5,917
47	1810	Major spare parts	0		8,757	1,121	0	9,878	0	0	0	0	9,878
47	1815	Transformer Stations	2.50%	1	100,005	3,280	0	103,285	13,408	4,004	14	17,426	85,859
47	1820	Distribution Stations	3.33%	1	23,111	1,205	0	24,316	4,367	1,391	0	5,758	18,558
47	1830	Poles, Towers & Fixtures	2.22%		129,521	14,911	(154)	144,278	7,784	3,255	(14)	11,025	133,253
47	1835	O/H Cond & Devices	2.50%		113,753	10,628	(131)	124,250	8,728	3,505	(9)	12,224	112,026
47	1840	U/G Conduit	1.67%		79,016	18,430	0	97,446	3,719	1,583	0	5,302	92,144
47	1845	U/G Cond & Devices	2.22%		245,766	34,636	(1,292)	279,110	16,809	7,082	(93)	23,798	255,312
47	1850	Line Transformers	2.92%	2	152,506	12,218	(1,480)	163,244	18,162	6,673	(215)	24,620	138,624
47	1855	Services (OH and UG)	3.25%	2	62,707	5,444	0	68,151	11,006	3,394	0	14,400	53,751
47	1860	Meters	5.33%	2	28,859	2,633	(1,605)	29,887	3,823	1,735	(120)	5,438	24,449
47	1862	Smart Meters	6.67%		48,371	1,463	0	49,834	10,587	3,559	0	14,146	35,688
47	1875	Streetlighting	4.00%		2,102	22	0	2,124	215	90	0	305	1,819
		Subtotal Distribution Assets	n/a		1,025,152	110,298	(4,681)	1,130,769	99,803	36,770	(437)	136,136	994,633
General Plant Assets													
1	1908	Building & Fixtures - Head office	2.00%	1	41,127	2,425	0	43,552	2,782	962	0	3,744	39,808
13	1910	Leasehold Improvements	30.00%		216	(25)	0	191	8	17	0	25	166
8	1915	Office Equipment	10.00%		4,894	44	0	4,938	1,610	594	0	2,204	2,734
50	1920	Computer hardware	20.42%	2	8,990	2,337	0	11,327	4,152	1,765	3	5,920	5,407
12	1611	Computer Software	22.78%	2	15,291	1,508	0	16,799	7,363	3,045	12	10,420	6,379
10	1930	Transportation	9.05%	2	13,415	1,008	(120)	14,303	4,139	1,757	(91)	5,805	8,498
8	1935	Stores Equipment	10.00%		3	142	0	145	(1)	5	1	5	140
8	1940	Tools, Shop & Garage	10.00%		3,753	564	0	4,317	1,228	450	0	1,678	2,639
8	1955	Communication Equipment	21.67%	2	2,116	119	0	2,235	1,186	361	0	1,547	688
8	1960	Miscellaneous equipment	10.00%		0	0	0	0	0	0	0	0	0
47	1980	System Supervisory Equip	7.78%	2	10,179	1,125	0	11,304	3,448	1,016	15	4,479	6,825
47	1990	Other Tangible property	n/a		0	0	0	0	0	0	0	0	0
		Subtotal General Plant Assets	n/a		99,984	9,247	(120)	109,111	25,915	9,972	(60)	35,827	73,284
Other Capital													
47	2005	Prop. Under Capital Lease-Addiscott	4.00%		17,549	0	0	17,549	2,195	731	0	2,926	14,623
		Subtotal Other Capital Assets	n/a		17,549	0	0	17,549	2,195	731	0	2,926	14,623
		Total Assets Before Contributed Capital	n/a		1,142,685	119,545	(4,801)	1,257,429	127,913	47,473	(497)	174,889	1,082,540
47	1995/1996	Contributed Capital	varies		(305,036)	(22,608)	798	(326,846)	(25,741)	(9,413)	90	(35,064)	(291,782)
		NET DISTRIBUTION ASSETS	n/a		837,649	96,937	(4,003)	930,583	102,172	38,060	(407)	139,825	790,758
		Less Socialized Renewable Energy Generation Investments (input as negative) (5)			(1,837)	(1,054)	0	(2,891)	(145)	(105)	0	(250)	(2,641)
		Less Other Non Rate-Regulated Utility Assets *(input as negative) (4)*			112	60	0	172	(28)	(45)	0	(73)	245
		Total PP&E			835,924	95,943	(4,003)	927,864	101,999	37,910	(407)	139,502	788,359

10		Transportation
8		Stores Equipment
8		Tools, Shop & Garage

Less: *Fully Allocated Depreciation*	
Transportation	$ 1,757
Stores Equipment	$ 5
Tools, Shop & Garage	$ 450
less - Non- distribution	-$ 45
Net Depreciation	$ 35,803

NOTES:

(1) This is the depreciation rate on the largest component within the asset class. Actual depreciation is calculated on the specific rate for each component within the class.

(2) This is the average depreciation rate of subclass of assets within the asset group

(3) Work in progress expenditures have been removed

(4) Non-distribution assets have been removed. In some years the net impact is adding cost because the removal of the contributed capital on streetlighting exceeded the cost

(5) Renewable Generation ("RGEN") capital costs for 2012 and 2013 are included in the closing 2014 fixed assets balances above. In 2014 received Board approval for the renewable generation connection rate protection("RGCRP") amount of $1,344k . This represents 94% of the total RGEN costs to be recovered from all provincial ratepayers through the IESO and not directly from PowerStream ratepayers. Accordingly the RGCRP amount is removed from the fixed assets and depreciation as they are not included in revenue requirement. The residual 6%, otherwise known as the RGEN direct benefit, remain in rate base and therefore are recovered from PowerStream rate payers as part of this Custom IR rate application

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Appendix G-2a-1
Fixed Asset Continuity Schedule

Year 2015

					COST (000's)				ACCUMULATIVE DEPRECIATION (000's)				
CCA Class	GL account	Detail Asset Class	Depreciation Rate	Notes	Opening Balance	Additions (3)	Disposals/ Adjustments	Closing Balance	Opening Balance	Additions (3)	Disposals/ Adjustments	Closing Balance	Net Book Value (000's
Distribution Assets													
47	1610	Hydro One TS - Contributed Capital	2.50%		4,953	0	0	4,953	893	288	0	1,181	3,772
n/a	1805	Land	0		22,422	1,125	0	23,547	0	0	0	0	23,547
CEC	1612	Land Rights	0		873	33	0	906	0	0	0	0	906
1	1808	Building & Fixtures	2.50%		6,718	211	0	6,929	801	215	0	1,016	5,913
47	1810	Major spare parts	0		9,878	0	0	9,878	0	0	0	0	9,878
47	1815	Transformer Stations	2.50%	1	103,285	2,968	0	106,253	17,426	4,065	0	21,491	84,762
47	1820	Distribution Stations	3.33%	1	24,316	4,071	0	28,387	5,758	1,444	0	7,202	21,185
47	1830	Poles, Towers & Fixtures	2.22%		144,278	16,590	(87)	160,781	11,025	3,605	(14)	14,616	146,165
47	1835	O/H Cond & Devices	2.50%		124,250	12,857	(130)	136,977	12,224	3,799	(10)	16,013	120,964
47	1840	U/G Conduit	1.67%		97,446	7,573	0	105,019	5,302	1,799	0	7,101	97,918
47	1845	U/G Cond & Devices	2.22%		279,110	37,965	(433)	316,642	23,798	8,059	(92)	31,765	284,877
47	1850	Line Transformers	2.92%	2	163,244	7,463	(1,901)	168,806	24,620	6,936	(215)	31,341	137,465
47	1855	Services (OH and UG)	3.25%	2	68,151	3,653	0	71,804	14,400	3,467	0	17,867	53,937
47	1860	Meters	5.33%	2	29,887	4,012	(661)	33,238	5,438	1,944	(330)	7,052	26,186
47	1860	Smart Meters	6.67%		49,834	1,185	0	51,019	14,146	3,648	0	17,794	33,225
47	1875	Streetlighting	4.00%		2,124	2	0	2,126	305	91	0	396	1,730
		Subtotal Distribution Assets	n/a		1,130,769	99,708	(3,212)	1,227,265	136,136	39,360	(661)	174,835	1,052,430
General Plant Assets													
1	1908	Building & Fixtures - Head office	2.00%	1	43,552	3,761	0	47,313	3,744	1,024	0	4,768	42,545
13	1910	Leasehold Improvements	30.00%		191	0	0	191	25	3	0	28	163
8	1915	Office Equipment	10.00%		4,938	97	0	5,035	2,204	596	0	2,800	2,235
50	1920	Computer hardware	20.42%	2	11,327	2,036	0	13,363	5,920	1,949	0	7,869	5,494
12	1611	Computer Software	22.78%	2	16,799	47,637	0	64,436	10,420	5,354	0	15,774	48,662
10	1930	Transportation	9.05%	2	14,303	2,263	0	16,566	5,805	1,814	0	7,619	8,947
8	1935	Stores Equipment	10.00%		145	535	0	680	5	39	0	44	636
8	1940	Tools, Shop & Garage	10.00%		4,317	558	0	4,875	1,678	473	0	2,151	2,724
8	1955	Communication Equipment	21.67%	2	2,235	364	0	2,599	1,547	250	0	1,797	802
8	1960	Miscellaneous equipment	10.00%		0	0	0	0	0	0	0	0	0
47	1980	System Supervisory Equip	7.78%	2	11,304	1,301	0	12,605	4,479	1,032	0	5,511	7,094
47	1990	Other Tangible property	n/a		0	0	0	0	0	0	0	0	0
		Subtotal General Plant Assets	n/a		109,111	58,552	0	167,663	35,827	12,534	0	48,361	119,302
Other Capital													
47	2005	Prop. Under Capital Lease-Addiscott	4.00%		17,549	0	0	17,549	2,926	731	0	3,657	13,892
		Subtotal Other Capital Assets	n/a		17,549	0	0	17,549	2,926	731	0	3,657	13,892
		Total Assets Before Contributed Capital	n/a		1,257,429	158,260	(3,212)	1,412,477	174,889	52,625	(661)	226,853	1,185,624
47	1995/1996	Contributed Capital	varies		(326,846)	(18,323)	993	(344,176)	(35,064)	(9,958)	90	(44,932)	(299,244)
		NET DISTRIBUTION ASSETS	n/a		930,583	139,937	(2,219)	1,068,301	139,825	42,667	(571)	181,921	886,380
		Less Socialized Renewable Energy Generation Investments (input as negative) (5)			(2,891)	(76)	0	(2,967)	(250)	(119)	0	(369)	(2,598)
		Less Other Non Rate-Regulated Utility Assets (input as negative) (4)			172	(2)	0	170	(73)	(44)	0	(117)	287
		Total PP&E			927,864	139,859	(2,219)	1,065,504	139,502	42,504	(571)	181,435	884,069

10		Transportation
8		Stores Equipment
8		Tools, Shop & Garage

Less: *Fully Allocated Depreciation*	
Transportation	$ 1,814
Stores Equipment	$ 39
Tools, Shop & Garage	$ 473
less - Non- distribution	-$ 44
Net Depreciation	$ 40,297

NOTES:

(1) This is the depreciation rate on the largest component within the asset class. Actual depreciation is calculated on the specific rate for each component within the class.

(2) This is the average depreciation rate of 2 subclass of assets within the asset group

(3) Work in progress expenditures have been removed

(4) Non-distribution assets have been removed. In some years the net impact is adding cost because the removal of the contributed capital on streetlighting exceeded the cost

(5) Renewable Generation ("RGEN") capital costs for 2014 and unrecovered costs from prior years are included in the closing 2015 fixed assets balances. The renewable generation connection rate protection("RGCRP") addtions represents 94% of the above in the amount of $1,054k. This amount was approved by the OEB and represents the eligible renewable generation connection rate protection total that PowerStream will receive from Ontario ratepayers through the IESO. The residual 6%, otherwise known as the RGEN direct benefit, has been included in the above 2015 fixed asset addtions and will be added to rate base to be recovered from PowerStream ratepayers.

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Appendix G-2a-1
Fixed Asset Continuity Schedule

Year 2016

CCA Class	GL account	Detail Asset Class	Depreciation Rate	Notes	COST (000's) Opening Balance	Additions (3)	Disposals/ Adjustments	Closing Balance	ACCUMULATIVE DEPRECIATION (000's) Opening Balance	Additions (3)	Disposals/ Adjustments	Closing Balance	Net Book Value (000's
Distribution Assets													
47	1610	Hydro One TS - Contributed Capital	2.50%		4,953	0	0	4,953	1,181	288	0	1,469	3,484
n/a	1805	Land	0		23,547	2,889	0	26,436	0	0	0	0	26,436
CEC	1612	Land Rights	0		906	34	0	940	0	0	0	0	940
1	1808	Building & Fixtures	2.50%		6,929	76	0	7,005	1,016	219	0	1,235	5,770
47	1810	Major spare parts	0		9,878	0	0	9,878	0	0	0	0	9,878
47	1815	Transformer Stations	2.50%	1	106,253	2,891	0	109,144	21,491	4,135	0	25,626	83,518
47	1820	Distribution Stations	3.33%	1	28,387	491	0	28,878	7,202	1,484	0	8,686	20,192
47	1830	Poles, Towers & Fixtures	2.22%		160,781	23,545	(87)	184,239	14,616	4,060	(14)	18,662	165,577
47	1835	O/H Cond & Devices	2.50%		136,977	24,397	(130)	161,244	16,013	4,229	(10)	20,232	141,012
47	1840	U/G Conduit	1.67%		105,019	6,333	0	111,352	7,101	1,893	0	8,994	102,358
47	1845	U/G Cond & Devices	2.22%		316,642	38,603	(433)	354,812	31,765	9,056	(92)	40,729	314,083
47	1850	Line Transformers	2.92%	2	168,806	13,235	(1,901)	180,140	31,341	7,274	(215)	38,400	141,740
47	1855	Services (OH and UG)	3.25%	2	71,804	4,118	0	75,922	17,867	3,522	0	21,389	54,533
47	1860	Meters	5.33%	2	33,238	2,924	(1,176)	34,986	7,052	2,165	(588)	8,629	26,357
47	1860	Smart Meters	6.67%		51,019	2,384	0	53,403	17,794	3,767	23	21,584	31,819
47	1875	Streetlighting	4.00%		2,126	2	0	2,128	396	91	0	487	1,641
		Subtotal Distribution Assets	n/a		1,227,265	121,922	(3,727)	1,345,460	174,835	42,183	(896)	216,122	1,129,338
General Plant Assets													
1	1908	Building & Fixtures - Head office	2.00%	1	47,313	398	0	47,711	4,768	1,068	0	5,836	41,875
13	1910	Leasehold Improvements	30.00%		191	0	0	191	28	(1)	0	27	164
8	1915	Office Equipment	10.00%		5,035	13	0	5,048	2,800	598	0	3,398	1,650
50	1920	Computer hardware	20.42%	2	13,363	2,194	0	15,557	7,869	2,161	28	10,058	5,499
12	1611	Computer Software	22.78%	2	64,436	9,413	0	73,849	15,774	8,382	0	24,156	49,693
10	1930	Transportation	9.05%	2	16,566	3,124	0	19,690	7,619	1,953	0	9,572	10,118
8	1935	Stores Equipment	10.00%		680	0	0	680	44	65	0	109	571
8	1940	Tools, Shop & Garage	10.00%		4,875	478	0	5,353	2,151	498	0	2,649	2,704
8	1955	Communication Equipment	21.67%	2	2,599	268	0	2,867	1,797	209	0	2,006	861
8	1960	Miscellaneous equipment	10.00%		0	0	0	0	0	0	0	0	0
47	1980	System Supervisory Equip	7.78%	2	12,605	1,596	0	14,201	5,511	1,044	8	6,563	7,638
47	1990	Other Tangible property	n/a		0	0	0	0	0	0	0	0	0
		Subtotal General Plant Assets	n/a		167,663	17,484	0	185,147	48,361	15,977	36	64,374	120,773
Other Capital									0				
47	2005	Prop. Under Capital Lease-Addiscott	4.00%		17,549	0	0	17,549	3,657	733	0	4,390	13,159
		Subtotal Other Capital Assets	n/a		17,549	0	0	17,549	3,657	733	0	4,390	13,159
		Total Assets Before Contributed Capital	n/a		1,412,477	139,406	(3,727)	1,548,156	226,853	58,893	(860)	284,886	1,263,270
47	1995/1996	Contributed Capital	varies		(344,176)	(22,014)	993	(365,197)	(44,932)	(10,620)	90	(55,462)	(309,734)
		NET DISTRIBUTION ASSETS	n/a		1,068,301	117,392	(2,734)	1,182,959	181,921	48,273	(770)	229,424	953,536
		Less Socialized Renewable Energy Generation Investments (input as negative) (5)			(2,967)	(67)	0	(3,034)	(369)	(110)	0	(479)	(2,555)
		Less Other Non Rate-Regulated Utility Assets (input as negative) (4)			170	(2)	0	168	(117)	(44)	0	(161)	329
		Total PP&E			1,065,504	117,323	(2,734)	1,180,093	181,435	48,119	(770)	228,784	951,309

10		Transportation
8		Stores Equipment
8		Tools, Shop & Garage

Less: *Fully Allocated Depreciation*

Transportation	$	1,953
Stores Equipment	$	65
Tools, Shop & Garage	$	498
less - Non- distribution	-$	44
Net Depreciation	$	45,713

NOTES:

(1) This is the depreciation rate on the largest component within the asset class. Actual depreciation is calculated on the specific rate for each component within the class.
(2) This is the average depreciation rate of the subclass of assets within the asset group
(3) Work in progress expenditures have been removed
(4) Non-distribution assets have been removed. In some years the net impact is adding cost because the removal of the contributed capital on streetlighting exceeded the cost

(5) Renewable Generation ("RGEN") capital costs for 2015 are included in the closing 2016 fixed assets balances. The renewable generation connection rate protection("RGCRP") addtions represents 94% of the RGEN costs and for 2017 the calculated amount is $76k. Upon approval PowerStream will receive the recoveries from Ontario ratepayers through the IESO. The residual 6%, otherwise known as the RGEN direct benefit, has been included in the above 2016 fixed asset addtions and therefore added to rate base to be recovered from PowerStream ratepayers.

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Fixed Asset Continuity Schedule
Year 2017

					COST (000's)				ACCUMULATIVE DEPRECIATION (000's)				
CCA Class	GL account	Detail Asset Class	Depreciation Rate	Notes	Opening Balance	Additions (3)	Disposals/ Adjustments	Closing Balance	Opening Balance	Additions (3)	Disposals/ Adjustments	Closing Balance	Net Book Value (000's
Distribution Assets													
47	1610	Hydro One TS - Contributed Capital	2.50%		4,953	0	0	4,953	1,469	288	0	1,757	3,196
n/a	1805	Land	0		26,436	0	0	26,436	0	0	0	0	26,436
CEC	1612	Land Rights	0		940	34	0	974	0	0	0	0	974
1	1808	Building & Fixtures	2.50%		7,005	77	0	7,082	1,235	220	0	1,455	5,627
47	1810	Major spare parts	0		9,878	0	0	9,878	0	0	0	0	9,878
47	1815	Transformer Stations	2.50%	1	109,144	24,962	0	134,106	25,626	4,377	0	30,003	104,103
47	1820	Distribution Stations	3.33%	1	28,878	2,886	0	31,764	8,686	1,461	0	10,147	21,617
47	1830	Poles, Towers & Fixtures	2.22%		184,239	24,299	(87)	208,451	18,662	4,583	(14)	23,231	185,220
47	1835	O/H Cond & Devices	2.50%		161,244	23,360	(130)	184,474	20,232	4,778	(10)	25,000	159,474
47	1840	U/G Conduit	1.67%		111,352	7,083	0	118,435	8,994	2,001	0	10,995	107,440
47	1845	U/G Cond & Devices	2.22%		354,812	43,436	(433)	397,815	40,729	10,062	(92)	50,699	347,116
47	1850	Line Transformers	2.92%	2	180,140	13,586	(1,901)	191,825	38,400	7,682	(215)	45,867	145,958
47	1855	Services (OH and UG)	3.25%	2	75,922	4,203	0	80,125	21,389	3,580	0	24,969	55,156
47	1860	Meters	5.33%	2	34,986	3,207	(1,176)	37,017	8,629	2,342	(588)	10,383	26,634
47	1860	Smart Meters	6.67%		53,403	1,536	0	54,939	21,584	3,888	0	25,472	29,467
47	1875	Streetlighting	4.00%		2,128	2	0	2,130	487	91	0	578	1,552
		Subtotal Distribution Assets	n/a		1,345,460	148,671	(3,727)	1,490,404	216,122	45,353	(919)	260,556	1,229,848
General Plant Assets													
1	1908	Building & Fixtures - Head office	2.00%	1	47,711	403	0	48,114	5,836	1,073	0	6,909	41,205
13	1910	Leasehold Improvements	30.00%		191	0	0	191	27	(1)	0	26	165
8	1915	Office Equipment	10.00%		5,048	24	0	5,072	3,398	598	0	3,996	1,076
50	1920	Computer hardware	20.42%	2	15,557	2,954	0	18,511	10,058	2,502	0	12,560	5,951
12	1611	Computer Software	22.78%	2	73,849	10,466	0	84,315	24,156	9,482	0	33,638	50,677
10	1930	Transportation	9.05%	2	19,690	2,686	0	22,376	9,572	2,046	0	11,618	10,758
8	1935	Stores Equipment	10.00%		680	0	0	680	109	66	0	175	505
8	1940	Tools, Shop & Garage	10.00%		5,353	473	0	5,826	2,649	507	0	3,156	2,670
8	1955	Communication Equipment	21.67%	2	2,867	513	0	3,380	2,006	212	0	2,218	1,162
8	1960	Miscellaneous equipment	10.00%		0	0	0	0	0	0	0	0	0
47	1980	System Supervisory Equip	7.78%	2	14,201	1,093	0	15,294	6,563	1,064	0	7,627	7,667
47	1990	Other Tangible property	n/a		0	0	0	0	0	0	0	0	0
		Subtotal General Plant Assets	n/a		185,147	18,612	0	203,759	64,374	17,549	0	81,923	121,836
Other Capital													
47	2005	Prop. Under Capital Lease-Addiscott	4.00%		17,549	0	0	17,549	4,390	731	0	5,121	12,428
		Subtotal Other Capital Assets	n/a		17,549	0	0	17,549	4,390	731	0	5,121	12,428
		Total Assets Before Contributed Capital	n/a		1,548,156	167,283	(3,727)	1,711,712	284,886	63,633	(919)	347,600	1,364,112
47	1995/1996	Contributed Capital	varies		(365,197)	(22,923)	993	(387,126)	(55,462)	(11,322)	90	(66,694)	(320,432)
		NET DISTRIBUTION ASSETS	n/a		1,182,959	144,360	(2,734)	1,324,586	229,424	52,311	(829)	280,906	1,043,680
		Less Socialized Renewable Energy Generation Investments (input as negative) (5)			(3,034)	0	0	(3,034)	(479)	(108)	0	(587)	(2,447)
		Less Other Non Rate-Regulated Utility Assets *(input as negative)* *(4)*			168	(2)	0	166	(161)	(44)	0	(205)	371
		Total PP&E			1,180,093	144,358	(2,734)	1,321,717	228,784	52,159	(829)	280,114	1,041,602

10		Transportation
8		Stores Equipment
8		Tools, Shop & Garage

Less: *Fully Allocated Depreciation*	
Transportation	$ 2,046
Stores Equipment	$ 66
Tools, Shop & Garage	$ 507
less - Non- distribution	-$ 44
Net Depreciation	$ 49,648

NOTES:

(1) This is the depreciation rate on the largest component within the asset class. Actual depreciation is calculated on the specific rate for each component within the class.

(2) This is the average depreciation rate of the subclass of assets within the asset group

(3) Work in progress expenditures have been removed

(4) Non-distribution assets have been removed. In some years the net impact is adding cost because the removal of the contributed capital on streetlighting exceeded the cost

(5) Renewable Generation ("RGEN") accumulative capital costs for 2016 are included in the closing 2017 fixed assets balances. The renewable generation connection rate protection("RGCRP") addtions represents 94% of the RGEN costs and for 2017 the calculated amount is $67k. Upon approval PowerStream will receive the recoveries from Ontario ratepayers through the IESO. The residual 6%, otherwise known as the RGEN direct benefit, has been included in the above 2017 fixed asset addtions and is added to rate base to be recovered from PowerStream ratepayers.

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Appendix G-2a-1
Fixed Asset Continuity Schedule
Year 2018

CCA Class	GL account	Detail Asset Class	Depreciation Rate	Notes	COST (000's) Opening Balance	Additions (3)	Disposals/ Adjustments	Closing Balance	ACCUMULATIVE DEPRECIATION (000's) Opening Balance	Additions (3)	Disposals/ Adjustments	Closing Balance	Net Book Value (000's
Distribution Assets													
47	1610	Hydro One TS - Contributed Capital	2.50%		4,953	0	0	4,953	1,757	288	0	2,045	2,908
n/a	1805	Land	0		26,436	9	0	26,445	0	0	0	0	26,445
CEC	1612	Land Rights	0		974	35	0	1,009	0	0	0	0	1,009
1	1808	Building & Fixtures	2.50%		7,082	156	0	7,238	1,455	223	0	1,678	5,560
47	1810	Major spare parts	0		9,878	0	0	9,878	0	0	0	0	9,878
47	1815	Transformer Stations	2.50%	1	134,106	4,765	0	138,871	30,003	4,685	0	34,688	104,183
47	1820	Distribution Stations	3.33%	1	31,764	9,507	0	41,271	10,147	1,567	0	11,714	29,557
47	1830	Poles, Towers & Fixtures	2.22%		208,451	22,367	(87)	230,731	23,231	5,102	(14)	28,319	202,412
47	1835	O/H Cond & Devices	2.50%		184,474	22,313	(130)	206,657	25,000	5,310	(10)	30,300	176,357
47	1840	U/G Conduit	1.67%		118,435	7,478	0	125,913	10,995	2,123	0	13,118	112,795
47	1845	U/G Cond & Devices	2.22%		397,815	43,414	(433)	440,796	50,699	11,128	(92)	61,735	379,061
47	1850	Line Transformers	2.92%	2	191,825	14,439	(1,901)	204,363	45,867	8,092	(215)	53,744	150,619
47	1855	Services (OH and UG)	3.25%	2	80,125	4,408	0	84,533	24,969	3,643	0	28,612	55,921
47	1860	Meters	5.33%	2	37,017	4,366	(1,176)	40,207	10,383	2,544	(588)	12,339	27,868
47	1860	Smart Meters	6.67%		54,939	1,259	0	56,198	25,472	4,003	0	29,475	26,723
47	1875	Streetlighting	4.00%		2,130	2	0	2,132	578	91	0	669	1,463
		Subtotal Distribution Assets	n/a		1,490,404	134,518	(3,727)	1,621,195	260,556	48,799	(919)	308,436	1,312,759
General Plant Assets													
1	1908	Building & Fixtures - Head office	2.00%	1	48,114	407	0	48,521	6,909	1,082	0	7,991	40,530
13	1910	Leasehold Improvements	30.00%		191	0	0	191	26	(1)	0	25	166
8	1915	Office Equipment	10.00%		5,072	35	0	5,107	3,996	427	0	4,423	684
50	1920	Computer hardware	20.42%	2	18,511	1,355	0	19,866	12,560	2,741	0	15,301	4,565
12	1611	Computer Software	22.78%	2	84,315	6,320	0	90,635	33,638	9,386	0	43,024	47,611
10	1930	Transportation	9.05%	2	22,376	2,910	0	25,286	11,618	2,156	0	13,774	11,512
8	1935	Stores Equipment	10.00%		680	0	0	680	175	66	0	241	439
8	1940	Tools, Shop & Garage	10.00%		5,826	573	0	6,399	3,156	522	0	3,678	2,721
8	1955	Communication Equipment	21.67%	2	3,380	317	0	3,697	2,218	215	0	2,433	1,264
8	1960	Miscellaneous equipment	10.00%		0	0	0	0	0	0	0	0	0
47	1980	System Supervisory Equip	7.78%	2	15,294	816	0	16,110	7,627	1,071	0	8,698	7,412
47	1990	Other Tangible property	n/a		0	0	0	0	0	0	0	0	0
		Subtotal General Plant Assets	n/a		203,759	12,733	0	216,492	81,923	17,665	0	99,588	116,904
Other Capital													
47	2005	Prop. Under Capital Lease-Addiscott	4.00%		17,549	0	0	17,549	5,121	731	0	5,852	11,697
		Subtotal Other Capital Assets	n/a		17,549	0	0	17,549	5,121	731	0	5,852	11,697
		Total Assets Before Contributed Capital	n/a		1,711,712	147,251	(3,727)	1,855,236	347,600	67,195	(919)	413,876	1,441,360
47	1995/1996	Contributed Capital	varies		(387,126)	(23,833)	993	(409,966)	(66,694)	(12,073)	90	(78,678)	(331,288)
		NET DISTRIBUTION ASSETS	n/a		1,324,586	123,418	(2,734)	1,445,270	280,906	55,122	(829)	335,198	1,110,072
		Less Socialized Renewable Energy Generation Investments (input as negative) (5)			(3,034)	0	0	(3,034)	(587)	(106)	0	(693)	(2,341)
		Less Other Non Rate-Regulated Utility Assets (input as negative) (4)			166	(2)	0	164	(205)	(44)	0	(249)	412
		Total PP&E			1,321,717	123,416	(2,734)	1,442,399	280,114	54,972	(829)	334,256	1,108,144

10		Transportation
8		Stores Equipment
8		Tools, Shop & Garage

Less: *Fully Allocated Depreciation*		
Transportation	$	2,156
Stores Equipment	$	66
Tools, Shop & Garage	$	522
less - Non- distribution	-$	44
Net Depreciation	$	52,334

NOTES:

(1) This is the depreciation rate on the largest component within the asset class. Actual depreciation is calculated on the specific rate for each component within the class.

(2) This is the average depreciation rate of the subclass of assets within the asset group

(3) Work in progress expenditures have been removed

(4) Non-distribution assets have been removed. In some years the net impact is adding cost because the removal of the contributed capital on streetlighting exceeded the cost

(5) Renewable Generation ("RGEN") accumulative capital costs for 2017 are included in the closing 2018 fixed assets balances. The renewable generation connection rate protection("RGCRP") addtions represents 94% of the RGEN costs and for 2017 there are no additional costs. Upon approval PowerStream will receive the recoveries from Ontario ratepayers through the IESO. The residual 6%, otherwise known as the RGEN direct benefit, is included in the 2017 fixed asset balances and is added to rate base to be recovered from PowerStream ratepayers.

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Fixed Asset Continuity Schedule

Year **2019**

CCA Class	GL account	Detail Asset Class	Depreciation Rate	Notes	COST (000's) Opening Balance	COST Additions (3)	COST Disposals/ Adjustments	COST Closing Balance	ACCUMULATIVE DEPRECIATION (000's) Opening Balance	ACCUM. DEPR. Additions (3)	ACCUM. DEPR. Disposals/ Adjustments	ACCUM. DEPR. Closing Balance	Net Book Value (000's
Distribution Assets													
47	1610	Hydro One TS - Contributed Capital	2.50%		4,953	0	0	4,953	2,045	288	0	2,333	2,620
n/a	1805	Land	0		26,445	758	0	27,203	0	0	0	0	27,203
CEC	1612	Land Rights	0		1,009	35	0	1,044	0	0	0	0	1,044
1	1808	Building & Fixtures	2.50%		7,238	137	0	7,375	1,678	227	0	1,905	5,470
47	1810	Major spare parts	0		9,878	0	0	9,878	0	0	0	0	9,878
47	1815	Transformer Stations	2.50%	1	138,871	4,262	0	143,133	34,688	4,771	0	39,459	103,674
47	1820	Distribution Stations	3.33%	1	41,271	13,038	0	54,309	11,714	1,873	0	13,587	40,722
47	1830	Poles, Towers & Fixtures	2.22%		230,731	18,249	(87)	248,893	28,319	5,553	(14)	33,858	215,035
47	1835	O/H Cond & Devices	2.50%		206,657	29,344	(130)	235,871	30,300	5,917	(10)	36,207	199,664
47	1840	U/G Conduit	1.67%		125,913	7,232	0	133,145	13,118	2,245	0	15,363	117,782
47	1845	U/G Cond & Devices	2.22%		440,796	42,793	(433)	483,156	61,735	12,194	(92)	73,837	409,319
47	1850	Line Transformers	2.92%	2	204,363	14,830	(1,901)	217,292	53,744	8,504	(215)	62,033	155,259
47	1855	Services (OH and UG)	3.25%	2	84,533	4,842	0	89,375	28,612	3,737	0	32,349	57,026
47	1860	Meters	5.33%	2	40,207	5,416	(1,176)	44,447	12,339	2,748	(588)	14,499	29,948
47	1860	Smart Meters	6.67%		56,198	1,248	0	57,446	29,475	4,174	0	33,649	23,797
47	1875	Streetlighting	4.00%		2,132	2	0	2,134	669	91	0	760	1,374
		Subtotal Distribution Assets	n/a		1,621,195	142,186	(3,727)	1,759,654	308,436	52,322	(919)	359,839	1,399,815
General Plant Assets													
1	1908	Building & Fixtures - Head office	2.00%	1	48,521	417	0	48,938	7,991	1,090	0	9,081	39,857
13	1910	Leasehold Improvements	30.00%		191	0	0	191	25	(1)	0	24	167
8	1915	Office Equipment	10.00%		5,107	13	0	5,120	4,423	246	0	4,669	451
50	1920	Computer hardware	20.42%	2	19,866	2,310	0	22,176	15,301	2,559	0	17,860	4,316
12	1611	Computer Software	22.78%	2	90,635	7,880	0	98,515	43,024	9,835	0	52,859	45,656
10	1930	Transportation	9.05%	2	25,286	3,098	0	28,384	13,774	2,362	0	16,136	12,248
8	1935	Stores Equipment	10.00%		680	0	0	680	241	66	0	307	373
8	1940	Tools, Shop & Garage	10.00%		6,399	589	0	6,988	3,678	542	0	4,220	2,768
8	1955	Communication Equipment	21.67%	2	3,697	317	0	4,014	2,433	202	0	2,635	1,379
8	1960	Miscellaneous equipment	10.00%		0	0	0	0	0	0	0	0	0
47	1980	System Supervisory Equip	7.78%	2	16,110	1,159	0	17,269	8,698	1,080	0	9,778	7,491
47	1990	Other Tangible property	n/a		0	0	0	0	0	0	0	0	0
		Subtotal General Plant Assets	n/a		216,492	15,783	0	232,275	99,588	17,981	0	117,569	114,706
Other Capital													
47	2005	Prop. Under Capital Lease-Addiscott	4.00%		17,549	0	0	17,549	5,852	731	0	6,583	10,966
		Subtotal Other Capital Assets	n/a		17,549	0	0	17,549	5,852	731	0	6,583	10,966
		Total Assets Before Contributed Capital	n/a		1,855,236	157,969	(3,727)	2,009,478	413,876	71,034	(919)	483,991	1,525,487
47	1995/1996	Contributed Capital	varies		(409,966)	(23,802)	993	(432,775)	(78,678)	(12,831)	90	(91,419)	(341,357)
		NET DISTRIBUTION ASSETS	n/a		1,445,270	134,167	(2,734)	1,576,703	335,198	58,203	(829)	392,572	1,184,130
		Less Socialized Renewable Energy Generation Investments (input as negative) (5)			(3,034)	0	0	(3,034)	(693)	(105)	0	(798)	(2,236)
		Less Other Non Rate-Regulated Utility Assets (input as negative) (4)			164	(2)	0	161	(249)	(44)	0	(293)	454
		Total PP&E			1,442,399	134,164	(2,734)	1,573,830	334,256	58,054	(829)	391,481	1,182,348

10		Transportation
8		Stores Equipment
8		Tools, Shop & Garage

Less: *Fully Allocated Depreciation*	
Transportation	$ 2,362
Stores Equipment	$ 66
Tools, Shop & Garage	$ 542
less - Non- distribution	-$ 44
Net Depreciation	$ 55,189

NOTES:

(1) This is the depreciation rate on the largest component within the asset class. Actual depreciation is calculated on the specific rate for each component within the class.

(2) This is the average depreciation rate of the subclass of assets within the asset group

(3) Work in progress expenditures have been removed

(4) Non-distribution assets have been removed. In some years the net impact is adding cost because the removal of the contributed capital on streetlighting exceeded the cost

(5) Renewable Generation ("RGEN") accumulative capital costs for 2018 are included in the closing 2019 fixed assets balances. The renewable generation connection rate protection("RGCRP") addtions represents 94% of the RGEN costs and for 2018 there are no additional costs. Upon approval PowerStream will receive the recoveries from Ontario ratepayers through the IESO. The residual 6%, otherwise known as the RGEN direct benefit, is included in the 2018 fixed asset balances and is added to rate base to be recovered from PowerStream ratepayers.

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Appendix G-2a-1
Fixed Asset Continuity Schedule
Year **2020**

CCA Class	GL account	Detail Asset Class	Depreciation Rate	Notes	COST (000's) Opening Balance	Additions (3)	Disposals/ Adjustments	Closing Balance	ACCUMULATIVE DEPRECIATION (000's) Opening Balance	Additions (3)	Disposals/ Adjustments	Closing Balance	Net Book Value (000's
Distribution Assets													
47	1610	Hydro One TS - Contributed Capital	2.50%		4,953	0	0	4,953	2,333	288	0	2,621	2,332
n/a	1805	Land	0		27,203	10	0	27,213	0	0	0	0	27,213
CEC	1612	Land Rights	0		1,044	36	0	1,080	0	0	0	0	1,080
1	1808	Building & Fixtures	2.50%		7,375	139	0	7,514	1,905	231	0	2,136	5,378
47	1810	Major spare parts	0		9,878	0	0	9,878	0	0	0	0	9,878
47	1815	Transformer Stations	2.50%	1	143,133	3,697	0	146,830	39,459	4,859	0	44,318	102,512
47	1820	Distribution Stations	3.33%	1	54,309	7,656	0	61,965	13,587	2,105	0	15,692	46,273
47	1830	Poles, Towers & Fixtures	2.22%		248,893	18,906	(87)	267,712	33,858	5,974	(14)	39,818	227,894
47	1835	O/H Cond & Devices	2.50%		235,871	21,065	(130)	256,806	36,207	6,556	(10)	42,753	214,053
47	1840	U/G Conduit	1.67%		133,145	7,902	0	141,047	15,363	2,375	0	17,738	123,309
47	1845	U/G Cond & Devices	2.22%		483,156	48,289	(433)	531,012	73,837	13,273	(92)	87,018	443,994
47	1850	Line Transformers	2.92%	2	217,292	14,552	(1,901)	229,943	62,033	8,909	(215)	70,727	159,216
47	1855	Services (OH and UG)	3.25%	2	89,375	4,777	0	94,152	32,349	3,864	0	36,213	57,939
47	1860	Meters	5.33%	2	44,447	2,865	(1,176)	46,136	14,499	2,930	(588)	16,841	29,295
47	1860	Smart Meters	6.67%		57,446	5,655	0	63,101	33,649	4,480	0	38,129	24,972
47	1875	Streetlighting	4.00%		2,134	2	0	2,136	760	91	0	851	1,285
		Subtotal Distribution Assets	n/a		1,759,654	135,551	(3,727)	1,891,478	359,839	55,935	(919)	414,855	1,476,623
General Plant Assets													
1	1908	Building & Fixtures - Head office	2.00%	1	48,938	417	0	49,355	9,081	1,101	0	10,182	39,173
13	1910	Leasehold Improvements	30.00%		191	0	0	191	24	(1)	0	23	168
8	1915	Office Equipment	10.00%		5,120	286	0	5,406	4,669	175	0	4,844	562
50	1920	Computer hardware	20.42%	2	22,176	2,531	0	24,707	17,860	2,650	0	20,510	4,197
12	1611	Computer Software	22.78%	2	98,515	8,212	0	106,727	52,859	9,975	0	62,834	43,893
10	1930	Transportation	9.05%	2	28,384	2,948	0	31,332	16,136	2,373	0	18,509	12,823
8	1935	Stores Equipment	10.00%		680	0	0	680	307	66	0	373	307
8	1940	Tools, Shop & Garage	10.00%		6,988	543	0	7,531	4,220	553	0	4,773	2,758
8	1955	Communication Equipment	21.67%	2	4,014	310	0	4,324	2,635	206	0	2,841	1,483
8	1960	Miscellaneous equipment	10.00%		0	0	0	0	0	0	0	0	0
47	1980	System Supervisory Equip	7.78%	2	17,269	1,204	0	18,473	9,778	1,120	0	10,898	7,575
47	1990	Other Tangible property	n/a		0	0	0	0	0	0	0	0	0
		Subtotal General Plant Assets	n/a		232,275	16,451	0	248,726	117,569	18,218	0	135,787	112,939
Other Capital													
47	2005	Prop. Under Capital Lease-Addiscott	4.00%		17,549	0	0	17,549	6,583	733	0	7,316	10,233
		Subtotal Other Capital Assets	n/a		17,549	0	0	17,549	6,583	733	0	7,316	10,233
		Total Assets Before Contributed Capital	n/a		2,009,478	152,002	(3,727)	2,157,753	483,991	74,886	(919)	557,958	1,599,795
47	1995/1996	Contributed Capital	varies		(432,775)	(25,323)	993	(457,105)	(91,419)	(13,522)	90	(104,852)	(352,254)
		NET DISTRIBUTION ASSETS	n/a		1,576,703	126,679	(2,734)	1,700,648	392,572	61,364	(829)	453,106	1,247,541
		***Less Socialized Renewable Energy Generation Investments** (input as negative) (5)*			(3,034)	0	0	(3,034)	(798)	(104)	0	(902)	(2,132)
		***Less Other Non Rate-Regulated Utility Assets** (input as negative) (4)*			161	(2)	0	159	(293)	(44)	0	(337)	496
		Total PP&E			1,573,830	126,677	(2,734)	1,697,773	391,481	61,216	(829)	451,868	1,245,906

10		Transportation
8		Stores Equipment
8		Tools, Shop & Garage

Less: *Fully Allocated Depreciation*	
Transportation	$ 2,373
Stores Equipment	$ 66
Tools, Shop & Garage	$ 553
less - Non- distribution	-$ 44
Net Depreciation	$ 58,328

NOTES:

(1) This is the depreciation rate on the largest component within the asset class. Actual depreciation is calculated on the specific rate for each component within the class.

(2) This is the average depreciation rate of the subclass of assets within the asset group

(3) Work in progress expenditures have been removed

(4) Non-distribution assets have been removed. In some years the net impact is adding cost because the removal of the contributed capital on streetlighting exceeded the cost

(5) Renewable Generation ("RGEN") accumulative capital costs for 2020 are included in the closing 2020 fixed assets balances. The renewable generation connection rate protection("RGCRP") addtions represents 94% of the RGEN costs and for 2019 and 2020 there are no additional costs. Upon approval PowerStream will receive the recoveries from Ontario ratepayers through the IESO. The residual 6%, otherwise known as the RGEN direct benefit, is included in the 2020 fixed asset balances and is added to rate base to be recovered from PowerStream ratepayers.

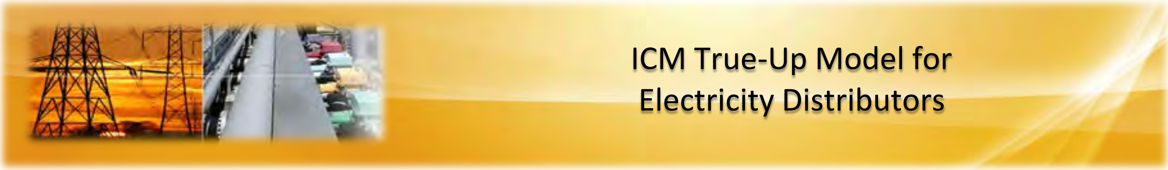
ICM True-Up Model

Version 4.00

Utility Name	PowerStream Inc.
Assigned EB Number	EB-2015-0103
Name and Title	Tom Barrett, Manager, Rates Applications
Phone Number	905-532-4640
Email Address	tom.barrett@powerstream.ca
Date	24-Feb-15
Last COS Re-based Year	**2013**

Note: Drop-down lists are shaded blue; Input cells are shaded green.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results. The use of any models and spreadsheets does not automatically imply Board approval. The onus is on the distributor to prepare, document and support its application. Board-issued Excel models and spreadsheets are offered to assist parties in providing the necessary information so as to facilitate an expeditious review of an application. The onus remains on the applicant to ensure the accuracy of the data and the results.



Sheet 2: ICM Capital Cost Data

1 Capital Costs

	Asset Type	2014 Audited Actual
ICP 1 UNDERGROUND CABLE REHABILITATION	Asset type must be selected to enable calculations	Audited Actual
ICP 1.1	Poles	24,226
ICP 1.2	Overhead Conductor	19,823
ICP 1.3	Underground Conduit	2,305,442
ICP 1.4	Underground Conductor	723,816
ICP 1.5	Underground Injected Cable	3,890,145
ICP 1.6	Underground Transformers	49,234
ICP 1.7	Overhead Transformers	393
ICP 1.8	Overhead Services	3,551
ICP 1.9		
ICP 1.10		
Total Underground Cable Rehabilitation		$ 7,016,630

	Asset Type	Audited Actual
ICP 2 SYSTEM RENEWAL - POLE REPLACEMENTS		
ICP 2.1.	Poles	961,466
ICP 2.2	Overhead Conductor	406,931
ICP 2.3	Underground Conductor	56,172
ICP 2.4	Overhead Transformers	117,810
ICP 2.5	Underground Transformers	12,990
ICP 2.6	Overhead Services	79,026
ICP 2.7	Underground Conduit	19,646
ICP 2.8	System Supervisory Equipment	175
ICP 2.9	Distribution Station Equipment - Normally Primary below 50 kV	146
ICP 2.10	Underground Injected Cable	51
Total System Renewal - Pole Replacements		$ 1,654,412

	Asset Type	Audited Actual
ICP 3 SYSTEM RENEWAL - STATION REPLACEMENTS		
ICP 3.1	Poles	25,605
ICP 3.2	Overhead Conductor	79,225
ICP 3.3	RTU's	79,025
ICP 3.4	Underground Conductor	3,329
ICP 3.5	Underground Transformers	74
ICP 3.6	Overhead Services	509
ICP 3.7	System Supervisory Equipment	320
ICP 3.8	Distribution Station Equipment - Normally Primary below 50 kV	9,923
ICP 3.9	Transformer Station Equipment - Normally Primary above 50 kV	125,164
ICP 3.10		
Total System Renewal - Station Replacements		$ 323,174

	Asset Type	Audited Actual
ICP 4 SYSTEM RENEWAL - SWITCHGEAR & TRANFORMER REPLACEMENTS		
ICP 4.1	Poles	9,421

ICP 4.2	Overhead Conductor	2,502
ICP 4.3	Underground Conduit	186,340
ICP 4.4	Underground Conductor	925,519
ICP 4.5	Overhead Transformers	12
ICP 4.6	Underground Transformers	165,200
ICP 4.7	Overhead Services	23,764
ICP 4.8	RTU's	-7,819
ICP 4.9	Distribution Station Equipment - Normally Primary below 50 kV	2,217
ICP 4.10	Land Rights	19
Total System Renewal - Switchgear & Transformer ReplacementS		$ 1,307,175

ICP 5 SYSTEM CAPACITY RELIEF	**Asset Type**	Audited Actual
ICP 5.1	Poles	285,853
ICP 5.2	Overhead Conductor	193,612
ICP 5.3	Underground Conduit	87,407
ICP 5.4	Underground Conductor	75,667
ICP 5.5	Overhead Transformers	10,496
ICP 5.6	Overhead Services	-470
ICP 5.7	RTU's	2,324
ICP 5.8		
ICP 5.9		
ICP 5.10		
Total System Capacity Relief		$ 654,890
Total Capital Costs Related to Incremental Capital Projects (ICP)		$ 10,956,281

OTHER CAPITAL COST	**Asset Type**	Audited Actual
A		
B		
C		
Total Other Capital Costs		$ -
Total ICM Capital Costs		$ 10,956,281

2 Aggregated ICM Costs by Category

2.1	**Capital**	**Account**	
2.1.1	Poles	1830	$ 1,306,572
2.1.2	Overhead Conductor	1835	$ 702,093
2.1.3	Underground Conduit	1840	$ 2,598,835
2.1.4	Underground Conductor	1845	$ 1,784,503
2.1.5	Underground Injected Cable	1846	$ 3,890,196
2.1.6	Overhead Transformers	1849	$ 128,712
2.1.7	Underground Transformers	1850	$ 227,498
2.1.8	Overhead Services	1855	$ 106,380
2.1.9	RTU's	1981	$ 73,531
2.1.10	System Supervisory Equipment	1980	$ 494
2.1.11	Distribution Station Equipment - Normally Primary below 50 kV	1820	$ 12,286
2.1.12	Transformer Station Equipment - Normally Primary above 50 kV	1815	$ 125,164
2.1.13	Land Rights	1612	$ 19
2.1.14			
	Total Capital Costs		**$ 10,956,281**

ICM True-Up Model for Electricity Distributors

Sheet 3: Parameters and Rates

	2014
Cost of Capital	
Capital Structure	
Deemed Short-term Debt Capitalization	4.0%
Deemed Long-term Debt Capitalization	56.0%
Deemed Equity Capitalization	40.0%
Preferred Shares	
Total	100.0%
Cost of Capital Parameters	
Deemed Short-term Debt Rate	2.08%
Long-term Debt Rate (actual/embedded/deemed)1	4.15%
Target Return on Equity (ROE)	8.93%
Return on Preferred Shares	
WACC	5.98%
Working Capital Allowance	
Working Capital Allowance Rate	13.0%
(% of the sum of Cost of Power + controllable expenses)	
Taxes/PILs	
Aggregate Corporate Income Tax Rate	26.00%
Capital Tax (until July 1st, 2010)	0.00%

Depreciation Rates
(expressed as expected useful life in years)

	Account		
Poles - years	1830	45	
- rate (%)		2.22%	
Overhead Conductor - years	1835	40	
- rate (%)		2.50%	
Underground Conduit - years	1840	60	
- rate (%)		1.67%	
Underground Conductor - years	1845	45	
- rate (%)		2.22%	
U/G Injected Cable - years	1846	20	
- rate (%)		5.00%	
Overhead Transformers - years	1849	40	
- rate (%)		2.50%	
Underground Transformers - years	1850	30	
- rate (%)		3.33%	
OH Services - years	1855	40	
- rate (%)		2.50%	
RTU's - years	1981	15	
- rate (%)		6.67%	
System Supervisory Equipment - years	1980	15	
- rate (%)		6.67%	
Distribution Station Equipment - years	1820	30	
- rate (%)		3.33%	
Transformer Station Equipment - years	1815	40	
- rate (%)		2.50%	
Land Rights - years	1612	-	*no depreciation (ECE)*
- rate (%)		0.00%	

CCA Rates

Poles - CCA Class	47
Pole - CCA Rate	8%
Overhead Conductor - CCA Class	47
Overhead Conductor - CCA Rate	8%
Underground Conduit - CCA Class	47
Underground Conduit - CCA Rate	8%
Underground Conductor - CCA Class	47
Underground Conductor - CCA Rate	8%
U/G Injected Cable - CCA Class	47
U/G Injected Cable - CCA Rate	8%
Overhead Transformers - CCA Class	47
Overhead Transformers - CCA Rate	8%
Underground Transformers - CCA Class	47
Underground Transformers - CCA Rate	8%
OH Services - CCA Class	47
OH Services - CCA Rate	8%
RTU's - CCA Class	8
RUT's - CCA Rate	20%
System Supervisory Equipment - CCA Class	8
System Supervisory Equipment - CCA Rate	20%
Distribution Station Equipment - CCA Class	47
Distribution Station Equipment - CCA Rate	8%
Transformer Station Equipment - CCA Class	47
Transformer Station Equipment - CCA Rate	8%
Land Rights - CCA Class	
Land Rights - CCA Rate	

Assumptions

[1] *Fiscal calendar year (January 1 to December 31) used.*
3 *Amortization is done on a striaght line basis and no "half-year" rule applied.*

Sheet 4: ICM Assets - Net Book Value

Net Fixed Assets - Poles

	2014
Gross Book Value	
Opening Balance	
Capital Additions during year (from ICM Costs)	$ 1,306,572
Retirements/Removals (if applicable)	
Closing Balance	$ 1,306,572
Accumulated Depreciation	
Opening Balance	
Amortization expense during year	-$ 29,035
Retirements/Removals (if applicable)	
Closing Balance	-$ 29,035
Net Book Value	
Opening Balance	$ -
Closing Balance	$ 1,277,537
Incremental CAPEX	**$ 1,277,537**

Net Fixed Assets - Overhead Conductor

	2014
Gross Book Value	
Opening Balance	
Capital Additions during year (from ICM Costs)	$ 702,093
Retirements/Removals (if applicable)	
Closing Balance	$ 702,093
Accumulated Depreciation	
Opening Balance	
Amortization expense during year	-$ 17,552
Retirements/Removals (if applicable)	
Closing Balance	-$ 17,552

Net Book Value		
Opening Balance	$	-
Closing Balance	$	684,541
Incremental CAPEX	**$**	**684,541**

Net Fixed Assets - Underground Conduit

Gross Book Value		
Opening Balance		
Capital Additions during year (from ICM Costs)	$	2,598,835
Retirements/Removals (if applicable)		
Closing Balance	$	2,598,835
Accumulated Depreciation		
Opening Balance		
Amortization expense during year	-$	43,314
Retirements/Removals (if applicable)		
Closing Balance	-$	43,314
Net Book Value		
Opening Balance	$	-
Closing Balance	$	2,555,521
Incremental CAPEX	**$**	**2,555,521**

Net Fixed Assets - Underground Conductor

Gross Book Value		
Opening Balance		
Capital Additions during year (from ICM Costs)	$	1,784,503
Retirements/Removals (if applicable)		
Closing Balance	$	1,784,503
Accumulated Depreciation		
Opening Balance		
Amortization expense during year	-$	39,656
Retirements/Removals (if applicable)		
Closing Balance	-$	39,656
Net Book Value		
Opening Balance	$	-
Closing Balance	$	1,744,847
Incremental CAPEX	**$**	**1,744,847**

Net Fixed Assets - U/G Injected Cable

Gross Book Value		
Opening Balance		
Capital Additions during year (from ICM Costs)	$	3,890,196
Retirements/Removals (if applicable)		
Closing Balance	$	3,890,196
Accumulated Depreciation		

Opening Balance		
Amortization expense during year	-$	194,510
Retirements/Removals (if applicable)		
Closing Balance	-$	194,510
Net Book Value		
Opening Balance	$	-
Closing Balance	$	3,695,686
Incremental CAPEX	**$**	**3,695,686**

Net Fixed Assets - OH Transformers

Gross Book Value		
Opening Balance		
Capital Additions during year (from ICM Costs)	$	128,712
Retirements/Removals (if applicable)		
Closing Balance	$	128,712
Accumulated Depreciation		
Opening Balance		
Amortization expense during year	-$	3,218
Retirements/Removals (if applicable)		
Closing Balance	-$	3,218
Net Book Value		
Opening Balance	$	-
Closing Balance	$	125,494
Incremental CAPEX	**$**	**125,494**

Net Fixed Assets - UG Transformers

Gross Book Value		
Opening Balance		
Capital Additions during year (from ICM Costs)	$	227,498
Retirements/Removals (if applicable)		
Closing Balance	$	227,498
Accumulated Depreciation		
Opening Balance		
Amortization expense during year	-$	7,583
Retirements/Removals (if applicable)		
Closing Balance	-$	7,583
Net Book Value		
Opening Balance	$	-
Closing Balance	$	219,914
Incremental CAPEX	**$**	**219,914**

Net Fixed Assets - OH Services

Gross Book Value		
Opening Balance		
Capital Additions during year (from ICM Costs)	$	106,380
Retirements/Removals (if applicable)		
Closing Balance	$	106,380
Accumulated Depreciation		
Opening Balance		
Amortization expense during year	-$	2,660
Retirements/Removals (if applicable)		
Closing Balance	-$	2,660
Net Book Value		
Opening Balance	$	-
Closing Balance	$	103,721
Incremental CAPEX	**$**	**103,721**

Net Fixed Assets - RTUs

Gross Book Value		
Opening Balance		
Capital Additions during year (from ICM Costs)	$	73,531
Retirements/Removals (if applicable)		
Closing Balance	$	73,531
Accumulated Depreciation		
Opening Balance		
Amortization expense during year	-$	4,902
Retirements/Removals (if applicable)		
Closing Balance	-$	4,902
Net Book Value		
Opening Balance	$	-
Closing Balance	$	68,629
Incremental CAPEX	**$**	**68,629**

Net Fixed Assets - System Supervisory Equipment

Gross Book Value		
Opening Balance		
Capital Additions during year (from ICM Costs)	$	494
Retirements/Removals (if applicable)		
Closing Balance	$	494

Accumulated Depreciation	
Opening Balance	
Amortization expense during year	-$ 33
Retirements/Removals (if applicable)	
Closing Balance	-$ 33
Net Book Value	
Opening Balance	$ -
Closing Balance	$ 461
Incremental CAPEX	**$ 461**

Net Fixed Assets - Distribution Station Equipment

Gross Book Value	
Opening Balance	
Capital Additions during year (from ICM Costs)	$ 12,286
Retirements/Removals (if applicable)	
Closing Balance	$ 12,286
Accumulated Depreciation	
Opening Balance	
Amortization expense during year	-$ 410
Retirements/Removals (if applicable)	
Closing Balance	-$ 410
Net Book Value	
Opening Balance	$ -
Closing Balance	$ 11,876
Incremental CAPEX	**$ 11,876**

Net Fixed Assets - Transformer Station Equipment

Gross Book Value	
Opening Balance	
Capital Additions during year (from ICM Costs)	$ 125,164
Retirements/Removals (if applicable)	
Closing Balance	$ 125,164
Accumulated Depreciation	
Opening Balance	
Amortization expense during year	-$ 3,129
Retirements/Removals (if applicable)	
Closing Balance	-$ 3,129
Net Book Value	
Opening Balance	$ -
Closing Balance	$ 122,034
Incremental CAPEX	**$ 122,034**

Net Fixed Assets - Land Rights

Gross Book Value		
Opening Balance		
Capital Additions during year (from ICM Costs)	$	19
Retirements/Removals (if applicable)		
Closing Balance	$	19
Accumulated Depreciation		
Opening Balance		
Amortization expense during year	$	-
Retirements/Removals (if applicable)		
Closing Balance	$	-
Net Book Value		
Opening Balance	$	-
Closing Balance	$	19
Incremental CAPEX	**$**	**19**

Additions	**$**	**10,956,281**	#
Incremental CAPEX	**$**	**10,610,281**	#
Total Amortization	**-$**	**346,001**	#

ICM True-Up Model for Electricity Distributors

Sheet 6: CCA For PILs Calculation

UCC/Class 47

	2014 Audited Actual
Opening UCC	$ -
Capital Additions	$ 10,882,256
Retirements/Removals (if applicable)	
UCC Before Half Year Rule	$ 10,882,256
Half Year Rule (1/2 Additions - Disposals)	$ 5,441,128
Reduced UCC	$ 5,441,128
CCA Rate Class	47
CCA Rate	8%
CCA	$ 435,290.24
Closing UCC	$ 10,446,966

UCC/Class 8

	2014 Audited Actual
Opening UCC	$ -
Capital Additions RTU's	$ 74,025
Retirements/Removals (if applicable)	
UCC Before Half Year Rule	$ 74,025
Half Year Rule (1/2 Additions - Disposals)	$ 37,013
Reduced UCC	$ 37,013
CCA Rate Class	8
CCA Rate	20%
CCA	$ 7,403
Closing UCC	$ 66,623

Sheet 6: Incremental Capital Adjustment

Return on Rate Base

Incremental Capital CAPEX			$	10,956,281	B
Depreciation Expense			$	346,001	C
Incremental Capital CAPEX to be included in Rate Base			$	10,610,281	D = B - C
Deemed ShortTerm Debt %	4.0%	E	$	424,411	G = D * E
Deemed Long Term Debt %	56.0%	F	$	5,941,757	H = D * F
Short Term Interest	2.08%	I	$	8,828	K = G * I
Long Term Interest	4.15%	J	$	246,583	L = H * J
Return on Rate Base - Interest			$	255,411	M = K + L
Deemed Equity %	40.0%	N	$	4,244,112	P = D * N
Return on Rate Base -Equity	8.93%	O	$	378,999	Q = P * O
Return on Rate Base - Total			$	634,410	R = M + Q

Amortization Expense

Amortization Expense - Incremental		C	$	346,001	S

Grossed up PIL's

Regulatory Taxable Income		O	$	378,999	T
Add Back Amortization Expense		S	$	346,001	U
Deduct CCA			$	442,693	V
Incremental Taxable Income			$	282,307	W = T + U - V
Current Tax Rate (F1.1 Z-Factor Tax Changes)	26.0%	X			
PIL's Before Gross Up			$	73,400	Y = W * X
Incremental Grossed Up PIL's			$	99,189	Z = Y / (1 - X)

Ontario Capital Tax

Incremental Capital CAPEX			$	10,956,281	AA
Less : Available Capital Exemption (if any)			$	-	AB
Incremental Capital CAPEX subject to OCT			$	10,956,281	AC = AA - AB
Ontario Capital Tax Rate (F1.1 Z-Factor Tax Changes)	0.000%	AD			
Incremental Ontario Capital Tax			$	-	AE = AC * AD

Incremental Revenue Requirement

Return on Rate Base - Total		Q	$	634,410	AF
Amortization Expense - Total		S	$	346,001	AG
Incremental Grossed Up PIL's		Z	$	99,189	AH
Incremental Ontario Capital Tax		AE	$	-	AI
Incremental Revenue Requirement			$	1,079,600	AJ = AF + AG + AH + AI

This worksheet calculates the funding adder revenues.

Sheet 7: ICM Funding Adder Revenues

Prescribed Interest Rates	Approved Deferral and Variance Accounts	CWIP
2006 Q1		
2006 Q2	4.14%	4.68%
2006 Q3	4.59%	5.05%
2006 Q4	4.59%	4.72%
2007 Q1	4.59%	4.72%
2007 Q2	4.59%	4.72%
2007 Q3	4.59%	5.18%
2007 Q4	5.14%	5.18%
2008 Q1	5.14%	5.18%
2008 Q2	4.08%	5.18%
2008 Q3	3.35%	5.43%
2008 Q4	3.35%	5.43%
2009 Q1	2.45%	6.61%
2009 Q2	1.00%	6.61%
2009 Q3	0.55%	5.67%
2009 Q4	0.55%	4.66%
2010 Q1	0.55%	4.34%
2010 Q2	0.55%	4.34%
2010 Q3	0.89%	4.66%
2010 Q4	1.20%	4.01%
2011 Q1	1.47%	4.29%
2011 Q2	1.47%	4.29%
2011 Q3	1.47%	4.29%
2011 Q4	1.47%	3.92%
2012 Q1	1.47%	3.92%
2012 Q2	1.47%	3.23%
2012 Q3	1.47%	3.23%
2012 Q4	1.47%	3.70%
2013 Q1	1.47%	3.70%
2013 Q2	1.47%	3.17%
2013 Q3	1.47%	3.17%
2013 Q4	1.47%	3.17%
2014 Q1	1.47%	2.89%
2014 Q2	1.47%	2.89%
2014 Q3	1.47%	2.89%
2014 Q4	1.47%	2.89%
2015 Q1	1.47%	2.89%
2015 Q2	1.47%	2.89%
2015 Q3	1.47%	2.89%
2015 Q4	1.47%	2.89%

Account 1511 - Sub-account ICM Funding Adder Revenues

Date	Year	Quarter	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Principal & Interest (Cumm.)	Board Approved ICM Funding Adder	Board Approved ICM Funding Adder (Cumm.)
Jan-14	2014	Q1	$ -	$ -	1.47%	$ -	$ -	$ -	$ -
Feb-14	2014	Q1	$ -	$ -	1.47%	$ -	$ -	$ -	$ -
Mar-14	2014	Q1	$ -	$ 81,633.07	1.47%	$ -	$ 81,633.07	$ 83,403.75	$ 83,403.75
Apr-14	2014	Q2	$ 81,633.07	$ 79,489.14	1.47%	$ 100.00	$ 161,222.21	$ 83,403.75	$ 166,807.50
May-14	2014	Q2	$ 161,122.21	$ 101,852.75	1.47%	$ 197.37	$ 263,272.33	$ 83,403.75	$ 250,211.24
Jun-14	2014	Q2	$ 262,974.96	$ 88,915.12	1.47%	$ 322.14	$ 352,509.59	$ 83,403.75	$ 333,614.99
Jul-14	2014	Q3	$ 351,890.08	$ 96,907.28	1.47%	$ 431.07	$ 449,847.94	$ 83,403.75	$ 417,018.74
Aug-14	2014	Q3	$ 448,797.36	$ 102,961.39	1.47%	$ 549.78	$ 553,359.11	$ 83,403.75	$ 500,422.49
Sep-14	2014	Q3	$ 551,758.75	$ 98,095.57	1.47%	$ 675.90	$ 652,130.58	$ 83,403.75	$ 583,826.24
Oct-14	2014	Q4	$ 649,854.32	$ 93,325.99	1.47%	$ 796.07	$ 746,252.64	$ 83,403.75	$ 667,229.98
Nov-14	2014	Q4	$ 743,180.31	$ 87,338.40	1.47%	$ 910.40	$ 834,501.44	$ 83,403.75	$ 750,633.73
Dec-14	2014	Q4	$ 830,518.71	$ 96,981.68	1.47%	$ 1,017.39	$ 932,500.51	$ 83,403.75	$ 834,037.48
Jan-15	2015	Q1	$ 927,500.39	$ 77,333.33	1.47%	$ 1,136.19	$ 1,010,970.03	$ 69,503.12	$ 903,540.60
Feb-15	2015	Q1	$ 1,004,833.72	$ 77,333.33	1.47%	$ 1,230.92	$ 1,089,534.29	$ 69,503.12	$ 973,043.73
Mar-15	2015	Q1	$ 1,082,167.06	$ 77,333.33	1.47%	$ 1,325.65	$ 1,168,193.27	$ 69,503.12	$ 1,042,546.85
Apr-15	2015	Q2	$ 1,159,500.39	$ 77,333.33	1.47%	$ 1,420.39	$ 1,246,946.99	$ 69,503.12	$ 1,112,049.97
May-15	2015	Q2	$ 1,236,833.72	$ 77,333.33	1.47%	$ 1,515.12	$ 1,325,795.45	$ 69,503.12	$ 1,181,553.10
Jun-15	2015	Q2	$ 1,314,167.06	$ 77,333.33	1.47%	$ 1,609.85	$ 1,404,738.63	$ 69,503.12	$ 1,251,056.22
Jul-15	2015	Q3	$ 1,391,500.39	$ 77,333.33	1.47%	$ 1,704.59	$ 1,483,776.55	$ 69,503.12	$ 1,320,559.34
Aug-15	2015	Q3	$ 1,468,833.72	$ 77,333.33	1.47%	$ 1,799.32	$ 1,562,909.21	$ 69,503.12	$ 1,390,062.47
Sep-15	2015	Q3	$ 1,546,167.06	$ 77,333.33	1.47%	$ 1,894.05	$ 1,642,136.59	$ 69,503.12	$ 1,459,565.59
Oct-15	2015	Q4	$ 1,623,500.39	$ 77,333.33	1.47%	$ 1,988.79	$ 1,721,458.71	$ 69,503.12	$ 1,529,068.71
Nov-15	2015	Q4	$ 1,700,833.72	$ 77,333.33	1.47%	$ 2,083.52	$ 1,800,875.57	$ 69,503.12	$ 1,598,571.84
Dec-15	2015	Q4	$ 1,778,167.06	$ 77,333.33	1.47%	$ 2,178.25	$ 1,880,387.15	$ 69,503.12	$ 1,668,074.96
Total Funding Adder Revenues Collected				**$ 1,855,500.39**		**$ 24,886.76**	**$ 1,880,387.15**		

NOTE: Funding adder revenues are up to December 2014 actuals

This worksheet calculates the interest on amortization/depreciation expense, in the absence of monthly data.

Sheet 8: Interest on Amortization (Annual Data)

Year	OM&A	Amortization Expense (from Sheet 6)	Cumulative OM&A and Amortization Expense	Average Cumulative OM&A and Amortization Expense	Average Annual Prescribed Interest Rate for Deferral and Variance Accounts (from Sheets 8A and 8B)	Simple Interest on OM&A and Amortization Expenses
2014	$ -	$ 346,000.76	$ 346,000.76	$ 173,000.38	1.47%	$ 2,543.11
2015	$ -	$ 346,000.76	$ 692,001.53	$ 519,001.15	1.47%	$ 7,629.32
Cumulative Interest to 2014						$ 2,543.11
Cumulative Interest to 2015						$ 10,172.42

ICM True-Up Model for Electricity Distributors

This worksheet calculates the ICM Incremental Revenue Requirement.

Sheet 9: ICM Incremental Revenue Requirement True-up

	2014	2015	Total
Deferred and forecasted ICM Incremental Revenue Requirement (from Sheet 6)	**$ 1,079,600**	**$ 1,079,600**	**$ 2,159,199**
Interest on Deferred and forecasted Amortization Expense (Sheet 8)	$ 2,543	$ 7,629	$ 10,172
ICM Funding Adder Revenues (from Sheet 7)	$ 927,500	$ 928,000	$ 1,855,500
ICM Funding Adder Interest (from Sheet 7)	$ 5,000	$ 19,887	$ 24,887
Net Deferred Revenue Requirement	**$ 149,642**	**$ 139,342**	**$ 288,985**

Appendix G-4: Cost of Power Historic and Forecast by Account

Account		2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Bridge Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year	2020 Test Year
4705	Commodity	566,291,804	623,332,033	667,399,795	741,502,767	527,616,463	489,025,785	573,465,911	609,945,760	645,172,167	676,835,947	683,003,777
4707	Global Adjustment Non-RPP					253,334,229	353,503,551	373,730,754	343,702,034	354,927,915	350,057,342	361,558,775
4708	WMS including RRRP	47,590,790	48,080,106	45,115,072	45,789,416	48,291,356	50,187,908	50,281,293	50,142,785	50,007,538	49,842,037	49,705,534
4714	Transmission Network	51,006,312	52,534,019	58,748,678	62,280,620	63,647,721	66,371,567	67,622,986	68,583,522	69,564,627	70,519,365	71,531,065
4716	Transmission Connection	24,847,123	25,559,804	26,233,013	26,199,446	26,908,153	29,417,591	30,021,199	30,502,104	30,998,668	31,490,271	32,014,411
4750	Low Voltage	1,582,384	1,951,377	1,986,409	2,301,273	2,303,704	4,182,723	4,654,991	4,882,065	5,103,784	5,334,655	5,320,773
4751	SME				2,149,419	3,178,054	3,250,964	3,440,602	3,507,875	2,979,432	-	-
Total	**Cost of Power**	**691,318,413**	**751,457,339**	**799,482,967**	**880,222,940**	**925,279,679**	**995,940,089**	**1,103,217,737**	**1,111,266,145**	**1,158,754,131**	**1,184,079,615**	**1,203,134,336**

Appendix G-4: 2015 Cost of Power Forecast by Month

Components	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total
VOLUMES													
Energy Purchased PS South (kWh)													
Energy Purchased PS North(kWh)													
Total Purchases (kWh)[1]	*761,018,584*	*720,482,683*	*721,054,626*	*658,815,876*	*680,701,941*	*777,724,538*	*871,881,404*	*826,166,538*	*693,029,962*	*656,082,058*	*667,212,098*	*770,725,828*	**8,804,896,137**
RPP Customer Base	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	
Non-RPP Customer Base[2]	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	
RPP kWh	352,982,125	334,180,417	334,445,701	305,577,594	315,728,975	360,730,823	404,403,463	383,199,604	321,447,063	304,309,571	309,472,001	357,484,621	**4,083,961,957**
Non-RPP kWh	408,036,459	386,302,265	386,608,925	353,238,283	364,972,966	416,993,716	467,477,942	442,966,934	371,582,899	351,772,487	357,740,097	413,241,207	**4,720,934,180**
Historic Ratios (kW)[3]													
System kW/Energy Purchased kWh - IESO	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	
System Line/System kW - IESO	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	
System Transformer/System kW - IESO	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	
System kW/Energy Purchased kWh - HONI	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	
System Line/System kW - HONI	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	
Low Voltage/System kW - HONI	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	
kW Quantities													
Transmission Network - IESO	1,316,143	1,246,038	1,247,027	1,139,389	1,177,240	1,345,035	1,507,875	1,428,813	1,198,560	1,134,661	1,153,910	1,332,931	**15,227,622**
Transmission Line Connection - IESO	1,404,138	1,329,346	1,330,401	1,215,566	1,255,947	1,434,962	1,608,688	1,524,341	1,278,694	1,210,522	1,231,058	1,422,048	**16,245,710**
Transmission Transformation Connection - IES	386,793	366,190	366,481	334,847	345,971	395,284	443,139	419,905	352,237	333,458	339,115	391,726	**4,475,146**
Transmission Network - HONI	220,857	209,093	209,259	191,197	197,548	225,705	253,031	239,764	201,126	190,403	193,633	223,674	**2,555,291**
Transmission Line Connection - HONI	221,482	209,685	209,851	191,738	198,107	226,344	253,747	240,442	201,695	190,942	194,181	224,307	**2,562,520**
LV Charges - HONI	303,158	287,010	287,238	262,445	271,163	309,813	347,321	329,110	276,074	261,356	265,789	307,025	**3,507,501**
RATES													
Commodity (RPP)	0.09496	0.09496	0.09496	0.09496	0.09496	0.09496	0.09496	0.09496	0.09496	0.09496	0.09930	0.09930	**0.09568**
Commodity (Non-RPP)	0.02548	0.02059	0.02059	0.02059	0.01951	0.01951	0.01951	0.01696	0.01696	0.01696	0.02669	0.02669	**0.02084**
Global Adjustment Rate/kWh	0.07488	0.07488	0.07488	0.07488	0.07488	0.07488	0.07488	0.07488	0.07488	0.07488	0.07488	0.07488	**0.07488**
Transmission Network - IESO	3.78000	3.7800	3.7800	3.7800	3.7800	3.7800	3.7800	3.7800	3.7800	3.7800	3.7800	3.7800	**3.7800**
Transmission Line Connection - IESO	0.86000	0.8600	0.8600	0.8600	0.8600	0.8600	0.8600	0.8600	0.8600	0.8600	0.8600	0.8600	**0.8600**
Transmission Transformation Connection- IESO	2.00000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	**2.0000**
Transmission Network - HONI	3.448	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	**3.4482**
Transmission Line Connection - HONI	0.751	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	**0.7512**
Transmission Transformation Connection - HONI	1.784	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	**1.7838**
LV Charges - HONI	1.123	1.1227	1.1227	1.1227	1.1227	1.1227	1.1227	1.1227	1.1227	1.1227	1.1227	1.1227	**1.1227**
Wholesale Market Charge (per kWh)	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	**0.0057**
Monthly Service charges (fixed per account)	453.7000	453.70	453.70	453.70	453.70	453.70	453.70	453.70	453.70	453.70	453.70	453.70	**453.70**
LVDS (per kW)	2.0247	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	**2.0247**
Specific ST Lines (per km)	960.9097	960.91	960.91	960.91	960.91	960.91	960.91	960.91	960.91	960.91	960.91	960.91	**960.91**
COP EXPENSE													
Commodity (RPP)	$ 33,519,183	$ 31,733,772	$ 31,758,964	$ 29,017,648	$ 29,981,623	$ 34,254,999	$ 38,402,153	$ 36,388,634	$ 30,524,613	$ 28,897,237	$ 30,730,104	$ 35,497,685	**$ 390,706,616**
Commodity (Non-RPP)	10,396,769	7,953,964	7,960,278	7,273,176	7,120,623	8,135,547	9,120,495	7,512,719	6,302,046	5,966,061	9,548,083	11,029,408	**$ 98,319,169**
Commodity Global Adjustment (Non-RPP)	30,553,770	28,926,314	28,949,276	26,450,483	27,329,176	31,224,489	35,004,748	33,169,364	27,824,128	26,340,724	26,787,578	30,943,502	**$ 353,503,551**
Transmission Network - IESO	4,975,021	4,710,025	4,713,764	4,306,889	4,449,965	5,084,233	5,699,767	5,400,914	4,530,558	4,289,017	4,361,778	5,038,480	**$ 57,560,411**
Transmission Line Connection - IESO	1,207,558	1,143,237	1,144,145	1,045,387	1,080,115	1,234,067	1,383,472	1,310,933	1,099,676	1,041,049	1,058,710	1,222,962	**$ 13,971,311**
Transmission Transformation Connection- IESO	773,585	732,380	732,961	669,695	691,942	790,567	886,279	839,809	704,474	666,916	678,230	783,453	**$ 8,950,292**
Transmission Network - HONI	761,560	720,995	721,567	659,284	681,186	778,277	872,501	826,754	693,523	656,548	667,686	771,274	**$ 8,811,155**
Transmission Line Connection - HONI	166,377	157,515	157,640	144,033	148,818	170,030	190,615	180,620	151,513	143,436	145,869	168,499	**$ 1,924,965**
Transmission Transformation Connection - HONI	395,079	374,035	374,332	342,021	353,383	403,752	452,633	428,901	359,783	340,602	346,380	400,119	**$ 4,571,023**
LV Charges - HONI	340,355	322,226	322,482	294,647	304,435	347,827	389,937	369,492	309,948	293,424	298,402	344,697	**$ 3,937,871**
Wholesale Market Charge	4,337,806	4,106,751	4,110,011	3,755,250	3,880,001	4,433,030	4,969,724	4,709,149	3,950,271	3,739,668	3,803,109	4,393,137	**$ 50,187,908**
Monthly Service charges (26 accounts)	11,796	11,796	11,796	11,796	11,796	11,796	11,796	11,796	11,796	11,796	11,796	11,796	**$ 141,554**
LVDS (on average 1500 kW)	3,037	3,873	3,873	3,873	3,873	3,873	3,873	3,873	3,873	3,873	3,873	3,873	**$ 45,643**
Specific ST Lines (5km)	4,805	4,805	4,805	4,805	4,805	4,805	4,805	4,805	4,805	4,805	4,805	4,805	**$ 57,655**
SME	270,914	270,914	270,914	270,914	270,914	270,914	270,914	270,914	270,914	270,914	270,914	270,914	**$ 3,250,964**
Total Cost of Power	**$ 87,717,615**	**$ 81,172,603**	**$ 81,236,809**	**$ 74,249,902**	**$ 76,312,655**	**$ 87,148,207**	**$ 97,663,711**	**$ 91,428,677**	**$ 76,741,921**	**$ 72,666,070**	**$ 78,717,317**	**$ 90,884,603**	**$ 995,940,089**

Appendix G-4: 2016 Cost of Power Forecast by Month

Components	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total
VOLUMES													
Energy Purchased PS South (kWh)													
Energy Purchased PS North(kWh)													
Total Purchases (kWh)[1]	*761,541,737*	*731,221,172*	*721,978,612*	*659,600,164*	*681,639,924*	*778,711,763*	*872,775,976*	*826,771,265*	*693,464,178*	*656,288,778*	*667,139,807*	*770,146,110*	**8,821,279,486**
RPP Customer Base	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	
Non-RPP Customer Base2	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	
RPP kWh	353,224,778	339,161,235	334,874,272	305,941,369	316,164,038	361,188,726	404,818,391	383,480,094	321,648,464	304,405,454	309,438,470	357,215,731	**4,091,561,022**
Non-RPP kWh	408,316,959	392,059,937	387,104,340	353,658,795	365,475,886	417,523,037	467,957,586	443,291,172	371,815,713	351,883,324	357,701,337	412,930,378	**4,729,718,465**
Historic Ratios (kW)[3]													
System kW/Energy Purchased kWh - IESO	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	
System Line/System kW - IESO	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	
System Transformer/System kW - IESO	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	
System kW/Energy Purchased kWh - HONI	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	
System Line/System kW - HONI	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	
Low Voltage/System kW - HONI	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	
kW Quantities													
Transmission Network - IESO	1,317,048	1,264,610	1,248,625	1,140,745	1,178,862	1,346,743	1,509,422	1,429,859	1,199,311	1,135,018	1,153,785	1,331,929	**15,255,956**
Transmission Line Connection - IESO	1,405,103	1,349,159	1,332,106	1,217,013	1,257,678	1,436,783	1,610,339	1,525,457	1,279,495	1,210,903	1,230,924	1,420,979	**16,275,939**
Transmission Transformation Connection - IESO	387,059	371,648	366,950	335,246	346,448	395,785	443,594	420,212	352,458	333,563	339,078	391,432	**4,483,473**
Transmission Network - HONI	221,009	212,210	209,527	191,424	197,820	225,992	253,291	239,939	201,252	190,463	193,612	223,506	**2,560,046**
Transmission Line Connection - HONI	221,634	212,810	210,120	191,966	198,380	226,631	254,007	240,618	201,821	191,002	194,160	224,138	**2,567,288**
LV Charges - HONI	303,366	291,288	287,606	262,757	271,537	310,206	347,677	329,351	276,247	261,438	265,760	306,794	**3,514,027**
RATES													
Commodity (RPP)	0.10888	0.10888	0.10888	0.10888	0.10888	0.10888	0.10888	0.10888	0.10888	0.10888	0.10888	0.10888	**0.10888**
Commodity (Non-RPP)	0.02706	0.02706	0.02706	0.02706	0.02706	0.02706	0.02706	0.02706	0.02706	0.02706	0.02706	0.02706	**0.02706**
Global Adjustment Rate/kWh	0.07902	0.07902	0.07902	0.07902	0.07902	0.07902	0.07902	0.07902	0.07902	0.07902	0.07902	0.07902	**0.07902**
Transmission Network - IESO	3.8539	3.8539	3.8539	3.8539	3.8539	3.8539	3.8539	3.8539	3.8539	3.8539	3.8539	3.8539	**3.8539**
Transmission Line Connection - IESO	0.8725	0.8725	0.8725	0.8725	0.8725	0.8725	0.8725	0.8725	0.8725	0.8725	0.8725	0.8725	**0.8725**
Transmission Transformation Connection- IESO	2.0772	2.0772	2.0772	2.0772	2.0772	2.0772	2.0772	2.0772	2.0772	2.0772	2.0772	2.0772	**2.0772**
Transmission Network - HONI	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	**3.4482**
Transmission Line Connection - HONI	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	**0.7512**
Transmission Transformation Connection - HONI	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	**1.7838**
LV Charges - HONI	1.2500	1.2500	1.2500	1.2500	1.2500	1.2500	1.2500	1.2500	1.2500	1.2500	1.2500	1.2500	**1.2500**
Wholesale Market Charge (per kWh)	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	**0.0057**
Monthly Service charges (fixed per account)	441.7000	441.70	441.70	441.70	441.70	441.70	441.70	441.70	441.70	441.70	441.70	441.70	**441.70**
LVDS (per kW)	1.5666	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	**1.5666**
Specific ST Lines (per km)	821.1486	821.15	821.15	821.15	821.15	821.15	821.15	821.15	821.15	821.15	821.15	821.15	**821.15**
COP EXPENSE													
Commodity (RPP)	$ 38,457,971	$ 36,926,778	$ 36,460,027	$ 33,309,906	$ 34,422,918	$ 39,325,060	$ 44,075,317	$ 41,752,072	$ 35,020,044	$ 33,142,681	$ 33,690,660	$ 38,892,493	**$ 445,475,927**
Commodity (Non-RPP)	11,049,385	10,609,457	10,475,355	9,570,291	9,890,071	11,298,509	12,663,309	11,995,816	10,061,632	9,522,246	9,679,686	11,174,228	**$ 127,989,984**
Commodity Global Adjustment (Non-RPP)	32,264,205	30,979,615	30,588,036	27,945,251	28,879,008	32,991,647	36,976,861	35,027,781	29,379,966	27,804,957	28,264,682	32,628,746	**$ 373,730,754**
Transmission Network - IESO	5,075,814	4,873,722	4,812,119	4,396,355	4,543,254	5,190,256	5,817,211	5,510,581	4,622,065	4,374,284	4,446,608	5,133,164	**$ 58,795,435**
Transmission Line Connection - IESO	1,225,907	1,177,098	1,162,219	1,061,804	1,097,283	1,253,547	1,404,968	1,330,911	1,116,318	1,056,474	1,073,941	1,239,758	**$ 14,200,229**
Transmission Transformation Connection- IESO	803,983	771,973	762,215	696,360	719,628	822,110	921,416	872,848	732,111	692,864	704,320	813,067	**$ 9,312,895**
Transmission Network - HONI	762,083	731,741	722,492	660,069	682,124	779,265	873,396	827,359	693,957	656,755	667,614	770,694	**$ 8,827,550**
Transmission Line Connection - HONI	166,492	159,863	157,842	144,205	149,023	170,245	190,810	180,752	151,608	143,481	145,853	168,373	**$ 1,928,547**
Transmission Transformation Connection - HONI	395,351	379,610	374,812	342,429	353,870	404,265	453,098	429,215	360,009	340,709	346,343	399,818	**$ 4,579,529**
LV Charges - HONI	379,208	364,110	359,507	328,446	339,421	387,758	434,597	411,689	345,309	326,797	332,201	383,492	**$ 4,392,534**
Wholesale Market Charge	4,340,788	4,167,961	4,115,278	3,759,721	3,885,348	4,438,657	4,974,823	4,712,596	3,952,746	3,740,846	3,802,697	4,389,833	**$ 50,281,293**
Monthly Service charges (26 accounts)	11,484	11,484	11,484	11,484	11,484	11,484	11,484	11,484	11,484	11,484	11,484	11,484	**$ 137,810**
LVDS (on average 1500 kW)	2,997	2,997	2,997	2,997	2,997	2,997	2,997	2,997	2,997	2,997	2,997	2,997	**$ 35,963**
Specific ST Lines (5km)	7,390	7,390	7,390	7,390	7,390	7,390	7,390	7,390	7,390	7,390	7,390	7,390	**$ 88,684**
SME	286,717	286,717	286,717	286,717	286,717	286,717	286,717	286,717	286,717	286,717	286,717	286,717	**$ 3,440,602**
Total Cost of Power	**$ 95,229,775**	**$ 91,450,515**	**$ 90,298,491**	**$ 82,523,426**	**$ 85,270,538**	**$ 97,369,906**	**$ 109,094,394**	**$ 103,360,208**	**$ 86,744,353**	**$ 82,110,683**	**$ 83,463,193**	**$ 96,302,254**	**$ 1,103,217,737**

Appendix G-4: 2017 Cost of Power Forecast by Month

Components	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total
VOLUMES													
Energy Purchased PS South (kWh)													
Energy Purchased PS North(kWh)													
Total Purchases (kWh)[1]	*761,071,123*	*720,642,992*	*721,384,111*	*658,725,413*	*680,785,221*	*777,853,858*	*871,768,040*	*825,419,033*	*691,937,471*	*654,530,295*	*665,105,381*	*767,756,965*	**8,796,979,903**
RPP Customer Base	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	
Non-RPP Customer Base2	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	
RPP kWh	353,006,494	334,254,773	334,598,526	305,535,634	315,767,603	360,790,805	404,350,881	382,852,890	320,940,334	303,589,819	308,494,846	356,107,578	**4,080,290,182**
Non-RPP kWh	408,064,629	386,388,218	386,785,585	353,189,778	365,017,619	417,063,053	467,417,159	442,566,143	370,997,137	350,940,476	356,610,536	411,649,387	**4,716,689,721**
Historic Ratios (kW)[3]													
System kW/Energy Purchased kWh - IESO	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	
System Line/System kW - IESO	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	
System Transformer/System kW - IESO	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	
System kW/Energy Purchased kWh - HONI	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	
System Line/System kW - HONI	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	
Low Voltage/System kW - HONI	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	
kW Quantities													
Transmission Network - IESO	1,316,234	1,246,316	1,247,597	1,139,232	1,177,384	1,345,259	1,507,679	1,427,520	1,196,671	1,131,977	1,150,266	1,327,797	**15,213,931**
Transmission Line Connection - IESO	1,404,235	1,329,642	1,331,009	1,215,399	1,256,101	1,435,200	1,608,479	1,522,962	1,276,678	1,207,659	1,227,171	1,416,571	**16,231,104**
Transmission Transformation Connection - IESO	386,819	366,272	366,648	334,802	346,014	395,349	443,082	419,525	351,682	332,669	338,044	390,218	**4,471,123**
Transmission Network - HONI	220,872	209,140	209,355	191,170	197,572	225,743	252,998	239,547	200,809	189,953	193,022	222,813	**2,552,994**
Transmission Line Connection - HONI	221,497	209,731	209,947	191,711	198,131	226,382	253,714	240,225	201,377	190,490	193,568	223,443	**2,560,216**
LV Charges - HONI	303,179	287,074	287,369	262,409	271,196	309,864	347,276	328,812	275,639	260,737	264,950	305,842	**3,504,347**
RATES													
Commodity (RPP)	0.10992	0.10992	0.10992	0.10992	0.10992	0.10992	0.10992	0.10992	0.10992	0.10992	0.10992	0.10992	**0.10992**
Commodity (Non-RPP)	0.03423	0.03423	0.03423	0.03423	0.03423	0.03423	0.03423	0.03423	0.03423	0.03423	0.03423	0.03423	**0.03423**
Global Adjustment Rate/kWh	0.07287	0.07287	0.07287	0.07287	0.07287	0.07287	0.07287	0.07287	0.07287	0.07287	0.07287	0.07287	**0.07287**
Transmission Network - IESO	3.9293	3.9293	3.9293	3.9293	3.9293	3.9293	3.9293	3.9293	3.9293	3.9293	3.9293	3.9293	**3.9293**
Transmission Line Connection - IESO	0.8851	0.8851	0.8851	0.8851	0.8851	0.8851	0.8851	0.8851	0.8851	0.8851	0.8851	0.8851	**0.8851**
Transmission Transformation Connection- IESO	2.1573	2.1573	2.1573	2.1573	2.1573	2.1573	2.1573	2.1573	2.1573	2.1573	2.1573	2.1573	**2.1573**
Transmission Network - HONI	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	**3.4482**
Transmission Line Connection - HONI	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	**0.7512**
Transmission Transformation Connection - HONI	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	**1.7838**
LV Charges - HONI	1.3182	1.3182	1.3182	1.3182	1.3182	1.3182	1.3182	1.3182	1.3182	1.3182	1.3182	1.3182	**1.3182**
Wholesale Market Charge (per kWh)	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	**0.0057**
Monthly Service charges (fixed per account)	424.8700	424.87	424.87	424.87	424.87	424.87	424.87	424.87	424.87	424.87	424.87	424.87	**424.87**
LVDS (per kW)	1.5967	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60	**1.5967**
Specific ST Lines (per km)	865.0076	865.01	865.01	865.01	865.01	865.01	865.01	865.01	865.01	865.01	865.01	865.01	**865.01**
COP EXPENSE													
Commodity (RPP)	$ 38,802,860	$ 36,741,650	$ 36,779,436	$ 33,584,811	$ 34,709,520	$ 39,658,520	$ 44,446,691	$ 42,083,608	$ 35,278,112	$ 33,370,925	$ 33,910,091	$ 39,143,734	**$ 448,509,956**
Commodity (Non-RPP)	13,966,626	13,224,718	13,238,319	12,088,452	12,493,277	14,274,611	15,998,056	15,147,492	12,697,935	12,011,466	12,205,532	14,089,320	**$ 161,435,804**
Commodity Global Adjustment (Non-RPP)	29,735,397	28,155,852	28,184,808	25,736,704	26,598,590	30,391,106	34,060,377	32,249,500	27,034,314	25,572,798	25,985,972	29,996,616	**$ 343,702,034**
Transmission Network - IESO	5,171,894	4,897,163	4,902,199	4,476,399	4,626,308	5,285,942	5,924,141	5,609,174	4,702,093	4,447,891	4,519,755	5,217,328	**$ 59,780,289**
Transmission Line Connection - IESO	1,242,910	1,176,887	1,178,097	1,075,769	1,111,795	1,270,318	1,423,690	1,347,997	1,130,008	1,068,918	1,086,188	1,253,829	**$ 14,366,408**
Transmission Transformation Connection- IESO	834,485	790,157	790,970	722,267	746,455	852,887	955,860	905,040	758,683	717,667	729,262	841,816	**$ 9,645,547**
Transmission Network - HONI	761,612	721,155	721,897	659,194	681,269	778,407	872,388	826,006	692,429	654,996	665,578	768,303	**$ 8,803,234**
Transmission Line Connection - HONI	166,389	157,550	157,712	144,013	148,836	170,058	190,590	180,457	151,274	143,096	145,408	167,850	**$ 1,923,234**
Transmission Transformation Connection - HONI	395,107	374,119	374,503	341,974	353,427	403,819	452,575	428,513	359,216	339,797	345,287	398,578	**$ 4,566,913**
LV Charges - HONI	399,650	378,421	378,810	345,907	357,491	408,463	457,779	433,440	363,347	343,704	349,257	403,161	**$ 4,619,430**
Wholesale Market Charge	4,338,105	4,107,665	4,111,889	3,754,735	3,880,476	4,433,767	4,969,078	4,704,888	3,944,044	3,730,823	3,791,101	4,376,215	**$ 50,142,785**
Monthly Service charges (26 accounts)	11,047	11,047	11,047	11,047	11,047	11,047	11,047	11,047	11,047	11,047	11,047	11,047	**$ 132,559**
LVDS (on average 1500 kW)	3,054	3,054	3,054	3,054	3,054	3,054	3,054	3,054	3,054	3,054	3,054	3,054	**$ 36,654**
Specific ST Lines (5km)	7,785	7,785	7,785	7,785	7,785	7,785	7,785	7,785	7,785	7,785	7,785	7,785	**$ 93,421**
SME	292,323	292,323	292,323	292,323	292,323	292,323	292,323	292,323	292,323	292,323	292,323	292,323	**$ 3,507,875**
Total Cost of Power	**$ 96,129,245**	**$ 91,039,546**	**$ 91,132,850**	**$ 83,244,434**	**$ 86,021,653**	**$ 98,242,107**	**$ 110,065,432**	**$ 104,230,324**	**$ 87,425,665**	**$ 82,716,289**	**$ 84,047,640**	**$ 96,970,959**	**$ 1,111,266,145**

Appendix G-4: 2018 Cost of Power Forecast by Month

Components	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total
VOLUMES													
Energy Purchased PS South (kWh)													
Energy Purchased PS North(kWh)													
Total Purchases (kWh)[1]	*760,127,229*	*719,559,056*	*720,247,196*	*657,226,532*	*679,237,312*	*776,242,708*	*869,942,017*	*823,176,492*	*689,463,342*	*651,765,641*	*662,004,601*	*764,260,123*	**8,773,252,250**
RPP Customer Base	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	
Non-RPP Customer Base2	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	
RPP kWh	352,568,689	333,752,013	334,071,192	304,840,411	315,049,638	360,043,508	403,503,920	381,812,735	319,792,763	302,307,493	307,056,615	354,485,643	**4,069,284,620**
Non-RPP kWh	407,558,540	385,807,043	386,176,004	352,386,121	364,187,674	416,199,201	466,438,098	441,363,757	369,670,580	349,458,147	354,947,986	409,774,480	**4,703,967,630**
Historic Ratios (kW)[3]													
System kW/Energy Purchased kWh - IESO	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	
System Line/System kW - IESO	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	
System Transformer/System kW - IESO	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	
System kW/Energy Purchased kWh - HONI	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	
System Line/System kW - HONI	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	
Low Voltage/System kW - HONI	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	
kW Quantities													
Transmission Network - IESO	1,314,602	1,244,441	1,245,631	1,136,640	1,174,707	1,342,472	1,504,521	1,423,642	1,192,392	1,127,196	1,144,903	1,321,749	**15,172,895**
Transmission Line Connection - IESO	1,402,493	1,327,642	1,328,911	1,212,633	1,253,245	1,432,227	1,605,110	1,518,824	1,272,113	1,202,558	1,221,449	1,410,119	**16,187,325**
Transmission Transformation Connection - IESO	386,340	365,721	366,070	334,040	345,227	394,530	442,154	418,385	350,424	331,264	336,468	388,440	**4,459,063**
Transmission Network - HONI	220,598	208,825	209,025	190,735	197,123	225,275	252,468	238,896	200,091	189,151	192,122	221,798	**2,546,108**
Transmission Line Connection - HONI	221,223	209,416	209,616	191,275	197,681	225,913	253,182	239,572	200,657	189,686	192,666	222,425	**2,553,311**
LV Charges - HONI	302,803	286,642	286,916	261,811	270,580	309,222	346,548	327,919	274,653	259,636	263,715	304,449	**3,494,895**
RATES													
Commodity (RPP)	0.11559	0.11559	0.11559	0.11559	0.11559	0.11559	0.11559	0.11559	0.11559	0.11559	0.11559	0.11559	**0.11559**
Commodity (Non-RPP)	0.03716	0.03716	0.03716	0.03716	0.03716	0.03716	0.03716	0.03716	0.03716	0.03716	0.03716	0.03716	**0.03716**
Global Adjustment Rate/kWh	0.07545	0.07545	0.07545	0.07545	0.07545	0.07545	0.07545	0.07545	0.07545	0.07545	0.07545	0.07545	**0.07545**
Transmission Network - IESO	4.006	4.0062	4.0062	4.0062	4.0062	4.0062	4.0062	4.0062	4.0062	4.0062	4.0062	4.0062	**4.0062**
Transmission Line Connection - IESO	0.898	0.8979	0.8979	0.8979	0.8979	0.8979	0.8979	0.8979	0.8979	0.8979	0.8979	0.8979	**0.8979**
Transmission Transformation Connection- IESO	2.241	2.2405	2.2405	2.2405	2.2405	2.2405	2.2405	2.2405	2.2405	2.2405	2.2405	2.2405	**2.2405**
Transmission Network - HONI	3.448	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	**3.4482**
Transmission Line Connection - HONI	0.751	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	**0.7512**
Transmission Transformation Connection - HONI	1.784	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	**1.7838**
LV Charges - HONI	1.385	1.3849	1.3849	1.3849	1.3849	1.3849	1.3849	1.3849	1.3849	1.3849	1.3849	1.3849	**1.3849**
Wholesale Market Charge (per kWh)	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	**0.0057**
Monthly Service charges (fixed per account)	427.7900	427.79	427.79	427.79	427.79	427.79	427.79	427.79	427.79	427.79	427.79	427.79	**427.79**
LVDS (per kW)	1.6319	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	**1.6319**
Specific ST Lines (per km)	858.9937	858.99	858.99	858.99	858.99	858.99	858.99	858.99	858.99	858.99	858.99	858.99	**858.99**
COP EXPENSE													
Commodity (RPP)	$ 40,752,402	$ 38,577,437	$ 38,614,330	$ 35,235,628	$ 36,415,683	$ 41,616,395	$ 46,639,859	$ 44,132,638	$ 36,963,927	$ 34,942,855	$ 35,491,793	$ 40,973,978	**$ 470,356,925**
Commodity (Non-RPP)	15,146,245	14,337,886	14,351,598	13,095,852	13,534,438	15,467,361	17,334,407	16,402,560	13,738,201	12,987,039	13,191,060	15,228,596	**$ 174,815,242**
Commodity Global Adjustment (Non-RPP)	30,751,466	29,110,253	29,138,093	26,588,548	27,479,010	31,403,429	35,194,099	33,302,167	27,892,711	26,367,624	26,781,849	30,918,666	**$ 354,927,915**
Transmission Network - IESO	5,266,512	4,985,437	4,990,205	4,553,569	4,706,069	5,378,167	6,027,359	5,703,346	4,776,920	4,515,733	4,586,673	5,295,147	**$ 60,785,138**
Transmission Line Connection - IESO	1,259,365	1,192,153	1,193,293	1,088,881	1,125,348	1,286,065	1,441,305	1,363,824	1,142,291	1,079,834	1,096,798	1,266,213	**$ 14,535,369**
Transmission Transformation Connection- IESO	865,605	819,407	820,191	748,425	773,490	883,957	990,658	937,403	785,135	742,207	753,866	870,311	**$ 9,990,657**
Transmission Network - HONI	760,668	720,071	720,759	657,694	679,720	776,795	870,560	823,762	689,953	652,229	662,475	764,803	**$ 8,779,489**
Transmission Line Connection - HONI	166,182	157,313	157,464	143,686	148,498	169,706	190,191	179,966	150,734	142,492	144,730	167,086	**$ 1,918,047**
Transmission Transformation Connection - HONI	394,617	373,556	373,913	341,196	352,623	402,983	451,627	427,348	357,932	338,361	343,677	396,762	**$ 4,554,595**
LV Charges - HONI	419,352	396,971	397,350	362,583	374,726	428,242	479,935	454,135	380,367	359,570	365,219	421,632	**$ 4,840,080**
Wholesale Market Charge	4,332,725	4,101,487	4,105,409	3,746,191	3,871,653	4,424,583	4,958,669	4,692,106	3,929,941	3,715,064	3,773,426	4,356,283	**$ 50,007,538**
Monthly Service charges (26 accounts)	11,123	11,123	11,123	11,123	11,123	11,123	11,123	11,123	11,123	11,123	11,123	11,123	**$ 133,470**
LVDS (on average 1500 kW)	3,122	3,122	3,122	3,122	3,122	3,122	3,122	3,122	3,122	3,122	3,122	3,122	**$ 37,462**
Specific ST Lines (5km)	7,731	7,731	7,731	7,731	7,731	7,731	7,731	7,731	7,731	7,731	7,731	7,731	**$ 92,771**
SME	297,943	297,943	297,943	297,943	297,943	297,943	297,943	297,943	297,943	297,943			**$ 2,979,432**
Total Cost of Power	**$ 100,435,058**	**$ 95,091,889**	**$ 95,182,523**	**$ 86,882,172**	**$ 89,781,176**	**$ 102,557,602**	**$ 114,898,588**	**$ 108,739,175**	**$ 91,128,030**	**$ 86,162,927**	**$ 87,213,540**	**$ 100,681,451**	**$ 1,158,754,131**

Appendix G-4: 2019 Cost of Power Forecast by Month

Components	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total
VOLUMES													
Energy Purchased PS South (kWh)													
Energy Purchased PS North(kWh)													
Total Purchases (kWh)[1]	*757,994,447*	*717,375,329*	*718,021,843*	*654,938,171*	*676,903,543*	*773,861,529*	*867,504,492*	*820,673,715*	*686,907,308*	*649,158,348*	*659,334,268*	*761,543,944*	**8,744,216,936**
RPP Customer Base	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	
Non-RPP Customer Base2	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	
RPP kWh	351,579,443	332,739,138	333,039,010	303,779,004	313,967,169	358,939,049	402,373,326	380,651,876	318,607,201	301,098,157	305,818,039	353,225,802	**4,055,817,213**
Non-RPP kWh	406,415,003	384,636,191	384,982,833	351,159,167	362,936,373	414,922,480	465,131,166	440,021,839	368,300,107	348,060,191	353,516,230	408,318,142	**4,688,399,723**
Historic Ratios (kW)[3]													
System kW/Energy Purchased kWh - IESO	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	
System Line/System kW - IESO	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	
System Transformer/System kW - IESO	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	
System kW/Energy Purchased kWh - HONI	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	
System Line/System kW - HONI	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	
Low Voltage/System kW - HONI	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	
kW Quantities													
Transmission Network - IESO	1,310,913	1,240,664	1,241,782	1,132,682	1,170,670	1,338,354	1,500,305	1,419,314	1,187,971	1,122,686	1,140,285	1,317,052	**15,122,680**
Transmission Line Connection - IESO	1,398,558	1,323,613	1,324,805	1,208,411	1,248,939	1,427,834	1,600,612	1,514,206	1,267,397	1,197,747	1,216,522	1,405,107	**16,133,752**
Transmission Transformation Connection - IESO	385,256	364,611	364,939	332,877	344,041	393,320	440,915	417,113	349,125	329,939	335,111	387,060	**4,444,306**
Transmission Network - HONI	219,979	208,191	208,379	190,071	196,446	224,584	251,761	238,170	199,349	188,394	191,347	221,010	**2,537,681**
Transmission Line Connection - HONI	220,602	208,780	208,968	190,609	197,002	225,220	252,473	238,844	199,913	188,927	191,888	221,635	**2,544,860**
LV Charges - HONI	301,953	285,772	286,030	260,900	269,650	308,274	345,577	326,922	273,635	258,597	262,651	303,367	**3,483,329**
RATES													
Commodity (RPP)	0.11908	0.11908	0.11908	0.11908	0.11908	0.11908	0.11908	0.11908	0.11908	0.11908	0.11908	0.11908	**0.11908**
Commodity (Non-RPP)	0.04135	0.04135	0.04135	0.04135	0.04135	0.04135	0.04135	0.04135	0.04135	0.04135	0.04135	0.04135	**0.04135**
Global Adjustment Rate/kWh	0.07466	0.07466	0.07466	0.07466	0.07466	0.07466	0.07466	0.07466	0.07466	0.07466	0.07466	0.07466	**0.07466**
Transmission Network - IESO	4.085	4.0845	4.0845	4.0845	4.0845	4.0845	4.0845	4.0845	4.0845	4.0845	4.0845	4.0845	**4.0845**
Transmission Line Connection - IESO	0.911	0.9110	0.9110	0.9110	0.9110	0.9110	0.9110	0.9110	0.9110	0.9110	0.9110	0.9110	**0.9110**
Transmission Transformation Connection- IESO	2.327	2.3270	2.3270	2.3270	2.3270	2.3270	2.3270	2.3270	2.3270	2.3270	2.3270	2.3270	**2.3270**
Transmission Network - HONI	3.448	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	**3.4482**
Transmission Line Connection - HONI	0.751	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	**0.7512**
Transmission Transformation Connection - HONI	1.784	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	**1.7838**
LV Charges - HONI	1.455	1.4552	1.4552	1.4552	1.4552	1.4552	1.4552	1.4552	1.4552	1.4552	1.4552	1.4552	**1.4552**
Wholesale Market Charge (per kWh)	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	**0.0057**
Monthly Service charges (fixed per account)	430.1000	430.10	430.10	430.10	430.10	430.10	430.10	430.10	430.10	430.10	430.10	430.10	**430.10**
LVDS (per kW)	1.6430	1.64	1.64	1.64	1.64	1.64	1.64	1.64	1.64	1.64	1.64	1.64	**1.6430**
Specific ST Lines (per km)	868.5871	868.59	868.59	868.59	868.59	868.59	868.59	868.59	868.59	868.59	868.59	868.59	**868.59**
COP EXPENSE													
Commodity (RPP)	$ 41,865,328	$ 39,621,864	$ 39,657,573	$ 36,173,354	$ 37,386,539	$ 42,741,694	$ 47,913,755	$ 45,327,211	$ 37,939,064	$ 35,854,124	$ 36,416,158	$ 42,061,373	**$ 482,958,034**
Commodity (Non-RPP)	16,806,351	15,905,739	15,920,073	14,521,374	15,008,393	17,158,158	19,234,422	18,196,084	15,230,198	14,393,223	14,618,845	16,885,051	**$ 193,877,912**
Commodity Global Adjustment (Non-RPP)	30,344,801	28,718,695	28,744,577	26,219,148	27,098,488	30,980,008	34,728,818	32,854,041	27,498,969	25,987,764	26,395,137	30,486,898	**$ 350,057,342**
Transmission Network - IESO	5,354,454	5,067,522	5,072,089	4,626,467	4,781,630	5,466,539	6,128,030	5,797,219	4,852,296	4,585,638	4,657,521	5,379,528	**$ 61,768,932**
Transmission Line Connection - IESO	1,274,038	1,205,765	1,206,852	1,100,821	1,137,740	1,300,707	1,458,102	1,379,389	1,154,554	1,091,106	1,108,210	1,280,004	**$ 14,697,289**
Transmission Transformation Connection- IESO	896,478	848,438	849,202	774,594	800,572	915,244	1,025,995	970,609	812,403	767,758	779,793	900,676	**$ 10,341,761**
Transmission Network - HONI	758,533	717,885	718,532	655,404	677,385	774,412	868,121	821,257	687,396	649,620	659,803	762,085	**$ 8,750,433**
Transmission Line Connection - HONI	165,716	156,836	156,977	143,185	147,988	169,185	189,658	179,419	150,175	141,922	144,147	166,492	**$ 1,911,699**
Transmission Transformation Connection - HONI	393,509	372,422	372,758	340,008	351,412	401,747	450,361	426,049	356,605	337,008	342,290	395,352	**$ 4,539,522**
LV Charges - HONI	439,402	415,856	416,230	379,661	392,395	448,600	502,884	475,737	398,194	376,311	382,210	441,460	**$ 5,068,940**
Wholesale Market Charge	4,320,568	4,089,039	4,092,725	3,733,148	3,858,350	4,411,011	4,944,776	4,677,840	3,915,372	3,700,203	3,758,205	4,340,800	**$ 49,842,037**
Monthly Service charges (26 accounts)	11,183	11,183	11,183	11,183	11,183	11,183	11,183	11,183	11,183	11,183	11,183	11,183	**$ 134,191**
LVDS (on average 1500 kW)	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	**$ 37,717**
Specific ST Lines (5km)	7,817	7,817	7,817	7,817	7,817	7,817	7,817	7,817	7,817	7,817	7,817	7,817	**$ 93,807**
SME													**$ -**
Total Cost of Power	**$ 102,641,322**	**$ 97,142,204**	**$ 97,229,731**	**$ 88,689,306**	**$ 91,663,033**	**$ 104,789,447**	**$ 117,467,065**	**$ 111,126,998**	**$ 93,017,368**	**$ 87,906,819**	**$ 89,284,461**	**$ 103,121,862**	**$ 1,184,079,615**

Appendix G-4: 2020 Cost of Power Forecast by Month

Components	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total
VOLUMES													
Energy Purchased PS South (kWh)													
Energy Purchased PS North(kWh)													
Total Purchases (kWh)[1]	*755,464,290*	*724,774,797*	*715,359,690*	*652,204,907*	*674,121,985*	*771,048,057*	*864,649,853*	*817,762,276*	*683,959,440*	*646,174,421*	*656,297,278*	*758,452,139*	**8,720,269,134**
RPP Customer Base	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	46.38%	
Non-RPP Customer Base2	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	53.62%	
RPP kWh	350,405,885	336,171,223	331,804,227	302,511,238	312,677,004	357,634,080	401,049,263	379,301,467	317,239,896	299,714,126	304,409,396	351,791,734	**4,044,709,539**
Non-RPP kWh	405,058,405	388,603,575	383,555,463	349,693,669	361,444,982	413,413,977	463,600,590	438,460,808	366,719,544	346,460,295	351,887,882	406,660,404	**4,675,559,594**
Historic Ratios (kW)[2]													
System kW/Energy Purchased kWh - IESO	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	
System Line/System kW - IESO	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	106.69%	
System Transformer/System kW - IESO	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	29.39%	
System kW/Energy Purchased kWh - HONI	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	
System Line/System kW - HONI	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	100.28%	
Low Voltage/System kW - HONI	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	137.26%	
kW Quantities													
Transmission Network - IESO	1,306,537	1,253,461	1,237,178	1,127,955	1,165,860	1,333,489	1,495,368	1,414,278	1,182,873	1,117,526	1,135,033	1,311,705	**15,081,264**
Transmission Line Connection - IESO	1,393,890	1,337,265	1,319,894	1,203,368	1,243,807	1,422,643	1,595,345	1,508,834	1,261,958	1,192,241	1,210,919	1,399,402	**16,089,567**
Transmission Transformation Connection - IESO	383,970	368,372	363,586	331,487	342,627	391,890	439,464	415,633	347,627	328,422	333,567	385,488	**4,432,134**
Transmission Network - HONI	219,245	210,339	207,606	189,278	195,639	223,768	250,932	237,325	198,494	187,528	190,466	220,112	**2,530,731**
Transmission Line Connection - HONI	219,865	210,934	208,194	189,813	196,192	224,401	251,642	237,996	199,055	188,058	191,005	220,735	**2,537,891**
LV Charges - HONI	300,945	288,720	284,969	259,811	268,542	307,153	344,440	325,762	272,461	257,409	261,441	302,135	**3,473,789**
RATES													
Commodity (RPP)	0.12146	0.12146	0.12146	0.12146	0.12146	0.12146	0.12146	0.12146	0.12146	0.12146	0.12146	0.12146	**0.12146**
Commodity (Non-RPP)	0.04101	0.04101	0.04101	0.04101	0.04101	0.04101	0.04101	0.04101	0.04101	0.04101	0.04101	0.04101	**0.04101**
Global Adjustment Rate/kWh	0.07733	0.07733	0.07733	0.07733	0.07733	0.07733	0.07733	0.07733	0.07733	0.07733	0.07733	0.07733	**0.07733**
Transmission Network - IESO	4.164	4.1644	4.1644	4.1644	4.1644	4.1644	4.1644	4.1644	4.1644	4.1644	4.1644	4.1644	**4.1644**
Transmission Line Connection - IESO	0.924	0.9242	0.9242	0.9242	0.9242	0.9242	0.9242	0.9242	0.9242	0.9242	0.9242	0.9242	**0.9242**
Transmission Transformation Connection- IESO	2.417	2.4167	2.4167	2.4167	2.4167	2.4167	2.4167	2.4167	2.4167	2.4167	2.4167	2.4167	**2.4167**
Transmission Network - HONI	3.448	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	3.4482	**3.4482**
Transmission Line Connection - HONI	0.751	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	0.7512	**0.7512**
Transmission Transformation Connection - HONI	1.784	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	1.7838	**1.7838**
LV Charges - HONI	1.455	1.4552	1.4552	1.4552	1.4552	1.4552	1.4552	1.4552	1.4552	1.4552	1.4552	1.4552	**1.4552**
Wholesale Market Charge (per kWh)	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	**0.0057**
Monthly Service charges (fixed per account)	430.1000	430.10	430.10	430.10	430.10	430.10	430.10	430.10	430.10	430.10	430.10	430.10	**430.10**
LVDS (per kW)	1.6430	1.64	1.64	1.64	1.64	1.64	1.64	1.64	1.64	1.64	1.64	1.64	**1.6430**
Specific ST Lines (per km)	868.5871	868.59	868.59	868.59	868.59	868.59	868.59	868.59	868.59	868.59	868.59	868.59	**868.59**
COP EXPENSE													
Commodity (RPP)	$ 42,560,095	$ 40,831,161	$ 40,300,748	$ 36,742,839	$ 37,977,567	$ 43,438,027	$ 48,711,210	$ 46,069,735	$ 38,531,773	$ 36,403,103	$ 36,973,388	$ 42,728,419	**$ 491,268,063**
Commodity (Non-RPP)	16,610,667	15,935,886	15,728,872	14,340,265	14,822,164	16,953,313	19,011,369	17,980,435	15,038,464	14,207,671	14,430,246	16,676,362	**$ 191,735,714**
Commodity Global Adjustment (Non-RPP)	31,322,972	30,050,528	29,660,159	27,041,643	27,950,367	31,969,104	35,850,011	33,905,963	28,358,246	26,791,608	27,211,321	31,446,854	**$ 361,558,775**
Transmission Network - IESO	5,440,959	5,219,929	5,152,120	4,697,271	4,855,121	5,553,196	6,227,329	5,889,638	4,925,971	4,653,839	4,726,745	5,462,478	**$ 62,804,597**
Transmission Line Connection - IESO	1,288,193	1,235,863	1,219,808	1,112,119	1,149,491	1,314,766	1,474,373	1,394,422	1,166,266	1,101,836	1,119,097	1,293,288	**$ 14,869,523**
Transmission Transformation Connection- IESO	927,957	890,260	878,695	801,120	828,042	947,099	1,062,072	1,004,479	840,125	793,713	806,147	931,627	**$ 10,711,335**
Transmission Network - HONI	756,001	725,290	715,868	652,669	674,601	771,596	865,265	818,344	684,446	646,634	656,764	758,991	**$ 8,726,468**
Transmission Line Connection - HONI	165,163	158,453	156,395	142,588	147,380	168,570	189,034	178,783	149,530	141,269	143,483	165,816	**$ 1,906,463**
Transmission Transformation Connection - HONI	392,196	376,264	371,376	338,589	349,967	400,286	448,879	424,538	355,075	335,459	340,714	393,747	**$ 4,527,089**
LV Charges - HONI	437,936	420,145	414,687	378,077	390,782	446,969	501,229	474,049	396,485	374,581	380,449	439,668	**$ 5,055,058**
Wholesale Market Charge	4,306,146	4,131,216	4,077,550	3,717,568	3,842,495	4,394,974	4,928,504	4,661,245	3,898,569	3,683,194	3,740,894	4,323,177	**$ 49,705,534**
Monthly Service charges (26 accounts)	11,183	11,183	11,183	11,183	11,183	11,183	11,183	11,183	11,183	11,183	11,183	11,183	**$ 134,191**
LVDS (on average 1500 kW)	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	**$ 37,717**
Specific ST Lines (5km)	7,817	7,817	7,817	7,817	7,817	7,817	7,817	7,817	7,817	7,817	7,817	7,817	**$ 93,807**
SME													**$ -**
Total Cost of Power	**$ 104,230,428**	**$ 99,997,138**	**$ 98,698,424**	**$ 89,986,891**	**$ 93,010,120**	**$ 106,380,043**	**$ 119,291,418**	**$ 112,823,774**	**$ 94,367,092**	**$ 89,155,050**	**$ 90,551,390**	**$ 104,642,570**	**$ 1,203,134,336**