BOMA INTERROGATORIES

BOMA-1

Please provide copies of

(a) CDM Plan for 2011-2014;

(b) The extent to which the Company achieved its goals (KWh and KW) for that plan;

(c) draft CDM plan for 2015-2020;

(d) Status of microgrid pallet project, rationale, costs, results to date:

i. Amounts of connected DG, renewable and otherwise;
ii. Forecast for DG, renewable and otherwise
iii. Description of any impediments to DG and company's plans to remove them;
iv. Impact of the OEB's new distribution policy on the above

RESPONSE:

(a) Please refer to BOMA-1 Appendix A for PowerStream's 2013 Annual Report submitted to the OEB in September 2014, which contains the most recent 2011-2014 CDM plan.

(b) PowerStream's final 2011-2014 CDM results are verified by the IESO and will be provided by the IESO in September 2015. Based on internal (unverified) projections, PowerStream anticipates achieving more than 110% of its 2011-2014 energy target and more than 70% of its 2011-2014 demand target.

(c) Please refer to BOMA-1 Appendix B for PowerStream's CDM plan for 2015-2020, which has been approved by the IESO.

(d)

i. Refer to the DS Plan, Section 5.4.3 System Capability Assessment for Renewable Energy Generation, pages 1 to 2. A summary is below.

Connected FIT & MicroFIT Projects		
FIT Projects	***Count***	***Capacity (kW)***
Connected Projects by PowerStream	84	16016
MicroFIT Projects	***Count***	***Capacity (kW)***
Connected Projects by PowerStream	514	3621.73
		As of Aug. 1st 2014

ii. The forecast is shown in the DS Plan, Section 5.4.3 System Capability Assessment for Renewable Energy Generation, Figure 4.

iii. As stated in DS Plan, Section 5.4.3 System Capability Assessment for Renewable Energy Generation, page 14, there are no impediments.

iv. There are no known impacts of the OEB's new distribution policy on DG connections.

BOMA - 2

2. Please provide a copy of:

(a) PowerStream's ("PS") strategic objectives;

(b) Financial statements for each of the last three years (2012, 2013 and 2014), and rating agency reports, if any;

(c) Any regional planning documents that bear on PS's application;

(d) Detailed description of Copper Leaf C55 and how it was used to prioritize and optimize expenditures over the plan period;

(e) Written mandate for the Budget Working Group, budget submissions to that Group, and documents incorporating the reports from that Group, including its recommendations on "gaps between targets and detailed budget build amounts". Please explain fully.

RESPONSE:

a) For PowerStream's strategic objectives please see BOMA-2 Appendix A.

b) Please see the audited financial statements for the 2012 and 2013 attached in BOMA-2 Appendix B-1 and Appendix B-2. The 2014 audited financial statements have not been finalized yet, when they are we will submit them. Rating agency reports are attached as BOMA-2 Appendix C-1 and Appendix C-2.

c) Refer to the Consolidated DS Plan, Appendix B, OPA Letters.

d) Refer to C-CCC-25.

e) In 2013, as a result of COS rate application settlement agreement, PowerStream needed to address reductions to its OM&A. In order to arrive at these reductions the Budget Working Group (BWG) was created. The BWG continued to meet and have discussions during the 2014 business planning and budget process and is now part of the annual budget planning cycle. Their mandate is one of cost management and control along with the assessment of risk in order to prioritize spending based on the corporate strategy, objectives and business needs. Meetings are generally discussions aligning corporate objectives with OM&A and capital cost drivers or pressures. Some specific areas of focus include discussions on headcount, compensation drivers and material changes in business operations that may drive costs up or down. The mandate for this group is not written and was verbally agreed upon by the executive operating committee.

The OM&A and capital budget are reviewed by this group before being reviewed and approved at the executive level. Attached is Appendix D, the 2016 to 2020 budget reviewed by the budget working group and approved by the executives.

The group does not issue reports, rather findings from the group are incorporated into the final budget. The table below identifies the proposed OM&A budget targets for 2015 to 2020 along with the finalized budget for each of the years, which summarizes the reductions made between the targets and the detailed budget build.

(in Millions of Dollars)	Budget 2015	Budget 2016	Budget 2017	Budget 2018	Budget 2019	Budget 2020
OM&A – Proposed budget	93.6	95.8	98.1	100.8	103.5	106.4
Finalized budget	92.9	96.3	98.2	100.0	102.3	104.3

BOMA-3

Ref: Exhibit A, Tab 1, Page 4

Why does PS not accept the normal 50%-50% shown between ratepayers and shareholders of tax rate changes within an IRM period?

RESPONSE:

PowerStream is filing a Custom IR plan where the calculation of revenue requirement including the amount of taxes is done for each test year 2016 through 2020. The situation described above applies to a subsequent IRM period that is based on a previous test year. This is not the case in PowerStream's Custom IR plan.

BOMA-4

Ref: Exhibit C, Page 2

Please confirm that forecast debt rates for each year of the plan will be based on the latest available public information on interest rates.

RESPONSE:

The forecast debt rates for each year of the plan are not based on the latest available public information on interest rates.

The forecast debt rates for each year of the plan are and will be based on:

- Actual interest rates on the existing debt instruments
- Forecasted interested rates on the new debt, which are mainly affected by the deemed interest rates prescribed by the OEB at the time of annual adjustments.

BOMA-5

Why does PS not propose an earnings sharing plan?

RESPONSE:

Please see the response to A-CCC-13

BOMA-6

Ref: Exhibit F, Tab 2, Page 2 (Table 1)

What steps will PS take to reverse its declining productivity?

RESPONSE:

Please see the responses to F-Energy Probe-9 (c) and F-VECC-7.

BOMA-7

Ref: Exhibit F, Tab 2, Page 4(b)

Please quantify the impact on PS's costs increases of "replacement of capital stock and distribution infrastructure that did not attract a depreciation charge". Please discuss fully.

RESPONSE:

Capital cost and depreciation expense is the driving factor in the calculation of the actual/forecast capital cost. The actual/forecast capital cost plus the actual/forecast OM&A cost comprises the actual/forecast total cost. This total cost is then compared to the “predicted total cost” from the PEG predicted cost benchmarking model.

The upward trend in the capital cost and depreciation expense, discussed below, drives up actual/forecast total cost. Since the PEG model is based on historical relationships, its predicted costs do not take this continuing trend into account. This situation causes an increase in actual cost relative to the predicted cost from the PEG model. This appears as deterioration in performance when it only reflects the business condition described below.

Prior to the year 2000 most residential subdivision assets (switch gear, transformers and underground cable) were paid for by the developer and recorded on PowerStream’s books as fully contributed with a net cost of $0 and net depreciation expense of $0. Other upstream assets (main distribution lines, poles and substations) were partially funded by development fees. These contributions reduced the cost and related depreciation expense of these assets. When these assets are replaced the full cost is born by PowerStream and increases capital cost and depreciation expense.

This funding situation is common to most electricity local distributors in Ontario (LDCs). Much of PowerStream’s service territory is close to Toronto and was the site of considerable residential subdivision development in the period from the 1960s to present. The extent of the impact on PowerStream is likely greater than many other LDCs.

Replacement of existing assets (Sustainment) is a large part of PowerStream’s forecast capital spending leading to increasing levels of capital cost and depreciation as many of the assets being replaced have no costs in the accounting records. The resulting increase in capital cost used to compare to the predicted cost merely reflects this funding situation which is totally outside PowerStream's control. Until all the pre-2000 assets are replaced, there will be this continuing upward trend in capital cost and depreciation expense.

Estimating the impact of this factor on the cost increase requires information regarding the degree to which the assets being replaced where previously funded by developers and development charges. PowerStream's accounting system is not designed to track this information in the detail that would be required for this purpose. PowerStream is unable to provide an estimate.

BOMA-8

Ref: Exhibit F, Tab 2, Page 4 (c)

Does PS agree that bullets 2 and 3 are not business conditions, but rather management decisions taken to grow the business. Please discuss fully.

RESPONSE:

Exhibit F, Tab 2, Page 4(c), bullets 2 and 3 are:

- Extraordinary expenditures like a new transformer station; and
- A new Customer Information System, which requires substantial initial investments.

PowerStream does not agree that these are management decisions to grow the business.

These are decisions undertaken by management to address business conditions and necessary for PowerStream to meet its obligations.

PowerStream is required under the terms of its distribution licence to connect customers. To do so it must have sufficient capacity. PowerStream's System Planning department monitors the use of PowerStream's system and forecasts of future load to ensure that sufficient capacity will be in place. PowerStream has a long history of building its own transformer stations to supply customer load and this has been approved in numerous rate cases with the assets being deemed distribution assets.

PowerStream's current T&W customer billing system is over 30 years old, highly customized, used only by PowerStream and supported by a single supplier. This supplier has a small number of employees and the principal is past normal retirement age. In order to ensure that PowerStream can continue to meet its obligations with respect to billing customers and accommodate the changing requirements of this regulated industry, it is necessary to move to a modern, well supported customer billing system.

BOMA-9

Please explain at what point PS considers assets to be used or useful and adds them to rate base. Describe the extent to which and quantify, over the last five years, assets that it adds to rate base that are not yet energized and being used to distribute electricity, e.g. civil underground cable conduit structures into which electrical cable has not been placed and connected, partially completed stations which are not yet operational, and the like.

RESPONSE:

PowerStream assets are added to rate base when the asset is in the location and condition necessary for it to be capable of operating in the manner intended. For constructed assets, this is based on confirmation from the field staff that the assets are ready for use.

In a review of our 2010 to 2014 rate base fixed assets, all capital assets in rate base are energized with the exception of the land for a new Vaughan transformer station (TS#4). This land has a cost of $3.2 million and was added to rate base in 2014. A new transformer station is being constructed on this site.

BOMA-10

Ref: Exhibit G, Tab 2, Section 3.3.1, Page 22

Please provide a copy of the strategic direction five year capital success factors.

RESPONSE:

Refer to BOMA-10, Appendix A.

BOMA-11

Ref: Exhibit G, Tab 2, Section 5.2.3, Page 9

Please provide a copy of the reliability performance reports for the years 2010, 2011, 2012, 2013 and 2014.

RESPONSE:

The reports commenced in 2012. Refer to BOMA-11, Appendix A and Appendix B.

PowerStream Inc.

Conservation and Demand Management

2013 Annual Report

Submitted to:

Ontario Energy Board

September 30, 2014

Executive Summary

This annual report is submitted by PowerStream Inc. in accordance with the filing requirements set out in the CDM Code (Board File No. EB-2010-0215), specifically Appendix C Annual Report Template, as a progress report and modification to its September 27, 2013 Strategy. Accordingly, this report outlines PowerStream's CDM activities for the period of January 1, 2013 to December 31, 2013. It includes 2013 verified resource savings (demand and energy savings), 2013 participation and spending, successes and challenges and an updated outlook to 2014.

As noted in the CDM guidelines, released April 26, 2012, the Ontario Energy Board (OEB) has deemed Time-of-Use (TOU) pricing a Province-wide Board-Approved CDM Program. The Ontario Power Authority (OPA) is to provide measurement and verification on TOU and PowerStream will report these results upon receipt from the OPA. The OPA has indicated that verified results for TOU savings will not be available until August 2015.

PowerStream initiated the design of a Board-Approved CDM Program in Fall 2012 and filed an application (EB-2013-0070) with the OEB on March 13, 2013. On June 21, 2013, the OEB approved PowerStream's application as filed. PowerStream launched the Business Refrigeration Incentives Program[1] on September 20, 2013. There was an immediate positive response from the market, with 286 businesses enrolling in the program in less than four months. By the end of the 2013, 249 of these participants had site audits completed and 6 of them had their energy savings measures installed. In the initial few months of program delivery, the rate of installations did not keep pace with the rate of participant registrations and audits. This was due to challenges securing sufficient capacity of refrigeration contractors and sufficient local inventory of the energy savings measures. PowerStream has worked to address these issues and by the end of August 2014, 687 installations have been completed.

With respect to OPA-Contracted Province-wide CDM Programs, PowerStream accepted the OPA's Master Agreement in late February 2011. In 2011, PowerStream focused on building a foundation for CDM delivery, including planning, recruitment of staff, and procurement of third party vendors. With this foundation established, PowerStream's focus in 2012 and 2013 was the successful delivery and execution of the Province-wide CDM Programs. Six provincial initiatives, which were included in original portfolio of Province-Wide Programs, did not deliver savings in 2013 as they were either discontinued or removed from the Master Agreement.

The OPA conducted EM&V for the 2013 OPA-Contracted Province-wide Programs. PowerStream's verified achievements for 2013 were an incremental demand savings of 30.9 MW, of which 10.4 MW is guaranteed to persist to 2014, and 48.1 GWh of incremental energy

[1] In the application to the OEB, this program was referred to as the Direct Install Refrigeration Program. In order to better market the program and reach targeted participants, the program was renamed. The program design has not changed.

savings, which cumulates to 93.7 GWh at the end of 2014. Combined with 2011 and 2012 results, PowerStream has achieved, as of the end of 2013, a total of 28.5 MW and 377.5 GWh in verified savings, representing 29.8% and 92.7% of PowerStream's 2011-2014 demand and energy savings targets, respectively. Table 1 provides a comparison of the 2011-2013 verified results against the milestones identified in PowerStream's 2012 CDM Annual Report filed on September 27, 2013.

Table 1: 2013 Verified Results vs Milestones

Cumulative Progress to Date	2013 Milestone as per 2012 Annual Report		2013 Verified Annual Results		Variance to 2013 Milestone	
	Savings	% to Target	Savings	% to Target	Savings	% to Target
2014 Net Demand Savings (MW)	25.2	26.4%	28.5	29.8%	3.3	3%
2011-2014 Net Cumulative Energy Savings (GWh)	366.1	89.9%	377.5	92.7%	11.4	3%

As shown in Table 1 above, PowerStream's 2013 results were quite positive. As of the end of 2013, PowerStream's actual progress towards its four year targets is very close to the milestones set out in the 2012 Annual Report, with a positive variance of 3% for both demand and energy. Additional details on 2013 actual results, including a discussion of key drivers of variance compared to forecasted results, is provided in Section 3.1.

PowerStream's current projection as of September 18th, 2014 is to achieve 78.6% of its demand target and 108.8% of its energy target. This projection includes savings from OPA-Contracted Province-wide Programs, PowerStream's Business Refrigeration Incentive Program as well as TOU rates. The two largest contributors to PowerStream's projected shortfall against its demand savings target are TOU rates and the Demand Response 3 (DR3) Program. Both of these initiatives, which are either entirely or mostly outside of PowerStream's control, are likely to contribute far fewer demand savings than was contemplated during the setting of LDC targets and the design of the provincial CDM programs in 2010. The DR3 program was in fact cancelled in 2013. At the time the DR3 program was cancelled, PowerStream had roughly 6.2 MW and 27 customers who had signed agreements with the aggregators but not yet enrolled. In addition to these, PowerStream's peaksaverPLUS program is currently tracking lower than what was forecasted for 2014, contributing to the decrease in the current projection from what was forecasted in the 2012 Annual Report.

As with any forecasting exercise, there are known risks to achieving the CDM targets. In some cases these risks can be mitigated by PowerStream while in other cases, PowerStream has little to no control over the risks, such as TOU savings results or the cancellation of the DR3 program. PowerStream has developed a risk assessment and mitigation accordingly.

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Background

On September 16, 2010, the Ontario Energy Board (OEB) issued a Conservation and Demand Management (CDM) Code for Electricity Distributors[2] (Code). The Code sets out the obligations and requirements with which Local Distribution Companies (LDCs) must comply in relation to the CDM targets set out in their licenses. PowerStream's target is to achieve 95.57 MW of demand savings by December 31, 2014 and 407.34 GWh of cumulative energy savings over the period January 1, 2011 to December 31, 2014. To comply with the Code requirements, PowerStream filed a CDM Strategy Document[3] (Strategy) to the OEB on October 29, 2010 which laid out a high-level description of how it intended to achieve its CDM targets. The Strategy projected an achievement of 100.2% of its demand target and 101.8% of its energy target through the delivery of Ontario Power Authority (OPA) Contracted Province-Wide CDM Programs starting January 1, 2011. The Code also requires LDCs to file an Annual Report with the OEB.

PowerStream submitted its 2011 Annual Report[4] on September 28, 2012. In the report, PowerStream demonstrated its progress and modifications to the original Strategy. In that updated "2012 Strategy" PowerStream maintained a projected achievement of 100% of the demand and energy savings targets, although it was noted that the demand savings forecast included 21.6 MW from TOU savings and that there was high uncertainty and risk with these savings coming to fruition.

In relation to the 2011-2014 program term, the Minister of Energy on December 21, 2012, directed the OPA to fund CDM programs which meet the definition and criteria of OPA-Contracted Province-Wide CDM Programs for an additional one-year period from January 1, 2015 to December 31, 2015. The Ministerial Directive did not amend the timelines for LDCs to achieve their energy and demand savings targets. Therefore, PowerStream's main focus will remain on achieving CDM savings within the 2011-2014 timeframe.

PowerStream submitted its 2012 Annual Report[5] on September 27, 2013. In the report, PowerStream demonstrated its progress and modifications to the "2012 Strategy". In that updated "2013 Strategy", PowerStream reduced its forecasted energy savings to 101.4% from 120% and demand savings to 79.8% from 100%.

In 2013, PowerStream entered into an agreement with Collus PowerStream to deliver CDM on behalf of it. Since the savings achieved and the Program Administration Budget (PAB) spent by

[2] http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/214820/view/CDM_Code_20100916.PDF

[3] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0215/PowerStream_CDM%20Strategy_20101029.pdf

[4] http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/367872/view/2011%20PowerStream%20Annual%20CDM%20Report_Additional%20Information_20121012.PDF

[5] http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/411169/view/PowerStream_2012%20Annual%20CDM%20Report_2013Sep27.PDF

Collus PowerStream under this agreement does not affect PowerStream's results or budget, activities and results of Collus PowerStream will not be considered in this report.

PowerStream has prepared this document as its third Annual Report, in accordance with the code requirements, and to demonstrate its progress and modifications to the 2013 Strategy. This report covers the period of January 1, 2013 to December 31, 2013.

1 Board-Approved CDM Programs

1.1 Introduction

PowerStream initiated the design of a Board-Approved CDM Program in Fall 2012 and filed an application (EB-2013-0070[6]) with the OEB on March 13, 2013. On June 21, 2013, a Decision[7] was made and the OEB approved PowerStream's application as filed. PowerStream anticipated at the time that this program would generate 3.33 MW of demand savings that would persist to 2014 and 19.6 GWh of cumulative energy savings. This represents an additional 3.5% and 4.8% towards PowerStream's demand and energy targets, respectively. PowerStream launched the Business Refrigeration Incentives Program[8] on September 20, 2013.

In addition, in its April 26, 2012 CDM Guidelines[9], the OEB has deemed the implementation of Time-Of-Use (TOU) pricing to be a Province-wide Board-Approved CDM Program for the purposes of achieving the CDM targets. The OEB recognizes that a portion of the aggregate electricity demand target was intended to be attributable to savings achieved through the implementation of TOU Pricing. The OEB established TOU prices and has made the implementation of this pricing mechanism mandatory for distributors. On this basis, the OEB has determined that distributors will not have to file a Board-Approved CDM Program application regarding TOU pricing.

1.2 Program Description

1.2.1 BUSINESS REFRIGERATION INCENTIVES (BRI) PROGRAM

Description: The Business Refrigeration Incentives (BRI) Program promotes the identification and implementation of energy efficient equipment upgrades and maintenance measures to commercial refrigeration equipment. Participants receive significant value for participation. Program incentives include a comprehensive on-site electricity audit providing recommendations for equipment retrofit and maintenance; up to $2,500 in materials and labour to retrofit commercial refrigeration equipment performed by an authorized, licensed refrigeration or electrical contractor; and benchmarking of the facility to understand energy consumption versus other businesses of a similar size and operation. Eligible measures include: anti-sweat heater controls for coolers and freezers, strip curtains for walk-in coolers and freezers, night curtains on display cases, coil cleaning, Electronically Commutated Motor (ECM) upgrades, LED display case lighting, and LED A19 lamps for walk in coolers and freezers.

[6] http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/386474/view/PowerStream_APPL_CDM_20130313.PDF
[7] http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/400644/view/dec_order_PowerStream_20130621.PDF
[8] In the application to the OEB, this program was referred to as the Direct Install Refrigeration Program. In order to better market the program and reach targeted participants, the program was renamed. The program design has not changed.
[9] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2012-0003/CDM_Guidelines_Electricity_Distributor.pdf

Target Customer Type(s): General Service customers with an average annual demand of less than 250 kW; must have commercial grade refrigeration equipment used to cool products.

Objectives: The objective of the program is to offer installation of commercial refrigeration products and services of up to $2500. The purpose of this program is to assist customers in achieving electricity demand savings, by upgrading to more energy-efficient refrigeration equipment.

Delivery: PowerStream marketed the program and conducted the energy audit and benchmarking aspects of the program. PowerStream has engaged third party contractors to conduct the assessment and installation of the commercial refrigeration measures. PowerStream has also engaged a third party evaluator (from OPA's Vendor of Record list) to conduct Evaluation, Measurement and Verification (EM&V) of the program.

Initiative Activities/Progress:

PowerStream's activities specific to the BRI program are summarized in Table 2.

Table 2: Activities – BRI Program

Activities
PowerStream's main focus in 2013 with respect to the BRI program was to procure third party contractors, hire internal staff, enhance/build the infrastructure for the program, and marketing to generate the customer awareness and program participation. Key activities with respect to the above are summarized below: Third Party contractors: • Contracted a third party contractor to manage the installations • Contracted a third part evaluator (from OPA's Vendor of Records list) to conduct the EM&V of the program Internal staff: • Hired 2 Commercial Energy Advisors to perform the site energy audits. • Hired a staff member to manage the internal BRI phone line which customers use to call in to apply for the program Infrastructure development: • Modified the existing Microsoft Dynamics Customer Relationship Management (CRM) database by developing modules to handle and store all necessary BRI information Marketing and market research: PowerStream's strategy for delivering the BRI program is to generate awareness with qualified end users through a highly segmented and targeted marketing effort as well as to leverage channel partner relationships to drive participation. A mutli-touch point approach was implemented as follows: • Direct Mail to 4000+ qualified customers • Outbound Calling • Street Teams using our in-house assessment team • Chamber of commerce advertising - online & print • Community Newspaper Advertising • Email lead nurture campaign

1.2.2 TOU IMPLEMENTATION

Description: In August of 2010, the OEB issued a final determination to mandate TOU pricing for Regulated Price Plan (RPP) customers by June 2011, in order to support the Government's expectation for 3.6 million RPP consumers to be on TOU pricing by June 2011, and to ensure that smart meters funded at ratepayer expense are being used for their intended purpose.

Target Customer Type(s): Residential and small business customers (up to 250,000 kWh per year)

Objectives: TOU pricing is designed to incent the shifting of energy usage. Therefore peak demand reductions are expected, and energy conservation benefits may also be realized.

The RPP TOU price is adjusted twice annually by the OEB. A summary of the RPP TOU pricing, per kWh, is provided in Table 3.

Table 3: RPP TOU Pricing

Effective Date	On Peak	Mid Peak	Off Peak
November 1, 2010	9.9	8.1	5.1
May 1, 2011	10.7	8.9	5.9
November 1, 2011	10.8	9.2	6.2
May 1, 2012	11.7	10.0	6.5
November 1, 2012	11.8	9.9	6.3
May 1, 2013	12.4	10.4	6.7
November 1, 2013	12.9	10.9	7.2
May 1, 2014	13.5	11.2	7.5

Delivery: The OEB sets the TOU rates. Distributors install and maintain the smart meters and convert customers to TOU billing.

Initiative Activities/Progress: PowerStream began transitioning its RPP customers to TOU billing on August 2009. There are 325,129 PowerStream customers enrolled in TOU billing as of September 30, 2013 which represent 99.53% of PowerStream's mandated customer base.

1.3 Participation

PowerStream launched the BRI program 3 months after it was approved. As the program was launched late in 2013, much of the effort was on marketing, building the necessary infrastructure, generating program participation, and performing the site audits. There was an immediate positive response from the market, with 286[10] businesses enrolling in the program in less than four months. By the end of the 2013, 249[11] of these participants had site audits completed and 6 of them had their energy savings measures installed. In the initial few months of program delivery, the rate of installations did not keep pace with the rate of participant registrations and audits. This was due to challenges securing sufficient capacity of refrigeration contractors and sufficient local inventory of the energy savings measures. PowerStream has worked to address these issues and by the end of August 2014, 687 installations have been completed.

[10] The evaluation report indicates that only 269 businesses participated in the program in 2013. The reason for the difference is because the evaluation report is not including businesses that enrolled in the program what were later cancelled their application or were found to be ineligible.

[11] The evaluation report indicates that only 234 site audits were performed in 2013. The reason for the difference is because the evaluation report is not including audits completed for businesses that later cancelled their application or were found to be ineligible.

There are 325,129 PowerStream customers enrolled in TOU billing as of September 30, 2013, representing 99.53% of PowerStream's mandated customer base. Of those, 298,341 are residential customers and 27,096 are non-residential customers. PowerStream only has 91 mandated accounts remaining that have not yet had smart meters installed.

1.4 Spending

The Business Refrigeration Incentive (BRI) program received OEB approval on June 20, 2013 with approval of total funding to deliver the program of $4.1 Million. PowerStream began delivery of the BRI program on September 20, 2013. Table 4 below identifies the 2013 fixed and variable costs to the program.

Table 4: BRI Program 2013 Spending by Expense Category

Expense Category	2013
Fixed Program Costs	**416,783**
Program Administration	
Labour	240,185
Marketing	86,693
EM&V	19,378
Other	70,527
Variable Program Costs	**6,000**
Participant Based Fee (PBF)	
Participant Incentive Payments (PIP)	6,000
TOTAL COST	**422,783**

PowerStream does not have any expenses to report for the period of January 1, 2013 to December 31, 2013 in relation to TOU billing as a Board-Approved CDM Programs. Costs associated with the implementation of TOU pricing are recoverable through distribution rates, and not through the Global Adjustment Mechanism (GAM).

1.5 Evaluation

The BRI Program launched on September 20, 2013. Pursuant to the CDM Code, PowerStream has procured a third-party EM&V contractor from the OPA's EM&V Vendor of Record list. The key evaluation findings as summarized and provided by the third party evaluator for the BRI program are included in Table 5 below. The results of the impact evaluations (net-to-gross ratios and realization rates) and net demand and energy savings are outlined in Table 6 below. Please see Appendix A for the full evaluation report for 2013 for the BRI program.

Table 5: BRI Evaluation Findings

Business Refrigeration Initiative
• Wide variation in unit savings was seen across measures • The most common measures implemented were cleaning the condenser coils of coolers, and replacing motors with ECM models, followed by replacing display lighting with LED lights • Based on on-site monitoring, the realized gross energy and demand reductions are quite a bit lower than the prescriptive values from the literature, averaging about 67% for energy and 64% for demand of the prescriptive values • There is a very low free rider rate for these measures due to multiple barriers to upgrading efficiency of refrigeration units, including: lack of awareness of opportunities, lack of awareness of appropriate contractors, financial constraints, and limited availability of several of the technologies in the marketplace. • Due to a low number of installations resulting from a late start of the program, and challenges in ramping up installs, the energy savings and demand reduction from the program in 2013 were not material, estimated at 57,000 kWh and 6 kW.

Table 6: BRI Verified Evaluation Results

	Peak Demand	Energy
Realization Rate	0.64	0.67
Net-to-Gross	0.958	0.972
Net Savings	6.05 kW	57,427 kWh

In accordance with CDM Guidelines dated April 26, 2012 (Board File No. EB-2012-0003), the OEB requires that any evaluations of savings from TOU pricing should be conducted by the OPA for the province then allocated to distributors. PowerStream will report these results upon receipt from the OPA. As of September 30, 2014, the OPA has not released its verified results of TOU savings to distributors. The OPA has indicated that verified results for TOU savings will not be reported to LDCs until August 2015. As such, PowerStream is not able to provide any verified savings related to TOU program at this time.

1.6 CDM Variance Account

PowerStream offered the BRI program which is a Board Approved CDM Program in 2013 which created a variance account. Total fixed funding awarded for the BRI Program was $1,198,000. PowerStream's 2013 fixed program costs were $416,783 which created a variance amount of $781,217.

1.7 Additional Comments

While the OEB's CDM Guidelines clarified that savings from TOU rates, as verified by the OPA, will contribute towards LDCs' CDM targets, significant uncertainty remains as to actual amount of savings that will be achieved from TOU rates. The OPA has indicated that LDCs will not receive verified results until 2015 and as such this uncertainty presents a significant risk to LDCs with respect to their demand savings targets. OPA has indicated that the LDCs evaluated in 2014 show similar savings from TOU as the 2013 evaluation results. As such, at this time PowerStream is maintaining its forecast of 12.5 MW of demand savings coming from TOU implementation. This is a drop from PowerStream's initial forecast of 21.6 MW of demand savings from TOU rates that PowerStream stated in its 2011 Annual CDM report to the OEB. However, it still represents more than 13% of PowerStream's 2011-2014 demand savings target.

2 OPA-Contracted Province-Wide CDM Programs

2.1 Introduction

Effective February 25, 2011, PowerStream entered into an agreement (Master Agreement) with the OPA to deliver OPA-Contracted Province-Wide CDM Programs from January 1, 2011 to December 31, 2014. Table 7 summarizes the OPA-Contracted Province-Wide Programs that were in market and delivering results in 2013 and their targeted customers. It also includes the references to this document where their descriptions, objectives, and activities are detailed. In addition to the OPA-Contracted Province–Wide CDM Programs, pre-2011 Programs, 2010 Programs extended into 2011, were added to the list.

Table 7: Summary of OPA-Contracted Province-Wide Programs and pre-2011 Programs

Initiative	Description/Reference	Customer Class
Consumer Program		
Appliance Retirement	Appendix B - A	All residential rate classes
Appliance Exchange	Appendix B - B	All residential rate classes
HVAC Incentives	Appendix B - C	All residential rate classes
Conservation Instant Coupon Booklet	Appendix B - D	All residential rate classes
Bi-Annual Retailer Event	Appendix B - E	All residential rate classes
Residential Demand Response	Appendix B - G	All residential rate classes
New Construction Program	Appendix B - F	All residential rate classes
Commercial & Institutional Program		
Equipment Replacement Incentive Initiative	Appendix C - A	All general service classes
Direct Install Lighting	Appendix C - B	General Service < 50 kW
Existing Building Commissioning Incentive	Appendix C - C	All general service classes
New Construction and Major Renovation	Appendix C - D	All general service classes
Energy Audit	Appendix C - E	All general service classes
Industrial Program		
Process & System Upgrades	Appendix D - A	General Service 50 kW & above
Monitoring & Targeting	Appendix D- B	General Service 50 kW & above
Energy Manager	Appendix D - C	General Service 50 kW & above
Key Account Manager	Appendix D - D	All general service classes
Demand Response 3	Appendix D - E	General Service 50 kW & above
Low Income Program		
Low Income Program	Appendix E	All residential rate classes
Pre-2011 Programs completed in 2011-14		
Electricity Retrofit Incentive Program	Appendix C - A	All general service classes
High Performance New Construction	Appendix C - D	All general service classes

The initiatives that were either officially removed from the Master Agreement or discontinued and were not delivering savings in 2013 are listed in Table 8.

Table 8: OPA-Contracted Province-Wide Program Initiatives not In-market in 2013

Initiatives Not in Market in 2013	Status
Consumer Program	
Midstream Electronics	Removed from Master Agreement
Midstream Pool Equipment	Removed from Master Agreement
Home Energy Audit Tool	Removed from Master Agreement
Retailer Co-op	Discontinued
Commercial & Institutional Program	
Direct Service Space Cooling	Removed from Master Agreement
Demand Response 1	Removed from Master Agreement
Industrial Program	
Demand Response 1	Removed from Master Agreement

2.2 Program Descriptions

OPA-Contracted Province-Wide CDM Program descriptions and additional initiative information can be found on the saveONenergy website at https://saveonenergy.ca

2.2.1 CONSUMER PROGRAM

Description: Provides residential customers with programs/tools to help them understand and manage the amount of energy they use throughout their entire home by reducing the household's energy consumption while also helping the environment.

Targeted Customer Type(s): Residential Customers

Objective: To provide incentives to both existing homeowners and developers/builders to motivate the installation of energy efficiency measures in both existing and new home construction.

Activities: PowerStream's activities specific to the Consumer Program are summarized in Table 9.

Table 9: Activities – Consumer Program Level

Activities
PowerStream's main strategy in delivering Consumer Program Initiatives in 2013 was to continue to use market research to enhance PowerStream's understanding of the consumer segment and to inform marketing execution. A number of the market research activities and marketing activities in 2013 are summarized below: Market research: • Conservation, Awareness, Satisfaction and Attitudes Study (CASA). The purpose of this study is to track and understand the marketing impacts, barriers to program participation, and satisfaction of program participants. Results: high baseline awareness levels; traditional participation barriers being challenged; and strong satisfaction across all Consumer Initiatives. • Residential Customer Segmentation Study. The purpose of the study was to classify PowerStream's residential customer base into distinct segments to further develop an understanding of our customers and their needs as well as to facilitate targeted marketing and customized messaging to help promote program participation. Results: 3,753 customer interviews were conducted and 5 distinct segments emerged. • Residential Ethnic Focus Groups. The purpose of this study was to speak with two largely represented ethnic segments within our service territory: Chinese and Italian customers, to understand how different ethnic groups view PowerStream and the CDM initiatives. Key findings include: The proposal of advertising in different languages was positively received and marketing in multiple languages sets the expectation that all elements of program participation could be carried out in preferred language; Community based communications are preferred. Marketing and promotion: • Participated in 19 community events (e.g. Kempenfest, Markham Fair, Vaughan Earth Hour Event) to promote all Consumer Initiatives • Held 18 in-store events (e.g. Home Depot, Lowes) • Distributed approximately 800 handouts promoting Consumer Program Initiatives • Reached approximately 3,500 customers and gathered over 1,000 sign ups during events • Placed 107 print advertisements in local newspapers within PowerStream's service territory • Distributed 900,000 bill inserts to PowerStream customers • 296,172 Direct mail pieces mailed to our customers • 145 GO Train posters on train lines in our service territory • 20 Online ads running for an 8 week period

The targeted customer types, objectives, descriptions, and activities of each Consumer Program Initiative are detailed in Appendix B. The Appendix also includes additional comments, provided by the OPA-LDC Residential Working Group, regarding some of the lessons learned and future opportunities for each Consumer Program initiative.

2.2.2 COMMERCIAL AND INSTITUTIONAL (C&I) PROGRAM

Description: Provides commercial, institutional, agricultural and industrial organizations with energy-efficiency programs to help reduce their electrical costs while helping Ontario defer the need to build new generation and reduce its environmental footprint. Programs to help fund energy audits, to replace energy-wasting equipment or to pursue new construction that exceeds our existing codes and standards are available. Businesses can also pursue incentives for controlling and reducing their electricity demand at specific times.

Targeted Customer Type(s): Commercial, Institutional, Agricultural, Multi-family buildings, Industrial

Objective: Designed to assist building owners and operators as well as tenants and occupants in achieving demand and energy savings, and to facilitate a culture of conservation among these communities as well as the supply chains which serve them.

Activities: PowerStream's activities specific to the Commercial and Institutional (C&I) Program are summarized in Table 10.

Table 10: Activities – C&I Program Level

Activities
PowerStream's main strategies for delivering the C&I Program, and increasing program participation in 2013 were: develop relationships with key business customers and integrate market research results to improve sales and marketing execution. A number of the market research activities, sales and marketing activities in 2013 are summarized below. Market research: • Customer Awareness, Satisfaction, and Attitudes Study (CASA). The purpose of this study is to track and understand the marketing impacts, barriers to program participation, and satisfaction of program participants. Results: PowerStream's sales and marketing efforts are driving program awareness; PowerStream's highest priority initiatives have highest levels of awareness; and key drivers/barriers of participation are money, environment, relevance, and impact on business operations. • RETROFIT program focus groups. The purpose of this study was to speak with contractors and business customers (both participants and non-participants) to assess the overall interest in the program, motivations and barriers to participation, and to test potential messaging. Key findings include: Messaging surrounding "winning more business" resonated with contractors and messaging surrounding "bottom line savings" enticed business customers. All participants stressed the importance of a simplified application process and responsiveness (within 1-2 weeks) for application approvals. Marketing, promotion and sales: • Ongoing account management for 1400 accounts • Reached 540 new accounts in 2013 • Assigned an account specialist to every account greater than 500 kW • Hosted 16 events/workshops/information sessions • Participated in 7 community/industry events for both large and small business sectors to promote the suite of C&I Programs • Small Business (<50 kW): Placed 11 print ads; 6 online ads; distributed 14,000+ direct mail pieces; implemented an outbound calling campaign which generated 2000+ leads • Large Business (>50 kW): Direct Mail campaign to 2600+ contractors & 4,500+ customers • Launched monthly e-newsletter "Empower Your Business" reaching 1500+ customers and channel partners • Continued CDM Champions recognition program for channel partners

The targeted customer types, objectives, descriptions, and the activities of each C&I Program Initiative are detailed in Appendix C. The Appendix also includes additional comments, provided by the OPA-LDC C&I Working Group, regarding some of the lessons learned and future opportunities for each C&I Program initiative.

2.2.3 INDUSTRIAL PROGRAM

Description: Large facilities are discovering the benefits of energy efficiency through the Industrial Programs which are designed to help identify and promote energy saving opportunities. It includes financial incentives and technical expertise to help organizations modernize systems for enhanced productivity and product quality, as wells as provide a substantial boost to energy productivity. This allows facilities to take control of their energy so they can create long-term competitive energy advantages which reach across the organization.

Targeted Customer Type(s): Industrial, Commercial, Institutional, Agricultural

Objective: To provide incentives to both existing and new industrial customers to motivate the installation of energy efficient measures and to promote participation in demand management.

Activities: PowerStream's activities specific to the Industrial Program are summarized in Table 11. Most of the C&I activities listed in Table 10 are also applicable to the Industrial Program since these program's target audiences overlap and most initiatives are available to both C&I and Industrial customers**.**

Table 11: Activities – Industrial Program Level

Activities
PowerStream's main focus in 2013 for the Industrial Program was the renewal and management of Roving Energy Managers and Embedded Energy Managers and greater involvement and direct marketing of the Demand Response 3 Program. • Renewed 2 Roving Energy Managers to work with 6 PowerStream key business/industrial customers • Managed 6 Embedded Energy Managers to work with PowerStream and non-PowerStream customers • Built relationships and worked with Demand Response aggregators in promoting Demand Response 3 Program • Utilized PowerStream's CDM Key Account Specialist in conducting Demand Response 3 sales activities • PowerStream's first M&T application was submitted in 2013 and later approved and contracted in 2014

The targeted customers, objectives, descriptions, and activities of each Industrial Program Initiative are detailed in Appendix D. The Appendix also includes additional comments, provided by the OPA-LDC Industrial Working Group, regarding some of the lessons learned and future opportunities for each Industrial Program initiative.

2.2.4 LOW INCOME PROGRAM (Home Assistance)

Description: This is a turnkey program for income qualified customers. It offers residents the opportunity to take advantage of free installation of energy efficient measures that improve the comfort of their home, increase efficiency, and help them save money. All eligible customers receive a Basic and Extended Measures Audit, while customers with electric heat also receive a Weatherization Audit. The program is designed to coordinate efforts with gas utilities.

Targeted Customer Type(s): Income qualified Residential Customers

Objective: To offer free installation of energy efficient measures to income qualified households for the purpose of achieving electricity and peak demand savings.

Activities: PowerStream's activities specific to the Low Income Program are summarized in Table 12.

Table 12: Activities – Low Income Program

Activities
PowerStream launched this Program within its service territory in 2012. Major program delivery activities undertaken in 2013 were: • Held 11 outreach events/meeting • Distributed 6,000 updated HAP brochures to the third party service provider to provide to their energy auditors. • 306,000 bill inserts were distributed to PowerStream residential customers

The targeted customers, objectives, descriptions, and activities of the Low-Income Program Initiative are detailed in Appendix E. The Appendix also includes additional comments, provided by the OPA-LDC Residential Working Group, regarding some of the lessons learned and future opportunities for the Home Assistance Program.

2.2.5 Portfolio level activities

PowerStream's 2013 activities that are common to all programs are summarized in Table 13 below.

Table 13: Activities – Common to all Programs

Category	Activities
Planning	• Updated Program Delivery Plans for 2014, which includes budget, procurement, marketing, human resources and monitoring plans and annual demand and energy milestones • Planned staffing levels for the BRI program and its effect on staffing on other programs
Procurement	Completed 3 competitive proposal processes for the following purposes: • BRI Program – Installations • BRI Program – Evaluation, Measurement, & Verification • Advertising agency vendor of record
Staff Resourcing	Recruited 8 incremental staff members mainly for the BRI program and processing applications for the ERII program

2.3 Participation

Table 14 includes the number of participants in each OPA contracted province wide initiative that was offered by PowerStream in 2013. These results were quality controlled and verified by the OPA. It also includes true-up analysis and reporting for 2011 and 2012 program years. The true-up analysis and reporting will continue each year until the end of 2011-2014 reporting period. This true-up analysis ensures that energy and demand savings are properly categorized in the year that they were achieved and that any omissions and/or errors identified after the release of the verified results are properly accounted and reported for.

Table 14: Participation

Initiative	Activity Unit	2013 Participation	Cumulative 2011-2013 Participation
Consumer Program			
Appliance Retirement	Appliances	831	5,481
Appliance Exchange	Appliances	187	449
HVAC Incentives	Equipment	7,946	24,266
Conservation Instant Coupon Booklet	Items	23,028	60,249
Bi-Annual Retailer Event	Items	62,717	196,350
Retailer Co-op	Items	0	134
Residential Demand Response	Devices	21,152	21,152
Residential Demand Response (IHD)	Devices	19,678	19,678
Residential New Construction	Homes	0	9
Business Program			
Equipment Replacement Incentive Initiative	Projects	727	1,336
Direct Install Lighting	Projects	2,315	5,891
Building Commissioning	Buildings	0	0
New Construction	Buildings	4	5
Energy Audit	Audits	9	27
Small Commercial Demand Response (thermostat)	Devices	0	0
Small Commercial Demand Response (IHD)	Devices	0	0
Demand Response 3	Facilities	17	17
Industrial Program			
Process & System Upgrades	Projects	0	0
Monitoring & Targeting	Projects	0	0
Energy Manager	Projects	40	44
Equipment Replacement Incentive Initiative	Projects	0	34
Demand Response 3	Facilities	15	15
Home Assistance Program			
Home Assistance Program	Homes	906	1,164
Aboriginal Program			
Home Assistance Program	Homes	0	0
Direct Install Lighting	Projects	0	0
Pre-2011 Programs completed in 2011			
Electricity Retrofit Incentive Program	Projects	0	195
High Performance New Construction	Projects	1	23
Toronto Comprehensive	Projects	0	0
Multifamily Energy Efficiency Rebates	Projects	0	1
LDC Custom Programs	Projects	0	5
Other			
Program Enabled Savings	Projects	4	32
Time-of-Use Savings	Homes	0	0

2.4 Spending

Table 15 itemizes PowerStream's expenses, by funding category, for each Program Initiative that was offered in 2013. Program Administration Budget (PAB) expenses are futher detailed by expense category (as stipulated in the CDM Code, Appendix A) and are shown in Table 16. Participant Based Funding (PBF) and Participant Incentive Payments (PIP) are based on actual participation in applicable initiatives. The Capability Building Funding includes the Embedded Energy Managers, Roving Energy Managers, and the Key Account Manager. In addition, Pre-2011 Programs were not funded by the 2011-2014 Program terms, they were funded as per their respective program agreements.

In 2013, marketing and program execution continued to be at full force, which increased PAB spend on OPA-Contracted Province-wide Programs by 30% as compared to 2012. Moreover, PIP expenditures increased by 78% while PBF spend was more than two and a half times the amount compared to 2012 (this does not factor in spend on pre-2011 initiatives).

Table 15: 2013 Spending by Initiative ($)

Initiative	Program Administration Budget (PAB)	Participant Based Funding (PBF)	Participant Incentive Payments (PIP)	Capability Building Funding (CBF)	TOTAL
Consumer Program	**1,838,214**	**4,929,662**			**6,767,876**
Appliance Retirement	88,089	-	-	-	88,089
Appliance Exchange	16,102	-	-	-	16,102
HVAC Incentives	79,337	-	-	-	79,337
Conservation Instant Coupon Booklet	81,090	-	-	-	81,090
Bi-Annual Retailer Event	266	-	-	-	266
Residential Demand Response	1,506,387	4,929,662		-	6,436,049
Residential New Construction	66,943	-	-	-	66,943
Commercial and Institutional Program	**2,210,566**	**565,705**	**8,165,932**		**10,942,203**
Equipment Replacement Incentive Initiative (ERII)	1,563,848	-	5,277,142	-	6,840,990
Direct Install Lighting	438,313	565,705	2,810,552	-	3,814,570
Existing Building Commissioning Incentive	25,361	-	*5,506*	-	30,867
New Construction and Major Renovation Initiative	119,218	-	*35,052*	-	154,270
Energy Audit	63,826	-	37,680	-	101,506
Small Commercial Demand Response	Included in Residential Demand Response				
Demand Response 3	Included in Industrial Demand Response 3				
Industrial Program	**357,754**		**92,740**	**596,564**	**1,047,059**
Process & System Upgrades					
a) preliminary study	110	-	*20,000*	-	20,110
b) engineering study	52,913	-	*72,740*	-	125,653
c) program incentive	70,400	-	-	-	70,400
Monitoring & Targeting	17,674	-	-	-	17,674
Energy Manager (REM's and EEM's)	110,304	-	-	487,100	597,404
Equipment Replacement Incentive Initiative	Included in Commercial and Institutional ERII				
Demand Response 3	106,353	-	-	-	106,353
Key Account Manager				109,464	109,464
Low Income Program	**223,886**		**357,817**		**581,702**
Low Income Program	223,886	-	357,817	-	581,702
TOTAL Province-wide CDM PROGRAMS	**4,630,420**	**5,495,367**	**8,616,489**	**596,564**	**19,338,840**

Table 16: 2013 PAB Spend by Expense Category ($)

Program	Labour Costs	Customer Care, Advertising, Marketing	IT	Other Service Providers	Other	Total
Consumer	698,873	927,325	31,034	8,804	172,177	1,838,214
Commercial & Institutional	1,108,141	355,441	36,333	493,562	217,089	2,210,566
Industrial	266,606	32,200	5,299	3,123	50,527	357,754
Low Income	80,674	9,446	3,028	114,790	15,948	223,886
TOTAL	**2,154,294**	**1,324,412**	**75,694**	**620,279**	**455,741**	**4,630,420**

Table 17 and Table 18 below identify PowerStream's cumulative spend by Initiative and by expense category for the period 2011-2013.

Table 17: Cumulative 2011-2013 Spending by Initiative ($)

Initiative	Program Administration Budget (PAB)	Participant Based Funding (PBF)	Participant Incentives (PIP)	Capability Building Funding (CBF)	TOTAL
Consumer Program	**4,133,001**	**6,496,521**			**10,629,522**
Appliance Retirement	429,914	-	-	-	429,914
Appliance Exchange	195,269	-	-	-	195,269
HVAC Incentives	378,986	-	-	-	378,986
Conservation Instant Coupon Booklet	302,624	-	-	-	302,624
Bi-Annual Retailer Event	6,124	-	-	-	6,124
Retailer Co-op	9,178	-	-	-	9,178
Residential Demand Response	2,686,870	6,496,521	-	-	9,183,391
Residential New Construction	124,036	-	-	-	124,036
Commercial and Institutional Program	**4,753,290**	**1,427,615**	**14,495,986**		**20,676,891**
Equipment Replacement Incentive Initiative (ERII)	3,600,470	-	8,271,799	-	11,872,269
Direct Installed Lighting	631,869	1,427,615	6,075,122	-	8,134,606
Existing Building Commissioning Incentive	61,946	-	5,506	-	67,452
New Construction and Major Renovation Initiative	247,429	-	40,376	-	287,805
Energy Audit	211,576	-	103,183	-	314,759

Small Commercial Demand Response	Included in Residential Demand Response				
Demand Response 3	Included in Industrial Demand Response 3				
Industrial Program	**719,727**		**92,740**	**771,136**	**1,583,603**
Process & System Upgrades					
a) preliminary study	63,343	-	*20,000*	-	83,343
b) engineering study	116,207	-	*72,740*	-	188,947
c) program incentive	128,144	-	-	-	128,144
Monitoring & Targeting	33,184	-	-	-	33,184
Energy Manager	209,023	-	-	590,980	800,003
Equipment Replacement Incentive Initiative	Included in Commercial and Institutional ERII				
Demand Response 3	158,708	-	-	-	158,708
Key Account Manager	11,118			180,156	191,274
Low Income Program	**482,883**		**542,427**		**1,025,310**
Low Income Program	482,883	-	542,427	-	1,025,310
Pre-2011 Programs Completed in 2011-14	**145,460**	**742,957**	**3,150,425**		**4,038,842**
Electricity Retrofit Incentive Program	-	-	3,018,390	-	3,018,390
High Performance New Construction	-	-	-	-	-
Multifamily Energy Efficiency Rebates	-	-	-	-	-
Data Centre Incentive Program	-	-	83,260	-	83,260
PeakSaver Extension	145,460[12]	742,957	48,775		937,192
TOTAL Province-wide CDM PROGRAMS	**10,234,361**	**8,667,093**	**21,432,003**	**771,136**	**37,954,168**

Table 18: Cumulative 2011-2013 PAB Spend by expense category ($)

Program	Labour Costs	Customer Care, Advertising, Marketing	IT	Other Service Providers	Other	Total
Consumer	1,832,840	1,741,610	88,582	72,850	397,119	4,133,001
Commercial & Institutional	2,662,568	620,406	103,753	882,886	483,677	4,753,290
Industrial	542,185	60,381	15,515	9,267	92,379	719,727
Low Income	181,272	14,659	6,375	238,467	42,110	482,883
TOTAL	**5,218,865**	**2,437,056**	**214,225**	**1,203,470**	**1,015,285**	**10,088,901**

[12] The $145,460 in administration cost spent on the Peaksaver Extension is not charged against PowerStream's 2011-2014 PAB.

2.5 Evaluation

In order to assess the impacts (energy and demand savings) and the effectiveness of the conservation programs on its participants and/or market, the OPA conducted EM&V of the OPA-Contracted Province-Wide Programs. The key evaluation findings as summarized and provided by the OPA are included in Table 19 below. The results of the impact evaluations are summarized in Table 20 (net-to-gross ratios and realization rates) and Table 21 (net demand and net energy savings).

Table 19: Evaluation Findings

Initiative	Evaluation Findings – Provincial Level (Source: 2013 EM&V Summary Report from the OPA)
Consumer Program	
Appliance Retirement	• Overall participation continues to fall with 20,952 appliances recycled in 2013, compared with 34,146 in 2012 and 56,110 in 2011. The program has experienced close to a 40% reduction (39.1% 2011 to 2012, 41.1% 2012 to 2013) in recycled appliances in each subsequent year of operation. • Per unit savings increased for both energy (+15.4%) and demand (+4.0%) between 2012 and 2013 due to a greater proportion of refrigerators/freezers with large volumes and a manufacturer date before NAECA was implemented. Dehumidifiers also show a higher per unit savings related to the change in ENERGY STAR definitions. • Net to gross ratio stayed constant at around 43% between 2012 and 2013.
Appliance Exchange	• Increased per unit energy and demand savings due to an adjustment to the assumed consumption of "conventional" and Energy Star dehumidifiers. The calculated weighted average annual energy savings of an exchanged dehumidifier increased 36.6% • Of the participants surveyed who reported they had replaced the dehumidifiers they exchanged, 100% reported purchasing ENERGY STAR® models. • 48% increase in the number of eligible dehumidifiers collected in the program. In 2013, 5,337 dehumidifier units were collected compared to 3,617 dehumidifier units and 219 window air conditioners in 2012. • Net to Gross ratio (NTG) was 52.6% which is a slight increase of the 2012 NTG of 51.5%.
HVAC Incentives	• Per unit furnace savings decreased from 1139 kWh/yr in 2012 to 1090 kWh/yr due to a slight shift in the number of participants who use their furnace fan non-continuously both before and after the retrofit as opposed to changing from continuous to non-continuous operation. • Per unit energy and demand savings assumptions for central air conditioners did not change from 2012. • Total participation (equipment) increased 7.5% from 2012 to 91,581.
Conservation Instant Coupon Booklet	• Customers redeemed more than ten times as many annual coupons in 2013 as in 2012 because of new LED coupons and full year availability of all coupons. Customers redeemed 13% more annual coupons in 2013 than in 2011, the first full year of annual coupons due to the high volume of new LED coupons. • There was a significant reduction in savings specialty CFL related measures. In 2013, the findings showed around 30% of participants are replacing incandescent bulbs compared to 60% of participants replacing incandescent bulbs in 2012. • Despite the significant per unit savings reductions, the Net Annual Savings from Annual Coupons in 2013 was more than 5.5 times that in 2012. This is primarily because of higher participation due to the inclusion of LED coupons and full year availability of all coupons.

	• 93% of coupons redeemed in 2013 were for general purpose LEDS and specialty CFLs and LEDs, producing 89% of net annual energy savings and 84% of net demand savings. • Measure NTG ratio was approximately 8% higher in 2013 than in 2012 due to the inclusion of participant like spillover, i.e., purchase of additional coupon initiative measures without using coupons because of program influence.
Bi-Annual Retailer Event	• 36% lower net annual savings in 2013 compared to 2012 primarily because of significant reductions in per unit savings estimates for standard and specialty CFLs. In 2013, findings showed a decrease in replacement rate of incandescent bulbs. Only 30% of 2013 participants are estimated to have replaced incandescent bulbs compared to 60% of participants replacing incandescent bulbs in 2012. This leads to a change in the baseline assumption for the savings calculations. • 19% increase in the number of coupons redeemed during the Spring and Fall Events in 2013 compared to 2012 because of substantial increase in LED purchases with event coupons. • 87% of coupons redeemed were for general purpose and specialty CFLs and LEDs, producing 80% of net annual energy savings and 73% of net demand savings. • Measure NTG ratio was approximately 8% higher in 2013 than in 2012 due to the inclusion of participant like spillover, i.e., purchase of additional coupon initiative measures without using coupons because of program influence.
Residential Demand Response	• The cycling strategy for CAC load control was changed from 50% simple cycling to 60% simple cycling. • Under 1-in-10 year weather conditions, the 2013 estimated impacts for load control devices are higher than the 2012 estimates in all months and are between 10 and 15% higher during the core summer months of June through August. • This year's IHD analysis has yielded an estimate of no statistically significant energy savings. • Load impact estimates for the average small and medium business and for electric water heaters among residential customers are also unchanged from the prior year's analysis.
Residential New Construction	• Energy and demand savings for the Initiative increased by 300% compared to the combined 2011 and 2012 results ; number of projects also increased from 45 in 2011 and 2012 to 86 in 2013. • All projects are opting for the prescriptive or performance path. No custom project applications were received in 2013, similar to 2011-2012. • Net-to-gross ratio for the initiative was higher by 14% from 49% in 2012 to 63% in 2013. • 100% of participants found application process reasonable and understandable.
Commercial and Institutional Program	
Equipment Replacement Incentive Initiative	• A total of 8,785 projects completed in 2013. Reported energy savings for individual projects ranged from 1 kWh to over 5,000,000 kWh. • Net to Gross ratio (NTG) for energy was 72.8%, consistent with prior years. • NTG for demand was 72.0%, consistent with prior years. • NTG ratios are comparable to similar programs across North America.

Direct Installed Lighting	• In 2013 OPA introduced: a) an increase in the incentive to $1500 from $1000, b) new LED measures c) Agribusiness eligibility • 17,782 projects completed in 2013 (3.8% decrease from 2012). • However, 12.2% increase in Net Verified Energy Savings relative to 2012. • The average incentive per project and savings per project both increased between 2012 and 2013. • Net to Gross ratio (NTG) for 2013 remained unchanged at 94%.
Existing Building Commissioning Incentive	• No Commissioning projects completed the hand-off/completion phase in 2013. • 29 unique participants in the 2013 population. • Improvements to the chilled water system controls were the most commonly targeted measure. • Large variation in estimated savings results between investigation phase and implementation phase.
High Performance New Construction	• Number of projects increased by 25% from 69 in 2012 to 86 in 2013. • Custom projects, representing only about 8% of the total number of projects, account for 67% of verified demand savings and 54% of verified energy savings. • A realization rate of 72% for energy savings is low due to the low realization rate of the Agribusiness high ventilation, low speed fans which comprised of 15% of the HPNC prescriptive project energy savings. • Net-to-gross ratio for the initiative was higher by 5% from 49% in 2012 to 54% in 2013. • 100% of participants found the application process to be reasonable and understandable.
Energy Audit	• 319 audits were completed in 2013. • 2013 sample saw more recommended measures implemented without incentives (33% in 2013 vs. 13% in 2012). • The average per audit summer peak demands savings is estimated to be 13 kW.
Small Commercial Demand Response	• Not available. Summary of provincial evaluation findings was not provided by the OPA.
Demand Response 3	• See Demand Response 3 within Industrial Program.
Industrial Program	
Process & System Upgrades Initiative	• In 2013, three PSUI projects were put into service. Projects were very well documented and technical reviews were thorough. Most projects are delivering the level of energy savings expected or more (realization rates of 87% for energy savings and 86% for summer demand savings). • Good level of quality on M&V conducted in each project. The level of free-ridership was found to be very low, at only 7% for energy savings and 6% for demand savings, and no spillover was identified. • Energy Managers are seen as important drivers of program enabled savings projects.

Monitoring & Targeting	• Not applicable. No 2012 results.
Energy Manager	• See Process & Systems Upgrade Initiative for evaluations regarding Energy Manager (non-incented) savings. No separate evaluation findings were provided by the OPA.
Equipment Replacement Incentive Initiative	• See Equipment Replacement Incentive Initiative under C&I Program.
Demand Response 3	• The largest 20 contributors account for 60% of the contractual demand reduction – in other words, less than 5% of contributors account for the majority of the load reductions. • In 2013, DR-3 was successfully dispatched locally for the first time in order to provide assistance in restoring power after a prolonged power outage due to substation flooding.
Low Income Program	
Low Income Program	• Participation increased significantly to 26,756 participants in 2013 from 5,033 in 2012. • Realization rates were slightly lower in 2013 (0.88 for kWh and 0.26 for kW) than in 2012 (0.98 for kWh and 0.32 for kW) primarily due to researched installation verification and persistence factors. • Realization rate for demand savings remained low as FAST calculated kW savings for certain insulation measures remained very high and recommended revisions to kW savings factors were not yet in use in 2013 (changes to the FAST tool to address these issues were made in early 2014).
Pre-2011 Programs completed in 2011-2014	
Electricity Retrofit Incentive Program	• No projects completed for this initiative in 2013.
High Performance New Construction	• Initiative was not evaluated in 2013. • Net-to-Gross ratios used are consistent with the 2010 evaluation findings (realization rate of 100% and net-to-gross ratio of 50%).
Multifamily Energy Efficiency Rebates	• No projects completed for this initiative in 2013.
Data Centre Incentive Program	• No projects completed for this initiative in 2013.

Table 20: Verified Realization Rates and Net-to-Gross Ratios by Initiative (Source: 2013 PowerStream Final Report provided by the OPA)

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement	1.00	1.00	n/a		0.50	0.46	0.42		1.00	1.00	n/a		0.50	0.47	0.44	
Appliance Exchange	1.00	1.00	1.00		0.52	0.52	0.53		1.00	1.00	1.00		0.52	0.52	0.53	
HVAC Incentives	1.00	1.00	n/a		0.60	0.50	0.48		1.00	1.00	n/a		0.60	0.49	0.48	
Conservation Instant Coupon Booklet	1.00	1.00	1.00		1.14	1.00	1.11		1.00	1.00	1.00		1.11	1.05	1.13	
Bi-Annual Retailer Event	1.00	1.00	1.00		1.13	0.91	1.04		1.00	1.00	1.00		1.10	0.92	1.04	
Retailer Co-op	1.00	n/a	n/a		0.68	n/a	n/a		1.00	n/a	n/a		0.68	n/a	n/a	
Residential Demand Response	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Residential Demand Response (IHD)	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Residential New Construction	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Business Program																
Equipment Replacement Incentive Initiative	0.93	0.93	0.93		0.73	0.76	0.73		1.23	1.05	1.05		0.75	0.76	0.74	
Direct Install Lighting	1.08	0.69	0.82		0.93	0.94	0.94		0.90	0.85	0.84		0.93	0.94	0.94	
Building Commissioning	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
New Construction	n/a	n/a	0.97		0.50	n/a	0.54		n/a	n/a	0.99		0.50	n/a	0.54	
Energy Audit	n/a	n/a	1.02		n/a	n/a	0.66		n/a	n/a	0.97		n/a	n/a	0.66	
Small Commercial Demand Response	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Small Commercial Demand Response (IHD)	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Demand Response 3	0.76	n/a	n/a		n/a	n/a	n/a		1.00	n/a	n/a		n/a	n/a	n/a	

Industrial Program																
Process & System Upgrades	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Monitoring & Targeting	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Energy Manager	n/a	1.21	0.90		n/a	0.90	0.90		n/a	1.21	0.90		n/a	0.90	0.90	
Equipment Replacement Incentive Initiative																
Demand Response 3	0.84	n/a	n/a		n/a	n/a	n/a		1.00	n/a	n/a		n/a	n/a	n/a	
Home Assistance Program																
Home Assistance Program	n/a	0.23	0.54		n/a	1.00	1.00		n/a	0.99	0.86		n/a	1.00	1.00	
Aboriginal Program																
Home Assistance Program	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Direct Install Lighting	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program	0.77	n/a	n/a		0.52	n/a	n/a		0.78	n/a	n/a		0.52	n/a	n/a	
High Performance New Construction	1.00	1.00	1.00		0.50	0.50	0.50		1.00	1.00	1.00		0.50	0.50	0.50	
Toronto Comprehensive	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Multifamily Energy Efficiency Rebates	0.96	n/a	n/a		0.68	n/a	n/a		0.96	n/a	n/a		0.68	n/a	n/a	
LDC Custom Programs	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Other																
Program Enabled Savings	n/a	n/a	1.00		n/a	n/a	1.00		n/a	n/a	1.00		n/a	n/a	1.00	
Time-of-Use Savings	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	

Energy Manager, Aboriginal Program and Program Enabled Savings were not independently evaluated

Table 21: Verified Energy and Demand Savings by Initiative (Source: 2013 PowerStream Final Report provided by the OPA)

Initiative	Net Incremental Peak Demand Savings (kW)				Net Incremental Energy Savings (kWh)				2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
	2011	2012	2013	2014	2011	2012	2013	2014		
Consumer Program										
Appliance Retirement	159	94	53		1,160,946	662,323	354,976		303	7,338,875
Appliance Exchange	15	16	39		18,962	28,384	69,085		61	290,610
HVAC Incentives	2,829	1,635	1,658		5,192,089	2,761,285	2,830,426		6,122	34,713,062
Conservation Instant Coupon Booklet	80	15	34		1,295,153	92,817	511,655		129	6,482,375
Bi-Annual Retailer Event	112	98	79		1,950,839	1,777,858	1,140,456		288	15,417,844
Retailer Co-op	0	0	0		2,335	0	0		0	9,339
Residential Demand Response (thermostat)	1,251	3,873	11,897		3,239	28,587	16,249		0	48,075
Residential Demand Response (IHD)	0	0	0		0	0	0		0	0
Residential New Construction	0	0	0		0	0	0		0	0
Consumer Program Total	**4,445**	**5,731**	**13,760**		**9,623,565**	**5,351,253**	**4,922,846**		**6,904**	**64,300,180**
Business Program										
Equipment Replacement Incentive Initiative	1,225	4,690	5,114		7,512,897	25,834,397	28,469,682		10,994	164,305,694
Direct Install Lighting	2,106	1,437	2,327		5,296,278	5,424,343	7,944,313		5,092	50,600,302
Building Commissioning	0	0	0		0	0	0		0	0
New Construction	16	0	778		69,868	0	1,579,613		795	3,438,698
Energy Audit	0	52	79		0	251,763	436,057		131	1,627,401
Small Commercial Demand Response (thermostat)	0	0	0		0	0	0		0	0
Small Commercial Demand Response (IHD)	0	0	0		0	0	0		0	0
Demand Response 3	1,243	1,232	1,921		48,536	17,913	28,336		0	94,784
Business Program Total	**4,590**	**7,411**	**10,220**		**12,927,578**	**31,528,415**	**38,458,000**		**17,012**	**220,066,879**

Industrial Program										
Process & System Upgrades	0	0	0		0	0	0		0	0
Monitoring & Targeting	0	0	0		0	0	0		0	0
Energy Manager	0	19	421		0	36,000	3,717,682		114	5,349,159
Equipment Replacement Incentive Initiative	502	0	0		3,213,757	0	0		501	12,852,927
Demand Response 3	2,634	3,186	6,406		154,591	76,793	157,656		0	389,040
Industrial Program Total	**3,135**	**3,205**	**6,827**		**3,368,348**	**112,793**	**3,875,338**		**615**	**18,591,126**
Home Assistance Program										
Home Assistance Program	0	36	45		0	313,102	595,251		80	2,103,438
Home Assistance Program Total	**0**	**36**	**45**		**0**	**313,102**	**595,251**		**80**	**2,103,438**
Aboriginal Program										
Home Assistance Program	0	0	0		0	0	0		0	0
Direct Install Lighting	0	0	0		0	0	0		0	0
Aboriginal Program Total	**0**	**0**	**0**		**0**	**0**	**0**		**0**	**0**
Pre-2011 Programs completed in 2011										
Electricity Retrofit Incentive Program	1,958	0	0		9,540,024	0	0		1,958	38,160,095
High Performance New Construction	211	644	83		1,082,896	2,745,770	221,916		938	13,012,727
Toronto Comprehensive	0	0	0		0	0	0		0	0
Multifamily Energy Efficiency Rebates	75	0	0		194,534	0	0		75	778,138
LDC Custom Programs	81	0	0		533,038	0	0		81	2,132,152
Pre-2011 Programs completed in 2011 Total	**2,325**	**644**	**83**		**11,350,493**	**2,745,770**	**221,916**		**3,052**	**54,083,112**
Other										
Program Enabled Savings	0	0	5		0	0	7,515		5	15,030
Time-of-Use Savings	0	0	0		0	0	0		0	0
Other Total	**0**	**0**	**5**		**0**	**0**	**7,515**		**5**	**15,030**
Adjustments to 2011 Verified Results		**107**	**5**			**1,508,750**	**8,134**		**110**	**6,063,238**
Adjustments to 2012 Verified Results			**719**				**4,051,236**		**719**	**12,153,075**
Energy Efficiency Total	**9,368**	**8,736**	**10,715**		**37,063,617**	**39,928,041**	**47,878,626**		**27,668**	**358,627,866**
Demand Response Total (Scenario 1)	**5,128**	**8,291**	**20,225**		**206,366**	**123,292**	**202,240**		**0**	**531,898**
Adjustments to Previous Years' Verified Results Total	**0**	**107**	**724**		**0**	**1,508,750**	**4,059,370**		**829**	**18,216,313**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)	**14,496**	**17,134**	**31,664**		**37,269,983**	**41,560,083**	**52,140,236**		**28,497**	**377,376,078**

3 Combined CDM Reporting Elements

3.1 Progress Towards CDM Targets

PowerStream achieved a total of 30.9 MW of verified demand savings in 2013, of which 10.4 MW is guaranteed to persist to 2014, and 48.1 GWh of verified energy savings, which cumulates to 93.8 GWh at the end of 2014. Combined with 2011 and 2012 results, PowerStream has achieved, as of the end of 2013, a total of 28.5 MW of demand savings guaranteed to persist to 2014 and 377.5 GWh in cumulative energy savings, representing 29.8% and 92.7% of PowerStream's demand and energy savings targets, respectively. Table 22 illustrates the net peak demand and energy savings by program with their contribution towards the 2014 target.

Table 22: Summarized Program Results

	2013 Incremental Net Savings		Program to Date Contribution to Targets	
	Peak Demand Savings (MW)	Energy Savings (GWh)	Net Annual Peak Demand Savings (MW) in 2014	2011-2014 Net Cumulative Energy Savings (GWh)
Province-Wide CDM Programs				
Consumer Programs	13.76	4.92	6.50	61.91
Business Programs	17.05	42.33	18.34	252.61
Home Assistance Program	0.05	0.60	0.08	2.10
Pre-2011 Programs	0.08	0.22	3.38	57.02
Program Enabled Savings	0.01	0.01	0.19	3.74
Total Province-Wide CDM Programs	**30.94**	**48.08**	**28.50**	**377.38**
BRI Program	0.01	0.06	0.00	0.10
Total Portfolio	**30.95**	**48.14**	**28.50**	**377.47**

As shown in Table 23 below, PowerStream's 2013 results were quite positive. As of the end of 2013, PowerStream's actual progress towards its four year targets is very close to the milestones set out in the 2012 Annual Report, with a positive variance of 3% for both demand and energy.

Table 23: 2013 Results vs 2012 Milestones

Cumulative Progress to Date	2013 Milestone as per 2012 Annual Report		2013 Verified Annual Results		Variance to 2013 Milestone	
	Savings	% to Target	Savings	% to Target	Savings	% to Target
2014 Net Demand Savings (MW)	25.2	26.4%	28.5	29.8%	3.3	3%
2011-2014 Net Cumulative Energy Savings (GWh)	366.0	89.9%	377.5	92.7%	11.4	3%

The key factors contributing to the higher than forecasted results were:

- True-up in results for 2012 that was not anticipated at the time the forecast was set.
- Unexpected savings from a pre-2011 High Performance New Construction project completed in 2013
- Residential programs in general having a higher uptake than originally forecasted
- Achieved a significant amount of non-incented savings by energy managers which based on past experience was not expected
- Equipment Replacement Incentive Initiative and the Direct Install Lighting program both performed better than anticipated
- OPA released a guidance document to claiming Program Enabled Savings which allowed PowerStream to successfully claim Program Enabled Savings for the first time.

3.2 CDM Strategy Modifications

PowerStream updates its demand and energy savings forecasts twice a year – in December and September. At the end of each calendar year (also PowerStream's fiscal year), an internal estimate of year-end CDM results is made as well as updated outlook for remainder of CDM target period. In September of each year, PowerStream updates its 2011-2014 CDM outlook based on EM&V results of previous year received from OPA and progress within the current program year.

PowerStream's current projection as of September 18th, 2014 is to achieve 78.6% of its demand target and 108.8% of its energy target. This projection includes savings from OPA-Contracted Province-wide Programs, PowerStream's Business Refrigeration Incentive Program as well as TOU rates. The projected achievement of demand savings not only fall below PowerStream's target, but is also at further at risk because it is highly reliant on obtaining 12.5 MW of savings from TOU rates. As mentioned earlier, OPA will only be releasing the verified savings due to TOU rates in August of 2015.

Due to the uncertainty with TOU rates and due to the fact that PowerStream's current projection is to achieve only 78.6% of its demand savings target, PowerStream identified 5 tactics that will allow it to exceed its current projections. The focus of the tactics is to achieve demand savings as according to PowerStream's internal estimate, PowerStream has already met its energy target as of August 2014. The tactics were developed by CDM staff and were evaluated based on impact and ease of implementation. Due to the fact that less than half an year remains in the current framework, the main constraint to be considered when developing the tactics was time. Whatever the tactics chosen, needed to allow for the projects to be completed and for savings to be captured in the current framework. The 5 tactics chosen were the following:

1. *Following up on ERII projects in the pipeline:* Follow up on ERII project that have been sitting in "Pre-approved" or "Draft" status for a while to see if they would require any assistance with the application or the project itself.

2. *peaksaverPLUS "Last Chance/Home Audit" campaign:* Multi-tactic marketing campaign (bill insert, direct mail, radio, online) with last chance messaging and offering a free in-home energy audit for the first 500 customers. This campaign has been launched and will be in market September to November 2014. PowerStream estimates that there is potential to capture 1.5 MW – 2 MW of incremental savings due to this campaign.

3. *ERII "Quick Wins with Lighting" campaign:* Multi-tactic campaign (direct mail, LinkedIn, outbound calling) targeting lighting retrofit projects. This campaign has been launched and will be in market September to November 2014. PowerStream estimates that there is potential to capture up to 100 LED conversion lighting projects, which could lead to up to 1.5 MW in demand savings.

4. *Following up on HPNC projects in the pipeline:* Conduct monthly follow up phone calls with customers that have been pre-approved to see how their project is proceeding and to see if they would require any help with the application process. This initiative has already been launched. PowerStream estimates that there is potential to capture up to 1 MW of demand savings from these projects.

5. *BRI head office campaign:* Potential identified to capture up to 1 MW from multi-location customers and franchised retail locations through head office outreach and endorsement. A sales plan has been developed to determine largest opportunities and customer meetings are ongoing.

In its 2011 Annual CDM Report, filed in September 2012, PowerStream was still forecasting to achieve 100% of its demand savings targets. The single biggest contributor to the reduction in forecasted demand savings is TOU rates. In its 2011 Annual CDM Report, PowerStream had been estimating the contribution from TOU rates implementation at approximately 22MW. This assumption was based on the provincial savings estimate of 308MW that was used to set the LDCs' aggregate 2011-2014 CDM target of 1330MW and based on PowerStream at approximately 7% of the province. While verified TOU savings from the OPA will not be available until mid-2015, preliminary TOU evaluation findings for 4 LDCs (not including PowerStream) were presented to all LDCs by OPA at its 2012 EM&V workshop in early September 2013. Based on these preliminary findings, PowerStream has lowered its TOU savings forecast by approximately 10MW.

In its 2012 Annual CDM Report, filed in September 2013, PowerStream was forecasting on achieving 79.8% of its demand target and 101.4% of its energy target. As such, there is not much change in PowerStream's current projection and the forecast presented in the 2012 Annual CDM Report.

The main driver for the increase in projected energy savings over what was forecasted in the 2012 Annual CDM Report was overachieving on our 2013 milestones as already discussed in Section 3.1. The other major contributor was an increase in the pipeline of projects for HPNC.

The contributors for the small drop in the demand projection is the underperformance of the peaksaver PLUS program in 2014 and the cancellation of the Demand Response 3 (DR3) program. At the time the DR3 program was cancelled, PowerStream had roughly 6.2 MW and 27 customers who had signed agreements with the aggregators but not yet enrolled.

The DR3 program is a program that has underachieved extensively from the OPA's initial forecast. In the original (2010) provincial forecasts for the OPA-Contracted Province Wide Programs, it was anticipated that Demand Response initiatives within the Industrial and C&I Programs would contribute approximately 223 MW across the Province, representing approximately 21.5% of the total demand savings (1037 MW) forecasted for the OPA-Contract Province Wide Program Portfolio. PowerStream is currently projecting approximately 8.4 MW of savings from DR3 which represents less than 14% of PowerStream's total projected demand savings from OPA-Contracted Province Wide Programs. PowerStream believed there was still significant market potential for the DR3 program which could support the LDC's and the OPA in meeting the province wide demand target. As the DR subject matter expert on the OPA-LDC Industrial Program Working Group, PowerStream spearheaded the development of a second DR3 business case in the summer of 2013, which included recommendation to encourage greater participation in the program. This business case was presented to the OPA by the Working Group in October 2013 as an opportunity to make up a portion of the projected demand target shortfall. None of the recommended changes were implemented. While not formally communicated, PowerStream understands that there may have been a number of issues preventing these program improvements, including limited OPA procurement authority for Demand Response resources beyond 2014 and the current surplus of electricity capacity in the province over the next few years.

Table 24 and Table 25 below provide more detailed illustrations of the updated forecasts; showing the amount of demand savings persisting from one year to the next and the amount of energy that cumulates to 2014.

Table 24: Revised 2011-2014 Milestones, Demand

Year	Status	Program	Net Annual Demand Savings (MW)				Progress Against OEB Target (95.57 MW)	
			2011	2012	2013	2014	Running Total (MW)	%
2011	Verified	Province-Wide Programs	14.6	9.5	9.4	8.9	8.9	9.3%
2012	Verified	Province-Wide Programs		17.7	9.4	9.2	18.1	19.0%
	Estimated*	Province-Wide Programs		0.5	0.5	0.5	18.6	19.5%
2013	Verified	Province-Wide Programs			30.9	10.4	29.0	30.3%
	Verified	BRI Program (Board Approved)			0.0	0.0	29.0	30.3%
	Estimated*	Province-Wide Programs			0.4	0.4	29.4	30.8%
2014	Projected	Province-Wide Programs				32.4	61.8	64.6%
		BRI Program (Board Approved)				0.8	62.6	65.5%
		Time of Use Rates				12.5	**75.1**	**78.6%**

Table 25: Revised 2011-2014 Milestones, Energy

Year	Status	Program	Net Annual Energy Savings (GWh)				Cumulative Energy Savings (GWh)	Progress Against OEB Target (407.34 GWh)	
			2011	2012	2013	2014	2011-2014	Running Total (GWh)	%
2011	Verified	Province-Wide Programs	38.8	38.6	38.3	36.9	152.6	152.6	37.5%
2012	Verified	Province-Wide Programs		44.1	44.2	43.1	131.0	283.7	69.6%
	Estimated*	Province-Wide Programs		2.4	2.4	2.4	7.2	290.9	71.4%
2013	Verified	Province-Wide Programs			48.1	45.6	93.7	384.6	94.4%
	Verified	BRI Program (Board Approved)			0.1	0.0	0.1	384.7	94.4%
	Estimated*	Province-Wide Programs			2.9	2.9	5.7	390.4	95.8%
2014	Projected	Province-Wide Programs				47.4	47.4	437.8	107.5%
		BRI Program (Board Approved)				5.6	5.6	**443.4**	**108.8%**

* 2012 and 2013 Estimated Province-Wide Program results is PowerStream's estimate of how much savings PowerStream will get towards 2012 and 2013 results respectively as a true-up in the 2014 OPA Final Verified Report.

To summarize the modifications to the Strategy, Figure 1 and Figure 2 are provided to illustrate the comparison of demand and energy savings forecast from the original Strategy (Oct 2010) to the 2012 Strategy (Sep 2012), to the 2013 Strategy (Sep 2013), and to the September 2014 projection.

Figure 1: Comparison of Demand Savings Forecasts

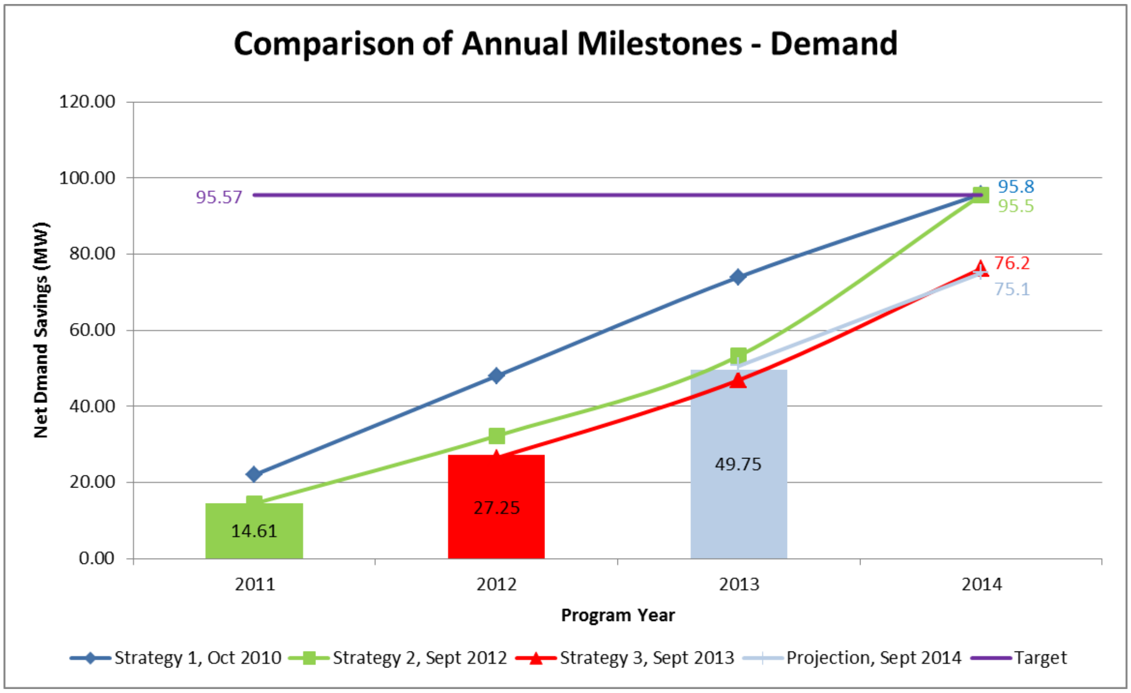
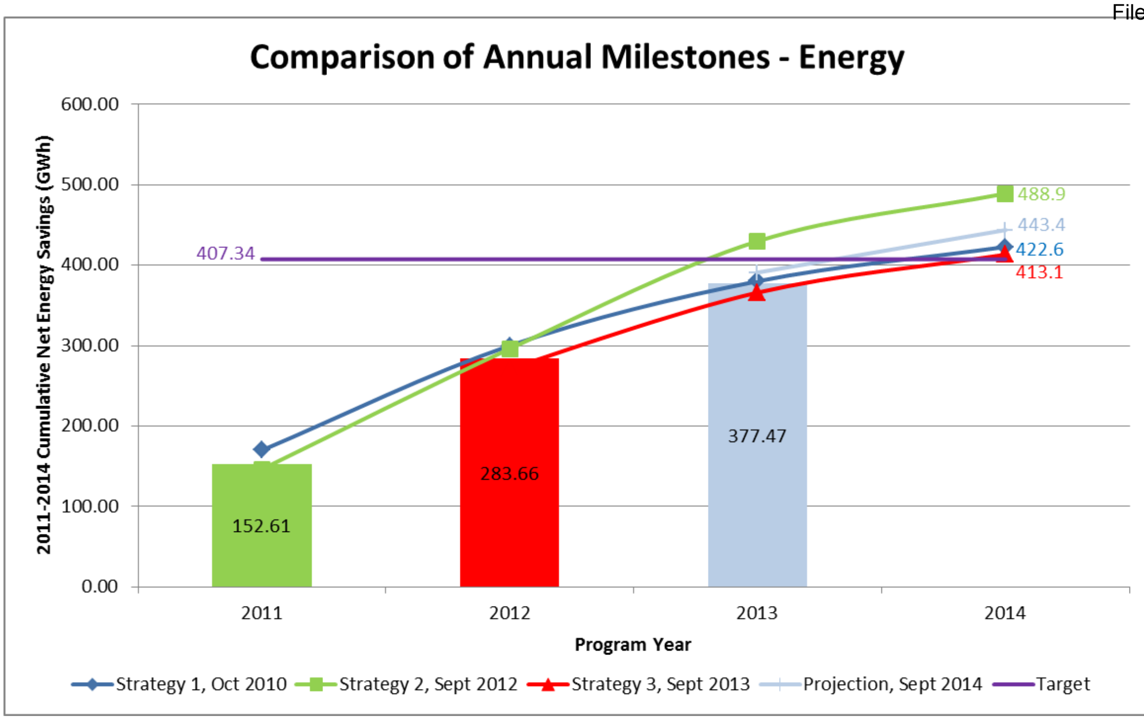


Figure 2: Comparison of Energy Savings Forecasts



As with any forecasting exercise, there are known risks to achieving the CDM targets. In some cases these risks can be mitigated by PowerStream while in other cases, PowerStream has little to no control over the risks, such as TOU savings results or the cancellation of the DR3 program. PowerStream has developed a risk assessment and mitigation accordingly. These risks, together with their impact and mitigation plan are summarized in Table 26 below.

Table 26: Risk Assessment and Mitigation Plan

Risks	Likelihood	Impact	Mitigation strategies
EM&V uncertainty – results much lower than planned due to Net-to-Gross adjustments (e.g. free ridership, realization rates)	Low	High	• Primarily outside of PowerStream control • Make conservative estimates using most up to date data assumptions
Time of Use (TOU) savings lower than forecasted	Medium	High	• Entirely outside of PowerStream control • Use the most up-to-date information available to forecast
Forecasted program participation levels are not achieved	Low	Medium	• Not seen as a major risk as participation forecasts are based on several years of actual data
Business Refrigeration Incentives Program - demand and/or energy savings lower than planned	Medium	Low	• Target measures with high savings potential • Actively monitor cost effectiveness of the program
OPA extension of commercial Equipment Replacement Incentive Initiative (ERII) to end of 2015 • Customers now have until end of 2015 to complete their projects, but only those completed in 2014 will count to our OEB target • Reduces sense of urgency for customers in 2014	High	Medium	• Communications/messaging with customers to encourage them to remind them to apply to finish their project and claim their incentive
ERII and HPNC projects not being captured towards PowerStream's result despite being completed in 2014 due to the time the OPA extracts the data	Medium	Medium	• Work with the OPA to ensure all HPNC projects completed in 2014 are captured even if the Pre-Billing Report (PBR) has not been submitted for the project • Communicate with pre-approved ERII applicants to encourage them to submit their post application as soon as their project is completed.

PowerStream revised its budget to provide a more accurate reflection of what PowerStream expects to spend. Table 27 shows the annual budget per program which includes Program Administration Budget, Participant Based Funding, Participant Incentive Payment, and Capability Building Funding.

The budgets were updated to factor in the expenses to date, remaining funds available from the OPA, and the detailed marketing and execution plans. PBF and PIP values, shown below, are estimates based on the projected number of participants in the applicable OPA-Contracted Province-wide Program Initiative. Similar to the demand and energy projection, the budgets include actual expenses incurred from 2011-2013 and forecast for 2014.

Table 27: Revised 2011-2014 Budget, OPA-Contracted Province Wide Programs ($)

		Residential	C&I	Industrial	Home Assistance	Total, by Year
2011	PAB	$987,887	$801,487	$77,714	$37,396	$1,904,483
	PBF/PIP	-	2,120,978	-	-	2,120,978
	CBF	-	-	-	-	-
	2011 total	987,887	2,922,465	77,714	37,396	$4,025,462
2012	PAB	1,306,900	1,741,236	284,259	221,601	3,553,996
	PBF/PIP	1,566,859	5,070,986	-	184,610	6,822,455
	CBF	-	-	174,572	-	174,572
	2012 total	2,873,759	6,812,223	458,831	406,210	$10,551,023
2013	PAB	1,838,214	2,210,566	357,754	223,886	4,630,420
	PBF/PIP	4,929,662	8,731,637	92,740	357,817	14,111,857
	CBF	-	-	596,564	-	596,564
	2013 total	6,767,876	10,942,203	1,047,059	581,713	$19,338,841
2014	PAB	2,385,172	3,123,108	459,178	209,549	6,177,007
	PBF/PIP	2,622,000	6,948,418	-	404,000	9,974,418
	CBF	-	-	861,263	-	861,263
	2014 total	5,007,172	10,071,526	1,320,441	613,549	$17,012,688
Total, by Program		$15,636,694	$30,748,417	$2,904,045	$1,638,858	$50,928,014

Comparing the 2013 actual spend to the 2013 budget provided in the 2012 Annual Report resulted in an overall spending variance of 6% as detailed in Table 28. The main reason for the PAB variance is largely due to later than anticipated start dates of additional resources and delay in contract/consulting services due to contracted project prioritization. PBF/PIP was overspent in 2013 due to more than estimated participation levels attributable to PeakSaver Plus, ERII, and SBL initiatives. Low income and HPNC resulted in lower than anticipated PIP results. CBF variance is mainly due to Q4 payments paid in 2014 for the Embedded Energy Managers.

Table 28: 2012 Spend VS. 2012 Budget

	2013 Budget per 2012 Annual Report	2013 Actual Spend	Variance to 2013 Budget	% Variance to 2013 Budget
PAB	$5,044,078	$4,630,420	$(413,658)	-8.2%
PBF/PIP	12,421,368	14,111,857	1,690,499	13.6%
CBF	778,828	596,564	(182,264)	-23.4%
2013 total	$18,244,274	$19,338,841	$1,094,577	6.0%

In addition to the budget above, PowerStream received an OEB approval on June 21, 2013 to deliver the Business Refrigeration Incentives Program at an estimated cost of up to $4.1 Million. The forecasted breakdown of the approved program delivery budget, as set out in PowerStream's application to the OEB, is provided in tables Table 29 and Table 30.

Table 29: Board Approved CDM Program 2013-2014 Forecast ($)

	2012	2013	2014	Total
Fixed Program Costs	78,204	538,215	582,042	1,198,461
Variable Program Costs	-	36,000	84,000	120,000
Subtotal - Program Costs	**78,204**	**574,215**	**666,042**	**1,318,461**
Customer Incentives	-	839,490	1,958,810	2,798,300
Total Delivery Costs	**78,204**	**1,413,705**	**2,624,852**	**4,116,761**

Table 30: Board Approved CDM Program Fixed Spend by Expense Category

Program Costs	2012 Actual	2013 Actual	2014 Forecast	Total
Legal		2,185	0	2,185
Program Administration		303,077	571,564	874,641
Marketing		86,693	110,000	196,693
Evaluation, Measurement & Verification		24,828	161,795	186,623
Total	**$0**	**$416,783**	**$843,359**	**$1,260,142**

Appendix A: BRI Evaluation Report

IndEco
Strategic Solutions for a Changing World™

Year 1 evaluation of the *Business Refrigeration Incentives* program

PowerStream *Business Refrigeration Incentives* program

Year 1 evaluation

This document was prepared for PowerStream by IndEco Strategic Consulting Inc.

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IndEco report B3872

29 August 2014

Contents

Executive summary

Purpose

This document reports on the results of the evaluation of the Business Refrigeration Incentives program offered by PowerStream through the end of 2013.

Scope and method

The scope of the project considers both process and impact issues related to the project.

Process related issues are based on interviews with persons responsible for delivering the program, including program administrators, auditors, persons responsible for marketing and installation.

In addition, an on-line survey was conducted of program participants. The survey was conducted between April 15, 2014 and May 12, 2014. All program participants as of early April were invited to respond and 103 agreed to do so. The survey provided information used in assessing satisfaction with the program, and for determining how much of gross energy savings identified can actually be attributed to the program (i.e. net energy savings.)

Several questions were added to a PowerStream comprehensive customer survey (CASA) to get perspectives on the program from non-participants.

Selected equipment at a random sample of facilities was logged for a period of time before and after installation of retrofit measures to assess real-world impacts of the installed measures. Measurements were taken at 19 facilities on 81 refrigeration units through the end of April, and actual measures were compared to estimated (prescriptive) values, and this ‘realization factor’ was applied to installations that occurred in 2013.

Status of data

Several types of data were used in the analysis, each with its own limitations.

Prescriptive data on estimated savings for particular retrofit measures were provided by PowerStream. Estimated savings were based on a review of the literature, and were based on ‘typical’ units. The range of potential unit sizes, or usage patterns and their impact on energy use was not available.

Survey data Surveys were sent to 281 facilities that had participated in the program as of the end of March 2014, and 103 responses were received. Overall, that response rate would provide results with a reasonable level of statistical confidence (90%±7%). However, some questions only applied to a subset of the sample, and the confidence that those responses are typical of a large population is lower.

Monitoring data were based on measures taken over roughly a two week period before and after installation of retrofit measures. In many cases, it was not possible to attribute savings to individual measures because multiple measures were installed simultaneously. Where individual measures types were installed, there appears to be a wide variation in the measured savings.

Main findings

The process being used for the program appears to be working well for the most part, and there is a reasonable level of customer satisfaction with the program, though it is lower than PowerStream has realized in other parts of the business. Customers indicate an interest in participating in the program. In fact, PowerStream has slowed marketing of the program at times because interest was greater than the ability to meet that interest.

At the end of 2013, there were 269 participants in the program, but installs had been completed at only 6 facilities. The number of installs was well below expectation due to a variety of factors including: the late start of the program, difficulty securing retrofit equipment, and changes in installers involved in the program.

PowerStream made changes to the program beginning in 2013, and continuing into early 2014 to address barriers to successful implementation.

PowerStream developed a powerful database for managing the project, which has rich information about program participants and progress of the program.

The impact of the program, measured in kilowatt-hours saved and kilowatts of demand reduced was well below expectations for 2013. Actual net savings were just over 57 MWh, and demand reductions were about 6 kW. The main reason for the low numbers was the low number of installations, and the smaller than expected number of measures per installation. In addition, actual unit savings were also lower than predicted at about 67% for energy and 64% for demand.

Impact measures are for the installed equipment. It was not possible to measure energy savings attributable to the audit portion of the project.

Conclusions and recommendations

The overall process used for the program appears to be working, though there were significant problems in realizing installations. PowerStream has taken numerous measures to address these problems, and is and should continue monitoring progress carefully. The pace of installations has picked up considerably in 2014.

Since 2013, PowerStream contractors have more experience with what to expect at customers' sites, and therefor what equipment needs to be stocked and taken to customers' sites, which specific brands of measures work best, and on the needs for distributors to carry equipment. Nevertheless, PowerStream should consider additional training for contractors on customer service to increase the customer satisfaction level.

Additional detail on pre-retrofit conditions of equipment, measures installed and the refrigeration units they are installed in should help to refine estimates of savings in the future.

Introduction

PowerStream's *Business Refrigeration Incentives* (BRI) program provides energy audits and refrigeration upgrades to qualifying businesses with a peak demand of less than 250 kW within the commercial and institutional sector at no charge for equipment valued up to $2,500. The program aims to overcome the substantial market barriers associated with promoting energy efficient refrigeration equipment upgrades to businesses including: limited awareness of energy use and electricity costs of refrigeration equipment, limited knowledge of opportunities to reduce energy use, limited availability of equipment from distributors, and limited access to capital to upgrade refrigeration equipment.

Target market and eligibility

The BRI program targets business owners within the commercial and institutional sector that have commercial grade refrigeration equipment.

In the PowerStream service territory, there are approximately 3,000 restaurants and 1,000 grocers. In addition, there are many other small commercial businesses with product refrigeration, including florists, medical laboratories, and school cafeterias.

In order to be eligible for the BRI program, customers must:

- Have a General Service (GS) Account with PowerStream. Customers with residential accounts will not be eligible.
- Have an average annual demand of less than 250 kW.
- Have commercial grade refrigeration equipment used to cool products (e.g. food to flowers). Customers with residential refrigeration equipment will not be eligible.

If the facility is leased, the participant must have the authority to have the measures installed as a condition of the lease or with the consent of the owner of the facility.

Evaluation goals and objectives

The overall goal of the BRI program is to achieve electricity savings and demand reductions that will contribute towards PowerStream's 2011-2014 CDM targets. Specific objectives include:

- To achieve electricity savings and peak demand reductions;
- To increase awareness of energy efficiency measures and programs; and
- To stimulate changes in behaviour, technology and market conditions that favour energy efficiency.

Program elements

Eligible participants in the BRI program receive a turn-key service that includes:

- A free electricity audit and assessment;
- A customized report and "Energy Action Plan" based on the electricity audit and assessment; and
- Up to $2,500 of eligible refrigeration measures and services provided and installed at no charge.

Table 1 describes the elements of the program that are undertaken to encourage participation and support energy and demand savings in eligible commercial and institutional customers.

Table 1 Description of elements

Element	Description
Direct marketing	PowerStream uses direct marketing methods to promote participation in the program. These include: direct mail inserts, follow up door-to-door community blitz, and direct calling.
Audit and assessment	Customers receive a free electricity audit and assessment based on the following data: • Customer profile/firmographics (e.g. type of business, operating hours); • Historical electricity consumption; and • Walk through audit results (e.g. load inventory, square footage, age of equipment). Once the customer agrees to the audit and assessment, PowerStream schedules and conducts the audit.
Electronic assessment report and work order	PowerStream provides customers with a customized, user friendly (electronic) report and Energy Action Plan that includes a description of: • Key end-uses driving electricity consumption patterns in the facility; • Specific eligible refrigeration recommendations for measures / services to be installed and associated energy and demand savings; • Additional opportunities for energy and demand savings related to other end-uses and other applicable CDM programs; and • A comparative benchmark of the facility's electricity use against similar businesses. PowerStream also provides customers will a work order for up to $2,500 in eligible refrigeration measures.

Element	Description
Follow-up and installation scheduling	PowerStream follows-up with customers to encourage them to sign the work order. Once customers sign the work order agreeing to the installation of measures, PowerStream schedules the installation.
Measure installation	PowerStream arranges for the installation of eligible refrigeration measures of up to $2,500 by a qualified refrigeration mechanic licensed in Ontario. Eligible measures that are included are as follows: • Anti-sweat heater controls for cooler or freezers • Night curtains on display cases • Cleaning cooler/freezer condenser coils • Energy efficient evaporator fan motors (ECM motor upgrade) • LED display case lighting • Strip curtains for walk-in coolers and freezers.
Quality assurance visit	PowerStream conducts quality assurance visits of a representative sample of participating facilities. The purpose of the visits is to collect information for EM&V and reinforce participants' confidence in the program.
Customer satisfaction survey	PowerStream delivers surveys to a representative sample of program participants (both customers who proceeded to the direct install phase of the program, and those who did not). The purpose of the surveys is to collect information for EM&V and reinforce participants' confidence in the program.

Expected savings

PowerStream has estimated that the BRI program will generate 3.3 MW and 19.6 GWh of net savings, representing an additional 3.5% and 4.8% towards PowerStream's 2011-2014 demand and energy targets, respectively.

Grocery stores and restaurant typically use approximately three times the amount of electricity per square foot of retail space compared to offices and other retail businesses. Refrigeration represents the largest single end-use of electricity in these facilities – 50% for restaurants and 72% for grocers.

Logic diagram

The logic model on the next page illustrates the theory of the PowerStream BRI program. The evaluation will assess the immediate outcomes only.

Objective #1
Achieve energy and demand savings among commercial customers

Objective #2
Increase awareness of energy efficiency measures and programs among commercial customers

Objective #3
Stimulate changes in behaviour, technology and market conditions that favour energy efficiency

KEY PROGRAM ELEMENTS

Direct marketing
- PowerStream
- Customers

Audit, assessment report and work order
- PowerStream
- Program participants

Follow-up and measure installation
- PowerStream
- Contractors
- Program participants

Quality assurance visit, customer survey & program evaluation
- PowerStream
- Program participants
- Evaluators

OUTPUTS

- PowerStream develops and disseminates information about the program to commercial customers.
- To promote participation in the program, PowerStream uses direct marketing methods such as: direct mail, follow-up door-to-door community blitz, and direct calling.

- PowerStream schedules and conducts free electricity audits and assessments for interested customers.
- PowerStream sends customers assessment reports with:
  1. Recommended eligible refrigeration measures
  2. Instructions for moving to direct install
  3. Cross-marketing of province-wide programs
  4. Energy benchmarking against other facilities
- PowerStream sends work orders for up to $2,500 in eligible measures.

- PowerStream follows up with customers to encourage them to sign the work order.
- Once customers have signed the work order agreeing to installation, PowerStream arranges for the installation of eligible refrigeration measures up to $2,500 by a qualified refrigeration mechanic:
  1. Anti-sweat heater controls
  2. Night curtains on display cases
  3. Cleaning cooler/freezer condenser coils
  4. Electronically Commutated Motor upgrade
  5. LED display case lighting
  6. Strip curtains

- PowerStream conducts quality assurance visits of a representative sample of participating facilities.
- PowerStream delivers surveys to a representative sample of program participants (customers that proceeded to direct install, and those that did not) and non-participants.
- Evaluation contractor evaluates program impacts (energy and demand savings) and process.

IMMEDIATE OUTCOMES

- Commercial customers are aware of the Direct Install Refrigeration Program.
- Commercial customers are more aware of refrigeration energy efficiency measures and their importance.
- Some commercial customers opt to participate in the program.

- Participants are aware of the energy use and costs of their refrigeration equipment, and relevant CDM opportunities.
- Participants understand how their energy use compares to other similar facilities.
- Participants are aware of other energy efficiency opportunities in their facilities, and other province-wide CDM programs that they may be eligible for.
- Participants discuss their free assessments with acquaintances.

- Participants sign up for the direct installation phase of the program.
- PowerStream sees immediate decreases in commercial energy use and peak demand (kW and kWh).
- Participants see decreases in their electricity use and bills.
- Participants discuss their free installations with acquaintances.
- There is an increased penetration of energy efficient products and controls in the market.

- Surveys and visits reinforce participants' confidence in the program.
- Participants reflect on their participation in the program.
- PowerStream improves, continues or terminates the program based on the evaluation results.

LONG-TERM OUTCOMES

- Increasing numbers of commercial customers opt to participate in the program.
- There is an increasing market for commercial energy efficiency products and services.

- Increasing numbers of customers participate in the free audit and assessment portion of the program.
- Increasing numbers of customers participate in other province-wide CDM programs.
- Participants seek other ways to improve energy efficiency in their facilities, to improve their relative energy performance.
- There is an increasing market for energy efficiency products & services.

- Increasing numbers of customers participate in the direct install portion of the program.
- PowerStream sees persistent decreases in kW and kWh.
- Participants are motivated to implement other energy efficiency measures and behavioural practices in their facilities and/or homes, without utility incentives.
- Participants are aware of the role of PowerStream and monitor other and province-wide CDM programs.
- Participants may be somewhat less motivated to conserve energy because of the increased efficiency of their refrigeration equipment.
- There is an increasing market for energy efficiency products & services.

Program participation

The BRI program officially launched on September 20, 2013. The information provided in this section covers program participation from four weeks before the launch date until the end of 2013.

Projected participation

At the start of the BRI program, PowerStream projected 1,200 customers would participate in the program by the end of 2014 (based on an earlier estimated launch date). Table 2 below illustrates the estimated participant breakdown over the two years.

Table 2 Projected participation breakdown (2013-2014)

	Total	Grocer	Restaurant
2013-2014 participants	1200	500	700
2013 participants	360 (30%)	150	210
2014 participants	840 (70%)	350	490

Actual participation in 2013

In 2013, over the course of 17 weeks, 269 participants applied to the BRI program, 234 audits were conducted, and 217 participants signed agreements. Due to equipment assessment and back-log issues, installations were only completed in six businesses. A list of installed measures is provided in Table 3 below.

Table 3 List of measures installed in 2013

Measure	Quantity
Clean condenser coils (cooler)	43
Clean condenser coils (freezer)	3
1/20 HP ECM fan motor upgrade	19
1/15 HP ECM fan motor upgrade	8
9 W ECM fan motor upgrade	19
Strip curtains - Walk-in freezer	1
Strip curtains - Walk-in cooler	2
LED case lighting - power supply	11
36" LED case lighting	1
48" LED case lighting	6
60" LED case lighting	16

The backlog on installation was caused by a number of factors, including:

- Later than anticipated program start-up
- Difficulty in signing up installers
- Difficulty in securing inventory for installations.

Sectoral distribution

In 2013, the following businesses completed the installation process:

- 2 bakeries
- 2 restaurants
- 1 do-it-yourself wine and beer outlet
- 1 convenience store.

Process evaluation

This section reviews the key elements of the BRI program (as outlined previously in Table 1), including the direct marketing, audit and assessment, installation, and quality assurance stages. The process evaluation focuses on identifying:

- How effective were the various marketing and outreach methods?
- What were the major barriers to program participation for customers and conversely, what is motivating customers to participate?
- Views on the initial telephone assessment with a PowerStream representative.
- How useful was the energy audit and the Energy Action Plan for program participants?
- Views on the assessment and installation process including opinions on installers, installed equipment and logistics of the installation. Are the resources assigned to the program sufficient?
- Any recommendations by program participants and non-participants on improving the program.
- Process improvements for key program elements as the program moves forward.

The process evaluation of the BRI program considers the results of the surveys sent out to 103 full and partial program participants and 19 non-participants, along with discussions held with key program administrators. The survey results include customers who participated in the program in the first quarter of 2014 (January to the beginning of April).

Direct marketing

Core-marketing activities included a direct mail communication piece, an outbound calling campaign, and web and print advertising. North American Industrial Classification System (NAICS) codes were used to identify eligible customers, and both non-participants and participants of other PowerStream CDM programs (e.g. small business lighting) were approached for the BRI program. The pre-qualification procedure involved identifying participants who are current PowerStream customers, have an energy demand less than 250 kW, and have refrigeration equipment.

The direct mail piece was sent out in batches of 500 over a 6-week period and accounted for 31% of the total appointments booked for 2013.

After the initial mailing, customers were contacted by telephone. In 2013, 119 participants were called. The outbound calling campaign consisted of a 10-minute phone survey where information on energy use, monthly energy bills, and contact details were collected. In 2013, 42% of the total appointments booked were made as a result of the outbound calling campaign.

Customers who did not sign up right away were sent a second mailing.

In addition, PowerStream fielded calls from customers who heard about the BRI program and called PowerStream for more information. 87 participants came in through in-bound calls.

Initial telephone assessment

After the direct marketing campaign, eligible customers were contacted by PowerStream to partake in an initial screening process where they were provided further information on the BRI program and the process. The majority of full and partial participants indicated that they were very satisfied with the initial screening process (80% and 70%, respectively) and that the PowerStream employee they spoke with clearly explained the program and was adequately able to answer questions. Very few customers (2%) indicated that the initial assessment was too long and they were not satisfied. At the end of the telephone assessment, 97% of customers proceeded with the BRI program.

Audit and assessment

In 2013, PowerStream completed 234 of the total targeted 360 audits for the BRI program. Audits were somewhat behind target in part because of the later than anticipated start-up date, and because installations lagged the audits and PowerStream did not want people to have to wait an excessive amount of time between the audit and the installation.

Overall, participants said that they were generally pleased with the audits and were appreciative that PowerStream staff were closely involved in each stage of the program delivery. Figure 1 below provides a breakdown of customer satisfaction level based on a survey of 82 customers who completed the audit phase of the BRI program.

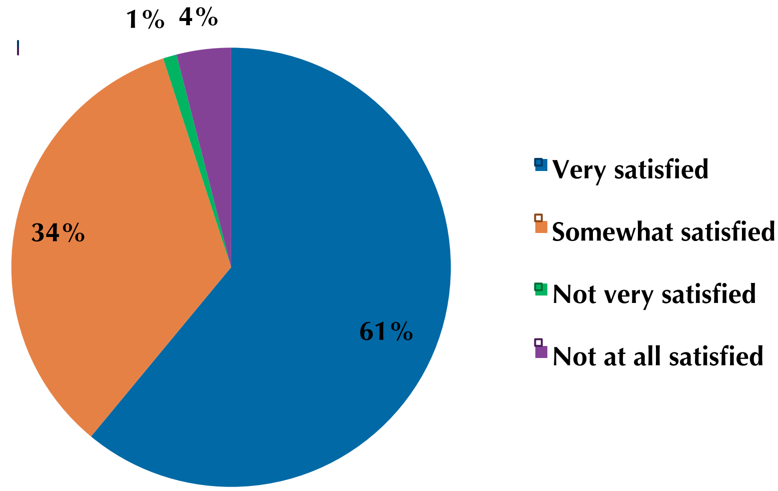

Figure 1 Satisfaction of survey respondents who completed the audit phase

The main reason for dissatisfaction was that the audit did not include enough information or was difficult to understand (20% of respondents indicated this). However, over three-quarters of full and partial participants agreed or strongly agreed that the auditor clearly explained the purpose of the audit (83%), was able to adequately identify energy savings (78%), and was able to help with any questions the customer had regarding equipment in their facility (78%). Of the 234 customers who were audited, 217 signed up for an assessment/installation. Due to the high demand for audits, PowerStream increased the number of auditors available (from one to two then to three).

PowerStream (and others) have pointed to the challenges in identifying suitable auditors for existing programs, and indicated this might be a problem for a greatly expanded program.

PowerStream also updated the original Energy Action Plan by automating and scaling back the audit process. As a result, more audits were conducted partway through the first year. A maximum of four one-hour audits were completed each business day. Audits included a walk through (not a complete inventory) and energy benchmarking. Customers received a brief report from the auditor, which was also passed directly to the installers. Overall, survey respondents were satisfied with the Energy Action Plan and indicated that the plan was understandable (82%), useful (82%) and at an appropriate level of detail (85%).

Measure installation

As outlined in the initial program plan, information from the audit went on to the assessor who then sub-contracted the work out to the installers.[1] PowerStream then reviewed the bill of materials prior to the installation to ensure all of the energy saving opportunities were being captured. The contractor found that the time and resource requirements for undertaking the assessment were significant due to the nature of the equipment and the needs for disassembly, in some cases, to identify retrofit opportunities. It was deemed more efficient to undertake the retrofit right away, rather than to schedule an additional visit. In response, PowerStream integrated the assessment and installation stages of BRI program delivery. The installers, along with site owners, made the final decisions on what equipment was to be updated and what the overall retrofit involved.

In the next year of the program, PowerStream should ensure it has a good understanding of two issues related to this change:

- The customer's and installer's choice of measures to implement may be based on criteria other than energy savings and demand reductions. For example, customers may be motivated by extending the life of their equipment, and installers may prefer measures that are quick and easy to install. PowerStream will want to ensure that it captures information on the total range of measures that could be implemented in each facility. This will help to assess whether customers' and installers' choices are sub-optimal, and will also help to assess whether the maximum budget allocated for each customer should be revisited as the program is extended.
- The inventory needs for an integrated process. Knowledgeable refrigeration contractors will know what equipment types to expect, based on information from the audit, and can ensure that the appropriate range of measures are on-hand. This knowledge will improve over time. PowerStream will want to ensure that opportunities are not being lost because of inadequate on-truck stock.

Despite some minor issues, most customers who completed the installation phase were satisfied with the process. Figure 2 below provides a breakdown of customer satisfaction level based on a survey of 54 customers who completed the installation phase. However, these satisfaction levels are lower than what PowerStream has seen for other services it provides, where annual customer satisfaction surveys have seen a satisfaction level of 86% to 88%.

[1] The BRI program allows customers who wish to do so to use their own installer. Review mechanisms will likely be required to ensure installations are consistent with overall program parameters, but this also has the potential to involve a broader range of contractors in the program, bringing more experience in the industry, and better insight for PowerStream of the sector, its needs and challenges.

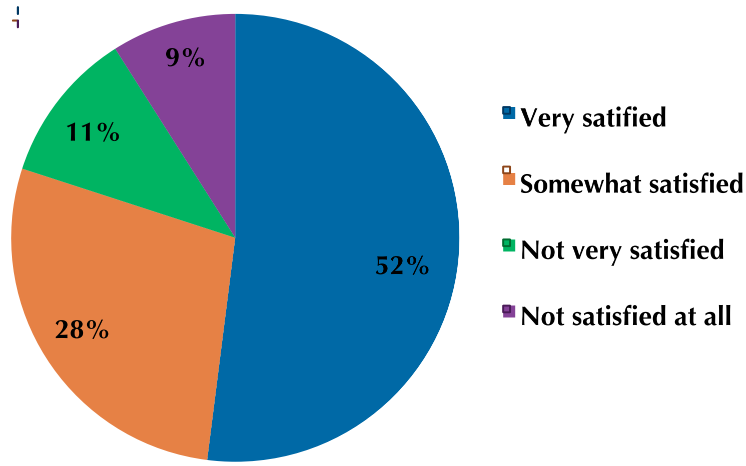

Figure 2 Satisfaction level of survey respondents who completed the installation phase

Reasons for dissatisfaction include: work not being completed as promised (24%), contractor was in a rush or did not keep the appointment (9%), contractor did not have the proper parts (6%), the work took longer than expected (4%), and the customer was not convinced that there are any real savings (4%).

Table 4 below provides a summary of how much respondents strongly agreed or agreed with the following statements related to the installation phase. The remainder of respondents either disagreed, strongly disagreed or neither agreed nor disagreed.

Table 4 Reasons for satisfaction from survey respondents who completed the installation phase

Reason	Strongly agree / agree
I was able to schedule a time for the installation that was convenient for me.	83%
The Installer arrived at the scheduled time.	83%
The Installer made an effort to ensure that the installation did not disrupt my business operations.	83%
The Installer's work was completed in a professional manner.	78%
I was given the opportunity to express my views on which equipment I preferred to be retrofitted.	70%
The Installer was able to help me with any questions I had regarding the equipment in my facility.	70%
The Installer clearly stated which equipment would be retrofitted, and provided suitable reasoning.	69%
The Installer had all the necessary equipment to complete the retrofit.	69%

In light of some of these values, and some of the findings of the QA/QC checks, discussed below, PowerStream is considering what sorts of training contractors require on customer service practices.

Another indicator of satisfaction is the referral rate. 56% of survey respondents indicated that they have recommended the BRI program to business colleagues. Of those who have not recommended the program to a business colleague (yet), 66% said it was somewhat (39%) or very (27%) that they would recommend the program to a business colleague.

Notwithstanding these generally favourable comments from participants, all parties involved in the project (PowerStream, the contractor and the EM&V team) are concerned about the slow pace of installations, and initiated steps in 2013, which have continued into 2014 to accelerate the rate of installations, while ensuring that installations are effective, thorough and of high quality.

Some of the obstacles to a faster installation rate included difficulties in contracting with qualified installers, getting the technology to be installed, and maintaining sufficient inventory on hand to address the widely varying technologies and situations encountered in the field. Towards the end of the year, PowerStream began to receive inquiries from additional contractors about the program, and from distributors interested in carrying inventory of measures used in the program. These are positive signs.

Among the steps that PowerStream has taken to improve the rate of installation are:

- Constant monitoring of the rate of installation, the value of measures installed (including relative to what was identified in the initial audit), and close communication with the contractor engaged to deliver the program.
- Changes to the installation protocol, to eliminate see whether the assessment and installation phases could be integrated, and attempting to ensure installer's vehicles have an extensive inventory of potential measures.
- Engaging additional contractors, independent of the originally contracted firm, to assess whether challenges faced are endemic to the program, or specific to the delivery firm.
- Exploring different contractor payment models to explore whether the contractor's and the program's objectives can be aligned.
- Discussions with additional distributors about their ability and willingness to stock the technology measures required by the program.
- Providing additional training to auditors (e.g. by shadowing installers) so that they have a better ability to identify potential savings.

Quality assurance / quality control visit

Upon completion of the audit and installation, in early 2014 PowerStream conducted quality assurance / quality control (QA/QC) visits of a representative sample of participating facilities (17 businesses). The purpose of the visits was to collect information for EM&V and reinforce participants' confidence in the program. The following table lists the QA/QC inspection criteria that were evaluated during the visits and the outcome.

Table 5 QA/QC inspection criteria for 17 participating businesses

Criteria	Yes	No	N/A / unknown
Was the assessor (contractor) on time?	94%	-	6%
Did the assessor have PowerStream branding to identify themselves as representing PowerStream?	100%	-	-
Was the assessor polite and professional?	94%	6%	-
Was the assessor's vehicle in good repair?	100%	-	-
Did the subcontractor install equipment in a safe manner?	94%	6%	-
Was the work done in an eligible manner, and was it installed in accordance with the program requirements?	88%	12%	-
Was the site left clean and all old materials removed from the site for proper decommissioning / recycling?	100%	-	-
Did the Participant sign the work order?	76%	12%	12%
Were all the other requirements of the Work Order and Participant Agreement complied with?	100%	-	-
Did the contractor complete all reasonable and eligible measures to maximize the incentive?	29%	71%	-
Did the subcontractors leave the Participant details of the warranty?	12%	82%	6%
Did the subcontractors leave the emergency contact information in case of premature equipment failure?	12%	82%	6%

Overall, 41% of customers indicated that all eligible measures as noted in the audit were installed; however, 53% stated that less than 75% of eligible measures were installed. Common comments and suggestions for improvement are listed in Table 6 below.

Table 6 Common comments and corrective actions from QA/QC visits of 17 participating businesses

Comment	Corrective action
Participant was lead to believe the contractor would be returning to the site to finish installation, but contractor never did.	Contractor should complete the installation or contact the participant to inform them that the installation has been completed.
Contractor did not leave behind a phone number or warranty paperwork.	Contractor should follow-up with the participant and provide contact information and warranty paperwork.
Contractor did not install certain measures that were identified in the audit and participant is still in the dark if any other measures will be implemented.	Contractor should follow-up with the participant and explain why certain measures were not installed or work with participant to install remaining eligible measures.
Participant was not given proper notice by the contractor and did not know the appointment time.	Contractor should contact participant ahead of time and ensure participant is aware of appointment time.

Table 5 makes clear that a number of customer service expectations were not being met for those customers with whom follow-up occurred, further pointing to the need for contractor training on customer service.

Customer satisfaction survey

A survey was delivered to 103 full or partial program participants in April 2014 to gather feedback and collect information on their experiences. Nineteen non-participants were also surveyed to understand the reasons for opting out of the BRI program. Table 7 below provides details on the firmographics of the full and partial program participant survey respondents.

Table 7 Firmographics of full and partial participant survey respondents

Firmographic	Full-participants	Partial-participants	Total
Rent	88%	81%	
Own	12%	19%	
Branch of a chain	0%	6%	
Franchise	44%	32%	
Independently owned	56%	62%	
Restaurant			59%
Other (not restaurant)			41%

Reasons for participation

When full and partial program participants were asked why they first decided to participate in the BRI program, 75% indicated that both of the following reasons were equally motivating factors:

1. The opportunity to have the energy usage in my facility reviewed by an energy efficiency expert.
2. The offer of up to $2500 in free energy efficiency upgrades for my facility.

Further to this, survey respondents were asked how appealing they found certain aspects of the program. Table 8 summarizes the percentage of respondents who indicated the program elements were either very appealing or somewhat appealing. The remainder of respondents either found them not very appealing, not at all appealing, or were unable to say.

Table 8 Degree of program aspect appeal to full and partial program participant survey respondents

Program aspect	Very appealing / somewhat appealing
The program is offered by PowerStream.	92%
The program is designed to help me reduce my electricity bills.	92%
The program will pay for the first $2500 of equipment I need.	92%
The program saves me from having to find a contractor.	84%

Reasons for non-participation

The following table summarizes the main reasons why business owners opted out of the BRI program based on the survey results of 19 respondents. The percentages provided indicate whether respondents strongly agreed or somewhat agreed with the accompanying statements.

Table 9 Reasons for non-participation in the BRI program

Reason for non-participation	Strongly agree / somewhat agree
I do not have time to participate in the BRI program.	59%
I am concerned about the costs associated with the BRI program.	85%
I am worried I will not be able to choose my own contractor.	46%
I feel retrofitting my equipment will not make my business any more energy efficient.	38%
Making changes to my equipment creates too large a risk of disruptions to my business.	48%
I do not understand the BRI program and why I am being approached about it.	64%

Program outcomes and referrals

At the time of the survey, 56% of respondents said that they had already recommended the BRI program to business colleagues, and 66% of respondents who had not yet recommended the program said that they were likely or very likely to recommend the program in the future. A very high majority (91%) indicated that they were very or somewhat likely to participate in other *saveONenergy* programs, and 89% said they were very or somewhat likely to implement other energy saving measures in their facilities in the future.

Overall program administration

Although not a step in the program *per se*, PowerStream has also developed thorough tools and process for managing the program, including: a comprehensive database on program participants that tracks both information about the participants as well as their status within the program (the CRM), weekly 'dashboard' reports on progress in the preceding week, issues that require resolution, and their urgency, and processes to follow up with customers when problems are identified.

PowerStream has (and continues) to make improvements to the program administration as needs or opportunities are identified.

Impact evaluation

In this section we consider various components of the impact evaluation, which measures energy savings and demand reductions from activities in 2013. The discussion takes into account:

- Gross prescriptive energy savings and demand reductions
- Realization factors for prescriptive energy savings and demand reductions
- Net energy savings and demand reductions
- Other impacts from the programs.

Gross prescriptive energy savings and demand reductions

Gross prescriptive energy savings and demand reductions are estimates savings and reductions made based on values from the literature, and without accounting for free riders or spill over.

PowerStream records in its database the date install was completed, and the work order showing what specific measures were undertaken or installed. In 2013, the measures outlined in Table 3 would result in savings of 87,978 kWh and a reduction of 9.88 kW in 2013 applying the prescriptive values, as shown in Table 10.

Table 10 Estimated 2013 gross energy savings and demand reductions (based on prescriptive saving estimates)

Measure	# installed in 2013	Gross demand savings per unit (kW/unit)	Gross first year energy savings per unit (kWh/unit)	Total estimated gross demand reduction (kW)	Total estimated gross first year energy savings (kWh)	Total estimated energy savings 2013-2014 (kWh)
Anti-sweat heater control - cooler (per door)	0	0.51	1250	0	0	0
Anti-sweat heater control - freezer (per door)	0	0.51	1250	0	0	0
Strip curtains - walk-in cooler	2	0.434	486	0.868	972	1,944
Strip curtains -- walk-in freezer	1	0.573	642	0.573	642	1,284
Night curtains on cases	0	0	888	0	0	0
Clean condenser coils - cooler	43	0.05	438	2.15	18,834	18,834
Clean condenser coils - freezer	3	0.18	1576.8	0.54	4,730	4,730
ECM fan motor upgrade	46	0.091	1202	4.186	55,292	110,584
LED case lighting	34	0.046	220.8	1.564	7,507	15,014
Total				**9.881**	**87,978**	**152,391**

In addition to these savings, there is anecdotal information about savings that occurred as a result of the audits themselves. For example, one audited facility was found to have an inappropriately programmed thermometer and once this was corrected, there were significant reductions in overall electricity use. Unfortunately, there is not a practical way to identify all measures taken as a result of the audits, and to report on energy savings (or demand reductions) associated with them.

In addition to these savings, there were potential interactive effects of these measures, e.g. in reducing the air conditioning load of the facility where the refrigeration unit runs more efficiently. These will be estimated for the program in the 2014 evaluation.

Realization factor and adjusted gross energy savings

Monitoring was undertaken of 19 facilities and 82 cooler or freezer units over the period between September 2013 and April 2014 to measure actual energy savings that were realized from measures installed in these units.[2] To measure actual savings, a data logger was placed on units at randomly selected facilities for approximately five week periods consisting of two weeks before installs were undertaken, a week during installs, and two weeks after measures were installed.

One expects the actual measurements to deviate somewhat from the literature values for numerous reasons, including natural variation in the population of refrigerators (e.g. age, usage patterns, size, etc.), variation in the measures installed (e.g. capacity of motor, type of LED lamp, etc.) To account for this, actual observations are compared to expected savings, and the ratio of these is the 'realization rate'.

We were, however, surprised by how much variation was observed across the units measured, with a number of units using *more* electricity after measures were installed. Although in some cases there are clear explanations for why this might be, in others there is no obvious reason.

Because multiple measures were often installed on the same refrigeration unit, it is not fully possible to estimate energy savings attributable to individual measures across the population of units monitored. However, we are able to calculate the total realization rate in all of the units monitored (which had a different mix of measures than were in the sample of completed installs in 2013), and in some cases, units only had a single measure installed. The resulting realization rates from these comparisons are presented in Table 11.

Table 11 Realization rates (actual/prescriptive values)

	Number of measures	Summer demand reductions	Winter demand reductions	First year energy savings
For all units monitored	215	0.64	0.57	0.67
Night curtains on cases	1	-	-	0.02
Clean condenser coils - cooler	13	2.17	1.72	1.32
Clean condenser coils - freezer	4	0.09	0.18	(0.06)
ECM fan motor upgrade	10.5	1.83	1.65	1.20

These numbers suggest that energy savings for ECM motors are 20% higher than the value from the literature, but night curtains are only 2

[2] Because only four facilities in total, and only one in which the installs had been completed in 2013, were monitored in 2013, we have chosen to look at the larger pool of observations available through April 2014.

percent of the savings reported in the literature. However, even within these groups, the variation is huge. The standard deviation for the 13 cleaning condenser coils – coolers is almost double the mean savings.

Net energy savings and demand reductions

Net energy savings and demand reductions are estimated by applying a "net to gross factor" that may take into account a number of components, most typically spillover and free riders.

Spillover

"Spillover" measures impacts of the program, beyond those directly associated with the measures installed by the program. In the context of this program, these might include:

- Measures taken by non-participants because of the existence of the program but not measured by the program. For example, non-participants may hear about the program and implement some of the measures on their own, even though they decide not to participate in the program.
- Measures taken by participants because of their experience with the program, but not measured by the program. For example, a participant choosing to implement energy efficiency measures in other, non-refrigeration parts of his or her facility.

A significant number (89%) of survey respondents indicated they expect to implement other energy saving measure in their facility in the future, as a result of having participated in the BRI program. Of those, 58% said they were 'very likely' to, and 31% said they were 'somewhat' likely to. Unfortunately, responses were not specific enough to measure the savings likely to accrue.

In addition, 91% said they were likely to participate in other saveONenergy program, with most of those (71%) saying they were very likely to.

Free riders

Free riders are persons who would have adopted the technologies or behaviours promoted by the program even if the program did not exist. The free rider rate can only be estimated, using a number of methodologies. For this project, the free ridership is estimated based on responses to questions to the program participants.

We estimate the free rider rate based on responses to questions related to whether the participants had plans to undertake an audit or upgrade their refrigeration system prior to hearing about the program, whether the program made it possible for them to implement the measures earlier than they otherwise would have, and how important energy and energy efficiency is to their overall business plans. We also asked them what about the program was appealing to them, including whether they saw advantage to not having to find a contractor to undertake the work.

Depending on their answers to the questions, they were identified as a free rider, a partial free rider, or not a free rider.

In addition to these considerations, which speak to the *intent* of participants, we also considered the availability of individual measures, and whether or not participants likely would have had the *ability* to implement these measures in the absence of the program. At least in 2013, several of the measures that are part of the program were extremely difficult to acquire, and it would not have been simple for a participant to obtain the technology required. A qualitative assessment of ability to obtain the technology was applied to each measure offered by the program to get a measure specific free rider rate.

In a survey of firms involved in the program in April 2014, 54 facilities indicated that they had completed the installation phase of the project. Of these, 4% indicated they had specific plans to improve their refrigeration program before signing up for the program, and 30% indicated they were considering doing so. All but one of those who were considering upgrades indicated that they were able to have improvements to their refrigeration equipment done earlier than otherwise would have happened.

We also asked representatives from these companies how important energy efficiency was to their business plan. A majority (56%) chose “Important, my business plan is influenced by my desire to achieve energy efficiency in my facility” and 44% chose “Important but only after all other needs of the business are fulfilled.” All those indicating they had specific plans chose the “important” option, as did 59% of those ‘considering’ upgrading their refrigeration equipment. The remainder of the ‘considering’ group, 41%, chose the ‘important but’ response.

All but one of the respondents who had completed installations indicated that one of the benefits of the program was that it saved them having to find a contractor to do the work, suggesting they were not likely in a position to proceed with the work in the near term in the absence of the program.

We assigned scores that estimate the extent of free ridership based on participants’ response to these questions as shown on Table 12.

Table 12 - Rating of partial free riders based on responses to survey

Responses	% Free rider	% of participants
Had specific plans, completed earlier because of the program, and consider energy efficiency as 'important'	75%	4%
Were considering upgrades, completed earlier than would otherwise have happened, and consider energy efficiency as 'important but'	10%	13%
Were considering upgrades, completed earlier than would otherwise have happened, and consider energy efficiency as 'important'	25%	17%
Were considering upgrades, didn't have earlier completion as a result of the program, and consider energy efficiency as 'important'	50%	2%
Did not have plans to upgrade their refrigeration equipment	0%	65%

We would have expected a full free rider to have had specific plans, not have completed the installation earlier, and to not see a benefit from the program finding him a contractor. A full free rider would also likely consider energy efficiency as 'important'.

Combining the partial free rider rating with the incidence gives an overall free ridership rate of 9.2%. As discussed above, this considers only 'intention' of participants.[3]

Program contractors found it difficult to obtain some of the measures, and the difficulty of acquiring and maintaining the technologies was one of the constraints on the number of installs completed. These suggest it would have been very difficult for participants to have installed these measures in the absence of the program, and the free ridership was decreased to reflect this difficulty. Estimates of the difficulty of obtaining the measures, a rating of this difficulty, and the resulting free ridership by measure are estimated as follows:

[3] Using a similar methodology, the free ridership for the audits is estimated to be 9.8%, but this is not used because it is not possible to estimate energy savings from the audit component of the program alone.

Table 13 Adjusted free rider rates and net to gross ratio

	Contractor rating of difficulty (1-5)	Ease of obtaining	Adjusted free rider	NTGR
ECM fan motor upgrade	1		-	1.00
Clean condensor coils - Cooler	5	1	0.09	0.91
LED case lighting	2	0.25	0.02	0.98
Clean condenser coils - Freezer	5	1	0.09	0.91
Strip curtains - Walk-in cooler	4	1	0.09	0.91
Strip curtains - Walk-in freezer	4	1	0.09	0.91
Night curtains on cases	3	0.75	0.07	0.93
Anti-sweat heater control - Cooler	2		-	1.00
Anti-sweat heater control - Freezer	2		-	1.00
Total (kW savings)			0.042	0.96
Total (kWh savings)			0.028	0.97

NOTE: Total free rider rates and NTGR are based on a weighted average taking into account the number of installs completed in 2013 and their prescriptive gross energy savings.

Applying the realization rate from Table 11 to the net energy savings above, in Table 13 results in an overall estimate of energy savings and demand reductions:

Table 14 Estimate of net energy savings and demand reductions from the program in 2013

	Gross savings	Realization rate	Adjusted gross savings	Net to gross factor	Net savings
Energy (kWh)	87,978	0.67	59,092.55	0.972	57,427
Summer peak demand (kW)	9.88	0.64	6.31	0.958	6.05
Winter peak demand (kW)	10	0.57	5.64	0.958	5.40

Cost-effectiveness evaluation

The Ontario Energy Board expects that programs offered by LDCs will be cost-effective, as measured by various tests prescribed by the Ontario Power Authority, and in particular the Total Resource Cost test (TRC) and the Program Administration Cost test (PAC). A description of these and how they are calculated is provided in the OPA's *Cost Effectiveness Guide*.[4]

The TRC test compares anticipated benefits (in avoided energy use and demand) over the life of the measure against the costs of the program (technology and administration) over its life. All dollars are expressed in present value. The PAC test considers only costs borne by the LDC for incentives and administration.

The benefits associated with the net energy savings and net demand reductions identified above, over the weighted average life of the measures installed have a value of $32,850 as expressed in 2013 dollars. (It is not feasible to calculate the benefits on a measure by measure basis because of the way measures were installed in groups on the same refrigeration units.)

The program costs in 2013 were $6,445 for variable costs (including customer incentives and program administration fees) and $416,783.17 for fixed costs (including labour, legal, shared services marketing, EM&V, telephone and other).

The net TRC benefits are thus -$390,000, suggesting the program was not cost effective in 2013. (The PAC test results are the same, as no participant incurred costs for technologies, which were all covered by the program.)

Significant program initiation costs were incurred in 2013, and as noted above only 6 installations were completed, though 269 participants had registered, 217 participants had signed agreements, and 234 field audits had been completed. Thus it cannot be concluded that the negative results as of the end of calendar 2013 are indicative of the program as a whole not being cost effective.

The OPA's cost effectiveness guide recognizes that the sort of situations described above are typical of multi-year programs, and suggests that annual reporting may be done for information purposes, but that the overall cost effectiveness assessment should be based on the full duration of the program.

[4] Ontario Power Authority. 2010. *Conservation and Demand Management Cost Effectiveness Guide*. Available at http://www.powerauthority.on.ca/sites/default/files/OPA%20CDM%20Cost%20Effectiveness%20Test%20Guide%20-%202010-10-15%20F.pdf

Conclusions and recommendations

PowerStream's Business Refrigeration Incentives (BRI) program provides several benefits to program participants, each of which is valued by the majority of participants:

- An on-site audit of energy use and major energy using equipment and identification of steps that the customer can take to reduce energy use
- A turnkey installation of up to $2500 worth of energy saving refrigeration equipment.

The program is designed to overcome the barriers to greater energy efficiency in facilities that have significant energy demand for refrigeration.

The program was only initiated in September 2013 and is scheduled to run through 2014. The program encountered a number of challenges that are being addressed by the program administrators.

Process findings

Direct marketing through incoming and outgoing calling is reported as the primary entry point for persons participating in the program, and is where the greatest effort is being extended. This approach appears to be effective.

The initial telephone assessment is effective at assessing eligibility and interest of prospective participants. There is a very low number (3%) of participants dropping out of the program once they pass this screen.

The audit is valued highly by program participants, and is important to building rapport between PowerStream and the participants. In theory, it should help participants to think about energy use comprehensively, not just about individual energy using parts of their business (like refrigeration). A high percentage of participants surveyed who had completed only the audit stage of the program indicated an intention to take other measures to reduce energy use, and to participate in other saveONenergy programs. However, is has proven difficult to attribute specific energy savings to the audits.

The installation stage of the program has encountered significant problems. As a result, installs completed in 2013 were far below targeted numbers. PowerStream has been addressing these problems proactively, and the pace of installs has picked up dramatically since December of 2013.

Overall, the program is being carefully and comprehensively managed, with a state of the art CRM system that captures customer information and tracks progress. The system is being refined as opportunities and needs are identified.

Impact findings

In 2013, there were significantly fewer installations than had been planned for reasons including: the late start of the program, challenges in getting qualified installers, and problems getting access to the technological measures needed for the installations. Consequently, the impact of the program was less than hoped for during the planning stages. An overview of the key program results in presented in Table 15.

Table 15 Overview of impact results

Program metric for 2013	Finding
Number of participants	269
Number of audits completed	234
Number of installs completed	6
Average cost of measures installed	$ 2,052
Summer demand realization rate	0.64
Winter demand realization rate	0.57
Energy realization rate	0.67
Gross verified summer demand savin	6.31
Gross verified winter demand saving:	5.64
Gross verified annual energy savings	59,093
Net to gross ratio (demand)	0.96
Net to gross ratio (energy)	0.97
Net summer peak demand savings (k	6.05
Net winter peak demand savings (kW	5.40
Net annual energy savings (kWh)	57,427

The realization rates are from units that had monitoring equipment installed on them through April 2014. In most cases, it was not possible to attribute specific savings to specific measures, and there is a wide variation in the savings realized due to factors related to usage, variation in equipment size (e.g. for motors), severity of cleaning required/done (for condenser coil cleaning), and other factors. In many cases, it is not clear what circumstances the prescriptive values are associated with.

As expected, free ridership for the program (estimated for all participants through April 2014) was very low as this is a sector that does not regularly invest in energy efficiency improvements. Their ability to do so is compounded by the unavailability of many retrofit technologies in the market.

Conclusions and recommendations

Process

On the process side, most aspects of the program are working very well, though the pace of installs to the end of December 2013 was far below expectations, even when the late start to the program is taken into account. Three issues in particular must be addressed:

- Ensuring that appropriately qualified installers are identified, and that the compensation offered to them is sufficient to sustain their interest in the program
- Working with equipment distributors to encourage them to stock refrigeration retrofit technologies
- Constructing processes and compensation schemes that ensure program objectives and installer objectives are aligned. For example, ensuring that the installer is not encouraged to skimp on measures because his or her on-truck inventory is inadequate, or that it is less lucrative to install measures that are more difficult to install but that yield greater energy savings.

PowerStream has already taken steps to address each of these, though the latter of these will be a continuing challenge for this (and other programs). PowerStream is addressing the latter one by considering increasing the payments per measure, and involving additional contractors with different payment structures.

A significant change in the original program concept was the integration of the assessment and installation stages. The advantage of integrating these stages is that one less site visit is required, and the contractor felt the work to complete the install was only a marginal increase over the work to conduct the assessment, for example if equipment had to be opened up to determine what installation would be possible. The disadvantages of removing this stage include: the contractor does not know what equipment will be needed, and will require a large inventory to meet all potential needs, the customer has limited opportunity to consider what retrofits make the most sense within the $2500 limit, or whether he or she is in a position to go beyond the $2500, and finally, the monitoring of units for EM&V purposes requires the data logger installer to guess which equipment will be retrofitted, and risks monitoring equipment that isn't retrofitted.

The results of the survey of participant satisfaction, and the QA/QC follow up suggest there is an opportunity for better training of installers in customer service, and program expectations.

Impact

On the impact side, the program was only just beginning in 2013 and the impact results are less than expected, but overall results cannot be inferred from these early results, which are limited primarily by the small number of installations completed.

The data for the units that were monitored before and after implementation show a fairly low overall realization rate, and there is significant variation across units and facilities. Some of this variation is inevitable as a result of variations in activity within facilities and other exogenous factors. Some of it relates to variations within the measures (e.g. motor capacity) that is not reflected in the prescriptive values. It would be helpful to have additional information on equipment characteristics, and the changes made (e.g. sizes of motors removed and the replacement motor, a qualitative assessment of how dirty condenser coils are, and whether a motor replaced is a condenser motor).[5]

Ideally, PowerStream would want to be able to assess the impact of the audit stage of the process, which would require specific information in the audits on measures to be taken, and subsequent follow-up to see whether recommended actions were implemented. This is not part of the project plan, and it is not clear whether it would be practical to measure the impact of recommended actions. It is likely that the measurable benefits of the audit stage will only be able to be measured as the qualitative value placed on it by customers.

[5] Information on equipment sizes is shown on facility invoices, but is not reported by unit, which is how impacts are being measured, and all units in a facility may not be logged.

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Appendix B: Activities by Initiative – Residential Program

A. APPLIANCE RETIREMENT INITIATIVE (Fridge and Freezer Pick-Up)

Target Customer Type(s): Residential Customers

Initiative Frequency: Year-round

Objectives: Achieve energy and demand savings by permanently decommissioning certain older, inefficient refrigeration appliances located in Ontario.

Description: This is an energy efficiency Initiative that offers individuals and businesses free pick-up and decommissioning of old large refrigerators and freezers. Window air conditioners and portable dehumidifiers will also be picked up if a refrigerator or a freezer is being collected.

Targeted End Uses: Large refrigerators, large freezers, window air conditioners, and portable dehumidifiers.

Delivery: OPA centrally contracts for province-wide marketing, call centre, appliance pick-up, and decommissioning process. LDC provides local marketing and coordination with municipal pick-up where available. Additional detail is available:

- saveONenergy website https://saveONenergy.ca/Consumer/Programs/Appliance-Retirement.aspx

In Market Date: March 2011 – PowerStream began offering Appliance Retirement soon after the Master Agreement was signed. Since Appliance Retirement is an initiative that was familiar to the customers, and there was minimal change to the initiative design compared to its predecessor program (The Great Refrigerator Roundup), the transition and launch of this initiative was simple and fast.

Initiative Activities/Progress: Please refer to Table 9 of this document.

Additional Comments (as provided by LDC-OPA Program Working Group):

- Due to the duration of the program, and the revised eligibility requirements to a minimum of 20 years old, this Initiative appears to have reached market saturation and has been under consideration for removal from the Portfolio.
- Rather than strictly remove this Initiative from the schedules, the OPA and LDCs could review what opportunities there are to include other measures such as stoves, dishwashers, washers and dryers. The framework of this Initiative may be a suitable foundation for a more holistic residential appliance retirement program. As such, the Residential portfolio could be strengthened through program evolution rather than weakened through diminished program offerings.
- As participation is very responsive to province wide advertising, OPA province-wide advertising should continue to play a key role if the initiative continues.
- Better relationships with retailers may play a role in increasing participation in this Initiative. Retailers can provide opportunities to capture replacement appliances and have them decommissioned after a sale has been committed.
- In an effort to capture additional savings in the perceived last year of the Initiative, the eligibility requirement for refrigerators was revised from 20 years old to 15 years old in Q2 2014.

B. APPLIANCE EXCHANGE INITIATIVE (Exchange Events)

Target Customer Type(s): Residential Customers

Initiative Frequency: Spring and Fall

Objective: The objective of this initiative is to remove and permanently decommission older, inefficient window air conditioners and portable dehumidifiers in Ontario.

Description: This initiative involves appliance exchange events. Exchange events are held at local retail locations and customers are encouraged to bring in their old room air conditioners (AC) and dehumidifiers in exchange for coupons/discounts towards the purchase of new energy efficient equipment. Window air conditioners were discontinued from the program in 2013.

Targeted End Uses: Window air conditioners and portable dehumidifiers

Delivery: OPA contracts with participating retailers for collection of eligible units. Additional detail is available:

- saveONenergy website https://saveonenergy.ca/Consumer/Programs/EXCHANGE-EVENT.aspx

In Market Date: May 2011 – PowerStream, together with the participating retailers in PowerStream's service area, began offering Appliance Exchange in the spring of 2011.

Initiative Activities/Progress: Please refer to Table 9 of this document.

Additional Comments (as provided by LDC-OPA Program Working Group):

- The design of the Initiatives, including eligible measures and incentives amounts are developed through the Residential Working Group. Retail Partner(s) are contracted by the OPA to deliver the initiatives province-wide. Individual LDCs have the opportunity to stage in-store events to drive the distribution of LDC coded Coupons and promotion of other programs in the portfolio.
- The restrictive, limited and sometimes non-participation of local stores can diminish the savings potential for this Initiative.
- To date there has only been one retailer participant in the Appliance Exchange Initiative.
- In 2012 there was a decrease in the number of window air conditioners being received through the program. A review of eligible measures in the Appliance Exchange program was conducted, and as these units are not cost effective on their own it was determined that they be removed from the program in order to improve the overall cost effectiveness of the Initiative.
- Notification to LDCs regarding retailer participation and eligible measures continues to be delayed. Improved communications will aid in appropriate resource allocation and marketing of the Initiative.
- This Initiative may benefit from the disengagement of the retailer and allowing LDCs to conduct these events, possibly as part of a larger community engagement effort, with the backing of ARCA for appliance removal.
- The initiative appears to require more promotion from retailers and LDCs.

C. HVAC INCENTIVES INITIATIVE (Heating and Cooling Incentives)

Target Customer Type(s): Residential Customers

Initiative Frequency: Year-round

Objective: The objective of this initiative is to encourage the replacement of existing heating systems with high efficiency furnaces equipped with Electronically Commutated Motors (ECM), and to replace existing central air conditioners (CAC) with ENERGY STAR® qualified systems and products**.**

Description: This is an energy efficiency initiative that provides rebates for the replacement of old heating or cooling systems with high efficiency furnaces (equipped with ECMs) and ENERGY STAR® qualified CACs by approved Heating, Refrigeration, and Air Conditioning Institute (HRAI) qualified contractors.

Targeted End Uses: Central air conditioners and furnaces

Delivery: OPA contracts centrally for delivery of the program and distributors are encouraged to convince local contractors to participate in the initiative. Additional detail is available:

- saveONenergy website https://saveonenergy.ca/Consumer/Programs/HVAC-Rebates.aspx

In Market Date: March 2011 – PowerStream began offering HVAC Incentives Initiative (HVAC) soon after the Master Agreement was signed. Since HVAC is an initiative that is familiar to the customers, and there was minimal change to the initiative design compared to its predecessor program (Heating and Cooling Rebates), the transition and launch of this initiative was simple and fast.

Initiative Activities/Progress: Please refer to Table 9 of this document.

Additional Comments (as provided by LDC-OPA Program Working Group):

- Incentive levels appear to be insufficient to prompt customers to upgrade HVAC equipment prior to end of useful life. An Air Miles incentive was introduced in 2013 to try and encourage early replacement.
- This Initiative is contractor driven with LDCs responsible for marketing efforts to customers. More engagement with the HVAC contractor channel should be undertaken to drive a higher proportion of furnace and CAC sales to eligible units.
- In an effort to build capability, mandatory training has been instituted for all participating HVAC contractors. This could present too much of a barrier for participation for some contractors as the application process already presents a restriction to contractor sales. It has been noted that there are approximately 4500-5000 HVAC contractors in the Province, however in 2013, only a total of 1,587 contractors completed the mandatory HVAC training and can participate in the program.
- There are cases where non-participating contractors are offering their own incentives (by discounting their installations to match value of the OPA incentive). As this occurs outside of the Initiative, savings are not credited to LDCs. OPA should consider this in future program impact evaluation studies.
- Changes to the Schedule in 2014 to allow for incentives for new installations, rather than strictly replacement units, may provide greater Initiative results.

D. CONSERVATION INSTANT COUPON BOOKLET INITIATIVE (Coupons)

Target Customer Type(s): Residential Customers

Initiative Frequency: Year-round

Objective: The objective of this initiative is to encourage households to purchase energy efficient products by offering discounts.

Description: This initiative provides customers with year-round coupons. The coupons offer instant rebates towards the purchase of a variety of low cost, easy to install energy efficient measures and can be redeemed at participating retailers. Booklets were directly mailed to customers and were also available at point-of-purchase. Downloadable coupons were also available at www.saveoneenergy.ca.

Targeted End Uses: ENERGY STAR® qualified standard compact fluorescent lights (CFLs), ENERGY STAR® qualified light fixtures, lighting control products, weather stripping, hot water pipe wrap, electric water heater blanket, heavy duty plug-in timers, advanced power bars, clothesline, and baseboard programmable thermostats

Delivery: The OPA develops the electronic version of coupons and posts them online for download. PowerStream distributes coupons at local events. The OPA enters into agreements with retailers to honour the coupons. Additional detail is available:

- saveONenergy website https://saveonenergy.ca/Consumer/Programs/Instant-Rebates.aspx

In Market Date: March 2011 – PowerStream official launch of the Coupon Initiative was when the OPA began mailing out the year-round conservation booklets to PowerStream customers.

Initiative Activities/Progress: Please refer to Table 9 of this document.

Additional Comments (as provided by LDC-OPA Program Working Group):

- The timeframe for retailer submission of redeemed coupons varies depending on the retailer and in some cases has been lengthy. The delays and incomplete results reporting limits the ability to react and respond to Initiative performance or changes in consumer behaviour.
- Coupon booklets were not printed and mailed out in 2013 so were not widely available to consumers without the ability to download and print online coupons. In addition, consumers may not have been aware of the online coupons. The Initiative may benefit from province-wide marketing as a substitute to a mail out campaign.
- The product list could be distinctive from the Bi-Annual Retailer Event Initiative in order to gain more consumer interest and uptake.
- Program evolution, including new products and review of incentive pricing for the coupon Initiatives, should be a regular activity to ensure continued consumer interest.
- In 2013, LDCs were provided with 3 custom coded coupons. All coupons have been provided with LDC custom coding in 2014 which allows LDCs to promote coupons based on local preferences.
- Consumer experience varies amongst retailers offering Coupon discounts which can limit redemptions. For example, a particular high volume 'participating retailer' does not accept coupons and have their own procedure. In addition, some retailers have static lists of eligible products and will not discount eligible products unless the product on the list.

- The saveONenergy programs would benefit from specific end cap displays, aisle product stands and product-specific areas. Having products throughout a retail environment weakens the impact.

E. BI-ANNUAL RETAILER EVENT INITIATIVE (Retailer Events)

Target Customer Type(s): Residential Customers

Initiative Frequency: Bi-annual events

Objective: The objective of this initiative is to provide instant point of purchase discounts to individuals at participating retailers for a variety of energy efficient products.

Description: Twice a year (Spring and Fall), participating retailers host month-long rebate events. During the months of April and October, customers are encouraged to visit participating retailers where they can find coupons redeemable for instant rebates towards a variety of low cost, easy to install energy efficient measures.

Targeted End Uses: Same as the conservation instant coupon booklet initiative

Delivery: The OPA enters into arrangements with participating retailers to promote the discounted products, and to post and honour related coupons. LDCs also refer retailers to the OPA. Additional detail is available:

- saveONenergy website https://saveonenergy.ca/Consumer/Programs/Instant-Rebates.aspx

In Market Date: May 2011 – PowerStream official launch of the Retailer Event is when the participating retailers held their Spring events in 2011.

Initiative Activities/Progress: Please refer to Table 9 of this document.

Additional Comments (as provided by LDC-OPA Program Working Group):

- This Initiative is strongly influenced by the retail participants and has no direct involvement from the LDCs.
- LDCs have the opportunity to stage in-store events to drive the distribution of LDC coded Coupons and promotion of other programs in the portfolio however this requires cooperation from the local retailer and LDC staff bandwidth.
- Limited engagement of local retailers can restrict the savings potential for this Initiative.
- The Product list has changed very little over the past five years.
- Program evolution, including new products and review of incentive pricing for the coupon Initiatives, must be a regular activity to ensure continued consumer interest.
- The Product list could be distinctive from the Conservation Instant Coupon Initiative in order to gain more consumer interest and uptake.
- A review conducted by the Residential Working Group identified three areas of need for Initiative evolution: 1) introduction of product focused marketing; 2) enhanced product selection and 3) improved training for retailers as retail staff tend not to be knowledgeable regarding the products or promotion.
- This Initiative may benefit from a more exclusive relationship with a retailer appropriate to the program. There should be a value proposition for both the retailer and LDC.
- Independently the Retailer Co-op and Bi-Annual Retailer Event Initiative may not present a value for the investment of LDC resources to support these events and should be backed by a strong Residential portfolio.

F. NEW CONSTRUCTION PROGRAM (New Home Construction)

Target Customer Type(s): Residential Customers

Initiative Frequency: Year-round

Objective: The objective of this initiative is to provide incentives to participants for the purpose of promoting the construction of energy efficient residential homes in the Province of Ontario.

Description: This is an energy efficiency initiative that provides incentives to homebuilders for constructing new homes that are efficient, smart, and integrated (applicable to new single family dwellings). Incentives are provided to homebuilders who install energy efficient measures as determined by a prescriptive list or via custom options, or by meeting or exceeding the EnerGuide performance rating system.

Targeted End Uses: All-off switch, ECM motors, ENERGY STAR® qualified CAC, lighting control products, lighting fixtures, EnerGuide 83 whole home, EnerGuide 85 whole homes

Delivery: Local engagement of builders is a responsibility of the LDC and will be supported by the OPA's air coverage driving builders to their LDC for additional information. Additional detail is available:

- saveONenergy website https://saveonenergy.ca/Consumer/Programs/New-Residential-Construction.aspx

In Market Date: January 2012 – Although the Schedule was out in 2011, PowerStream was not able to launch the initiative until early 2012. PowerStream placed emphasis on implementing initiatives that are effective and familiar to customers, and offer the greatest ratepayer value and greatest amount of persisting savings.

Initiative Activities/Progress: Please refer to Table 9 of this document.

Additional Comments (as provided by LDC-OPA Program Working Group):

- This Initiative provides incentives to home builders for incorporating energy efficiency into their buildings. To support this, LDCs need to provide education to the consumers regarding the importance of choosing the energy efficient builder upgrade options without an immediate benefit to the consumer.
- In 2012 the application process was streamlined, however continues to be too cumbersome for builders. This combined with limited return has resulted in this Initiative to continue to under-achieve.
- Administrative requirements, in particular individual home modeling, must align with perceived stakeholder payback
- Performance applications are expected to increase in 2014 due to some industry players interest in the Initiative. However, it is anticipated that the performance track will be the primary track used in applications, which provides low savings for the incentive provided. Savings and associated incentives may need to be revised to an appropriate level.
- The addition of LED light fixtures, application process improvement and moving the incentive from the builder to the home-owner may increase participation.
- This Initiative may benefit from collaboration with the Natural Gas utilities.

G. RESIDENTIAL DEMAND RESPONSE PROGRAM (*peaksaver* and *peaksaver* PLUS™)

Target Customer Type(s): Residential and Small Commercial Customers

Initiative Frequency: Year-round

Objective: The objectives of this initiative are to enhance the reliability of the Independent Electric System Operator (IESO)-controlled grid by accessing and aggregating specified residential and small commercial end uses for the purpose of load reduction, increasing consumer awareness of the importance of reducing summer demand, and providing consumers their current electricity consumption and associated costs.

Description*:* In ***peaksaver***PLUS™ participants are eligible to receive a free programmable thermostat or switch, including installation. Participants also receive access to price and real-time consumption information on an In Home Display (IHD).

Targeted End Uses: CACs, electric water heaters, and pool pumps

Delivery: PowerStream manages the initiative, procure the technology, install the control devices (through procured service provider), and promote/market the initiative. Additional detail is available:

- saveONenergy website https://saveonenergy.ca/Consumer/Programs/PeaksaverPlus.aspx

In Market Date: January 2011 – This is one initiative that was not halted even though PowerStream did not sign the Master Agreement until end of February 2011. The predecessor program was offered prior to 2011 and was extended until August 31, 2011. The ***peaksaver***PLUS™ initiative was not launched until May 2012 even though the Schedule was out in August 2011. The cause of the delay was primarily the lengthy time spent on studying which IHD technology would best meet both PowerStream and its customers' needs.

Initiative Activities/Progress: Please refer to Table 9 of this document.

Additional Comments (as provided by LDC-OPA Program Working Group):

- In Home Energy Display units that communicate with installed smart meter technology continue to mostly be in the development phase and are not ready for market deployment. There continues to be a lack of Energy Display selection in the marketplace.
- Smart Meters installed by most LDCs do not have the capability to communicate directly to an In Home Display and any mass replacement of newly installed meters with communicating abilities would not be fiscally responsible. When proposing technical Initiatives that rely on existing LDC hardware or technology there should be an extensive consultative process.
- Introduction of new technology requires incentives for the development of such technology. Appropriate lead times for LDC analysis and assessment, product procurement, and testing and integration into the Smart Meter environment are also required. Making seemingly minor changes to provincial technical specifications can create significant issues when all LDCs attempt to implement the solution in their individual environments.
- The variable funding associated with installing a load controllable thermostat is not sufficient unless it is combined with an In Home Display (IHD) which might not be possible all the time and when IHD is optional.
- Given the different LDC environments, and needs, each LDC is positioning the Initiative slightly differently. While a Thermostat has high marketability, it also carries a higher maintenance

liability due to no-heat and no-AC calls. A switch with an independent IHD is seen as a lower liability option but also has a much lower marketability.

- This is the main Initiative within the Residential portfolio that was to drive savings for LDC, however the 2012 evaluation indicated savings realized from the IHD were not statistically significant. LDCs were advised that the evaluation of the IHDs would continue with 2013 data.
- Verified demand savings in 2012 from the load control devices were less than originally anticipated. This prompted an increase to the load cycling strategy in 2013 in order to increase savings closer to the original business case.

Appendix C: Activities by Initiative – C&I Program

A. EFFICIENCY: EQUIPMENT REPLACEMENT INCENTIVE (ERII)

Target Customer Type(s): Commercial, Institutional, Agricultural, and Industrial Customers

Initiative Frequency: Year-round

Objective: The objective of this Initiative is to offer incentives to non-residential distribution customers to achieve reductions in electricity demand and consumption by upgrading to more energy efficient equipment for lighting, space cooling, ventilation, and other measures.

Description: The Equipment Replacement Incentive Initiative (ERII) offers financial incentives to customers for the upgrade of existing equipment to energy efficient equipment. Upgrade projects can be classified into either: 1) prescriptive projects, where prescribed measures replace associated required base case equipment; 2) engineered projects, where energy and demand savings and incentives are calculated for associated measures; or 3) custom projects for other energy efficiency upgrades.

Targeted End Uses: lighting, space cooling, ventilation, and other measures

Delivery: PowerStream manages the initiative, reviews and approves applications, conducts site visits (via third party service providers), pays approved applications, and promotes/markets the initiative. Applications are submitted online via the saveONenergy website. Additional detail is available:

- saveONenergy website https://saveONenergy.ca/Business/Program-Overviews/Retrofit-for-Commercial.aspx

In Market Date: March 2011 – PowerStream began offering ERII soon after the Master Agreement was signed. Since ERII is an initiative that is familiar to the customers, because it was relatively similar to its predecessor program (ERIP), it did not take long to launch this initiative.

Initiative Activities/Progress: Please refer to Table 10 of this document

Additional Comments (as provided by LDC-OPA Program Working Group):

- A large proportion of LDC savings are attributed to ERII.
- Capability building programs from Industrial programs have had very positive contributions to ERII program.
- This Initiative is limited by the state of the economy and the ability of commercial/institutional facility to complete capital upgrades.
- Applicants and Applicant Representatives continue to express dissatisfaction and difficulty with the online application system. This issue has been addressed by LDCs through application training workshops, Key Account Managers, channel partner/contractor training and LDC staff acting as customer Application Representatives. Although this has been an effective method of overcoming these issues and encouraging submissions, it also reflects on the complexity and time consuming nature of the application process. As such, Applicant Representatives continue to influence the majority of applications submitted. Continued development of Channel Partners is essential to program success.
- Prescriptive and Engineered worksheets provide a much needed simplified application process for customers. However, the eligible measures need to be updated and expanded in both

technology and incentive amounts to address changing product costs and evolution of the marketplace.

- A focus on demand incentives has limited some kWh project opportunities. In particular, night lighting projects have significant savings potential for customers but tend to have incentives of 10% of project cost or less.
- The requirement to have a customer invoice the LDC for their incentive is very burdensome for the customer and results in a negative customer experience and another barrier to participation.
- There is redundancy in the application process as customers may need to complete a worksheet and then enter most of that information over to the online application form. This can be cumbersome.
- Processing Head Office application became much easier for the Lead LDC after Schedule changes came into effect in August 2013. The changes implemented allowed the Lead LDC to review and approve all facilities in a Head Office application on behalf of all satellite LDCs under certain circumstances.
- The application process for Head Office projects remains a significant barrier. Applicants need to manually enter one application per facility associated with the project can be extremely onerous, often requiring a dedicated resource.
- Streamlining of the settlements systems resulted in significant improvement in the payment process in 2013.

B. DIRECT INSTALL INITIATIVE (Small Business Lighting)

Target Customer Type(s): Small Commercial, Institutional, Agricultural facilities and multi-family buildings

Initiative Frequency: Year-round

Objective: The objective of this initiative is to offer a free installation of eligible lighting and water heating measures of up to $1,500 to eligible owners and tenants of commercial, institutional and agricultural facilities and multi-family buildings, for the purpose of achieving electricity savings and peak demand savings.

Description: The Direct Installed Lighting (DIL) Initiative targets customers in the General Service <50kW account category. This Initiative offers turnkey lighting and electric hot water heater measures with a value up to $1,500 at no cost to qualifying small businesses. In addition, standard prescriptive incentives are available for eligible equipment beyond the initial $1,500 limit.

Target End Uses: Lighting and electric water heating measures

Delivery: PowerStream, through a third party service provider, conducts door-to-door blitz on eligible small businesses to encourage participating in the initiative. Participants may also enrol directly with PowerStream. PowerStream's service provider conducts the energy audit/walk-through, the installation of the efficient measure, and the disposal of the old equipment. PowerStream, together with the service provider, were also responsible for marketing and promotion. Additional detail is available:

- saveONenergy website https://saveonenergy.ca/Business/Program-Overviews/Small-Business-Lighting-and-AC.aspx

In Market Date: March 2011 – PowerStream began offering DIL soon after the Master Agreement was signed. Since DIL is an initiative that is familiar to the customers, because it was very similar to its predecessor program (Power Savings Blitz), the transition and launch of this initiative was simple and fast.

Initiative Activities/Progress: Please refer to Table 10 of this document

Additional Comments (as provided by LDC-OPA Program Working Group):

- LED lighting was introduced in 2013 as a new measure and has been well received by customers who may not have previously qualified for DIL eligible upgrades. This is an efficient product with a long estimate useful life.
- Cold start high output lighting was removed from the program. This particularly affected the farming customers who now have limited options within the program to utilize.
- The inclusion of a standard incentive for additional measures increased project size and drove higher energy and demand savings results in some situations. However, LDCs are unable to offer these standard incentives to prior participants. The ability to return to prior participants and offer a standard incentive on the remaining upgrades has potential to provide additional energy and demand savings.
- Many customers are not taking advantage of any additional measures, which may present an opportunity to for future savings with a new program offering.
- Electrical contractor's margins have been reduced due to no labour rate increase, increase cost of materials, greater distances between retrofit and more door knocking required before a successful sale. This has led to a reduction in vendor channel participation in some regions.
- Measure incentives and additional funding for fork lifts were introduced in September 2013 and were well received by installers. However, adjustments like these require longer lead times. As such, many customers were not able to benefit from this change in late 2013. Consideration

should be given to providing advanced notification to LDCs and contractors of the upcoming changes to allow for planning.

C. EXISTING BUILDING COMMISSIONING INCENTIVE INITIATIVE (Commissioning)

Target Customer Type(s): Commercial, Institutional, and Agricultural Customers

Initiative Frequency: Year-round

Objective: The objective of this initiative is to offer incentives for optimizing (but not replacing) existing chilled water systems for space cooling in non-residential facilities for the purpose of achieving implementation phase energy savings, implementation phase demand savings, or both.

Description: This initiative offers participant incentives for scoping study phase, investigation phase, implementation phase, and hand off/completion phase of the project

Targeted End Uses: Chilled water systems for space cooling

Delivery: PowerStream manages the initiative, reviews and approves applications, conducts site visits (via third party service providers), pays approved applications, and promotes/markets the initiative. Paper-based applications are submitted directly to PowerStream. Additional detail is available:

- saveONenergy website https://saveONenergy.ca/Business/Program-Overviews/Existing-Building-Commissioning.aspx

In Market Date: March 2011 – PowerStream began offering Commissioning soon after the Master Agreement was signed.

Initiative Activities/Progress: Please refer to Table 10 of this document

Additional Comments (as provided by LDC-OPA Program Working Group):

- Initiative name does not properly describe the Initiative.
- There was minimal participation for this Initiative. It is suspected that the lack of participation in the program is a result of the Initiative being limited to space cooling and a limited window of opportunity (cooling season) for participation.
- Participation is mainly channel partner driven, however the particulars of the Initiative have presented a significant barrier for many channel partners to participate.
- The customer expectation is that the program be expanded to include a broader range of measures for a more holistic approach to building recommissioning and chilled water systems used for other purposes should be made eligible and considered through Change Management.
- This initiative should be reviewed for incentive alignment with ERII, as currently a participant will not receive an incentive if the overall payback is less than 2 years.

D. NEW CONSTRUCTION AND MAJOR RENOVATION INITIATIVE (New Construction)

Target Customer Type(s): Commercial, Institutional, Agricultural and Industrial Customers

Initiative Frequency: Year-round

Objective: The objective of this initiative is to encourage builders of commercial, institutional, and industrial buildings (including multi-family buildings and agricultural facilities) to reduce electricity demand and/or consumption by designing and building new buildings with more energy-efficient equipment and systems for lighting, space cooling, ventilation and other measures.

Description: The New Construction initiative provides incentives for new buildings to exceed existing codes and standards for energy efficiency. The initiative uses both a prescriptive and custom approach.

Targeted End Uses: New building construction, building modeling, lighting, space cooling, ventilation and other measures

Delivery: PowerStream manages the initiative, reviews and approves applications, conducts site visits (via third party service providers), pays approved applications, and promotes/markets the initiative. Paper-based applications are submitted directly to PowerStream. Additional detail is available:

- saveONenergy website https://saveONenergy.ca/Business/Program-Overviews/New-Construction.aspx

In Market Date: March 2011 – PowerStream began offering New Construction soon after the Master Agreement was signed. Though the initial approach is to implement it internally, it was re-launched in quarter one 2012 when PowerStream finalized the procurement of a third party service provider to implement the initiative on its behalf.

Initiative Activities/Progress: Please refer to Table 10 of this document

Additional Comments (as provided by LDC-OPA Program Working Group):

- With the Ministerial Directive issued December 21, 2012, facilities with a completion date near the end of 2014 currently have some security that they will be compensated for choosing efficient measures. However, buildings that are in the planning phase with completion dates post-2015 may not participate due to funding uncertainty.
- Participants estimated completion dates tend to be inaccurate and are usually six months longer. This could result in diminished savings towards target when facilities are not substantially completed by December 31, 2014.
- The custom application process requires considerable customer support and skilled LDC staff. The effort required to participate through the custom stream exceeds the value of the incentive for many customers.
- There are no custom measure options for items that do not qualify under the prescriptive or engineered track as the custom path does not allow for individual measures, only whole building modelling.
- This Initiative has a very low net-to-gross ratio, which results in half the proposed target savings being 'lost'.
- The requirement to have a customer invoice the LDC for their incentive is very burdensome for the customer and results in a negative customer experience and a potential barrier to participation.

E. ENERGY AUDIT INITIATIVE (Audit Funding)

Target Customer Type(s): Commercial, Institutional, Agricultural and Industrial Customers

Initiative Frequency: Year-round

Objective: The objective of this initiative is to offer incentives to owners and lessees of commercial, institutional, multi-family buildings and agricultural facilities for the purpose of undertaking assessments to identify all possible opportunities to reduce electricity demand and consumption within their buildings or premises.

Description: This initiative provides participants incentives for the completion of energy audits of electricity consuming equipment located in the facility. Energy audits include development of energy baselines, use assessments and performance monitoring and reporting.

Targeted End Uses: Various measures

Delivery: PowerStream manages the initiative, review and approve applications, conduct site visits (via third party service providers), pay approved applications, and promote/market the initiative. Paper-based applications are submitted directly to PowerStream. Additional detail is available:

- saveONenergy website https://saveONenergy.ca/Business/Program-Overviews/Audit-Funding.aspx

In Market Date: March 2011 – PowerStream began offering Energy Audit Initiative soon after the Master Agreement was signed.

Initiative Activities/Progress: Please refer to Table 10 of this document

Additional Comments (as provided by LDC-OPA Program Working Group):

- The introduction of the new audit component for one system (i.e. compressed air), has increased customer participation.
- The energy audit Initiative is considered an 'enabling' Initiative and 'feeds into' other saveONenergy Initiatives.
- Evaluators in 2012 and 2013 recognized savings towards LDCs targets as a result of customers implementing low/no cost recommendations from their energy audits.
- Audit reports from consultants vary considerably and in some cases, while they adhere to the Initiative requirements, do not provide value for the Participant. A standard template with specific energy saving calculation requirements should be considered.
- Customers look to the LDCs to recommend audit companies. A centralized prequalified list provided by the OPA may be beneficial.
- Participation has been limited to one energy audit per customer which has restricted enabling and direction to the other Initiatives. This has been revised in 2014 and LDCs are now able to consider additional customer participation when presented with a new scope of work.
- Consideration should be given to allowing a building owner to undertake an audit limited to their lighting system. This way they may receive valuable information from neutral third party regarding the appropriate lighting solution for their facility instead of what a local supplier wants to sell.
- The requirement to have a customer invoice the LDC for their incentive is very burdensome for the customer and results in a negative customer experience and another barrier to participation.

Appendix D: Activities by Initiative – Industrial Program

A. PROCESS & SYSTEMS UPGRADES INITIATIVE (PSUI)

Target Customer Type(s): Industrial, Commercial, Institutional, and Agricultural Customers

Initiative Frequency: Year-round

Objectives: The objectives of this initiative are to:

- Offer distribution customers capital incentives and enabling initiatives to assist with the implementation of large projects and project portfolios;
- Implement system optimization project in systems which are intrinsically complex and capital intensive; and
- Increase the capability of distribution customers to implement energy management and system optimization projects.

Description: PSUI is an energy management initiative that includes three initiatives: (Preliminary Engineering Study (PES), Detailed Engineering Study (DES), and Project Incentive Initiative (PII)). The incentives are available to large distribution connected customers with projects or portfolio projects that are expected to generate at least 350 MWh of annualized electricity savings or, in the case of Micro-Projects, 100 MWh of annualized electricity savings. The capital incentive for this Initiative is the lowest of:

a) $200/MWh of annualized electricity savings
b) 70% of project cost
c) A one year payback

Targeted End Uses: Processes and systems

Delivery: PowerStream's Key Account Manager (KAM) works with targeted customers to identify possible projects that will be eligible for PSUI. Additional detail is available:

- saveONenergy website https://saveonenergy.ca/Business/Program-Overviews/Process-and-System-Upgrades.aspx

In Market Date: June 2011 – PowerStream began offering PSUI soon after the release of the Industrial Schedules. However, the Industrial Program Manager was not hired until September 2011 and the KAM until April 2012. As a result, the initiative was not fully executed until quarter two 2012.

Initiative Activities/Progress: Please refer to Table 10 of this document and Table 11 of this document

Additional Comments (as provided by LDC-OPA Program Working Group):

- Numerous energy studies have been submitted and completed. This is a strong indication that there is the potential for large projects with corresponding energy savings. Most of these studies have been initiated through the Energy Manager and KAM resources.
- This Initiative is limited by the state of the economy and the ability of a facility to complete large capital upgrades.
- There is typically a long sales cycle for these projects, and then a long project development cycle. As such, limited results are expected to be generated in 2013. The majority of the results are expected in 2014 with a much reduced benefit to cumulative energy savings targets.

- Delays with processing funding payments have caused delayed payments to Participants beyond contract requirements. In some cases, LDCs have developed a separate side agreement between the LDC and Participant acknowledging that the Participant cannot be paid until the funds are received.
- The contract required for PSUI is a lengthy and complicated document. A key to making PSUI successful is a new agreement which is a simplified with less onerous conditions for the customer.
- To partially address this, changes were made to the ERII Initiative which allowed smaller projects to be directed to the Commercial stream. Most industrial projects to-date have been submitted as ERII projects due to less onerous contract and M&V requirements.
- A business case was submitted by the Industrial Working Group in July 2012 which would change the upper limit for a small project from 700 MWh to 1 million dollars in incentives. This would allow more projects to be eligible for the new small capital project agreement and increase participant uptake, while still protecting the ratepayer. This small capital project agreement was finalized in August 2013.
- While there is considerable customer interest in on-site Load Displacement (Co-Generation) projects, in 2012 the OPA was accepting waste heat/waste fuel projects only. Natural gas generation projects were on hold awaiting a decision on whether PSUI will fund these types of projects. In June 2013, a decision was made to allow natural gas load displacement generation projects to proceed under PSUI. It is expected that a number of projects will proceed although results may not be counted towards LDC targets due to in-service dates beyond 2014.
- The requirement to have a customer invoice the LDC for their incentive is very burdensome for the customer and results in a negative customer experience and another barrier to participation.

B. MONITORING & TARGETING INITIATIVE (M&T)

Target Customer Type(s): Industrial, Commercial, Institutional and Agricultural Customers

Initiative Frequency: Year-round

Objective: This initiative offers access to funding for the installation of Monitoring and Targeting systems in order to deliver a minimum savings target at the end of 24 months and sustain for the term of the M&T Agreement.

Description: This initiative offers customers funding for the installation of a Monitoring and Targeting system to help them understand how their energy consumption might be reduced. A facility energy manager, who regularly oversees energy usage, will now be able to use historical energy consumption performance to analyze and set targets.

Targeted End Uses: Various measures

Delivery: PowerStream's Key Account Manager (KAM) works with targeted customers to identify possible projects that will be eligible for M&T. Additional detail is available:

- saveONenergy website https://saveonenergy.ca/Business/Program-Overviews/Process-and-System-Upgrades/Monitoring-and-Targeting.aspx

In Market Date: June 2011 – PowerStream began offering M&T soon after the release of the Industrial Schedules. However, the Industrial Program Manager was not hired until September 2011 and the KAM until April 2012. As a result, the initiative was not fully executed until quarter two 2012.

Initiative Activities/Progress: Please refer to Table 10 of this document and Table 11 of this document

Additional Comments (as provided by LDC-OPA Program Working Group):

- The M&T initiative is targeted at larger customers with the capacity to review the M&T data. This review requires the customer facility to employ an Energy Manager, or a person with equivalent qualifications, which has been a barrier for some customers. As such, a limited number of applications have been received to date.
- The savings target required for this Initiative can present a significant challenge for smaller customers.
- Changes were made to ERII in 2013 to allow smaller facilities to employ M&T systems.

C. ENERGY MANAGER INITIATIVE (Energy Managers)

Target Customer Type(s): Industrial, Commercial, Institutional and Agricultural Customers

Initiative Frequency: Year-round

Objective: The objective of this initiative is to provide customers and LDCs the opportunity to access funding for the engagement of energy managers in order to deliver a minimum annual savings target.

Description: This initiative provides customers the opportunity to access funding to engage an on-site, full time embedded energy manager, or an off-site roving energy manager who is engaged by the LDC. The role of the energy manager is to take control of the facility's energy use by monitoring performance, leading awareness programs, and identifying opportunities for energy consumption improvement, and spearheading projects. Participants are funded 80% of the embedded energy manager's salary up to $100,000 plus 80% of the energy manager's actual reasonable expenses incurred up to $8,000 per year. Each embedded energy manager has a target of 300 kW/year of demand savings from one or more facilities. LDCs receive funding of up to $120,000 for a Roving Energy Manager plus $8,000 for expenses.

Targeted End Uses: Various measures

Delivery: PowerStream was responsible for encouraging large customers to take opportunity of the Energy Manager initiative. Additional detail is available:

- saveONenergy website https://saveonenergy.ca/Business/Program-Overviews/Process-and-System-Upgrades/Energy-Managers.aspx

In Market Date: June 2011 – PowerStream began offering Energy Manager soon after the release of the Industrial Schedules. However, the Industrial Program Manager was not hired until September 2011 and the KAM until April 2012. As a result, the initiative was not fully executed until quarter two 2012.

Initiative Activities/Progress: Please refer to Table 10 of this document and Table 11 of this document

Additional Comments (as provided by LDC-OPA Program Working Group):

- The Energy Managers have proven to be a popular and useful resource for larger customers.
- LDCs that are too small to qualify for their own REM are teaming up with other utilities to hire an REM to be shared by the group of utilities.
- Some LDCs and Customers are reporting difficulties in hiring capable Roving and Embedded Energy Managers (REM/EEM), in some instances taking up to 7 months to have a resource in place.
- New energy managers require training, time to familiarize with facilities and staff and require time to establish "credibility". Energy Managers started filling their pipeline with projects in 2012 but few projects were implemented until 2013.

D. KEY ACCOUNT MANAGER (KAM)

Target Customer Type(s): Industrial, Commercial, Institutional and Agricultural Customers

Initiative Frequency: Year-round

Objective: This initiative offers LDCs the opportunity to access funding for the employment of a KAM in order to support them in fulfilling their obligations related to the PSUI. The KAM is considered to be a key element in assisting the consumer in overcoming traditional barriers related to energy management and help them achieve savings since the KAM can build relationships and become a significant resource of knowledge to the customer.

Description: The funding will be available for an LDC or a group of LDCs servicing a minimum of five Distribution Consumers each having at least 5MW of Annual Peak Demand. Funding for KAM is allocated on the basis that a fully-employed KAM is one who is employed on a full-time basis servicing ten Distribution Consumers each having at least 5MW of Annual Peak Demand.

Targeted End Uses: Various measures

Delivery: PowerStream was responsible for applying and receiving approval to hire a KAM. PowerStream's KAM is responsible for working with large customers in identifying energy savings opportunities and encouraging them to participate in the most appropriate programs.

In Market Date: April 2012 – PowerStream hired a KAM in April 2012. As a result, the initiative was not fully executed until quarter two 2012.

Initiative Activities/Progress: Please refer to Table 10 of this document and Table 11 of this document

Additional Comments (as provided by LDC-OPA Program Working Group):

- Customers appreciate dealing with a single contact to interface with an LDC, a resource that has both the technical and business background who can communicate easily with the customer and the LDC.
- Finding this type of skill set has been difficult. In addition, the short-term contract discourages some skilled applicants resulting in longer lead times to acquire the right resource.

E. DEMAND RESPONSE 3 (DR3)

Target Customer Type(s): Industrial, Commercial, Institutional and Agricultural Customers

Initiative Frequency: Year-round

Objective: This initiative provides for Demand Response (DR) payments to contracted participants to compensate them for reducing their electricity consumption by a pre-defined amount during a DR event.

Description: Demand Response 3 (DR3) is a demand response initiative for commercial and industrial customers, of 50 kW or greater to reduce the amount of power being used during certain periods of the year. The DR3 initiative is a contractual resource that is an economic alternative to procurement of new generation capacity. DR3 comes with specific contractual obligations requiring participants to reduce their use of electricity relative to a baseline when called upon. This Initiative makes payments for participants to be on standby and energy payments for the actual energy reduction provided during a demand response event. Participants are scheduled to be on standby approximately 1,600 hours per calendar year for possible dispatch of up to 100 hours or 200 hours within that year depending on the contract.

Targeted End Uses: Commercial and industrial operations

Delivery: DR3 is delivered by Demand Response Providers (DRP), under contract to the OPA. The OPA administers contracts with all DRPs and Direct Participants that provide in excess of 5 MW of demand response capacity. The OPA provides administration including settlement, measurement and verification, and dispatch. LDCs are responsible for outreach and marketing efforts. Additional detail is available:

- saveONenergy website https://saveonenergy.ca/Business/Program-Overviews/Demand-Response/Demand-Response-3.aspx

In Market Date: June 2011 – PowerStream began offering DR3 soon after the release of the Industrial Schedules. Most DR3 aggregators delivering DR3 in PowerStream's service area had already established relationships and contracts with PowerStream's customers prior to the launch of this initiative.

Initiative Activities/Progress: Please refer to Table 10 of this document and Table 11 of this document

Additional Comments (as provided by LDC-OPA Program Working Group):

- Until early 2013 customer data was not provided on an individual customer basis due to contractual requirements with the aggregators. This limited LDCs' ability to effectively market to prospective participants and verify savings.
- No program improvements were made in 2013 however, it was accepted that prior participants who renew their DR3 contract within the 2011-2014 term will contribute to LDC targets.
- As of 2013, Aggregators were able to enter into contracts beyond 2014 which has allowed them to offer a more competitive contract price (5 year) than if limited to 1 or 2 year contracts.
- Metering and settlement requirements are expensive and complicated and can reduce customer compensation amounts, and present a barrier to smaller customers.
- Compensation amounts for new contracts and renewals have been reduced from the initial launch of this program (premium zones and 200 hour option have been discontinued) and subsequently there has been a corresponding decrease in renewal revenue.

Appendix E: Low Income Program (Home Assistance Program)

Target Customer Type(s): Income Qualified Residential Customers

Initiative Frequency: Year-round

Objective: The objective of this program is to offer free installation of energy efficiency measures to income qualified households for the purpose of achieving electricity and peak demand savings.

Description: This is a turnkey program for income qualified customers. It offers residents the opportunity to take advantage of free installation of energy efficient measures that improve the comfort of their home, increase efficiency, and help them save money. All eligible customers receive a Basic and Extended Measures Audit, while customers with electric heat also receive a Weatherization Audit. The program is designed to coordinate efforts with gas utilities.

Targeted End Uses: End uses based on results of audit.

Delivery: PowerStream, through a third party service provider, conducts outreach to eligible participants in collaboration with social agencies. Participants may also enrol directly with the PowerStream. PowerStream's service provider conducts the energy audit/walk-through, the installation of the efficient measure, and the disposal of the old equipment. PowerStream, together with the service provider, were also responsible for marketing and promotion.

In Market Date: April 2012 – Although the Schedule was released midway through 2011, PowerStream was not able to launch the program until quarter two 2012. Even though the procurement process started in 2011, the contract with third party service provider was executed in 2012.

Initiative Activities/Progress: Please refer to Table 12 of this document.

Additional Comments (as provided by LDC-OPA Program Working Group):

- The process for enrolling in social housing was complicated and time consuming. This was addressed in late 2012 and showed some benefits in 2013.
- The financial scope, complexity, and customer privacy requirements of this Initiative are challenging for LDCs and most have contracted this program out. This Initiative may benefit from an OPA contracted centralized delivery agent.

OVERVIEW OF CDM PLAN
This CDM Plan must be used by the LDC in submitting a CDM Plan to the OPA under the Energy Conservation Agreement between the LDC and the OPA. The CDM Plan will consist of the information provided in this document and any additional information and supporting documents provided by the LDC to the OPA in support of this CDM Plan. Capitalized terms not otherwise defined herein have the meaning ascribed to them in the Energy Conservation Agreement as may be applicable.
Complete all fields within the CDM Plan that are applicable. Where additional space is required to complete a section of the CDM Plan, please append additional pages as required. The LDC should indicate that additional information has been attached in the related question field on the CDM Plan. Please refer to the CDM Plan Submission and Review Criteria Rules for further information.

A. General Information

1.

CDM Plan Submission Date: ***(MM /DD/ YYYY)***	12/18/2014
CDM Plan Version	Initial Submission

2.

LDC INFORMATION							
	LDC 1	**LDC 2**	**LDC 3**	**LDC 4**	**LDC 5**	**LCD 6**	**LCD 7**
LDC Name:	PowerStream Inc.	COLLUS PowerStream Corp.					
Company Representative:							
Name:	Milan Bolkovic	Ed Houghton					
Title:	Executive Vice President, Renewable Generation and Conservation	CEO and President					
Email Address:	milan.bolkovic@powerstream.ca	ehoughton@collus.com					
Phone Number (XXX-XXX-XXXX):	905-532-4601	705-445-1800, ext. 2222					

3.

Primary Contact for CDM Plan	
Name:	Raegan Bond
Title:	Vice President, CDM
Email Address:	raegan.bond@powerstream.ca
Phone Number (XXX-XXX-XXXX):	905-532-4540

Estimated Start Date of CDM Plan: ***(MM / DD / YYYY)***	01/01/15

LDC CONFIRMATION FOR CDM PLAN	
Each LDC to this CDM Plan has executed the Energy Conservation Agreement.	Yes
A completed Cost-Effectiveness Tool is attached and forms part of the CDM Plan.	Yes
A completed Achievable Potential Tool is attached and forms part of the CDM Plan.	Yes
All customer segments in each LDC's service area are served by the Programs set out in this CDM Plan.	Yes
The CDM Plan includes all electricity savings attributable to all Programs and pilot programs that have in-service dates between Jan 1, 2015 and December 31, 2020.	Yes
The CDM Plan Budget for each LDC includes all eligible funding under the full cost recovery and pay-for-performance mechanisms for Programs under its CDM Plan.	Yes

COMPLETE FOR CDM PLAN AMENDMENTS ONLY	
Select the reason(s) for CDM Plan amendment, as per ECA.	
One time each calendar year of the term	
LDC wishes to request an adjustment to the CDM Plan Budget	
The amendments to a provision of the ECA or any Rules will have a material effect on the CDM Plan	
LDC's actual spending under CDM Plan has exceeded (or is reasonably expected to exceed) the portion of the CDM Plan Budget allocated to the current year of the term	
Under a joint CDM Plan, LDCs that are parties to a joint CDM Plan reallocate any portion of their respective CDM Plan Targets and CDM Plan Budgets [*Reallocation not subject to OPA approval*]	
OPA has triggered remedies under Article 5 of the ECA	
LDC seeking to change its selection of the type of funding that it wishes to receive for each Program in the CDM Plan [ECA, section 4.1]	
Other (Please specify reason)	

B. LDC Authorization

LDC DECLARATION
Please complete the declaration for each LDC that is listed in this CDM Plan. A separate page with each LDC's signed declaration should be included as part of the CDM Plan submission.

LDC	
I represent that the information contained in this CDM Plan as it relates to the LDC is complete, true, and accurate in all respects. I acknowledge and agree to the following terms and conditions: (1) if this CDM Plan is approved by the OPA and accepted by each LDC to this CDM Plan, the CDM Plan together with any conditions to that approval is incorporated by reference into the Energy Conservation Agreement between the LDC and the OPA; (2) the LDC will offer the Programs set out in Table 2 of this CDM Plan to customers in its service area; and (3) the LDC of will implement this CDM Plan in accordance with the CDM Plan Budget.	
LDC's Legal Name:	PowerStream Inc
Company Representative:	Milan Bolkovic
Signature	
	I/We have the authority to bind the Corporation.
Date (MM/DD/YYYY)	

C. CDM Plan Summary

TABLE 1: SUMMARY OF CDM PORTFOLIO SAVINGS AND BUDGET										
		CDM PLAN TOTAL	LDC 1	LDC 2	LDC 3	LDC 4	LDC 5	LCD 6	LCD 7
a.	**Allocated LDC CDM Plan Target (MWh)** **Indicate total CDM Plan Target allocated to LDC(s)**	**552,300**	535,440.0	16,860.0					
b.	**CDM Plan MWh Savings** **Calculated as part of CDM Plan**	**552,338**	535,470	16,869	0	0	0	0	0
c.	**Allocated LDC CDM Plan Budget ($)** **Indicate total budget allocated to LDC**	**$145,143,080**	$140,696,240.00	$4,446,840.00					
d.	**Total CDM Plan Budget ($)** **Calculated as part of CDM Plan**	**$145,143,079**	$140,696,239	$4,446,840	$0	$0	$0	$0	$0
f.	**CDM Plan Cost Effectiveness**		**Total Resource Cost (TRC)**			**Program Administrator Cost (PAC)**			**Levelized Cost**
		Program Year	**Benefits ($)**	**Costs ($)**	**Ratio**	**Benefits ($)**	**Costs ($)**	**Ratio**	**($/kWh)**
	Indicate annual portfolio-level Cost Effectiveness for CDM Plan as determined by LDC(s) using output from Cost-Effectiveness Tool	2015	$33,805,673.27	$21,323,183.12	1.6	$29,396,237.63	$8,599,983.41	3.4	$0.014
		2016	$40,947,593.72	$26,167,869.42	1.6	$35,606,603.23	$16,921,772.43	2.1	$0.024
		2017	$48,174,826.60	$29,373,033.80	1.6	$41,891,153.56	$18,888,632.60	2.2	$0.024
		2018	$74,213,149.21	$54,861,961.61	1.4	$64,533,173.22	$31,291,523.06	2.1	$0.028
		2019	$75,887,628.32	$53,714,541.69	1.4	$65,989,242.02	$30,537,847.44	2.2	$0.028
		2020	$82,307,441.11	$53,017,597.18	1.6	$71,571,687.92	$30,223,504.90	2.4	$0.026
		CDM Plan Total	**$355,336,312**	**$238,458,187**	1.5	**$308,988,098**	**$136,463,264**	2.3	$0.025
g	**Plan Cost Effectiveness-Exceptions Rationale** **Complete this section if proposed plan does not meet minimum Cost-Effectiveness Thresholds set out in CDM Plan**								

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the OPA, could only be achieved

LDC 1:	PowerStream Inc.

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Province Wide Program Name	Approved Local or Regional Program or Pilot Program Name	Proposed Regional or Local CDM Program or Pilot Program Name	Program Start Date (MM/DD/YYYY)	Customer Segments Targeted by Program: Residential	Low-income	Small busine	Commercial	Agricultural	Institutional	Industrial	Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program): 2015 Anticipated Annual Budget ($)	2015 Energy Savings (MWh)	2016 Anticipated Annual Budget ($)	2016 Energy Savings (MWh)	2017 Anticipated Annual Budget ($)	2017 Energy Savings (MWh)	2018 Anticipated Annual Budget ($)	2018 Energy Savings (MWh)	2019 Anticipated Annual Budget ($)	2019 Energy Savings (MWh)	2020 Anticipated Annual Budget ($)	2020 Energy Savings (MWh)	Total 2015 - 2020: Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs	Retrofit Program			7/1/2015			Yes	Yes	Yes	Yes	Yes	5,572,484	19,037.7	9,088,822	38,075.3	9,091,229	38,075.3	9,114,645	38,075.3	9,143,666	38,075.3	9,168,080	38,075.3	$51,178,926	209,414.4
	Heating and Cooling Program			7/1/2015	Yes	Yes						1,214,974	1,251.5	-	-	-	-	-	-	-	-	-	-	$1,214,974	1,251.5
	Low Income Home Assistance Program			7/1/2015		Yes						46,305	39.2	39,028	78.4	39,033	78.4	39,080	78.4	39,140	78.4	39,190	78.4	$241,775	431.4
	High Performance New Construction Program			7/1/2015			Yes	Yes	Yes	Yes	Yes	175,026	342.0	182,202	684.0	182,245	684.0	182,665	684.0	183,185	684.0	183,623	684.0	$1,088,947	3,762.0
	Audit Funding Program			7/1/2015			Yes	Yes	Yes	Yes	Yes	87,119	363.4	173,000	726.8	173,045	726.8	173,492	726.8	174,045	726.8	174,510	726.8	$955,211	2,907.0
	Energy Manager Program			7/1/2015				Yes	Yes	Yes	Yes	288,108	1,484.0	919,930	3,957.3	1,150,225	4,946.7	1,153,262	4,946.7	1,157,026	4,946.7	1,160,192	4,946.7	$5,828,742	25,228.0
	Bi-Annual Coupon Event			7/1/2015	Yes	Yes						217,254	818.9	-	-	-	-	-	-	-	-	-	-	$217,254	818.9
			Business Refrigeration Program	1/20/2015			Yes						2,494.1		-		-		-		-		-		2,494.1
			Small Commercial Direct Install Program	1/1/2016			Yes						-		6,600.1		6,600.1		6,600.1		6,600.1		6,600.1		33,000.3
			IT Program	1/1/2017			Yes	Yes	Yes	Yes	Yes		-		-		3,307.2		3,599.0		3,988.1		4,279.9		15,174.1
			Whome Home Program	1/1/2016	Yes	Yes							-		807.0		888.1		968.5		1,049.6		1,129.9		4,843.1
			Home Energy Reports	1/1/2016	Yes	Yes							-		1,641.6		17,466.7		22,480.8		23,151.5		23,366.2		23,366.2
			Dynamic Pricing	1/1/2016	Yes	Yes							-		1,794.0		3,767.5		5,920.3		8,252.5		10,764.2		10,764.2
			Residential Solar	1/1/2018	Yes								-		-		-		2,347.7		2,347.7		2,347.7		7,043.0
			Shortfall - Residential	1/1/2018	Yes								-		-		-		23,460.0		23,460.0		23,460.0		70,380.0
			Shortfall - Business	1/1/2018			Yes	Yes	Yes	Yes	Yes		-		-		-		14,574.0		14,574.0		14,574.0		43,722.0
	Existing Building Commissioning Program			7/1/2015				Yes		Yes	Yes	-	-	-	-	-	-	-	-	-	-	-	-		
	Process and Systems Program			7/1/2015							Yes	-	-	-	-	-	-	-	-	-	-	-	-		
	Monitoring and Targeting Program			7/1/2015							Yes	-	-	-	-	-	-	-	-	-	-	-	-		
	Conservation Instant Coupon Booklet			7/1/2015	Yes	Yes						-	-	-	-	-	-	-	-	-	-	-	-		
	Residential New Construction Program			7/1/2015	Yes							-	-	-	-	-	-	-	-	-	-	-	-		
			Enhanced Retrofit	1/1/2016			Yes	Yes	Yes	Yes	Yes		-		429.7		429.7		429.7		429.7		429.7		2,148.3
			Enhanced Coupon	1/1/2016	Yes	Yes							-		7,452.1		7,452.1		7,452.1		7,452.1		7,452.1		37,260.6
			Enhanced HVAC	1/1/2016	Yes	Yes							-		2,958.9		3,303.9		3,204.8		3,105.7		3,006.6		15,579.9
FCR TOTAL												$8,312,195	25,830.8	$16,769,987	65,205.3	$19,097,567	87,726.4	$32,165,147	135,548.0	$32,020,762	138,922.0	$32,330,581	141,921.4	$140,696,239	509,589.0
Pay for Performance Programs																									
P4P TOTAL												$0	-	$0	-	$0	-	$0	-	$0	-	$0	-	$0	-
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) (Not funded through 2015-2020 CDM Framework)	Retrofit Initiative												19,037.7												19,037.7
	Heating and Cooling Initiative												1,251.5												1,251.5
	Low Income Home Assistance Program												274.5												274.5
	Direct Install Lighting												2,672.0												2,672.0
	High Performance New Construction												342.0												342.0
	Audit Funding												363.4												-
	Energy Manager (PSUI)												1,484.0												1,484.0
	Bi-Annual Retailer Event												818.9												818.9
	peaksaverPLUS												-												-
	Existing Building Commissioning												-												-
	Monitoring and Targeting (PSUI)												-												-
	Process and Systems Upgrades Program												-												-
													-												-
	Conservation Instant Coupon Booklet												-												-
	Program Enabled Savings												-												-
	Residential New Construction												-												-
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	26,244.0											0.0	25,880.6
TARGET GAP TOTAL																								0.0	
CDM PLAN TOTAL												$8,312,195	52,074.8	$16,769,987	65,205.3	$19,097,567	87,726.4	$32,165,147	135,548.0	$32,020,762	138,922.0	$32,330,581	141,921.4	$140,696,239	535,469.7
MINIMUM ANNUAL SAVINGS CHECK													True		True		True		True		True		True		

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the OPA, could only be achieved

LDC 2:	COLLUS PowerStream Corp.

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Province Wide Program Name	Approved Local or Regional Program or Pilot Program Name	Proposed Regional or Local CDM Program or Pilot Program Name	Program Start Date (MM/DD/YYYY)	Customer Segments Targeted by Program: Residential	Low-income	Small busine	Commercial	Agricultural	Institutional	Industrial	2015 Anticipated Annual Budget ($)	2015 Energy Savings (MWh)	2016 Anticipated Annual Budget ($)	2016 Energy Savings (MWh)	2017 Anticipated Annual Budget ($)	2017 Energy Savings (MWh)	2018 Anticipated Annual Budget ($)	2018 Energy Savings (MWh)	2019 Anticipated Annual Budget ($)	2019 Energy Savings (MWh)	2020 Anticipated Annual Budget ($)	2020 Energy Savings (MWh)	Total 2015 - 2020: Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs	Retrofit Program			7/1/2015			Yes	Yes	Yes	Yes	Yes	210,391	605.7	287,119	1,211.5	287,193	1,211.5	287,908	1,211.5	288,794	1,211.5	289,539	1,211.5	$1,650,944	6,663.2
	Heating and Cooling Program			7/1/2015	Yes	Yes						40,378	39.3	-	-	-	-	-	-	-	-	-	-	$40,378	39.3
	Low Income Home Assistance Program			7/1/2015		Yes						1,766	1.3	1,184	2.4	1,184	2.4	1,186	2.4	1,187	2.4	1,189	2.4	$7,696	13.0
	High Performance New Construction Program			7/1/2015			Yes	Yes	Yes	Yes	Yes	866	-	845	-	846	-	12,533	57.0	12,549	57.0	12,563	57.0	$40,203	171.0
	Audit Funding Program			7/1/2015			Yes	Yes	Yes	Yes	Yes	921	-	898	-	899	-	10,343	48.5	10,360	48.5	10,374	48.5	$33,794	145.4
	Energy Manager Program			7/1/2015				Yes	Yes	Yes	Yes	-	-	-	-	-	-	-	-	-	-	-	-		-
	Bi-Annual Coupon Event			7/1/2015	Yes	Yes						8,277	25.8	-	-	-	-	-	-	-	-	-	-	$8,277	25.8
			Business Refrigeration Program	1/20/2015			Yes						81.1		-		-		-		-		-		81.1
			Small Commercial Direct Install Program	1/1/2016			Yes						-		206.5		206.5		206.5		206.5		206.5		1,032.5
			IT Program	1/1/2017			Yes	Yes	Yes	Yes	Yes		-		-		97.3		97.3		97.3		97.3		389.1
			Whome Home Program	1/1/2016	Yes	Yes							-		25.7		28.1		30.4		32.7		35.9		152.8
			Home Energy Reports	1/1/2016	Yes	Yes							-		51.7		550.0		707.9		729.0		735.8		735.8
			Dynamic Pricing	1/1/2016	Yes	Yes							-		56.5		118.7		186.4		259.9		338.9		338.9
			Residential Solar	1/1/2018	Yes								-		-		-		77.1		77.1		77.1		231.3
			Shortfall - Residential	1/1/2018	Yes								-		-		-		817.0		817.0		817.0		2,451.0
			Shortfall - Business	1/1/2018			Yes	Yes	Yes	Yes	Yes		-		-		-		634.0		634.0		634.0		1,902.0
	Existing Building Commissioning Program			7/1/2015				Yes		Yes	Yes	-	-	-	-	-	-	-	-	-	-	-	-		
	Process and Systems Program			7/1/2015							Yes	-	-	-	-	-	-	-	-	-	-	-	-		
	Monitoring and Targeting Program			7/1/2015							Yes	-	-	-	-	-	-	-	-	-	-	-	-		
	Conservation Instant Coupon Booklet			7/1/2015	Yes	Yes						-	-	-	-	-	-	-	-	-	-	-	-		
	Residential New Construction Program			7/1/2015	Yes							-	-	-	-	-	-	-	-	-	-	-	-		
			Enhanced Retrofit	1/1/2016			Yes	Yes	Yes	Yes	Yes		-		14.0		14.0		14.0		14.0		14.0		70.2
			Enhanced Coupon	1/1/2016	Yes	Yes							-		234.7		234.7		234.7		234.7		234.7		1,173.3
			Enhanced HVAC	1/1/2016	Yes	Yes							-		93.0		103.8		100.7		97.6		94.5		489.7
FCR TOTAL												$287,789	753.2	$489,651	1,895.9	$554,192	2,566.9	$1,041,732	4,425.3	$1,034,603	4,519.2	$1,038,873	4,604.9	$4,446,840	16,105.3
Pay for Performance Programs																									
P4P TOTAL												$0	-	$0	-	$0	-	$0	-	$0	-	$0	-	$0	-
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) (Not funded through 2015-2020 CDM Framework)	Retrofit Initiative												605.7												605.7
	Heating and Cooling Initiative												39.3												39.3
	Low Income Home Assistance Program												8.9												8.9
	Direct Install Lighting												83.5												83.5
	High Performance New Construction												-												-
	Audit Funding												-												-
	Energy Manager (PSUI)												-												-
	Bi-Annual Retailer Event												25.8												25.8
	peaksaverPLUS												-												-
	Existing Building Commissioning												-												-
	Monitoring and Targeting (PSUI)												-												-
	Process and Systems Upgrades Program												-												-
																									-
	Conservation Instant Coupon Booklet												-												-
	Program Enabled Savings												-												-
	Residential New Construction												-												-
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	763.3											0.0	763.3
TARGET GAP TOTAL																								0.0	
CDM PLAN TOTAL												$287,789	1,516.5	$489,651	1,895.9	$554,192	2,566.9	$1,041,732	4,425.3	$1,034,603	4,519.2	$1,038,873	4,604.9	$4,446,840	16,868.6
MINIMUM ANNUAL SAVINGS CHECK													True		True		True		True		True		True		

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the OPA, could only be achieved with funding in addition to the CDM Plan Budget.

LDC 3:	

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)

Funding Mechanism	Province Wide Program Name	Approved Local or Regional Program or Pilot Program Name	Proposed Regional or Local CDM Program or Pilot Program Name	Program Start Date (MM/DD/YYYY)	Customer Segments Targeted by Program: Residential	Low-income	Small business	Commercial (inc. Multi-Fa	Agricultural	Institutional	Industrial	2015 Anticipated Annual Budget ($)	2015 Energy Savings (MWh)	2016 Anticipated Annual Budget ($)	2016 Energy Savings (MWh)	2017 Anticipated Annual Budget ($)	2017 Energy Savings (MWh)	2018 Anticipated Annual Budget ($)	2018 Energy Savings (MWh)	2019 Anticipated Annual Budget ($)	2019 Energy Savings (MWh)	2020 Anticipated Annual Budget ($)	2020 Energy Savings (MWh)	Total 2015 - 2020 Total CDM Plan Budget ($)	Total 2015 - 2020 Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs																									
FCR TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
Pay for Performance Programs																									
P4P TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*																									
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	0.0											0.0	0.0
TARGET GAP TOTAL																								0.0	
CDM PLAN TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
M[illegible]CK																									

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the OPA, could only be achieved with funding in addition to the CDM Plan Budget.

LDC 4:	

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Province Wide Program Name	Approved Local or Regional Program or Pilot Program Name	Proposed Regional or Local CDM Program or Pilot Program Name	Program Start Date (MM/DD/YYYY)	Customer Segments Targeted by Program							Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)													
												2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (inc. Multi-Fa	Agricultural	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs																									
FCR TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
Pay for Performance Programs																									
P4P TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*																									
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	0.0											0.0	0.0
TARGET GAP TOTAL																								0.0	
CDM PLAN TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
[illegible]																									

ONTARIO POWER AUTHORITY

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

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NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the OPA, could only be achieved with funding in addition to the CDM Plan Budget.

LDC 5:	

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Province Wide Program Name	Approved Local or Regional Program or Pilot Program Name	Proposed Regional or Local CDM Program or Pilot Program Name	Program Start Date (MM/DD/YYYY)	Customer Segments Targeted by Program							Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)													
												2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (inc. Multi-Fa	Agricultural	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs																									
FCR TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
Pay for Performance Programs																									
P4P TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*																									
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	0.0											0.0	0.0
TARGET GAP TOTAL																								0.0	
CDM PLAN TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
MINIMUM ANNUAL SAVINGS CHECK																									

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the OPA, could only be achieved with funding in addition to the CDM Plan Budget.

LDC 6:	

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Province Wide Program Name	Approved Local or Regional Program or Pilot Program Name	Proposed Regional or Local CDM Program or Pilot Program Name	Program Start Date (MM/DD/YYYY)	Customer Segments Targeted by Program							Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)													
												2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (inc. Multi-Fa	Agricultural	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs																									
FCR TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
Pay for Performance Programs																									
P4P TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*																									
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	0.0											0.0	0.0
TARGET GAP TOTAL																								0.0	
CDM PLAN TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
MINIMUM ANNUAL SAVINGS CHECK																									

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D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the OPA, could only be achieved with funding in addition to the CDM Plan Budget.

LDC 7:	

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Province Wide Program Name	Approved Local or Regional Program or Pilot Program Name	Proposed Regional or Local CDM Program or Pilot Program Name	Program Start Date (MM/DD/YYYY)	Customer Segments Targeted by Program							Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)													
												2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (inc. Multi-Fa	Agricultural	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs																									
FCR TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
Pay for Performance Programs																									
P4P TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*																									
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	0.0											0.0	0.0
TARGET GAP TOTAL																								0.0	
CDM PLAN TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
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E. Proposed Local and Regional Pilot CDM Programs

Notes
Complete the following Table(s) for each proposed local and regional Program or Pilot Program in the CDM Plan for which a business case has NOT previously been approved by OPA. Please refer to the Program Development and Rule Revision Guideline and the Business Case Template for full details on requirements and submission of a business case for approval of a local or regional Program. For the process for receiving funding for a Pilot Program, refer to the LDC Program Innovation Guideline.

TABLE 3a. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**	Business Refrigeration Program	*Use same "Program name" included in other worksheets*	
b.	**Program Type**	Proposed Local Program		
b.	**Estimated Business Case Submission Date *(MM / DD / YYYY)***	11/28/2014		
c.	**Customer Segment(s) Served by Programs**	Small Business		
d.	**Participating LDCs *(if applicable)***	PowerStream Inc.		
		COLLUS PowerStream Corp.		
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*	The Business Refrigeration Incentives (BRI) Program promotes the identification and implementation of energy efficient equipment upgrades and maintenance measures to commercial refrigeration equipment. Participants receive significant value for participation. Program incentives include a comprehensive on-site electricity audit providing recommendations for equipment retrofit and maintenance; up to $2,500 in materials and labour to retrofit commercial refrigeration equipment performed by an authorized, licensed refrigeration or electrical contractor (LDC hired		

TABLE 3b. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**	Whole Home Program	*Use same "Program name" included in other worksheets*	
b.	**Program Type**	Proposed Pilot		
b.	**Estimated Business Case Submission Date *(MM / DD / YYYY)***	1/7/2015		
c.	**Customer Segment(s) Served by Programs**	Residential	Low Income	
d.	**Participating LDCs *(if applicable)***	PowerStream Inc.		
		COLLUS PowerStream Corp.		
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*	The program is divided into 2 phases: Phase 1 includes energy assessment and direct install of measures (e.g. lighting, water, sealing, etc) while Phase 2 includes customers doing additional energy efficient upgrades (e.g. appliances, insulation, windows, etc) and applying for rebates upon project completion. PowerStream and Collus are looking at partnering with Gas Companies in offering this program.		

TABLE 3c. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**	Small Commercial Direct install Program	*Use same "Program name" included in other worksheets*	
b.	**Program Type**	Proposed Regional Program		
b.	**Estimated Business Case Submission Date *(MM / DD / YYYY)***	1/7/2015		
c.	**Customer Segment(s) Served by Programs**	Small Business		
d.	**Participating LDCs *(if applicable)***	PowerStream Inc.		
		COLLUS PowerStream Corp.		
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*	PowerStream and Collus anticipate that the new province-wide program replacing Direct Install Lighting will be available by January 1, 2016. The program is assumed to be offered to Small Businesses, a direct install type, and will include lighting, refrigeration, hvac, agriculture and other measures. Duration: 2016-2020		

TABLE 3d. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**	Home Energy Reports	*Use same "Program name" included in other worksheets*	
b.	**Program Type**	Proposed Local Program		
b.	**Estimated Business Case Submission Date *(MM / DD / YYYY)***	1/7/2015		
c.	**Customer Segment(s) Served by Programs**	Residential	Low Income	
d.	**Participating LDCs *(if applicable)***	PowerStream Inc.		
		COLLUS PowerStream Corp.		
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*	The program is designed to provide Home Energy Reports (paper-based) to residential customers. (Multiple reports in a year) Through the Home Energy Reports, LDCs can motivate customers to become more energy-efficient by providing them with energy-use comparison, energy use analysis, targeted tips and promotional offers. Duration: 2016-2020		

TABLE 3e. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**	IT Program	*Use same "Program name" included in other worksheets*	
b.	**Program Type**	Proposed Local Program		
b.	**Estimated Business Case Submission Date *(MM / DD / YYYY)***	1/7/2016		
c.	**Customer Segment(s) Served by Programs**	Commercial (inc. Multi-Family)	Institutional	Industrial
d.	**Participating LDCs *(if applicable)***	PowerStream Inc.		
		COLLUS PowerStream Corp.		
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*	The objective of this program is to provide incentives to customers who will undertake office equipment retrofit projects (from laptops to servers) or any other IT projects that will realize energy savings (e.g. virtualization,etc). Customers are required to apply for project pre-approval, and apply for incenitves after project implementation. Duration: 2017-2020		

TABLE 3f. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**	Dynamic Pricing	*Use same "Program name" included in other worksheets*	
b.	**Program Type**	Proposed Local Program		
b.	**Estimated Business Case Submission Date *(MM / DD / YYYY)***	1/7/2015		
c.	**Customer Segment(s) Served by Programs**	Residential	Low Income	
d.	**Participating LDCs *(if applicable)***	PowerStream Inc.		
		COLLUS PowerStream Corp.		
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*	The program introduces a new voluntary pricing plan for residential customers. Customers will have off-peak and on-peak price. The off-peak price is the same every day and the on-peak price is either low, medium or high. As a result of the new pricing plan, customers are expected to realized energy savings by changing the way they use their electricity. Currently, PowerStream is piloting this program under Smart grid Pilot Fund. Results of the Pilot program will be		

E. Proposed Local and Regional Pilot CDM Programs

Notes
Complete the following Table(s) for each proposed local and regional Program or Pilot Program in the CDM Plan for which a business case has NOT previously been approved by OPA. Please refer to the Program Development and Rule Revision Guideline and the Business Case Template for full details on requirements and submission of a business case for approval of a local or regional Program. For the process for receiving funding for a Pilot Program, refer to the LDC Program Innovation Guideline.

TABLE 3a. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**	Residential Solar	*Use same "Program name" included in other worksheets*	
b.	**Program Type**	Proposed Local Program		
b.	**Estimated Business Case Submission Date *(MM / DD / YYYY)***	1/7/2017		
c.	**Customer Segment(s) Served by Programs**	Residential	Low Income	
d.	**Participating LDCs *(if applicable)***	PowerStream Inc.		
		COLLUS PowerStream Corp.		
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*	The program is designed to provide incentives to customers who will install residential solar panels on their rooftops. The solar panels should not be connected to the grid and are installed for the purposes of savings electricty usage from the distribution grid. Customers will have to apply for pre-approval and then apply for incenitves upon project completion. Duration: 2018-2020		

TABLE 3b. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(MM / DD / YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3c. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(MM / DD / YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3d. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(MM / DD / YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3e. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(MM / DD / YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3f. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(MM / DD / YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

F. Detailed Information on Collaboration and Regional Planning

ADDITIONAL DETAILED INFORMATION	
Regional LDC Collaboration *Description of how the LDC will collaborate with other LDCs. If collaboration will not occur, description of why it will not occur.*	In addition to the inherent collaboration through a Joint CDM Plan between PowerStream and Collus PowerStream, both LDCs will seek out opportunities for further CDM program collaboration through their existing regional networks (e.g. CLD, CHEC) and industry committees/working groups (e.g. EDA). All facets of collaboration will be considered, including potential joint design/piloting of new programs as well as enhanced collaboration in the delivery of existing programs. As of December 2014, we have already initiated discussions with 3 other neighbouring LDCs. Once our joint CDM Plan has been approved by the OPA, we will proceed with more detailed planning and contracting of collaborative approaches with additional regional LDCs.
Gas Collaboration *Description of how the LDC will collaborate with other gas utility programs delivered in service area (if applicable). If collaboration will not occur, description of why it will not occur.*	PowerStream has been discussing potential collaboration opportunities with Enbridge Gas since Spring of 2014, including several meetings between the two companies and PowerStream's participation in many of Enbridge's DSM stakeholder consultation workshops in Fall 2014. Based on discussions to date,initial efforts willlikely focus on collaboration in the residential and small commerical sector, including fully integrated design and delivery of a Whole Home pilot program. Currently all areas for collaboration identified in the collaboration guidelines (promotion, enabling, design & delivery) are being considered by both PowerStream and Enbridge. PowerStream will also initiate discussions with Union Gas regarding opportunities in the Collus PowerStream territory. Specific strategies and tactics will be finalized after the new DSM framework is finalized.
CDM Contribution to Regional Planning *Description of how the LDC CDM Plan considers the electricity needs and investments identified in other plans or planned initiatives, completed or underway within the LDC's service area or region. This may included Integrated Regional Resource Plans or Municipal Community Energy Plans.*	PowerStream's 2015-2020 Conservation Targets are being built into the development of the IRRP and RIP for GTA North, as well as PowerStream's Distribution System Plan. PowerStream is also actively supporting the City of Vaughan and the City of Markham with their Community Energy Plans, by providing data and by participating on advisory committees.

G. Additional Documentation for CDM Plan (If applicable)

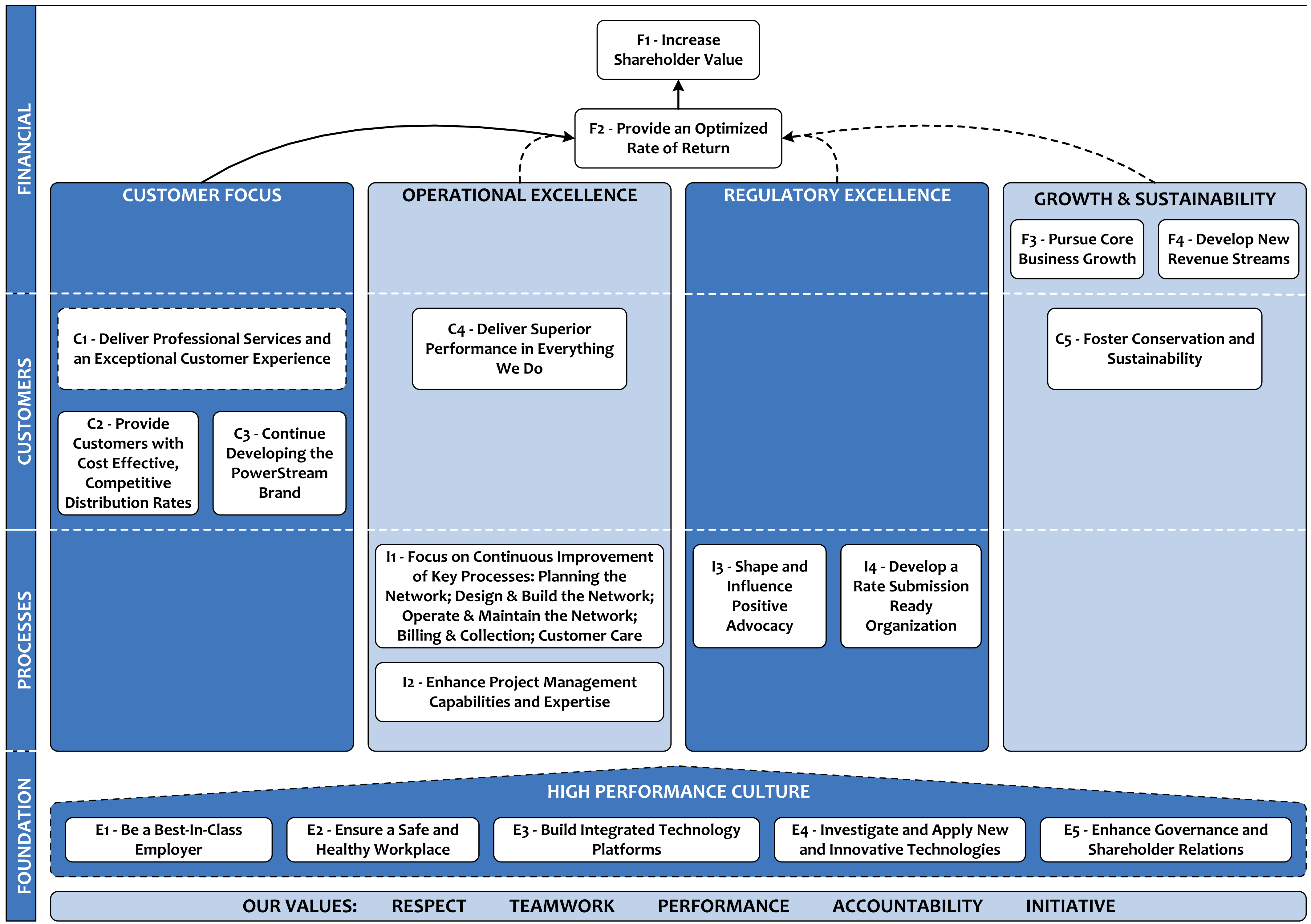
ADDITIONAL INFORMATION AND DOCUMENTATION	
Programs *Opportunity to provide any additional information on assumptions used for budgets and/or savings for approved 2015-2020 province-wide programs*	Please refer to the slidedeck entitled "2015-2020 CDM Plan - supporting documentation" which was included with this CDM Plan submission.
Approved Local and/or Regional Programs and Pilot Programs *Opportunity to provide any additional information on assumptions used for budgets and/or savings for approved 2015-2020 local or regional programs or pilot programs*	Please refer to the slidedeck entitled "2015-2020 CDM Plan - supporting documentation" which was included with this CDM Plan submission.
Proposed Local and/or Regional Programs and Pilot Programs *Opportunity to provide additional information on assumptions used for forecast budgets and/or savings for proposed programs or pilot programs*	Please refer to the slidedeck entitled "2015-2020 CDM Plan - supporting documentation" which was included with this CDM Plan submission.
Programs from 2011-2014/2015 CDM Framework *Opportunity to provide any additional information on assumptions used for budgets and/or savings from existing 2011-2014/2015 CDM Programs*	Please refer to the slidedeck entitled "2015-2020 CDM Plan - supporting documentation" which was included with this CDM Plan submission.
Programs funded through Pay-for-Performance *Opportunity to provide any additional information on assumptions used for budgets and/or savings for Pay for Performance Programs*	not applicable
Other *Additional assumptions used in the CDM Plan*	

PowerStream 2014 Strategy Map

OUR VISION: We will be a socially responsible company, committed to the environment and sustainable growth, leading the way into the future with boldness, innovation and best in class performance.

OUR MISSION: To deliver reliable power and related services safely and efficiently to support our customers' quality of life, and to provide value to our shareholders and the communities we serve.

OUR STRATEGY: By 2020, we will build on our core electricity distribution business to become Ontario's premier integrated energy services provider.



Financial statements of

PowerStream Inc.

December 31, 2012 and December 31, 2011

PowerStream Inc.

December 31, 2012 and December 31, 2011

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Independent Auditor’s Report

To the Shareholders of
PowerStream Inc.

We have audited the accompanying financial statements of PowerStream Inc., which comprise the balance sheet as at December 31, 2012, December 31, 2011 and January 1, 2011, and the statement of income and comprehensive income, statement of changes in equity and statement of cash flows for the years ended December 31, 2012 and December 31, 2011, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of PowerStream Inc. as at December 31, 2012, December 31, 2011 and January 1, 2011, and its financial performance and its cash flows for the years ended December 31, 2012 and December 31, 2011, in accordance with International Financial Reporting Standards.

Deloitte LLP

Chartered Professional Accountants, Chartered Accountants
Licensed Public Accountants
April 24, 2013

PowerStream Inc.

Balance sheets

as at December 31, 2012, December 31, 2011 and January 1, 2011

(In thousands of dollars)

	December 31 2012	December 31 2011 (Note 23)	January 1, 2011 (Note 23)
	$	$	$
Assets			
Current assets			
Cash	**19,963**	-	8,568
Accounts receivable	**82,423**	86,556	70,468
Unbilled revenue	**96,387**	90,369	92,207
Due from related parties (Note 10)	**3,014**	2,173	2,435
Inventories	**2,946**	3,267	3,050
Prepaids and other assets	**3,835**	3,035	2,718
	208,568	185,400	179,446
Property, plant and equipment (Note 7)	**820,923**	719,194	662,446
Intangible assets (Note 8)	**12,849**	8,990	4,073
Investment in a joint venture (Note 5)	**8,243**	-	-
Deferred tax assets (Note 20)	**34,082**	41,621	46,286
Goodwill (Note 3(h) and Note 8)	**42,543**	42,543	42,543
	1,127,208	997,748	934,794
Liabilities			
Current liabilities			
Bank indebtedness	**-**	8,039	-
Short-term debt (Note 11)	**25,000**	40,000	40,000
Bank term loan (Note 12)	**50,000**	-	-
Notes Payable (Note 12)	**16,328**	-	-
Infrastructure Ontario financing (Note 11)	**6,612**	3,206	827
Customer deposits	**13,064**	13,035	13,549
Accounts payable and accrued liabilities (Note 9)	**113,660**	116,113	105,339
Due to related parties (Note 10)	**13,950**	13,275	14,649
Income taxes payable	**2,230**	3,446	6,622
Liability for subdivision development	**4,251**	3,185	5,370
Finance lease obligation (Note 16)	**295**	277	259
	245,390	200,576	186,615
Long-term liabilities			
Notes payable (Note 12)	**166,102**	182,430	182,430
Debentures payable (Note 12)	**198,189**	124,489	123,765
Bank term loan (Note 12)	**-**	50,000	50,000
Infrastructure Ontario debentures (Note 12)	**1,911**	980	-
Finance lease obligation (Note 16)	**17,107**	17,402	17,679
Post-employment benefits (Note 13)	**18,048**	16,811	15,685
Deferred revenue	**82,759**	56,166	23,364
Deferred tax liabilities (Note 20)	**1,730**	505	61
Other liabilities	**-**	-	160
	485,846	448,783	413,144
Shareholders' equity			
Share capital (Note 14)	**280,301**	251,957	249,618
Accumulated other comprehensive income	**(739)**	(739)	-
Retained earnings	**116,410**	97,171	85,417
	395,972	348,389	335,035
	1,127,208	997,748	934,794

Approved on behalf of the Board on April 24, 2013

Dale Scarpitti Director

[signature] Director

PowerStream Inc.

Statements of income and other comprehensive income years ended December 31 2012 and December 31, 2011

(In thousands of dollars)

	2012	2011 (Note 23)
	$	$
Revenue		
Sale of energy	**811,506**	760,285
Distribution revenue	**159,839**	154,305
Other revenue	**18,039**	14,482
Total revenue	**989,384**	929,072
Cost of power purchased	**800,958**	758,051
Operating expenses (Note 19)	**89,502**	76,668
Depreciation and amortization	**33,364**	34,426
	65,560	59,927
Share in profits from joint venture (Note 5)	**150**	-
Interest income	**1,293**	303
Interest expense	**24,392**	24,466
Income before income taxes	**42,611**	35,764
Income tax expense (Note 20)	**7,285**	10,153
Net income	**35,326**	25,611
Other comprehensive income		
Remeasurement of defined benefit obligation (Note 13)	**-**	(739)
Total income and other comprehensive income for the year	**35,326**	24,872

PowerStream Inc.

Statements of changes in equity
years ended December 31 2012 and December 31, 2011

(In thousands of dollars)

	Share Capital	Accumulated other comprehensive income	Retained earnings	Total
	$	$	$	$
As at January 1, 2011 (Note 23)	249,618	-	85,417	335,035
Net income	-	-	25,611	25,611
Other comprehensive income, (net of tax of $267)	-	(739)	-	(739)
Dividends paid	-	-	(13,857)	(13,857)
Issuance of Class A common shares (Note 14)	2,339	-	-	2,339
Balance at December 31, 2011 (Note 23)	**251,957**	**(739)**	**97,171**	**348,389**
Net income	-	-	35,326	35,326
Other comprehensive income, net of tax	-	-	-	-
Dividends paid	-	-	(16,087)	(16,087)
Issuance of Class A common shares (Note 14)	28,344	-	-	28,344
Balance at December 31, 2012	**280,301**	**(739)**	**116,410**	**395,972**

PowerStream Inc.

Statements of cash flows
years ended December 31 2012 and December 31, 2011
(In thousands of dollars)

	2012	2011 (Note 23)
	$	$
Operating activities		
Net income for the year	**35,326**	24,872
Adjustments to determine cash provided by operating activities:		
Share of income of joint venture	**(150)**	-
Depreciation of property, plant and equipment	**32,354**	33,906
Amortization of intangible assets	**2,825**	2,166
Post-employment benefits	**1,237**	1,126
Amortization of deferred revenue	**(1,164)**	(291)
Finance costs	**23,099**	24,163
Income tax expense (net of $267 allocated to 2011 OCI)	**7,285**	9,886
Loss on disposal of property, plant and equipment	**1,530**	942
	102,342	96,770
Net change in non-cash operating working capital (Note 21)	**(2,950)**	(8,380)
Cash generated from operating activities	**99,392**	88,390
Interest paid	**(23,369)**	(23,344)
Income tax received	**1,578**	-
Income taxes paid	**(1,458)**	(7,649)
Net cash generated from operating activities	**76,143**	57,397
Financing activities		
Dividends paid	**(16,087)**	(13,857)
Proceeds from Infrastructure Ontario financing	**4,337**	3,359
Proceeds from the issuance of Class A common shares	**28,344**	2,339
Proceeds from issuance of debenture	**198,175**	-
Repayment of debenture	**(125,000)**	-
Repayment of short-term debt	**(15,000)**	-
Payment of finance lease obligation	**(277)**	(259)
Net cash generated (used) in financing activities	**74,492**	(8,418)
Investing activities		
Contributions received from customers	**27,757**	33,093
Purchase of property, plant and equipment	**(135,613)**	(91,596)
Purchase of intangible assets	**(6,684)**	(7,083)
Acqusition of interest in joint venture	**(8,093)**	-
Net cash used in investing activities	**(122,633)**	(65,586)
Increase (decrease) in cash during the year	**28,002**	(16,607)
(Bank indebtedness) cash, beginning of year	**(8,039)**	8,568
Cash (bank indebtedness), end of year	**19,963**	(8,039)

1. Description of the business

PowerStream Inc. (the "Corporation") was amalgamated on January 1, 2009, under the Business Corporations Act (Ontario) and is owned by the Corporation of the City of Vaughan (the "City of Vaughan"), through its wholly owned subsidiary, Vaughan Holdings Inc.; the Corporation of the City of Markham (the "City of Markham"), through its wholly owned subsidiary, Markham Enterprises Corporation; and the Corporation of the City of Barrie (the "City of Barrie"), through its wholly owned subsidiary, Barrie Hydro Holdings Inc. The Corporation is jointly controlled by these three municipalities. The Corporation is incorporated and domiciled in Canada with its head and registered office located at 161 Cityview Boulevard, Vaughan, ON L4H 0A9.

The principal activity of the Corporation is distribution of electricity in the service area of Alliston, Aurora, Barrie, Beeton, Bradford West Gwillimbury, Markham, Penetanguishene, Richmond Hill, Thornton, Tottenham and Vaughan in the Province of Ontario, under a license issued by the Ontario Energy Board ("OEB"). The Corporation is regulated under the OEB and adjustments to the distribution rates require OEB approval. Collingwood PowerStream Utility Services ("Collus") which 50% of the shares were purchased by the Corporation in 2012 distributes electricity in Collingwood, Thornbury, Stayner and Creemore.

As a condition of its distribution license, the Corporation is required to meet specified Conservation and Demand Management ("CDM") targets for reductions in electricity consumption and peak electricity demand. As part of this initiative, the Corporation is delivering Ontario Power Authority ("OPA") funded programs in order to meet its targets.

Under the Green Energy and Green Economy Act, 2009, the Corporation and other Ontario electricity distributors have new opportunities and responsibilities for enabling renewable generation.
The Corporation has commenced operations of a Solar Generation Business unit, in 2010, as permitted by these changes.

2. Basis of preparation

(a) Statement of compliance

These financial statements are the first annual financial statements of the Corporation prepared in accordance with International Financial Reporting Standards ("IFRS") and IFRS 1 *First-time Adoption of International Financial Reporting Standards* ("IFRS 1") has been applied. An explanation of how the transition to IFRS has affected the reported financial position, financial performance and cash flows of the Corporation is provided in note 23.

(b) Basis of measurement

The financial statements have been prepared on a historical cost basis.

(c) Presentation currency

The financial statements are presented in Canadian dollars, which is also the Corporation's functional currency. All financial information has been rounded to the nearest thousand, except when otherwise noted.

(d) Use of estimates and judgments

The preparation of financial statements in conformity with IFRS requires management to make estimates, assumptions and judgments that affect the application of accounting policies and the amounts reported and disclosed in the financial statements. Estimates and underlying assumptions are continually reviewed and are based on historical experience and other factors that are considered to be relevant. Actual results may differ from these estimates.

2. Basis of preparation (continued)

(d) Use of estimates and judgments (continued)

Significant sources of estimation uncertainty include the following:

(i) Unbilled revenue

The measurement of unbilled revenue is based on an estimate of the amount of electricity delivered to customers between the date of the last bill and the end of the year.

(ii) Useful lives of depreciable assets.

Depreciation and amortization expense is based on estimates of the useful lives of property, plant and equipment and intangible assets. The Corporation estimates the useful lives of its property, plant and equipment and intangible assets based on management's judgment, historical experience and an asset study conducted by an independent consulting firm.

(iii) Cash Generating Units (CGU)

Determining whether a CGU is impaired requires an estimation of the value in use. The value in use calculation requires the Corporation to estimate the future cash flows expected to arise from the CGU and a suitable discount rate in order to calculate the present value.

(iv) Valuation of financial instruments

As described in Note 17, the Corporation uses the discounted cash flow model to estimate the fair value of the financial instruments for disclosure purposes. Valuation of financial instruments uses the same estimation techniques as determining the value in use for CGUs as noted above.

(v) Other Areas

There are a number of other areas in which the Corporation makes estimates; these include accounts receivable, inventories, employee future benefits and income taxes. These amounts are reported based on the amounts expected to be recovered/refunded and an appropriate allowance has been provided based on the Corporation's best estimate of unrecoverable amounts.

3. Significant accounting policies

The Corporation's financial statements are the representations of management prepared in accordance with IFRS. The accounting policies set out below have been applied consistently to all years presented in these financial statements and in preparing the opening IFRS balance sheet at January 1, 2011 for the purposes of the transition to IFRS, unless otherwise indicated.

The financial statements reflect the following significant accounting policies:

(a) Rate regulation

The Ontario Energy Board Act, 1998 gave the OEB increased powers and responsibilities to regulate the electricity industry. These powers and responsibilities include the power to approve or fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers and the responsibility for ensuring that distribution companies fulfill obligations to connect and service customers. The OEB may prescribe license requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, and filing process requirements for rate-setting purposes.

The Corporation recognizes revenue when electricity is delivered to customers based on OEB approved rates. Operating costs and expenses are recorded when incurred, unless such costs qualify for recognition as part of an item of property, plant and equipment or as an intangible asset.

3. Significant accounting policies (continued)

(b) Revenue recognition

(i) Electricity distribution and sale

Revenue from the sale and distribution of electricity is recorded on the basis of cyclical billings based on electricity usage and also includes unbilled revenue accrued in respect of electricity delivered but not yet billed. Revenue is generally comprised of the following:

- Electricity Price and Related Rebates. The electricity price and related rebates represent a pass through of the commodity cost of electricity.
- Distribution Rate. The distribution rate is designed to recover the costs incurred by the Corporation in delivering electricity to customers, as well as the ability to earn the OEB allowed rate of return. Distribution charges are regulated by the OEB and typically comprise a fixed charge and a usage-based (consumption) charge.
- Retail Transmission Rate. The retail transmission rate represents a pass through of costs charged to the Corporation for the transmission of electricity from generating stations to the Corporation's service area. Retail transmission rates are regulated by the OEB.
- Wholesale Market Service Charge. The wholesale market service charge represents a pass through of various wholesale market support costs charged by the Independent Electricity System Operator ("IESO").

(ii) Other revenue

Other revenue includes revenue from the sale of other services, contributions from customers and performance incentive payments.

Revenue related to the sale of other services is recognized as services are rendered.

Certain items of property, plant and equipment are acquired or constructed with financial assistance in the form of contributions from developers or customers ("customer contributions"). Such contributions, whether in cash or in-kind, are recognized as deferred revenue and amortized into income over the life of the related assets. Contributions in-kind are valued at their fair value at the date of their contribution.

Performance incentive payments under CDM programs are recognized by the Corporation when there is reasonable assurance that the program conditions have been satisfied and the incentive payment will be received.

Government grants under CDM programs are recognized when there is reasonable assurance that the grant will be received and all attached conditions will be complied with. When the grant relates to an expense item, it is recognized as income over the period necessary to match the grant on a systematic basis to the costs that it is intended to compensate.

(c) Finance costs

Finance costs comprise interest expense on borrowings.

Borrowing costs are calculated using the effective interest rate method and are recognized as an expense unless they are capitalized as part of the cost of a qualifying asset, which is an asset that takes a substantial period of time to get ready for its intended use.

3. Significant accounting policies (continued)

(d) Financial instruments

Financial assets and financial liabilities are initially recognized at fair value and are subsequently accounted for based on their classification as loans and receivables or as other liabilities. Transaction costs for financial assets classified as loans and receivables and financial liabilities classified as other liabilities are capitalized as part of the carrying value at initial recognition.

(i) *Loans and receivables*

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. Subsequent to initial recognition, such financial assets are carried at amortized cost using the effective interest rate method, less any impairment losses. Losses are recognized in net income when the loans and receivables are derecognized or impaired.

Loans and receivables are assessed at each reporting date to determine whether there is objective evidence of impairment. A financial asset is impaired if objective evidence indicates that a loss event has occurred after the initial recognition of the asset and the loss event has had a negative effect on estimated future cash flows of the asset which are reliably measureable.

Loans and receivables are comprised of cash, accounts receivable, unbilled revenue and amounts due from related parties.

(ii) *Other liabilities*

All non-derivative financial liabilities are classified as other liabilities. Subsequent to initial recognition, other liabilities are measured at amortized cost using the effective interest method.

Financial liabilities are derecognized when either the Corporation is discharged from its obligation, the obligation expires, or the obligation is cancelled or replaced by a new financial liability with substantially modified terms.

Financial liabilities are further classified as current or non-current depending on whether they will fall due within twelve months after the balance sheet date or beyond.

Other liabilities are comprised of bank indebtedness, short-term debt, Infrastructure Ontario financing, customer deposits, accounts payable and accrued liabilities, amounts due to related parties, notes payable, debentures payable, bank term loan, Infrastructure Ontario debentures, and liability for subdivision development.

(e) Inventories

Inventories, which consist of parts and supplies acquired for internal construction or consumption, are valued at the lower of cost and net realizable value. Cost is determined on a weighted-moving average basis and includes expenditures incurred in acquiring the inventories and other costs to bring the inventories to their existing location and condition.

(f) Property, plant and equipment

Property, plant and equipment (“PP&E”) used in rate-regulated activities and acquired prior to January 1, 2011 is measured at deemed cost at date of transition (see Note 23(b)(ii)) less accumulated depreciation. All other PP&E is measured at cost less accumulated depreciation. Cost includes expenditures that are directly attributable to the acquisition of the asset and includes contracted services, cost of materials, direct labour, overhead costs and borrowing costs incurred in respect of qualifying assets constructed subsequent to January 1, 2011. When parts of an item of PP&E have different useful lives, they are accounted for as separate components of PP&E.

Major spare parts and standby equipment are recognized as items of PP&E.

(In thousands of dollars)

3. Significant accounting policies (continued)

(f) Property, plant and equipment (continued)

When items of PP&E are retired or otherwise disposed of, a gain or loss on disposal is determined by comparing the proceeds from disposal with the carrying amount of the item and is included in net income.

Depreciation of PP&E is recognized on a straight-line basis over the estimated useful life of each component of PP&E. The estimated useful lives for the current and comparative years are as follows:

Land	Indefinite
Buildings	10 to 60 years
Transformer stations	20 to 40 years
Transformers and meters	15 to 40 years
Plant and equipment	3 to 20 years
Other	3 to 37.5 years

Depreciation methods and useful lives are reviewed at each financial year-end and any changes are adjusted prospectively.

(g) Intangible assets

Intangible assets include land rights, computer software and capital contributions. Capital contributions relate to the contributions made to Hydro One for a transformer station that was built outside the City of Barrie.

Land rights held by the Corporation are effective in perpetuity and there is no foreseeable limit to the period over which the rights are expected to provide benefit to the Corporation. Land rights have therefore been assessed as having an indefinite useful life and are not amortized.

Land rights used in rate-regulated activities and acquired prior to January 1, 2011 are measured at deemed cost. All other land rights are measured at cost.

Computer software and capital contributions used in rate-regulated activities and acquired prior to January 1, 2011 are measured at deemed cost less accumulated amortization. All other ccomputer software and capital contributions are measured at cost less accumulated amortization.

Computer software and capital contributions are amortized on a straight-line basis over the estimated useful lives from the date that they are available for use. The estimated useful lives for the current and comparative periods are as follows:

Computer software	4 years
Capital contributions	37.5 years

Amortization methods and useful lives are reviewed at each financial year-end and adjusted prospectively.

(h) Goodwill

Goodwill represents the excess of the purchase price over the fair value assigned to the Corporation's interest of the net identifiable assets acquired on the acquisition, by predecessor corporations, of the former Richmond Hill Hydro Inc., Penetanguishene Hydro, Essa Hydro, New Tecumseth Hydro and Bradford West Gwillimbury Hydro.

Goodwill is measured at cost and is not amortized. The company's policy on goodwill arising on acquisition of an associate is described in note 3(n) below.

3. Significant accounting policies (continued)

(i) Impairment of non-financial assets

The carrying amounts of the Corporation's non-financial assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. Goodwill and intangible assets with indefinite lives are tested annually for impairment and when circumstances indicate that the carrying value may be impaired. An impairment loss is recognized if the carrying amount of an asset or CGU exceeds its recoverable amount.

The Corporation has two CGU's, the rate regulated business and the Permitted Generation Business unit. Two CGU's were determined as Management views the Corporation as having two distinct lines of business.

The recoverable amount of an asset or CGU is the greater of its value in use and fair value less costs to sell. Value in use is calculated as the present value of the estimated future cash flows expected to be derived from an asset or CGU.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows that are largely independent of those from other assets or CGUs. Goodwill acquired in a business combination is allocated to groups of CGUs that are expected to benefit from the synergies of the combination.

Impairment losses are recognized in net income. Impairment losses relating to CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the CGUs and then to reduce the carrying amounts of the other assets in the CGUs on a pro rata basis.

An impairment loss in respect of goodwill is not reversed. In respect of other assets, an impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

(j) Employee benefits

The Corporation provides both short-term employee benefits and post-employment benefits. The post-employment benefits are provided through a defined benefit plan.

A defined benefit plan is a post-retirement benefit plan that specifies either the benefits to be received by an employee, or the method of determining those benefits.

(i) Short-term employee benefits

Short-term employee benefit obligations are recognized as the related services are rendered to the Corporation. Short-term employee benefit obligations are measured on an undiscounted basis and recognized as an expense unless the amount qualifies for capitalization as part of the cost of an item of inventory, PP&E or an intangible asset.

(ii) Multi-employer defined benefit plan

The Corporation provides a pension plan to its full-time employees through the Ontario Municipal Employees Retirement System ("the OMERS plan"). The OMERS plan is a multi-employer defined benefit plan which provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. The OMERS plan is financed by equal contributions from participating employers and employees, and by the investment earnings of the fund.

3. Significant accounting policies (continued)

(j) Employee benefits (continued)

(ii) Multi-employer defined benefit plan (continued)

It is not practicable to determine the present value of the Corporation's obligation or the related current service cost under the OMERS plan as OMERS computes its obligations in accordance with an actuarial valuation in which all the benefit plans are co-mingled and therefore information for individual plans cannot be determined. As a result, the Corporation accounts for the OMERS plan as a defined contribution plan where contributions to the OMERS plan are recognized as an employee benefit expense in the periods during which services are rendered by employees.

(iii) Non-pension defined benefit plans

The Corporation provides certain health, dental and life insurance benefits under unfunded defined benefit plans to its eligible retired employees (the "defined benefit plans").

The Corporation's net obligation in respect of the defined benefit plans is calculated by estimating the amount of future benefit that employees have earned in return for their service in the current and prior periods. The calculated benefit is discounted to determine its present value. The discount rate is the yield at the reporting date on AA credit-rated bonds that have maturity dates approximating the terms of the Corporation's obligations and that are denominated in the same currency in which the benefits are expected to be paid. The calculation of the defined benefit obligation is performed by an independent qualified actuary using the projected unit credit method.

Remeasurement of the net defined benefit liability, which is comprised of actuarial gains and losses, is recognized immediately in the balance sheet with a charge or credit to other comprehensive income in the year in which they occur.

Past service costs arising from plan amendments is recognized immediately in net income at the earlier of the date the plan amendment occurs or when any related restructuring costs or termination benefits are recognized.

(k) Customer deposits

Customer deposits are collections from customers to guarantee the payment of energy bills. Deposits that are refundable to customers on demand are classified as a current liability. Interest is paid on customer deposits.

(l) Leases

Leases in which the Corporation assumes substantially all of the risks and rewards of ownership are classified as finance leases. On initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset. Payments under finance leases are apportioned between interest expense and a reduction of the outstanding liability.

Other leases are operating leases and are not recognized in the Corporation's balance sheet. Payments made under operating leases are recognized as an expense on a straight-line basis over the term of the lease.

3. Significant accounting policies (continued)

(m) Payment in lieu of corporate income taxes ("PILs")

Under the Electricity Act, 1998, the Corporation is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). The payments in lieu of taxes are calculated on a basis as if the Corporation was a taxable company under the Income Tax Act (Canada).

Income tax expense comprises current and deferred tax and is recognized in net income except to the extent that it relates to items recognized directly in other comprehensive income.

Current tax is the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized, using the liability method, on temporary differences arising between the carrying amount of balance sheet items and their corresponding tax basis, using the substantively enacted income tax rates for the years in which the differences are expected to reverse.

In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill.

A deferred tax asset is recognized for deductible temporary differences, to the extent that it is probable that future taxable income will be available against which they can be utilized.

(n) Investments in joint ventures

A joint venture is a contractual arrangement whereby two or more parties undertake an economic activity that is subject to joint control. The Corporation owns 50% of Collus. This investment is accounted for using the equity method and is recognized initially at cost.

Any excess cost over the acquisition of the Corporations share of the net fair value of the identifiable assets and liabilities of Collus is recognized as goodwill and included in the carrying value of the investment.

If Collus is in a loss position, then when the Corporation's share of losses in Collus equals or exceeds its interest, the Corporation would discontinue recognizing its share of further losses.

The financial statements include the Corporation's share of the income of Collus, from the purchase date being July 31, 2012.

4. Changes in accounting policies

Future accounting changes

There are new standards, amendments to standards and interpretations which have not been applied in preparing these financial statements. In particular, this includes IFRS 9 *Financial Instruments* which is effective from periods beginning on or after January 1, 2015, IFRS 13 *Fair Value Measurement* which is effective for periods beginning on or after January 1, 2013, and amendments to IFRS 7 and IFRS 9 which are effective at the date of adoption of IFRS 9.

All of the above standards or amendments relate to the measurement and disclosure of financial assets and liabilities. The extent of the impact on adoption of these standards and amendments has not yet been determined.

(In thousands of dollars)

5. Investment in a joint venture

In 2012 the Corporation acquired a 50% interest in Collus, a joint venture of which the Corporation has joint control. The cost of the investment includes transaction costs and the share of Collus net income amounting to $8,243.

Collus is involved in the distribution of electricity in Collingwood, Thornbury, Stayner and Creemore as well as the provision of other utility services in the service area of Clearview and the Town of The Blue Mountains in the Province of Ontario. Collus' principal place of business is the Town of Collingwood.

The following judgments were used in determining that the investment was a joint venture:

- Joint control was established by assessing that both the Corporation and the City of Collingwood have unanimous consent over key transactions within Collus. This was done through the agreements that were signed.
- This classification of the investment in Collus as a joint venture was determined through analysis of the rights and obligations of the investment, specifically the legal structure.

Summarized financial information for Collus follows. There were no significant restrictions from borrowing arrangements or any commitments incurred on behalf of Collus in relation to the Corporation.

	2012
	$
Total Assets	**26,982**
Total Liabilities	**19,789**
Net Revenue	**7,323**
Total income and other comprehensive income	**300**
Share of income and other comprehensive income	**150**

6. Inventories

During fiscal 2012, an amount of $34 (2011 - $109) was recorded as an expense for the write-down of obsolete or damaged inventory to net realizable value.

(In thousands of dollars)

7. Property, plant and equipment

	Land and Buildings	Distribution and Other Assets	Construction Work -in-Progress		Total
	$	$	$		$
Cost or deemed cost					
Balance at January 1, 2011	56,410	579,564	26,472		662,446
Additions	1,050	94,630	(1,526)		94,154
Transfers to Intangibles	-	(1,795)	-		(1,795)
Disposals	-	(3,627)	-		(3,627)
Balance at December 31, 2011	57,460	668,772	24,946		751,178
Additions	7724	88,740	39,150		135,614
Adjustments		1,953	-		1,953
Disposals		(1,638)	-		(1,638)
Balance at December 31, 2012	**65,184**	**757,827**	**64,096**		**887,107**
Accumulated depreciation					
Balance at January 1, 2011	-	-	-		-
Depreciation expense	1,110	32,796	-		33,906
Adjustments	-	-	-		-
Disposals	-	(1,922)	-		(1,922)
Balance at December 31, 2011	1,110	30,874	-		31,984
Depreciation expense	1,124	31,230	-		32,354
Adjustments	-	1,953	-		1,953
Disposals	-	(107)	-		(107)
Balance at December 31, 2012	**2,234**	**63,950**	**-**		**66,184**
Carrying amounts					
At January 1, 2011	56,410	579,564	26,472	-	662,446
At December 31, 2011	56,350	637,898	24,946	-	719,194
At December 31, 2012	**62,950**	**693,877**	**64,096**	**-**	**820,923**

Included in PP&E costs is $13,639 (2011 - $12,235) of operating expenses and $778 (2011 - $303) of interest capitalized during the year. These costs have been capitalized at a rate of 5.2% (2011 – 5.63%).

The Corporation leases its operations centre under a finance lease agreement. The leased operations centre secures the lease obligation. At December 31, 2012 the net carrying amount of the operations centre was $16,086 (2011 - $16,818; January 1, 2011 - $17,549).

(In thousands of dollars)

8. Intangible assets and goodwill

(a) Intangible assets

	Land Rights	Computer Software	Capital Contributions	Total
	$	$	$	$
Cost or deemed cost				
Balance at January 1, 2011	730	2,731	612	4,073
Additions	35	5,256	(3)	5,288
Transfers from PP&E	-	1,795	-	1,795
Disposals	-	-	-	-
Balance at December 31, 2011	765	9,782	609	11,156
Additions	32	2,289	4,363	6,684
Transfers	-	-	-	-
Disposals	-	-	-	-
Balance at December 31, 2012	**797**	**12,071**	**4,972**	**17,840**
Accumulated amortization				
Balance at January 1, 2011	-	-	-	-
Amortization expense	-	2,137	29	2,166
Disposals	-	-	-	-
Balance at December 31, 2011	-	2,137	29	2,166
Amortization expense		2,537	288	2,825
Disposals	-	-	-	-
Balance at December 31, 2012	**-**	**4,674**	**317**	**4,991**
Carrying amounts				
At January 1, 2011	730	2,731	612	4,073
At December 31, 2011	765	7,645	580	8,990
At December 31, 2012	**797**	**7,397**	**4,655**	**12,849**

(b) Impairment testing of goodwill and indefinite life intangible assets

For the purpose of impairment testing, goodwill with a carrying amount of $42,543 (2011 - $42,543; January 1, 2011 – $42,543) and land rights with a carrying amount of $797 (2011 - $765; January 1, 2011 - $730) are allocated to the Corporation's rate-regulated CGU. The Corporation tested goodwill and land rights for impairment as at December 31, 2012, December 31, 2011 and at January 1, 2011 in accordance with its policy described in Note 3.

The recoverable amount of the rate-regulated CGU was determined based on its value-in-use. The Corporation has used discounted cash flow analysis to determine value in use. The value-in-use was determined in the same manner at December 31, 2012, December 31, 2011 and January 1, 2011.

(In thousands of dollars)

8. Intangibles assets and goodwill (continued)

(b) Impairment testing of goodwill and indefinite life intangible asset (continued)

The calculation of value in use for the rate regulated CGU was based on the following key assumptions:

- Cash flows were projected based on past experience and actual operating results using a 5 year forecast with growth rates of 2.5% (2011 - 2.5%, January 1, 2011 – 2.5%) built into the forecast. Growth rates were determined using the Bank of Canada inflation forecast.
- A pre-tax discount rate of 6.30% (2011- 6.77%, January 1, 2011 – 7.22%) and terminal value was used to discount the cash flows, this is derived from the Weighted Average Cost of Capital calculation. A discount rate increase of 1.6% would result in the carrying amount of the rate regulated CGU exceeding the recoverable amount by $3 million.

The calculation of value in use for the Permitted Generation Business unit CGU was based on the following key assumptions:

- Cash flows were projected based on past experience and actual operating results using a 5 year forecast with growth rates of 2.5% (2011 - 2.5%, January 1, 2011 – 2.5%) built into the forecast. Growth rates were determined using the Bank of Canada inflation forecast.
- A pre-tax discount rate of 9.18% (2011 - 8.58%, January 1, 2011 – 8.93%) and terminal value was used to discount the cash flows, this is derived from the Weighted Average Cost of Capital calculation. A discount rate increase of 4% would result in the carrying amount of the Permitted Generation Business unit CGU exceeding the recoverable amount by $5 million.

9. Accounts payable and accrued liabilities

	2012	2011	January 1, 2011
	$	$	$
Accounts payable - energy purchases	**58,480**	60,133	59,689
Debt retirement charge payable - OEFC	**4,319**	4,131	4,340
Payroll payable	**4,963**	5,125	5,120
Interest payable	**3,420**	3,089	3,089
Commodity taxes payable	**(1,395)**	2,757	1,967
Customer receivables in credit balances	**3,456**	4,415	8,263
Other accounts payable and accrued liabilities	**40,417**	36,463	22,871
	113,660	116,113	105,339

10. Related party balances and transactions

(a) Transactions with jointly controlling shareholders

The amount due to / (from) related parties is comprised of amounts payable to / (receivable from) the City of Vaughan, the City of Markham and the City of Barrie and their wholly-owned subsidiaries.

(In thousands of dollars)

10. Related party balances and transactions (continued)

(a) Transactions with jointly controlling shareholders (continued)

Components of the amounts due to / (from) related parties are as follows:

	2012	2011	January 1, 2011
	$	$	$
Due from:			
City of Vaughan	**673**	648	538
City of Markham	**1,483**	789	950
City of Barrie	**858**	736	947
	3,014	2,173	2,435
Due to:			
City of Vaughan	**6,523**	6,360	5,957
City of Markham	**7,145**	6,633	6,023
City of Barrie	**282**	282	2,669
	13,950	13,275	14,649

Other significant related party transactions with the jointly controlling shareholders not otherwise disclosed separately in the financial statements, are summarized below:

		2012			2011	
	City of Vaughan	**City of Markham**	**City of Barrie**	City of Vaughan	City of Markham	City of Barrie
	$	**$**	**$**	$	$	$
Revenue						
Energy and distribution	**5,527**	**7,741**	**6,746**	5,079	5,905	6,316
Shared services	**1,781**	**2,791**	**-**	1,725	2,323	652
Total Revenue	**7,308**	**10,532**	**6,746**	6,804	8,228	6,968
Expenses						
Realty taxes	**661**	**456**	**283**	748	410	290
Facilities rental and other	**29**	**19**	**12**	211	37	41
Total	**6,618**	**10,057**	**6,451**	5,845	7,781	6,637

These transactions are in the normal course of operations and are recorded at the exchange amount. The Corporation has certain operating leases with the City of Vaughan, City of Markham and City of Barrie to lease rooftops on a number of buildings for which feed-in tariff contracts have been obtained. The current year lease expense has been included in the ‘Facilities rental and other’ line on the table above, and the future operating lease commitments have been disclosed in Note16.

(In thousands of dollars)

10. Related party balances and transactions (continued)

(b) Key management personnel compensation

Key management personnel are comprised of the Corporation's senior management team. The compensation paid or payable to key management personnel is as follows:

	2012	2011
	$	$
Short-term employment benefits and salaries	**7,526**	6,646
Post-employment benefits	**2**	2
Termination benefits	**178**	185
	7,706	6,833

11. Short-term debt

(a) Credit facilities

On December 17, 2008 the Corporation executed an unsecured credit facility with a Canadian chartered bank. The credit facility is renewable annually. The credit facility agreement provides an extendible 364-day committed revolving credit facility of $75,000, an uncommitted demand facility of $25,000 for a specific purpose, and an uncommitted Letter of Guarantee facility of $15,000.

As at December 31, 2012, the Corporation had utilized $14,999 (2011 - $12,484, January 1, 2011 - $12,484) of the uncommitted Letter of Guarantee facility for a letter of credit that was provided to the IESO to mitigate the risk of default on energy payments. With the opening of Ontario's electricity market to wholesale and retail competition on May 1, 2002 ("Open Access"), the IESO requires all purchasers of electricity in Ontario to provide security to mitigate the risk of their default based on their expected purchases from the IESO administered spot market. The IESO could draw on the letter of credit if the Corporation defaults on its payment. Further, as at December 31, 2012, an additional $450 (2011 - $555, January 1, 2011 - $444) of the uncommitted Letter of Guarantee facility was utilized as security for operation projects.

The 364-day committed revolving credit facility can be drawn upon by direct advances, bearing interest at the lower of prime plus 0.15% or Bankers' Acceptance of a stamping fee plus 110 basis points (1.10% per annum). The uncommitted demand facility bears an interest rate at the lower of prime minus 0.10% or Bankers' Acceptance of a stamping fee plus 85 basis points (0.85% per annum). The Letter of Guarantee facility bears a charge of 50 basis points (0.50%) per annum.

The amount of short-term debt drawn on the credit facilities consists of:

	2012	2011	January 1, 2011
	$	$	$
364-day committed revolving credit facility	**-**	15,000	15,000
Uncommitted demand facility	**25,000**	25,000	25,000
	25,000	40,000	40,000

(In thousands of dollars)

11. Short-term debt (continued)

(b) Ontario Infrastructure and Lands Corporation ("Infrastructure Ontario") financing

On October 15, 2010 the Corporation secured financing with Infrastructure Ontario for its Permitted Generation Business unit. The funding is available for up to 5 years from the date that the agreement was signed.

As at December 31, 2012, the Corporation has utilized $8,523 (2011 - $4,186, January 1, 2011 - $827) of the $90,000 financing facility, of which $1,911 (2011 – $980, January 1, 2011 – Nil) was transferred to a long-term debenture. Each advance bears interest at a floating rate per annum as determined by Infrastructure Ontario. The advance interest rate at December 31, 2012 was 1.74% and interest expense for the year was $13.

The Corporation will pay Infrastructure Ontario a stand-by fee calculated at a rate of 25 basis points (0.25%) on the unadvanced balance of the committed amount should the Corporation fail to draw any funds pursuant to the agreement from Infrastructure Ontario during any period of 12 consecutive months commencing initially from October 15, 2010 and subsequently from the date of the draw of any such funds until the earlier of the facility termination date October 15, 2015 or the full advance of the committed amount. Infrastructure Ontario financing is secured by the assets of the Permitted Generation Business unit. The financial covenants require a debt service coverage ratio of 1:1 or higher, a debt to capital ratio of 70% or lower, and a current ratio of 1:1 or higher. See Note 18 on the compliance of the covenant.

12. Long-term debt

(a) Bank term loan

The bank term loan of $50,000 (2011 - $50,000, January 1, 2011 - $50,000) is a 5 year fixed rate term loan with a Canadian Chartered Bank which bears interest at an annual rate of 5.08%. It is a non-amortizing loan with repayment at the end of the contracted term, February 26, 2013. The financial covenants require a total debt to capitalization ratio of no greater than 0.60:1, and to maintain an interest coverage ratio of no less than 1.25:1. See Note 18 on the compliance of the covenant.

(b) Debentures payable

	2012	2011	January 1, 2011
	$	$	$
6.45% unsecured debentures due August 15, 2012, interest payable in arrears semi-annually on August 15 and February 15	**-**	124,489	123,765
3.958% unsecured debentures due July 30, 2042, interest payable in arrears semi-annually on January 30 and July 30	**198,189**	-	-
	198,189	124,489	123,765

In August 2012 the Corporation repaid the Electricity Distributors Finance Corporation ("EDFIN") debenture upon its maturity in the amount of $125,000.

In July 2012 the Corporation raised gross proceeds of $200,000 (net of transaction costs of $1,811) through a private placement offering. The debentures rank *pari passu* with all of the Corporation's other senior unsubordinated and unsecured obligations.

(In thousands of dollars)

12. Long-term debt (continued)

(b) Debentures payable (continued)

The debentures are subject to a financial covenant. This covenant requires that neither the Corporation nor any designated subsidiary may incur any funded obligation (other than non-recourse debt, capital lease obligations, intercompany indebtedness and purchase money obligations) unless the aggregate principal amount of the consolidated funded obligations does not exceed 75% of the total consolidated capitalization. As at December 31, 2012 the Corporation is in compliance with this covenant.

(c) Notes payable

	2012	2011	January 1, 2011
	$	$	$
Promissory note issued to the City of Vaughan	**78,236**	78,236	78,236
Deferred interest on promissory note issued to the City of Vaughan	**-**	8,743	8,743
Promissory note issued to the City of Markham	**67,866**	67,866	67,866
Deferred interest on promissory note issued to the City of Markham	**-**	7,585	7,585
Promissory note issued to the City of Barrie	**20,000**	20,000	20,000
Total long term notes payable	**166,102**	182,430	182,430
Less current portion:			
Deferred interest on promissory note issued to the City of Vaughan	**8,743**	-	-
Deferred interest on promissory note issued to the City of Markham	**7,585**	-	-
Total current notes payable	**16,328**	-	-
Total notes payable	**182,430**	-	-

On June 1, 2004 an unsecured 20 year term promissory note was issued to the City of Vaughan in the amount of $78,236. Interest thereon commenced on June 1, 2004 at an annual rate of 5.58%.

On June 1, 2004 an unsecured 20 year term promissory note was issued to the City of Markham in the amount of $67,866. Interest thereon commenced on June 1, 2004 at an annual rate of 5.58%.

On December 31, 2008, an unsecured 16 year term promissory note was issued to the City of Barrie in the amount of $20,000. Interest thereon commenced on January 1, 2009 is at an annual rate of 5.58%.

The three promissory notes are repayable 90 days following demand by the City of Vaughan, the City of Markham, and the City of Barrie, with subordination and conditions. These notes have been classified as long-term as it is not the intent of the City of Vaughan, the City of Markham, or the City of Barrie to demand repayment before January 1, 2014.

At the request of the City of Vaughan and the City of Markham, eight quarters of interest have been deferred commencing October 1, 2006. This deferred interest will be repayable in full on October 31, 2013 and is subject to the same interest rate and conditions as the original note.

12. Long-term debt (continued)

(d) Infrastructure Ontario debentures

As at December 31, 2012, the Corporation had transferred $1,911 (2011 - $980; January 1, 2011 - $Nil) of the construction financing it has accessed from Infrastructure Ontario into long-term debt.

A note in the amount of $980 bears interest at a rate of 4.09% per annum payable on May 15 and November 15 each year and matures on November 17, 2031.

A note in the amount of $931 bears interest at a rate of 3.54% per annum payable on February 15 and August 15 each and matures on August 1, 2032.

13. Post-employment benefits

(a) Multi-employer defined benefit plan

During fiscal 2012, the expense recognized in conjunction with the OMERS plan, which is equal to contributions due for the year was $4,591 (2011 - $3,714). At December 31, 2012, $698 (2011 - $633; January 1, 2011 - $532) of contributions were payable to the OMERS plan and were included in accounts payable and accrued liabilities on the balance sheet.

As at December 31, 2012, OMERS had approximately 420,000 members, of whom approximately 533 are current employees of the Corporation. The accrued benefit obligation of the OMERS plan as shown in OMERS financial statements as at December 31, 2012 is $69,122 million, with a funding deficit of $9,924 million. The funding deficit will result in future payments by the participating employers.

The Corporation shares in the actuarial risks of the other participating entities in the OMERS plan and its future contributions may therefore be increased due to actuarial losses relating to the other participating entities. In addition, the withdrawal of other participating entities from the OMERS plan may also result in an increase to the Corporation’s future contribution requirements.

(In thousands of dollars)

13. Post-employment benefits (continued)

(b) Non-pension defined benefit plans

A reconciliation of the obligation for the defined benefit plans is as follows:

	2012	2011
	$	$
Defined benefit obligation, beginning of the year	**16,811**	15,685
Amounts recognized in net income:		
Current service cost	**1,051**	992
Interest expense	**744**	745
Past service cost and gains/losses arising from settlements	**-**	(1,298)
	1,795	439
Amounts recognized in other comprehensive income:		
Remeasurement of defined benefit obligation:		
Actuarial gains/losses arising from changes in demographic assumptions	**-**	-
Actuarial gains/losses arising from changes in financial assumptions	**-**	1,006
	-	1,006
Payments from the plan	**(558)**	(319)
Defined benefit obligation, end of the year	**18,048**	16,811

Actuarial gains and losses recognized in other comprehensive income for 2012 nil (2011 - $1,006) include a tax amount of 2012 nil (2011 - $267) and thus are presented on a net basis in other comprehensive income as 2012 nil (2011 - $739).

The obligation for the defined benefit plans is presented in the balance sheet as post-employment benefits.

The significant actuarial assumptions used to determine the present value of the obligation for the defined benefit plans are as follows:

	2012	2011
	%	%
Discount rate	**4.50**	4.50
Rate of compensation increase	**3.50**	3.50
Medical benefits costs escalation	**5.00 - 7.63**	5.00 - 8.00
Dental benefits costs escalation	**5.00**	5.00

(In thousands of dollars)

14. Share capital

The Corporation's authorized share capital is made up of an unlimited number of common shares, and an unlimited number of Class A non-voting common shares, all of which are without nominal or par value.

The share capital issued and outstanding during the period is as follows:

	Common shares		Class A common shares		Total
	Shares	$	Shares	$	$
Balance at January 1, 2011	100,000	247,183	4,056	2,435	249,618
Issued for cash	-	-	3,899	2,339	2,339
Balance at December 31, 2011	100,000	247,183	7,955	4,774	251,957
Issued for cash	-	-	47,240	28,344	28,344
Balance at December 31, 2012	**100,000**	**247,183**	**55,195**	**33,118**	**280,301**

Of the total 100,000 common shares issued, 45,315 common shares are registered under Vaughan Holdings Inc., 34,185 common shares are registered under Markham Enterprises Corporation and 20,500 common shares are registered under Barrie Hydro Holdings Inc.

On November 23, 2010 a Subscription Agreement was signed between the Corporation and its Shareholders for new Class A common shares for the purposes of the Shareholders providing equity for the Corporation's Permitted Generation Business unit. The articles of incorporation and shareholders agreement were amended in order to proceed with the subscription agreement. This Subscription Agreement expired on December 31, 2011 and as such, a revised Subscription Agreement was signed between the Corporation and its Shareholders on January 1, 2012 to extend the equity financing in respect of the Corporation's Permitted Generation Business unit.

The maximum amount of Class A common shares that are available under the subscription agreement is 100,000. During the year, an additional 47,240 (2011 – 3,899) of the Class A common shares were issued under the subscription agreement for an amount of $28,344 (2011 - $2,339).

Of the total 55,195 (2011 – 7,955) Class A common shares issued, 25,011 (2011 – 3,604) Class A common shares are registered under Vaughan Holdings Inc., 18,869 (2011 – 2,720) Class A common shares are registered under Markham Enterprises Corporation and 11,315 (2011 – 1,631) Class A common shares are registered under Barrie Hydro Holdings Inc.

Dividends

The Corporation has established a dividend policy to pay a minimum of 50% of Modified IFRS ("MIFRS", framework used for reporting to the OEB) net income, excluding the Permitted Generation Business unit income, with consideration given to the following:

- Cash position at the beginning of the current year;
- Working capital requirements for the current year; and
- Net capital expenditures required for the current year.

The Corporation paid a dividend of $160.87 per share (2011 – $138.57) on the common shares during the year, amounting to a total dividend of of $16,087 (2011 - $13,857). The Corporation is proposing to continue to follow the practice of proposing a dividend to be paid on common shares in 2013 that represents 50% of the MIFRS net income in the amount of $149.16 per share amount to $14,916. There is no tax affect as the dividends are paid out on an after tax basis.

14. Share capital (continued)

The Corporation has also established a dividend policy for its Permitted Generation Business unit to distribute a dividend on the Class A common shares determined as follows:

- The Corporation will target an IRR of 10.5% on the Permitted Generation Business Unit.
  As each project is completed by the Permitted Generation Business Unit, the Corporation expects to make distributions calculated with reference to the Class A Common Shares equity injections made by the Shareholders from time to time, provided that the amount of each dividend will be at the discretion of the Board of Directors ("Board") and may be greater or lesser than the below having regard to the financial and operating results of the Corporation as a whole;
  - For purposes of the dividend declaration that follows receipt of the unaudited IFRS financial statements for the Permitted Generation Business unit at mid-year, such amounts shall be the greater of:
    - the amounts reported in the most recent unaudited year-end IFRS financial statements for the Permitted Generation Business unit, or
    - the sum of fifty percent (50%) of the amounts reported in the most recent unaudited year-end IFRS financial statements for the Permitted Generation Business unit plus 100% of the amounts reported in the most recent unaudited mid-year IFRS financial statements for the Permitted Generation Business unit (i.e. for a six-month period).
- In the Post-Construction Period or earlier as determined by the Board, the net free cash flow will be paid to the holders of the Class A Common Shares subject to the criteria listed below:
  - Dividends will be declared by the Corporation's Board of Directors after due consideration is given to the following:
    - All financial covenants on any debt issued by the Corporation.
    - Qualifications to meet external bond rating criteria and ensure no adverse impact on the current credit rating of the Corporation. The Corporation will advise the Shareholders of its credit rating from time to time (and at least on an annual basis).
    - Cash flow requirements of the Permitted Generation Business Unit of the Corporation to meet working capital requirements and short-term (2 year) plans of capital expenditures.
    - The maintenance of the planned 60/40 debt to equity ratio.

There have been no dividends on Class A common shares paid during the year (2011 - $Nil).

15. Insurance

The Corporation maintains appropriate types and levels of insurance with major insurers. With respect to liability insurance, the Corporation is a member of the Municipal Electricity Association Reciprocal Insurance Exchange ("MEARIE"). A reciprocal insurance exchange may be defined as a group of persons formed for the purpose of exchanging reciprocal contracts of indemnity or inter-insurance with each other. MEARIE is licensed to provide general liability insurance to its members.

Insurance premiums charged to each member consist of a levy per thousands of dollars of service revenue subject to a credit or surcharge based on each member's claims experience. The maximum coverage is $24,000 for liability insurance, $411,460 for property insurance and $15,000 for vehicle insurance.

(In thousands of dollars)

16. Leases

(a) Finance leases

The Corporation leases its operations centre under a 25 year lease agreement. The lease agreement includes both land and building elements. Upon entering into this lease arrangement, the Corporation classified the building element of the lease as a finance lease since it was determined that substantially all of the benefits and risks incidental to ownership of the operation centre were transferred to the Corporation (the lessee). The component of the annual basic rent related to the land is classified and recorded as an operating lease and the component related to the building is classified as a finance lease.

			2012
	Future minimum lease payments (including interest)	**Interest**	**Present value of minimum lease payments**
	$	**$**	**$**
Less than one year	**1,430**	**1,135**	**295**
Between one and five years	**7,150**	**5,344**	**1,806**
More than five years	**24,996**	**9,695**	**15,301**
	33,576	**16,174**	**17,402**

			2011			January 1, 2011
	Future minimum lease payments	Interest	Present value of minimum lease payments	Future minimum lease payments	Interest	Present value of minimum lease payments
	$	$	$	$	$	$
Less than one year	$ 1,430	$ 1,153	277	1,430	1,171	259
Between one and five years	7,150	5,459	1,691	7,149	5,566	1,583
More than five years	26,425	10,714	15,711	27,856	11,760	16,096
	35,005	17,326	17,679	36,435	18,497	17,938

Interest on the lease obligation during fiscal 2012 amounted to $1,153 (2011 - $1,171) based on the rate of 6.57% per annum (2011 – 6.57%). Amortization of the corresponding PP&E during fiscal 2012 amounted to $733 (2011 - $731) based on the straight-line method with a useful life equal to the term of the lease (25 years).

(In thousands of dollars)

16. Leases (continued)

(b) Operating leases

The Corporation is also committed to lease agreements for various vehicles, equipment,rooftops and the land portion of the finance lease for solar projects that have been classified as operating leases. The leases typically run for a period of 5 to 20 years.

The future minimum non-cancellable annual lease payments (including the land portion of the operating centre lease referred to in (a) above) are as follows:

	2012	2011	January 1, 2011
	$	$	$
Less than one year	**1,612**	1,348	1,128
Between one and five years	**7,793**	7,360	5,796
More than five years	**24,599**	25,063	21,125
	34,004	33,771	28,049

During the year ended December 31, 2012 an expense of $1656 (2011 - $990) was recognized in net income in respect of operating leases.

17. Financial instruments and risk management

(a) Fair value of financial instruments

The Corporation's accounting policies relating to the recognition and measurement of financial instruments are disclosed in Note 3(d).

The carrying amount of cash, accounts receivable, unbilled revenue, amounts due from related parties, bank indebtedness, liability for subdivision development, short-term debt, short- term Infrastructure Ontario financing, customer deposits, accounts payable and accrued liabilities and amounts due to related parties approximates fair value because of the short maturity of these instruments.

The carrying value and fair value of the Corporation's other financial instruments are as follows:

		2012		2011		January 1, 2011
Description	**Carrying value**	**Fair value**	Carrying value	Fair value	Carrying value	Fair value
	$	**$**	$	$	$	$
Liabilities						
Notes payable	**182,430**	**225,972**	182,430	226,432	182,430	207,468
Debentures payable	**198,189**	**222,172**	124,489	130,509	123,765	131,326
Infrastructure Ontario	**1,911**	**2,066**	980	1,063	-	-
Bank term loan	**50,000**	**50,244**	50,000	51,829	50,000	52,529
	432,530	**500,454**	357,899	409,833	356,195	391,323

(In thousands of dollars)

17. Financial instruments and risk management (continued)

(a) Fair value of financial instruments (continued)

The carrying amounts shown in the table are included in the balance sheets under the indicated captions.

The fair value of notes payable, debentures payable and bank term loan, which is determined for disclosure purposes, is calculated using the discounted cash flow model based on the contractual terms of the instrument discounted using an appropriate market rate of interest.

(b) Risk factors

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation's exposure to a variety of risks such as credit risk, interest rate risk and liquidity risk as well as related mitigation strategies have been discussed below. However, the risks described below are not exhaustive of all the risks nor will the mitigation strategies eliminate the Corporation's exposure to all risks listed.

(c) Credit risk

The Corporation's primary source of credit risk to its accounts receivable result from customer's failing to discharge their dues for electricity consumed and billed.

The Corporation has approximately 355,000 (2011 - 335,000) residential and commercial customers. In order to mitigate such potential credit risks, the Corporation has taken various measures in respect of its Energy customers such as collecting security deposits and/or letters of credit amounting to $15,216 (2011 - $15,436, January 1, 2011 - $17,043) in accordance with OEB guidelines, reviewing Dun & Bradstreet ("D&B") reports for the top 3000 commercial customers with an outstanding balance of $5 or more, in-house collection department as well as external collection agencies and a bad debt insurance policy for $4,500 (2011 - $4,500, January 1, 2011 - $4,500) related to energy receivables. Thus, the Corporation monitors and limits its exposure to such credit risks on an ongoing basis.

Pursuant to their respective terms, accounts receivable are aged as follows at December 31:

	2012		2011		January 1, 2011	
	Total		Total		Total	
	$	**%**	$	%	$	%
Less than 30 days	**70,205**	**84**	72,592	83	56,537	78
30 - 60 days	**9,151**	**11**	7,992	9	8,493	12
61 - 90 days	**2,218**	**3**	4,426	5	3,434	5
Greater than 91 days	**2,336**	**3**	3,017	3	4,082	5
Total outstanding	**83,910**	**100**	88,027	100	72,546	100
Less: allowance for doubtful accounts	**(1,487)**	**(2)**	(1,471)	(2)	(2,078)	(3)
	82,423	**99**	86,556	98	70,468	97

As at December 31, 2012, there was no significant concentration of credit risk with respect to any financial assets.

(In thousands of dollars)

17. Financial instruments and risk management (continued)

(d) Interest rate risk

The Corporation manages its exposure to interest rate risk by issuing long term fixed rate debt in the form of debentures, promissory notes and bank loans. It also ensures that all payment obligations are met by adopting proper capital planning.

As part of the Corporations' revolving demand operating credit facility, the Corporation may utilize the line of credit for working capital and/or capital expenditure purposes. Such short-term borrowing may expose the Corporation to short-term interest rate fluctuations as follows:

	2012	2011	January 1, 2011
364 day revolving facility			
Prime based loans	**PR*+0.15% p.a.**	PR*+0.15% p.a.	PR*+0.15% p.a.
Bankers Acceptances	**SF*+1.10% p.a.**	SF*+1.10% p.a.	SF*+1.10% p.a.
Demand facility			
Prime based loans	**PR*–0.15% p.a.**	PR*–0.10% p.a.	PR*–0.10% p.a.
Bankers acceptances	**SF*+0.85% p.a.**	SF*+0.90% p.a.	SF*+0.90% p.a.
Letter of guarantee facility	**0.50% p.a.**	0.50% p.a.	0.50% p.a.
Infrastructure Ontario financing	**Floating rate p.a.**	Floating rate p.a.	Floating rate p.a.

Note: PR - Prime Rate, SF* - Stamping Fee*

A sensitivity analysis was conducted to examine the impact of a change in the prime rate or stamping fee on the short-term debt. A variation of 1% (100 basis points), with all other variables held constant, would increase or decrease the annual interest expense by approximately $420.

Cash balances that are not required for day to day obligations earn an interest of Prime minus 1.7% per annum. Fluctuations in this interest rate could impact the level of interest income earned by the Corporation.

(e) Liquidity risk

Liquidity risks are those risks associated with the Corporation's inability to meet obligations associated with financial liabilities such as repayment of principal or interest payments on debts.

The Corporation monitors its liquidity risks on a regular basis to ensure there is sufficient cash flow to meet the obligations as they fall due as well as minimize the interest expense. Cash flow forecasts are prepared to monitor liquidity risks. Liquidity risks associated with its short-term and long-term debt are as follows:

			2012			2011
Maturity period	**Principal ***	**Interest**	**Total**	Principal *	Interest	Total
	$	**$**	**$**	$	$	$
Less than 1 year	**238,685**	**19,098**	**257,783**	273,541	8,068	281,609
1-5 years	**365**	**85,753**	**86,118**	106,511	10,801	117,312
6-10 years	**441**	**85,822**	**86,263**	224	136	360
Over 10 years	**365,395**	**149,857**	**515,252**	166,641	115,195	281,836
	604,886	**340,530**	**945,416**	546,917	134,200	681,117

* The principal includes $1,811 (2011 - $511) of deferred issuing cost amortization

(In thousands of dollars)

17. Financial instruments and risk management (continued)

(f) Hedging/Derivative risk

The Corporation has a swap and derivative transaction policy to enable the Corporation to enter into agreements such as interest rate swaps where 100% of the floating rate risk is hedged into a fixed rate. This is done for prudent risk management purposes and not speculative purposes.
The Corporation has not entered into any such transactions during the year current or prior years.

18. Capital structure

The Corporation's main objectives in the management of capital are to:

(i) Ensure that there is access to various funding options at the lowest possible rates for the various capital initiatives and working capital requirements necessary for the rate-regulated business;

(ii) Ensure compliance with various covenants related to its short-term debt, Infrastructure Ontario financing, bank term loan, debentures payable and Infrastructure Ontario debentures;

(iii) Consistently maintain a high credit rating for the Corporation;

(iv) Maintain a split of approximately 60% debt, 40% equity as recommended by the OEB;

(v) Ensure interest rate fluctuations are mitigated primarily by long term borrowings as well as capital planning; and

(vi) Deliver appropriate financial returns to shareholders.

The Corporation considers shareholders' equity, long-term debt and certain short-term debt as its capital. The capital structure as at December 31, 2012 is as follows:

	2012	2011	January 1, 2011
	$	$	$
Shareholders' equity			
Share capital (Note 14)	**280,301**	251,957	249,618
Accumulated other comprehensive income	**(739)**	(739)	-
Retained earnings	**116,410**	97,171	85,417
Total equity	**395,972**	348,389	335,035
Short-term debt			
Short-term debt (Note 11)	**25,000**	40,000	40,000
Infrastructure Ontario financing (Note 11)	**6,612**	3,206	827
Bank term loan (Note 12)	**50,000**	-	-
Notes payable (Note 12)	**16,328**	-	-
Long-term debt			
Bank term loan (Note 12)	-	50,000	50,000
Debentures payable (Note 12)	**198,189**	124,489	123,765
Notes payable (Note 12)	**166,102**	182,430	182,430
Infrastructure Ontario debentures (Note 12)	**1,911**	980	-
Total debt	**464,142**	401,105	397,022
Total capital	**860,114**	749,494	732,057

(In thousands of dollars)

18. Capital structure (continued)

As at December 31, 2012, the Corporation was in compliance with covenants related to its short-term debt, bank term loan and debentures payable. The Corporation received a waiver with respect to the current ratio covenant calculation as at December 31, 2012 on its Infrastructure Ontario financing covenants. Details relating to covenants are disclosed in Note 11 and Note 12.

The Corporation is within the debt and equity requirements of the OEB. The Corporation's dividend policy is disclosed in Note 14.

19. Operating expenses

Operating expenses comprise:

	2012	2011
	$	$
Labour	**43,775**	33,592
Contract / Consulting	**14,052**	11,755
Materials	**1,124**	1,116
Vehicle	**1,392**	1,691
Other	**29,159**	28,514
Total	**89,502**	76,668

20. Income taxes

(a) Income tax expense

PILs recognized in net income comprise the following:

	2012	2011
	$	$
Current tax expense		
Current year	**(1,479)**	4,778
Deferred tax expense		
Origination and reversal of temporary differences	**11,161**	5,108
Change in deferred tax rate	**(2,397)**	-
	8,764	5,108
Income tax expense (2011 net of $267 allocated to OCI)	**7,285**	9,886

(In thousands of dollars)

20. Income taxes (continued)

(b) Reconciliation of effective tax rate

The PILs income tax expense differs from the amount that would have been recorded using the combined Canadian federal and provincial statutory income tax rates. The reconciliation between the statutory and effective tax rates is as follows:

	2012	2011
	$	$
Income before taxes	**42,611**	35,764
Statutory Canadian federal and provincial income tax rates	**26.50%**	28.25%
Expected tax provision on income at statutory rates	**11,292**	10,103
Increase (decrease) in income taxes resulting from:		
Permanent differences	**484**	262
Changes and differences in deferred tax rate	**(2,397)**	689
Scientific Research & Experimental Development tax credits	**(762)**	(668)
Other	**(1,332)**	(500)
Income tax expense (2011 net of $267 allocated to OCI)	**7,285**	9,886

Statutory Canadian federal and provincial income tax rates for the current year comprise 15% (2011: 16.5%) for federal corporate tax and 11.5% (2011: 11.75%) for corporate tax in Ontario. On January 1, 2012 federal corporate tax decreased from 16.5% to 15% (2011: 18% to 16.5%). There was no change in the provincial corporate tax rate in 2012 (2011: 12% to 11.5%).

(c) Deferred tax assets

Deferred tax assets are attributable to the following:

	2012	2011	January 1, 2011
	$	$	$
Employee future benefits	**4,783**	4,203	3,921
Property, plant and equipment	**30,265**	34,943	40,141
Intangible assets	**1,484**	1,517	1,643
Smart meter costs deferred	**-**	467	-
Other deductible temporary differences	**(2,450)**	491	581
	34,082	41,621	46,286

Movements in deferred tax balances during the year were as follows:

	2012	2011
	$	$
Balance at January 1	**41,621**	46,286
Recognized in net income	**(7,539)**	(4,398)
Recognized in OCI related to employee future benefits	**-**	(267)
Balance at December 31	**34,082**	41,621

(In thousands of dollars)

20. Income taxes (continued)

(d) Deferred tax liabilities

Deferred tax liability of $1,730 at December 31, 2012 (2011 - $505, January 1, 2011 - $61) represents differences between book and tax values of property, plant and equipment.

21. Net change in non-cash operating working capital

	2012	2011
	$	$
Accounts receivable	**4,133**	(16,088)
Unbilled revenue	**(6,018)**	1,838
Inventories	**321**	(217)
Prepaids and other assets	**(800)**	(317)
Due from a related party	**(841)**	262
Accounts payable and accrued liabilities	**(1,515)**	10,375
Customer deposits	**29**	(514)
Due to related parties	**675**	(1,374)
Liability for subdivision development	**1,066**	(2,185)
Other liabilities	**-**	(160)
	(2,950)	(8,380)

22. Contingencies, commitments and guarantees

(a) Contingencies

(i) Legal claims

The Corporation has been named as a defendant in several actions. No provision has been recorded in the financial statements for these potential liabilities as the Corporation expects that these claims are adequately covered by its insurance.

(b) Commitments

As at December 31, 2012, the Corporation has entered into agreements for capital projects and is committed to making payments of $48,700 in 2013.

(c) Guarantees

In the normal course of business, the Corporation enters into agreements that meet the definition of a guarantee as follows:

(i) The Corporation has provided indemnities under lease agreements for the use of various operating facilities. Under the terms of these agreements the Corporation agrees to indemnify the counterparties for various items including, but not limited to, all liabilities, loss, suits, and damages arising during, on or after the term of the agreement. The maximum amount of any potential future payment cannot be reasonably estimated.

22. Contingencies, commitments and guarantees (continued)

(c) Guarantees (continued)

(ii) Indemnity has been provided to all directors and/or officers of the Corporation for various items including, but not limited to, all costs to settle suits or actions due to association with the Corporation, subject to certain restrictions. The Corporation has purchased directors' and officers' liability insurance to mitigate the cost of any potential future suits or actions. The term of the indemnification is not explicitly defined, but is limited to the period over which the indemnified party served as a trustee, director or officer of the Corporation. The maximum amount of any potential future payment cannot be reasonably estimated.

(iii) In the normal course of business, the Corporation has entered into agreements that include indemnities in favor of third parties, such as purchase and sale agreements, confidentiality agreements, engagement letters with advisors and consultants, outsourcing agreements, leasing contracts, information technology agreements and service agreements. These indemnification agreements may require the Corporation to compensate counterparties for losses incurred by the counterparties as a result of breaches in representation and regulations or as a result of litigation claims or statutory sanctions that may be suffered by the counterparty as a consequence of the transaction. The terms of these indemnities are not explicitly defined and the maximum amount of any potential reimbursement cannot be reasonably estimated.

The nature of these indemnification agreements prevents the Corporation from making a reasonable estimate of the maximum exposure due to the difficulties in assessing the amount of liability which stems from the unpredictability of future events and the unlimited coverage offered to counterparties. Historically, the Corporation has not made any significant payments under such or similar indemnification agreements and therefore no amount has been accrued in the balance sheet with respect to these agreements.

23. First-time adoption of IFRS

As stated in note 1, these are the first annual financial statements of the Corporation prepared in accordance with IFRS. The Corporation's financial statements were previously prepared in accordance with Generally Accepted Accounting Principles in Canada (Canadian GAAP).

The accounting policies described in note 3 have been applied in preparing the financial statements for the year end December 31, 2012, the comparative information provided for the year ended December 31, 2011 and in the preparation of the opening IFRS balance sheet as at January 1, 2011 (the date of transition).

(a) Mandatory exceptions

IFRS 1 states that estimates made in accordance with IFRS at the date of transition should be consistent with estimates made under Canadian GAAP (after adjustments to reflect any differences in accounting policies). Accordingly, estimates previously made under Canadian GAAP were not revised at the date of transition except where necessary to reflect changes in accounting policies.

(b) Elected exemptions

In preparing these financial statements in accordance with IFRS 1, the Corporation has elected a few of the optional exemptions that are available to a first-time adopter of IFRS. The optional exemptions elected by the Corporation are described below.

23. First-time adoption of IFRS (continued)

(b) Elected exemptions (continued)

(i) Business combinations

IFRS 1 provides an optional exemption whereby a first-time adopter may elect not to apply IFRS retrospectively to business combinations that occurred prior to the date of transition. This exemption applies equally to acquisitions of investments in associates and interests in joint ventures that occurred prior to the date of transition. The Corporation elected this exemption and did not restate business combinations that occurred prior to the date of transition.

(ii) Deemed cost

A first-time adopter with rate-regulated activities may hold items of PP&E or intangible assets for which the carrying amount of such items includes amounts that were determined in accordance with previous GAAP but do not qualify for capitalization under IFRS. In such cases the first-time adopter may elect to use the previous GAAP carrying amount of such an item at the date of transition as deemed cost.

Under Canadian GAAP, the carrying amount of the Corporation's PP&E and intangible assets used in rate-regulated activities was based on historical cost but included certain amounts that would not qualify for capitalization under IFRS. The Corporation elected to use the carrying amount of these items as determined under Canadian GAAP as deemed cost on the date of transition.

The items for which the deemed cost exemption was elected are part of the Corporation's rate-regulated CGU. As described in note 8, the rate-regulated CGU was tested for impairment at the date of transition and it was determined that the CGU was not impaired.

(iii) Leases

The Corporation has elected under IFRS 1 not to reassess whether an arrangement contains a lease under IFRIC 4 for contracts that were assessed under Canadian CGAAP. Arrangements entered into before the effective date of EIC 150 that have not subsequently been assessed under EIC 150, were assessed under IFRIC 4 and no additional leases were identified.

(iv) Transfers of assets from customers

The Corporation has elected to apply the transitional provisions in IFRIC 18 *Transfers of Assets from Customers.* This provision states that the effective date of this standard should be July 1, 2009 or the date of transition to IFRS whichever is later.

(v) Employee benefits

The Corporation has elected the IFRS 1 exemption which recognizes all unamortized cumulative actuarial gains and losses at the date of transition to retained earnings.

(c) Impact of transition

In preparing its opening IFRS consolidated balance sheet, the Corporation has adjusted amounts reported previously in its financial statements prepared in accordance with Canadian GAAP. IFRS 1 requires an entity to explain how the transition from its previous GAAP to IFRS affected its reported financial position, financial performance and cash flows by providing reconciliations of shareholders' equity, comprehensive income and cash flows for prior periods.

An explanation of how the transition from Canadian GAAP to IFRS has affected the Corporation's financial position and performance is set out in the following tables and accompanying notes.

(In thousands of dollars)

23. First-time adoption of IFRS (continued)

Reconciliation of the balance sheet as at January 1, 2011:

	References	Canadian GAAP January 1, 2011	IFRS Adjustments	IFRS January 1, 2011
		$	$	$
Assets				
Current assets				
Cash		8,568	-	8,568
Accounts receivable	A	69,366	1,102	70,468
Unbilled revenue		92,207	-	92,207
Due from Related parties	G	-	2,435	2,435
Inventories		3,050	-	3,050
Prepaids and other assets		2,718	-	2,718
		175,909	3,537	179,446
Property, plant and equipment	C	642,059	20,387	662,446
Regulatory assets	A	31,961	(31,961)	-
Intangible assets	A	4,792	(719)	4,073
Deferred tax assets	D	54,539	(8,253)	46,286
Goodwill		42,543	-	42,543
		951,803	(17,009)	934,794
Liabilities				
Current liabilities				
Short-term debt		40,000	-	40,000
Infrastructure Ontario financing		827	-	827
Customer deposits	E	1,478	12,071	13,549
Accounts payable and accrued liabilities		105,339	-	105,339
Due to related parties	G	12,214	2,435	14,649
Income taxes payable		6,622	-	6,622
Liability for subdivision development	E	4,138	1,232	5,370
Finance lease obligation		259	-	259
		170,877	15,738	186,615
Long-term liabilities				
Notes payable		182,430	-	182,430
Debentures payable		123,765	-	123,765
Bank term loan		50,000	-	50,000
Finance lease obligation		17,679	-	17,679
Deferred revenue	C	-	23,364	23,364
Post-employment benefits	B	14,007	1,678	15,685
Deferred tax liabilities		61	-	61
Regulatory liabilities	A	69,540	(69,540)	-
Construction deposits	C	23,364	(23,364)	-
Customer deposits	E	12,071	(12,071)	-
Liability for subdivision development	E	1,232	(1,232)	-
Other liabilities		160	-	160
		494,309	(81,165)	413,144
Shareholders' equity				
Share capital		249,618	-	249,618
Retained earnings	A,B,D	36,999	48,418	85,417
		286,617	48,418	335,035
		951,803	-	934,794

(In thousands of dollars)

23. First-time adoption of IFRS (continued)

Reconciliation of the balance sheet as at December 31, 2011:

	References	Canadian GAAP December 31, 2011	IFRS Adjustments	IFRS December 31, 2011
		$	$	$
Assets				
Current assets				
Cash		-	-	-
Accounts receivable	A	86,933	(377)	86,556
Due from a related party	G	-	2,173	2,173
Unbilled revenue		90,369	-	90,369
Inventories		3,267	-	3,267
Prepaids and other		3,035	-	3,035
		183,604	1,796	185,400
Property, plant and equipment	A,C	690,041	29,153	719,194
Regulatory assets	A	14,591	(14,591)	-
Intangible assets	A	6,852	2,138	8,990
Deferred tax assets	B,D	49,533	(7,912)	41,621
Goodwill		42,543	-	42,543
		987,164	10,584	997,748
Liabilities				
Current liabilities				
Bank indebtedness		8,039	-	8,039
Short-term debt		40,000	-	40,000
Infrastructure Ontario financing		3,206	-	3,206
Customer deposits	E	1,005	12,030	13,035
Accounts payable and accrued liabilities		116,113	-	116,113
Due to related parties	G	11,102	2,173	13,275
Income taxes payable		3,446	-	3,446
Liability for subdivision development	E	2,984	201	3,185
Finance lease obligation		277	-	277
		186,172	14,404	200,576
Long-term liabilities				
Notes payable		182,430	-	182,430
Debentures payable		124,489	-	124,489
Bank term loan		50,000	-	50,000
Infrastructure Ontario debentures		980	-	980
Finance lease obligation		17,402	-	17,402
Deferred revenue	C	-	56,166	56,166
Post-employment benefits	B	15,265	1,546	16,811
Deferred tax liabilities		505	-	505
Regulatory liabilities	A	59,246	(59,246)	-
Construction deposits	C	33,045	(33,045)	-
Customer deposits	E	12,030	(12,030)	-
Liability for subdivision development	E	201	(201)	-
		495,593	(46,810)	448,783
Shareholders' equity				
Share capital		251,957	-	251,957
Accumulated other comprehensive income		-	(739)	(739)
Retained earnings	A,B,C, D	53,442	43,729	97,171
		305,399	42,990	348,389
		987,164	-	997,748

(In thousands of dollars)

23. First-time adoption of IFRS (continued)

Reconciliation of statement of comprehensive income for year ended December 31, 2011:

	Reference	Canadian GAAP December 31, 2011	IFRS Adjustments	IFRS December 31, 2011
		$	$	$
Revenue				
Sale of energy	A	751,457	8,828	760,285
Distribution revenue	A	160,914	(6,609)	154,305
Other revenue	A,C, F	10,052	4,430	14,482
Total revenue		922,423	6,649	929,072
Cost of power purchased	A	751,457	6,594	758,051
		170,966	55	171,021
Operating expenses	C	65,492	11,176	76,668
Depreciation and amortization	C	46,127	(11,701)	34,426
		59,347	580	59,927
Finance costs	C	23,821	342	24,163
Loss on disposals of assets		-	-	-
Income before income taxes		35,526	11,939	35,764
Income tax expense		5,222	4,931	10,153
Net income		30,304	7,008	25,611
Other comprehensive income				
Remeasurement of defined benefit obligation, net of tax	B	-	(739)	(739)
Total comprehensive income for the year		30,304	6,269	24,872

Explanation of adjustments:

(a) *Rate-regulated assets and liabilities*

At the date of transition, the Corporation derecognized all rate-regulated assets and liabilities that did not qualify for recognition under IFRS. Certain items that were presented as rate-regulated assets under Canadian GAAP qualify for recognition as other types of assets under IFRS. The effect is to increase PP&E by $20,387 at January 1, 2011 and by $29,153 at December 31, 2011; to decrease intangible assets by $719 at January 1, 2011 and increase it by $2,138 at December 31, 2011; to increase accounts receivable by $1,102 at January 1, 2011 and by $2,173 at December 31, 2011.

The total impact of this adjustment decreased total assets by $19,444 at January 1, 2011 and increased by $8,411 at December 31, 2011; decreased total liabilities by $69,540 at January 1, 2011 and by $36,125 at December 31, 2011 and increased retained earnings by $50,096 at January 1, 2011 and by $44,536 at December 31, 2011.

(In thousands of dollars)

23. First-time adoption of IFRS (continued)

(a) *Rate-regulated assets and liabilities (continued)*

The movements of the regulatory accounts are shown in the table below:

	January 1, 2011	December 31, 2011
	$	$
Assets		
Accounts Receivable	1,102	(377)
Property, Plant and Equipment	20,387	29,153
Regulatory assets	(31,961)	(14,591)
Intangible assets	(719)	2,138
Deferred tax assets	(8,253)	(7,912)
Total	(19,444)	8,411
Liablities		
Deferred tax liablities	(69,540)	(59,246)
Relcass construction deposits	(23,364)	(33,045)
Deferred revenue	23,364	56,166
Total	(69,540)	(36,125)
Retained Earnings		
Total change in assets	19,444	(8,411)
Total change in liablities	(69,540)	(36,125)
Total	(50,096)	(44,536)

(b) *Application of IAS 19 (June 2011)*

The Corporation adopted IAS 19 (June 2011) on January 1, 2012 and now accounts for employee benefits as described in its accounting policy. However, the Corporation has elected the IFRS 1 exemption which recognizes all cumulative unamortized actuarial gains and losses at the date of transition to retained earnings and going forward all actuarial gains and losses to other comprehensive income.

The Corporation also adjusted past service costs from predecessor utilities, and the transitional obligation from the adoption of Canadian GAAP section 3461 through retained earnings upon transition to IFRS.

The effect was to increase the post-employee benefit obligation by $1,678 at January 1, 2011 and by $1,546 at December 31, 2011; to decrease retained earnings by $1,678 at January 1, 2011 and by $1,678 at December 31, 2011; and to decrease operating expense by $132 for the year ended December 31, 2011.

The effect of recognizing actuarial gains and losses to other comprehensive income along with the related tax impact is a decrease in other comprehensive income by $739 at December 31, 2011, an increase in retained earnings by $739, a decrease in deferred tax assets by $267 and an increase in tax expense by $267.

23. First-time adoption of IFRS (continued)

(c) Capital assets

(i) Useful lives

The Corporation has adopted IAS 16 *Property, plant and equipment,* as a result the useful lives of the assets were reassessed to ensure management estimates are consistent with the actual asset use and assets were componentized as required by IAS 16. There was no impact on January 1, 2011, but for December 31, 2011 depreciation and amortization expense decreased by $11,701 and capital assets increased by $11,701.

(ii) Capitalization policy

In line with IAS 16 *Property, plant and equipment* requirements, the Corporation has assessed its capitalization policy to ensure that only directly attributable costs are included within its capital assets. The effect was to increase operating expenses balance by $11,176 for the year ended December 31, 2011 and to decrease capital assets balance by $11,176 as at December 31, 2011.

(iii) Interest capitalization

The Corporation applied IAS 23 *Borrowing Costs*. There was no impact to the balance sheet as at January 1, 2011. However, at December 31, 2011 finance costs increased by $342 and the capital asset balance decreased by $342; this was due to changing the definition of assets that qualify as taking a substantial period of time to get ready for their intended use.

(iv) Customer contributions

Under Canadian GAAP, customer contributions were netted against the cost of PP&E and amortized to income, as an offset to depreciation expense, on the same basis as the assets for which the customer contributions were received. Customer contributions were presented as construction deposits until the time that the related assets were put into service, at which point the contributions were reclassified as an offset to PP&E.

Under IFRIC 18 *Transfers of Assets from Customers*, customer contributions are recognized initially as deferred revenue, not as construction deposits, and are amortized into income over the life of the related assets.

The effect of the above is to increase deferred revenue by $23,364 at January 1, 2011 and by $33,045 at December 31, 2011; to decrease construction deposits by $23,364 at January 1, 2011 and by $33,045 at December 31, 2011; to increase PP&E by $23,121 at December 31, 2011 and to increase other revenue and depreciation expense by $291 for the year ended December 31, 2011.

(d) Deferred taxes

Deferred income taxes have decreased as a result of removing the gross-up that was required for rate-regulated accounting. The impact was to decrease retained earnings balance by $8,253 as at January 1, 2011 and to decrease rate regulated liability balance by $7,912 for the year ended December 31, 2011, however, as the rate regulated liability balance is not allowed to be recognized under IFRS this adjustment increased the tax provision.

The following reclassifications were made due to differences in presentation between Canadian GAAP and IFRS:

23. First-time adoption of IFRS (continued)

(e) *Current liabilities*

Under Canadian GAAP certain liabilities were presented as non-current on the basis that there was no intent for the liabilities to be settled within 12 months of the reporting date. The Corporation does not have the unconditional right to defer settlement of these liabilities and as a result, the liabilities must be presented as current liabilities under IFRS.

The effect is that customer deposits and the liability for subdivision development have been reclassified as current liabilities.

(f) *Other revenue*

Under Canadian GAAP, certain incidental revenue earned by the Corporation was presented as an offset to associated expenses. Netting of these accounts is not allowed under IFRS therefore, revenue is presented on a gross basis under IFRS.

The effect of the aforementioned is to increase other revenue and Finance Costs by $470 for the year ended December 31, 2011.

(g) *Due from a related party*

Under Canadian GAAP, amounts due from one of the Corporation’s related parties were netted against amounts due to other shareholders. Netting of these accounts is not allowed under IFRS therefore, the amounts due from the related party are presented as a separate asset and liability under IFRS.

Financial statements of

PowerStream Inc.

December 31, 2013

PowerStream Inc.

December 31, 2013

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Independent Auditor's Report

To the Shareholder of
PowerStream Inc.

We have audited the accompanying financial statements of PowerStream Inc., which comprise the balance sheet as at December 31, 2013, the statements of income and other comprehensive income, changes in equity and of cash flows for the year ended December 31, 2013, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of PowerStream Inc. as at December 31, 2013, and its financial performance and its cash flows for the year ended December 31, 2013, in accordance with International Financial Reporting Standards.

Deloitte LLP

Chartered Professional Accountants, Chartered Accountants
Licensed Public Accountants
April 22, 2014

PowerStream Inc.

Balance sheet
as at December 31, 2013

(In thousands of dollars)

	2013	2012 (Restated - Note 23)
	$	$
Assets		
Current assets		
Cash	**-**	19,963
Accounts receivable (Note 17(c))	**90,629**	82,423
Unbilled revenue	**115,840**	96,387
Due from related parties (Note 10)	**2,739**	3,014
Inventories (Note 6)	**2,956**	2,946
Prepaids and other assets	**3,896**	3,835
	216,060	208,568
Long-term assets		
Property, plant and equipment (Note 7)	**926,470**	814,446
Intangible assets (Note 8)	**13,147**	12,849
Investment in a joint venture (Note 5)	**7,256**	8,243
Deferred tax assets (Note 20)	**22,537**	32,352
Goodwill (Note 3(h) and Note 8(b))	**42,543**	42,543
	1,228,013	1,119,001
Liabilities		
Current liabilities		
Bank indebtedness (Note 11)	**7,368**	-
Short-term debt (Note 11)	**70,000**	25,000
Bank term loan (Note 12)	**-**	50,000
Current portion of notes payable (Note 12)	**-**	16,328
Infrastructure Ontario financing (Note 11)	**48,315**	6,612
Customer deposits	**13,357**	13,064
Accounts payable and accrued liabilities (Note 9)	**136,694**	113,660
Due to related parties (Note 10)	**15,775**	13,950
Income taxes payable	**1,351**	2,230
Liability for subdivision development	**5,600**	4,251
Current portion of finance lease obligation (Note 16)	**315**	295
	298,775	245,390
Long-term liabilities		
Notes payable (Note 12)	**182,430**	166,102
Debentures payable (Note 12)	**198,221**	198,189
Infrastructure Ontario debentures (Note 12)	**-**	1,911
Finance lease obligation (Note 16)	**16,792**	17,107
Post-employment benefits (Note 13)	**19,317**	18,048
Deferred revenue	**101,342**	82,759
	518,102	484,116
Shareholders' equity		
Share capital (Note 14)	**288,718**	280,301
Accumulated other comprehensive income	**(739)**	(739)
Retained earnings	**123,157**	109,933
	411,136	389,495
	1,228,013	1,119,001

Approved on behalf of the Board on April 22, 2014

_______________ Director _______________ Director

The accompanying notes to the financial statements are an integral part of this financial statement.

PowerStream Inc.

Statement of income and other comprehensive income year ended December 31, 2013

(In thousands of dollars)

	2013	2012
	$	$
Revenue (Note 10(a))		
Sale of energy	**888,218**	811,506
Distribution revenue	**156,993**	159,839
Other revenue	**19,503**	18,039
Total revenue	**1,064,714**	989,384
Cost of power purchased	**883,876**	800,958
Operating expenses (Note 19)	**85,583**	89,502
Depreciation and amortization	**36,939**	33,364
	58,316	65,560
Share in (loss)/income from joint venture (Note 5)	**(987)**	150
Interest income	**1,452**	1,293
Interest expense	**21,809**	24,392
Income before income taxes	**36,972**	42,611
Income tax expense (Note 20)	**8,832**	7,285
Net income	**28,140**	35,326
Other comprehensive income		
Remeasurement of defined benefit obligation	**-**	-
Total income and other comprehensive income for the year	**28,140**	35,326

The accompanying notes to the financial statements are an integral part of this financial statement.

PowerStream Inc.

Statement of changes in equity
year ended December 31, 2013

(In thousands of dollars)

	Share capital	Accumulated other comprehensive income	Retained earnings (Restated - Note 23)	Total (Restated - Note 23)
	$	$	$	$
As at January 1, 2012, as previously reported	251,957	(739)	97,171	348,389
Correction of error (Note 23)	-	-	(6,477)	(6,477)
Restated as at January 1, 2012	251,957	(739)	90,694	341,912
Net income	-	-	35,326	35,326
Other comprehensive income, net of tax	-	-	-	-
Total comprehensive income for the year	-	-	35,326	35,326
Dividends paid	-	-	(16,087)	(16,087)
Issuance of Class A common shares (Note 14)	28,344	-	-	28,344
Balance at December 31, 2012	**280,301**	**(739)**	**109,933**	**389,495**
Net income	-	-	28,140	28,140
Other comprehensive income, net of tax	-	-	-	-
Total comprehensive income for the year	-	-	28,140	28,140
Dividends paid	-	-	(14,916)	(14,916)
Issuance of Class A common shares (Note 14)	8,417	-	-	8,417
Balance at December 31, 2013	**288,718**	**(739)**	**123,157**	**411,136**

The accompanying notes to the financial statements are an integral part of this financial statement.

PowerStream Inc.

Statement of cash flows
year ended December 31, 2013

(In thousands of dollars)

	2013	2012 (Restated - Note 23)
	$	$
Operating activities		
Net income for the year	**28,140**	35,326
Adjustments to determine cash provided by operating activities:		
Share of loss/(income) from joint venture	**987**	(150)
Depreciation of property, plant and equipment	**35,999**	32,354
Amortization of intangible assets	**2,940**	2,825
Post-employment benefits	**1,269**	1,237
Loss on disposal of property, plant and equipment	**1,386**	1,530
Amortization of deferred revenue	**(1,888)**	(1,164)
Finance costs	**20,357**	23,099
Capital tax expense	**129**	-
Income tax expense	**8,832**	7,285
	98,151	102,342
Net change in non-cash operating working capital (Note 21)	**(4,802)**	(8,030)
Cash generated from operating activities	**93,349**	94,312
Interest paid	**(21,418)**	(23,369)
Income tax received	**-**	1,578
Income taxes paid	**-**	(1,458)
	71,931	71,063
Financing activities		
Repayment of bank term loan	**(50,000)**	-
Dividends paid	**(14,916)**	(16,087)
Proceeds from Infrastructure Ontario financing	**39,792**	4,337
Proceeds from the issuance of Class A common shares	**8,417**	28,344
Proceeds from issuance of debenture	**-**	198,175
Repayment of debenture	**-**	(125,000)
Repayment of short-term debt	**45,000**	(15,000)
Payment of finance lease obligation	**(295)**	(277)
	27,998	74,492
Investing activities		
Contributions received from customers	**20,471**	27,757
Purchase of intangible assets	**(3,238)**	(6,684)
Investment in a joint venture	**-**	(8,093)
Purchase of property, plant and equipment	**(144,493)**	(130,533)
	(127,260)	(117,553)
(Decrease)/increase in cash during the year	**(27,331)**	28,002
Cash/(bank indebtedness), beginning of year	**19,963**	(8,039)
(Bank indebtedness)/cash, end of year (Note 11(a))	**(7,368)**	19,963

The accompanying notes to the financial statements are an integral part of this financial statement.

1. Description of the business

PowerStream Inc. (the “Corporation”) was amalgamated on January 1, 2009, under the Business Corporations Act (Ontario) and is wholly owned by PowerStream Holdings Inc., which in turn is owned by the Corporation of the City of Vaughan (the “City of Vaughan”), through its wholly owned subsidiary, Vaughan Holdings Inc.; the Corporation of the City of Markham (the “City of Markham”), through its wholly owned subsidiary, Markham Enterprises Corporation; and the Corporation of the City of Barrie (the “City of Barrie”), through its wholly owned subsidiary, Barrie Hydro Holdings Inc. PowerStream Holdings Inc. is jointly controlled by these three municipalities. The Corporation is incorporated and domiciled in Canada with its head and registered office located at 161 Cityview Boulevard, Vaughan, ON L4H 0A9.

The principal activity of the Corporation is distribution of electricity in the service areas of Alliston, Aurora, Barrie, Beeton, Bradford West Gwillimbury, Markham, Penetanguishene, Richmond Hill, Thornton, Tottenham and Vaughan in the Province of Ontario, under a license issued by the Ontario Energy Board (“OEB”). The Corporation is regulated under the OEB and adjustments to the distribution rates require OEB approval. Collingwood PowerStream Utility Services Corp. (“Collus PowerStream”) is a joint venture between the Corporation and the City of Collingwood. It distributes electricity in Collingwood, Thornbury, Stayner and Creemore.

As a condition of its distribution license, the Corporation is required to meet specified Conservation and Demand Management (“CDM”) targets for reductions in electricity consumption and peak electricity demand. As part of this initiative, the Corporation is delivering Ontario Power Authority (“OPA”) funded programs in order to meet its targets.

Under the Green Energy and Green Economy Act, 2009, the Corporation and other Ontario electricity distributors have new opportunities and responsibilities for enabling renewable generation.
The Corporation has commenced operations of a Solar Generation Business unit, in 2010, as permitted by these changes.

2. Basis of preparation

(a) *Statement of compliance*

These financial statements are prepared in accordance with International Financial Reporting Standards (“IFRS”), as issued by the International Accounting Standards Board (IASB).

(b) *Basis of measurement*

The financial statements have been prepared on a historical cost basis.

(c) *Presentation currency*

The financial statements are presented in Canadian dollars, which is also the Corporation’s functional currency. All financial information has been rounded to the nearest thousand, except when otherwise noted.

(d) *Use of estimates and judgments*

The preparation of financial statements in conformity with IFRS requires management to make estimates, assumptions and judgments that affect the application of accounting policies and the amounts reported and disclosed in the financial statements. Estimates and underlying assumptions are continually reviewed and are based on historical experience and other factors that are considered to be relevant. Actual results may differ from these estimates.

2. Basis of preparation (continued)

(d) Use of estimates and judgments (continued)

Significant sources of estimation uncertainty, assumptions and judgments include the following:

(i) Unbilled revenue

The measurement of unbilled revenue is based on an estimate of the amount of electricity delivered to customers between the date of the last bill and the end of the year.

(ii) Useful lives of depreciable assets

Depreciation and amortization expense is based on estimates of the useful lives of property, plant and equipment and intangible assets. The Corporation estimates the useful lives of its property, plant and equipment and intangible assets based on management's judgment, historical experience and an asset study conducted by an independent consulting firm.

(iii) Cash Generating Units ("CGU")

Determining CGU's for impairment testing is based on Management's judgment. This requires an estimation of the value in use. The value in use calculation requires an estimate of the future cash flows expected to arise from the CGU and a suitable discount rate in order to calculate the present value.

(iv) Valuation of financial instruments

As described in Note 17, the Corporation uses the discounted cash flow model to estimate the fair value of the financial instruments for disclosure purposes.

(v) Other areas

There are a number of other areas in which the Corporation makes estimates; these include accounts receivable, inventories, post-employment benefits and income taxes. These amounts are reported based on the amounts expected to be recovered/refunded and an appropriate allowance has been provided based on the Corporation's best estimate of unrecoverable amounts.

3. Significant accounting policies

The Corporation's financial statements are the representations of management, prepared in accordance with IFRS. The accounting policies set out below have been applied consistently to all years presented in these financial statements, unless otherwise indicated.

The financial statements reflect the following significant accounting policies:

(a) Rate regulation

The Ontario Energy Board Act, 1998 gave the Ontario Energy Board ("OEB") increased powers and responsibilities to regulate the electricity industry. These powers and responsibilities include the power to approve or fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers and the responsibility for ensuring that distribution companies fulfill obligations to connect and service customers. The OEB may prescribe license requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, and filing process requirements for rate-setting purposes.

The Corporation recognizes revenue when electricity is delivered to customers based on OEB approved rates. Operating costs and expenses are recorded when incurred, unless such costs qualify for recognition as part of an item of property, plant and equipment or as an intangible asset.

3. Significant accounting policies (continued)

(b) Revenue recognition

(i) Electricity distribution and sale

Revenue from the sale and distribution of electricity is recorded on the basis of cyclical billings based on electricity usage and also includes unbilled revenue accrued in respect of electricity delivered but not yet billed. Revenue is generally comprised of the following:

- Electricity Price and Related Rebates. The electricity price and related rebates represent a pass through of the commodity cost of electricity.
- Distribution Rate. The distribution rate is designed to recover the costs incurred by the Corporation in delivering electricity to customers, as well as the ability to earn the OEB allowed rate of return. Distribution charges are regulated by the OEB and typically comprise a fixed charge and a usage-based (consumption) charge.
- Retail Transmission Rate. The retail transmission rate represents a pass through of costs charged to the Corporation for the transmission of electricity from generating stations to the Corporation's service area. Retail transmission rates are regulated by the OEB.
- Wholesale Market Service Charge. The wholesale market service charge represents a pass through of various wholesale market support costs charged by the Independent Electricity System Operator (IESO).

(ii) Other revenue

Other revenue includes revenue from the sale of other services, contributions from customers and performance incentive payments.

Revenue related to the sale of other services is recognized as services are rendered.

Certain items of property, plant and equipment are acquired or constructed with financial assistance in the form of contributions from developers or customers ("customer contributions"). Such contributions, whether in cash or in-kind, are recognized as deferred revenue and amortized into income over the life of the related assets. Contributions in-kind are valued at their fair value at the date of their contribution.

Performance incentive payments under Conservation and Demand Management ("CDM") programs are recognized by the Corporation when there is reasonable assurance that the program conditions have been satisfied and the incentive payment will be received.

Government grants under CDM programs are recognized when there is reasonable assurance that the grant will be received and all attached conditions will be complied with. When the grant relates to an expense item, it is recognized as income over the period necessary to match the grant on a systematic basis to the costs that it is intended to compensate.

(c) Finance and borrowing costs

Finance costs comprise interest expense on borrowings and are recognized on an accrual basis using the effective interest rate method.

Borrowing costs are calculated using the effective interest rate method and are recognized as finance costs, unless they are capitalized as part of the cost of a qualifying asset, which is an asset that takes a substantial period of time to get ready for its intended use.

3. Significant accounting policies (continued)

(d) Financial instruments

Financial assets and financial liabilities are initially recognized at fair value and are subsequently accounted for based on their classification as loans and receivables or as other liabilities. Transaction costs for financial assets classified as loans and receivables and financial liabilities classified as other liabilities are capitalized as part of the carrying value at initial recognition.

(i) Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. Subsequent to initial recognition, such financial assets are carried at amortized cost using the effective interest rate method, less any impairment losses. Losses are recognized in net income when the loans and receivables are derecognized or impaired.

Loans and receivables are assessed at each reporting date to determine whether there is objective evidence of impairment. A financial asset is impaired if objective evidence indicates that a loss event has occurred after the initial recognition of the asset and the loss event has had a negative effect on estimated future cash flows of the asset which are reliably measureable.

Loans and receivables are comprised of cash, accounts receivable, unbilled revenue and amounts due from related parties.

(ii) Other liabilities

All non-derivative financial liabilities are classified as other liabilities. Subsequent to initial recognition, other liabilities are measured at amortized cost using the effective interest method.

Financial liabilities are derecognized when either the Corporation is discharged from its obligation, the obligation expires, or the obligation is cancelled or replaced by a new financial liability with substantially modified terms.

Financial liabilities are further classified as current or non-current depending on whether they will fall due within twelve months after the balance sheet date or beyond.

Other liabilities are comprised of bank indebtedness, short-term debt, Infrastructure Ontario financing, customer deposits, accounts payable and accrued liabilities, amounts due to related parties, notes payable, debentures payable, bank term loan, Infrastructure Ontario debentures, and liability for subdivision development.

(e) Inventories

Inventories, which consist of parts and supplies acquired for internal construction or consumption, are valued at the lower of cost and net realizable value. Cost is determined on a weighted-moving average basis and includes expenditures incurred in acquiring the inventories and other costs to bring the inventories to their existing location and condition.

(f) Property, plant and equipment

Property, plant and equipment (“PP&E”) is measured at cost less accumulated depreciation and accumulated impairment losses. Cost includes expenditures that are directly attributable to the acquisition of the asset and includes contracted services, cost of materials, direct labour and borrowing costs incurred in respect of qualifying assets constructed subsequent to January 1, 2011. When parts of an item of PP&E have different useful lives, they are accounted for as separate components of PP&E.

Major spare parts and standby equipment are recognized as items of PP&E.

3. Significant accounting policies (continued)

(f) Property, plant and equipment (continued)

When items of PP&E are retired or otherwise disposed of, a gain or loss on disposal is determined by comparing the proceeds from disposal with the carrying amount of the item and is included in net income.

Depreciation of PP&E is recognized on a straight-line basis over the estimated useful life of each component of PP&E. The estimated useful lives for the current and comparative years are as follows:

Land and buildings	
Land	Indefinite
Buildings	10 to 60 years
Distribution and other assets	
Transformer stations	20 to 40 years
Transformers and meters	15 to 40 years
Plant and equipment	3 to 20 years
Other	3 to 37.5 years

Depreciation methods and useful lives are reviewed at each financial year-end and any changes are adjusted prospectively.

(g) Intangible assets

Intangible assets include land rights, computer software and capital contributions. Capital contributions relate to the contributions made to Hydro One for a transformer station that was built outside the City of Barrie.

Land rights held by the Corporation are effective in perpetuity and there is no foreseeable limit to the period over which the rights are expected to provide benefit to the Corporation. Land rights have therefore been assessed as having an indefinite useful life and are not amortized. Land rights are measured at cost.

Computer software and capital contributions are measured at cost less accumulated amortization and accumulated impairment losses.

Computer software and capital contributions are amortized on a straight-line basis over the estimated useful lives from the date that they are available for use. The estimated useful lives for the current and comparative periods are as follows:

Computer software	4 years
Capital contributions	17 years

Amortization methods and useful lives are reviewed at each financial year-end and adjusted prospectively.

(h) Goodwill

Goodwill represents the excess of the purchase price over the fair value assigned to the Corporation's interest of the net identifiable assets acquired on the acquisition, by predecessor corporations, of the former Richmond Hill Hydro Inc., Penetanguishene Hydro, Essa Hydro, New Tecumseth Hydro and Bradford West Gwillimbury Hydro.

Goodwill is measured at cost and is not amortized. The company's policy on goodwill arising on acquisition of an associate is described in note 3(n).

3. Significant accounting policies (continued)

(i) Impairment of non-financial assets

The carrying amounts of the Corporation's non-financial assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. Goodwill and intangible assets with indefinite lives are tested annually for impairment and when circumstances indicate that the carrying value may be impaired. An impairment loss is recognized if the carrying amount of an asset or CGU exceeds its recoverable amount.

The Corporation has two CGU's, the rate regulated business and the Permitted Generation Business unit. Two CGU's were determined, as Management views the Corporation as having two distinct lines of business.

The recoverable amount of an asset or CGU is the greater of its value in use and fair value less costs of disposal. Value in use is calculated as the present value of the estimated future cash flows expected to be derived from an asset or CGU.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows that are largely independent of those from other assets or CGUs. Goodwill acquired in a business combination is allocated to groups of CGUs that are expected to benefit from the synergies of the combination.

Impairment losses are recognized in net income. Impairment losses relating to CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the CGUs and then to reduce the carrying amounts of the other assets in the CGUs on a pro rata basis.

An impairment loss in respect of goodwill is not reversed. In respect of other assets, an impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

(j) Employee benefits

The Corporation provides both short-term employee benefits and post-employment benefits. The post-employment benefits are provided through a defined benefit plan.

A defined benefit plan is a post-retirement benefit plan that specifies either the benefits to be received by an employee, or the method of determining those benefits.

(i) Short-term employee benefits

Short-term employee benefit obligations are recognized as the related services are rendered to the Corporation. Short-term employee benefit obligations are measured on an undiscounted basis and recognized as an expense unless the amount qualifies for capitalization as part of the cost of an item of inventory, PP&E or an intangible asset.

(ii) Multi-employer defined benefit pension plan

The Corporation provides a pension plan to its full-time employees through the Ontario Municipal Employees Retirement System ("the OMERS plan"). The OMERS plan is a multi-employer defined benefit plan which provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. The OMERS plan is financed by equal contributions from participating employers and employees, and by the investment earnings of the fund.

3. Significant accounting policies (continued)

(j) Employee benefits (continued)

(ii) Multi-employer defined benefit pension plan (continued)

It is not practicable to determine the present value of the Corporation's obligation or the related current service cost under the OMERS plan as OMERS computes its obligations in accordance with an actuarial valuation in which all the benefit plans are co-mingled and therefore information for individual plans cannot be determined. As a result, the Corporation accounts for the OMERS plan as a defined contribution plan where contributions to the OMERS plan are recognized as an employee benefit expense in the periods during which services are rendered by employees.

(iii) Non-pension defined benefit plans

The Corporation provides certain health, dental and life insurance benefits under unfunded defined benefit plans to its eligible retired employees (the "defined benefit plans").

The Corporation's net obligation in respect of the defined benefit plans is calculated by estimating the amount of future benefit that employees have earned in return for their service in the current and prior periods. The calculated benefit is discounted to determine its present value. The discount rate is the yield at the reporting date on corporate bonds that have maturity dates approximating the terms of the Corporation's obligations and that are denominated in the same currency in which the benefits are expected to be paid. The calculation of the defined benefit obligation is performed by an independent qualified actuary using the projected unit credit method.

Remeasurement of the net defined benefit liability, which is comprised of actuarial gains and losses, is recognized immediately in the balance sheet with a charge or credit to other comprehensive income in the year in which they occur.

Past service costs arising from plan amendments is recognized immediately in net income at the earlier of the date the plan amendment occurs or when any related restructuring costs or termination benefits are recognized.

(k) Customer deposits

Customer deposits are collections from customers to guarantee the payment of energy bills. Deposits that are refundable to customers on demand are classified as a current liability. Interest is paid on customer deposits.

(l) Leases

Leases in which the Corporation assumes substantially all of the risks and rewards of ownership are classified as finance leases. On initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset. Payments under finance leases are apportioned between interest expense and a reduction of the outstanding liability.

Other leases are operating leases and are not recognized in the Corporation's balance sheet. Payments made under operating leases are recognized as an expense on a straight-line basis over the term of the lease.

3. Significant accounting policies (continued)

(m) Payment in lieu of corporate income taxes ("PILs")

Under the Electricity Act, 1998, the Corporation is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). The payments in lieu of taxes are calculated on a basis as if the Corporation was a taxable company under the Income Tax Act (Canada) and the Taxation Act, 2007 (Ontario).

Income tax expense comprises current and deferred tax and is recognized in net income except to the extent that it relates to items recognized directly in other comprehensive income.

Current tax is the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized, using the liability method, on temporary differences arising between the carrying amount of balance sheet items and their corresponding tax basis, using the substantively enacted income tax rates for the years in which the differences are expected to reverse.

In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill.

A deferred tax asset is recognized for deductible temporary differences, to the extent that it is probable that future taxable income will be available against which they can be utilized.

(n) Investments in joint ventures

A joint venture is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the arrangement. The Group owns 50% of Collingwood PowerStream Utility Services Corp. ("Collus PowerStream"). This investment is accounted for using the equity method and is recognized initially at cost.

Any excess cost over the acquisition of the Group's share of the net fair value of the identifiable assets and liabilities of Collus PowerStream is recognized as goodwill and included in the carrying value of the investment.

If Collus PowerStream is in a loss position, then when the Group's share of losses in Collus PowerStream equals or exceeds its interest, the Group would discontinue recognizing its share of further losses.

The financial statements include the Corporations's share of the (loss)/income and other comprehensive (loss)/income of Collus PowerStream for the year ended December 31, 2013.

4. Changes in accounting policies

Future accounting changes

There are new standards, amendments to standards and interpretations which have not been applied in preparing these financial statements. In particular, this includes IFRS 9 *Financial Instruments* which is tentatively effective from periods beginning on or after January 1, 2018 and amendments to IFRS 7 and IFRS 9 which are effective at the date of adoption of IFRS 9.

All of the above standards or amendments relate to the measurement and disclosure of financial assets and liabilities. The extent of the impact on adoption of these standards and amendments has not yet been determined.

4. Changes in accounting policies (continued)

Future accounting changes (continued)

New and revised standards

There is only one new and revised standard that is effective for annual periods beginning on or after January 1, 2013. Information on this new standard is presented below:

IFRS 13 Fair Value Measurement

The Corporation has applied IFRS 13 for the first time in the current year. IFRS 13 establishes a single source of guidance for fair value measurements and disclosures. The scope of IFRS 13 is broad; the fair value measurement requirements of IFRS 13 apply to both financial instrument items and non-financial instrument items for which other IFRSs require or permit fair value measurements and disclosures, except for share-based payment transactions that are within in the scope of IFRS 2 *Share-based Payments,* leasing transactions that are within the scope of IAS 17 *Leases*, and measurements that have some similarities to fair value but are not fair value (e.g. net realizable value for the purposes of measuring inventories or value in use for impairment assessment purposes).

IFRS 13 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction in the principle (or most advantageous) market at the measurement date under current market conditions. Fair value under IFRS 13 is an exit price regardless of whether that price is directly observable or estimated using another valuation technique. Also, IFRS 13 includes extensive disclosure requirements.

IFRS 13 requires prospective application from January 1, 2013. In addition, specific transitional provisions were given to entities such that they need to apply the disclosure requirements set out in the standard in comparative information provided for periods before the initial application of the Standard. In accordance with these transitional provisions, the Group has not made any new disclosures required by IFRS 13 for the 2012 comparative period (please see note 17(a) for the 2013 disclosures). Other than the additional disclosures, the application of IFRS 13 has not had any material impact on the amounts recognized in the financial statements.

5. Investment in a joint venture

The Corporation owns a 50% interest in Collus PowerStream, a joint venture of which the Corporation has joint control. The cost of the investment includes transaction costs and the share of Collus PowerStream's (loss)/income and other comprehensive (loss)/income since the acquisition. Collus PowerStream is involved in the distribution of electricity in Collingwood, Thornbury, Stayner and Creemore as well as the provision of other utility services in the service area of Clearview and the Town of The Blue Mountains in the Province of Ontario. Collus PowerStream's principal place of business is the Town of Collingwood.

The following judgments were used in determining that the investment was a joint venture:

- Joint control was established by assessing that both the Corporation and the City of Collingwood have unanimous consent over relevant activities within Collus PowerStream. This was done through the agreements that were signed.
- This classification of the investment in Collus PowerStream as a joint venture was determined through analysis of the rights and obligations of the investment, specifically the legal structure.

(In thousands of dollars)

5. Investment in a joint venture (continued)

Summarized financial information for Collus PowerStream follows. There were no significant restrictions from borrowing arrangements or any commitments incurred on behalf of Collus PowerStream in relation to the Corporation.

	2013	2012
	$	$
Total assets	**26,126**	26,982
Total liabilities	**19,429**	19,789
Net revenue	**5,156**	7,323
Total (loss)/income and other comprehensive (loss)/income	**(1,974)**	300
Share of (loss)/income and other comprehensive (loss)/income	**(987)**	150

6. Inventories

During fiscal 2013, an amount of $12 (2012 - $34) was recorded as an expense for the write-down of obsolete or damaged inventory to net realizable value.

7. Property, plant and equipment

	Land and buildings	Distribution and other assets (Restated - Note 23)	Work-in-progress	Total (Restated - Note 23)
	$	$	$	$
Cost				
Balance at January 1, 2012	57,460	662,295	24,946	744,701
Additions	7,724	88,740	39,150	135,614
Adjustments	-	1,953	-	1,953
Disposals	-	(1,638)	-	(1,638)
Balance at December 31, 2012	65,184	751,350	64,096	880,630
Additions	1,570	144,226	3,739	149,535
Disposals	-	(1,715)	-	(1,715)
Balance at December 31, 2013	**66,754**	**893,861**	**67,835**	**1,028,450**
Accumulated depreciation				
Balance at January 1, 2012	1,110	30,874	-	31,984
Depreciation expense	1,124	31,230	-	32,354
Adjustments	-	1,953	-	1,953
Disposals	-	(107)	-	(107)
Balance at December 31, 2012	2,234	63,950	-	66,184
Depreciation expense	1,148	34,851	-	35,999
Disposals	-	(203)	-	(203)
Balance at December 31, 2013	**3,382**	**98,598**	**-**	**101,980**
Carrying amounts				
At December 31, 2012	62,950	687,400	64,096	814,446
At December 31, 2013	**63,372**	**795,263**	**67,835**	**926,470**

(In thousands of dollars)

7. Property, plant and equipment (continued)

Included in PP&E costs is $15,415 (2012 - $13,639) of operating expenses and $659 (2012 - $778) of interest capitalized during the year. These costs have been capitalized at a rate of 5.87% (2012 - 5.2%).

Included in work-in-progress is $16,174 (2012 - $6,288) relating to costs incurred for a customer information system (CIS) project. At the completion of the project the costs will be assessed and those costs relating to computer software will be transferred and recorded as part of intangible assets on the balance sheet.

The Corporation leases its operations centre under a finance lease agreement. The leased operations centre is secured as collateral against the lease obligation. At December 31, 2013 the net carrying amount of the operations centre was $15,355 (2012 - $16,086).

8. Intangible assets and goodwill

(a) Intangible assets

	Land rights	Computer software	Capital contributions	Total
	$	$	$	$
Cost				
Balance at January 1, 2012	765	9,782	609	11,156
Additions	32	2,289	4,363	6,684
Transfers from PP&E	-	-	-	-
Disposals	-	-	-	-
Balance at December 31, 2012	797	12,071	4,972	17,840
Additions	30	3,236	-	3,266
Transfers	-	-	-	-
Disposals	-	-	-	-
Balance at December 31, 2013	**827**	**15,307**	**4,972**	**21,106**
Accumulated amortization				
Balance at January 1, 2012	-	2,137	29	2,166
Amortization expense	-	2,537	288	2,825
Disposals	-	-	-	-
Balance at December 31, 2012	-	4,674	317	4,991
Amortization expense	-	2,679	289	2,968
Disposals	-	-	-	-
Balance at December 31, 2013	**-**	**7,353**	**606**	**7,959**
Carrying amounts				
At December 31, 2012	797	7,397	4,655	12,849
At December 31, 2013	**827**	**7,954**	**- 4,366**	**13,147**

(In thousands of dollars)

8. Intangibles assets and goodwill (continued)

(b) Impairment testing of goodwill and indefinite life intangible asset

For the purpose of impairment testing, goodwill with a carrying amount of $42,543 (2012 - $42,543) and land rights with a carrying amount of $826 (2012 - $797) are allocated to the Corporation's rate regulated and Permitted Generation Business unit CGUs. The Corporation tested goodwill and land rights for impairment as at December 31, 2013 in accordance with its policy described in Note 3.

The total recoverable amount of $1,095 million, being $941,000 and $154,000 for the rate regulated and Permitted Generation Business unit CGUs respectively, was determined based on its value-in-use. The Corporation has used discounted cash flow analysis to determine value-in-use. The value-in-use was determined in the same manner at December 31, 2013 and December 31, 2012.

The calculation of value in use for the rate regulated CGU was based on the following key assumptions:

- Cash flows were projected based on past experience and actual operating results using a 5 year forecast with growth rates of 2.50% (2012 - 2.50%) built into the forecast. Growth rates were determined using the Bank of Canada inflation forecast.
- A pre-tax discount rate of 5.87% (2012- 6.30%) and terminal value was used to discount the cash flows, this is derived from the Weighted Average Cost of Capital calculation. A discount rate increase of 0.25% would result in the carrying amount of the regulated CGU exceeding the recoverable amount by $5 million.

The calculation of value in use for the Permitted Generation Business unit CGU was based on the following key assumptions:

- Cash flows were projected based on past experience and actual operating results using a 5 year forecast with growth rates of 2.50% (2012 - 2.50%) built into the forecast. Growth rates were determined using the Bank of Canada inflation forecast.
- A pre-tax discount rate of 8.93% (2012 - 9.18%) and terminal value was used to discount the cash flows, this is derived from the Weighted Average Cost of Capital calculation. A discount rate increase of 4% would result in the carrying amount of the Permitted Generation Business unit CGU exceeding the recoverable amount by $5 million.

Guidance was applied by IAS 36 *Impairment of Assets* Appendix A, in determining the Weighted Average Cost of Capital ("WACC") which is not asset specific.

9. Accounts payable and accrued liabilities

	2013	2012
	$	$
Accounts payable - energy purchases	**73,982**	58,480
Debt retirement charge payable - OEFC	**4,494**	4,319
Payroll payable	**5,956**	4,963
Interest payable	**3,298**	3,420
Commodity taxes payable	**(871)**	(1,395)
Customer receivables in credit balances	**3,809**	3,456
Other accounts payable and accrued liabilities	**46,026**	40,417
	136,694	113,660

(In thousands of dollars)

10. Related party balances and transactions

(a) Transactions with jointly controlling shareholders

The amount due to/(from) related parties is comprised of amounts payable to/(receivable from) the City of Vaughan, the City of Markham, the City of Barrie and their wholly-owned subsidiaries.

Components of the amounts due to/(from) related parties are as follows:

	2013	2012
	$	$
Due from:		
City of Vaughan	**(824)**	(673)
City of Markham	**(1,000)**	(1,483)
City of Barrie	**(709)**	(858)
	(2,533)	(3,014)
Due to:		
City of Vaughan	**7,241**	6,523
City of Markham	**8,252**	7,145
City of Barrie	**282**	282
	15,775	13,950

Other significant related party transactions with the jointly controlling shareholders not otherwise disclosed separately in the financial statements, are summarized below:

			2013			2012
	City of Vaughan	**City of Markham**	**City of Barrie**	City of Vaughan	City of Markham	City of Barrie
	$	**$**	**$**	$	$	$
Revenue						
Energy and distribution	**5,985**	**9,544**	**6,921**	5,527	7,741	6,746
Shared services	**1,676**	**1,939**	**-**	1,781	2,791	-
Total revenue	**7,661**	**11,483**	**6,921**	7,308	10,532	6,746
Expenses						
Realty taxes	**713**	**554**	**269**	661	456	283
Facilities rental and other	**19**	**59**	**53**	29	19	12
Total	**6,929**	**10,870**	**6,599**	6,618	10,057	6,451

These transactions are in the normal course of operations and are recorded at the exchange amount. The Corporation has certain operating leases with the City of Vaughan, City of Markham and City of Barrie to lease rooftops on a number of buildings for which feed-in tariff contracts have been obtained. The current year lease expense has been included in the ‘Facilities rental and other’ line on the table above, and the future operating lease commitments have been disclosed in Note16(b).

(In thousands of dollars)

10. Related party balances and transactions (continued)

(a) Inter-company balances

The amount due from inter-company related parties is comprised of a receivable from PowerStream Energy Services Inc., a subsidiary of PowerStream Holdings Inc., is as follows:

	2013	2012
	$	$
Due from:		
PowerStream Energy Services Inc.	**204**	-

(b) Key management personnel compensation

Key management personnel are comprised of the Corporation's senior management team. The compensation paid or payable to key management personnel is as follows:

	2013	2012
	$	$
Short-term employment benefits and salaries	**7,946**	7,526
Post-employment benefits	**954**	749
Termination benefits	**21**	178
	8,921	8,453

11. Short-term debt

(a) Credit facilities

On December 17, 2008 the Corporation executed an unsecured credit facility with a Canadian chartered bank. The credit facility is renewable annually. The credit facility agreement provides an extendible 364-day committed revolving credit facility of $75,000, an uncommitted demand facility of $25,000, and uncommitted Letter of Guarantee facilities of $15,000 and $336 respectively. As at December 31, 2013, the Corporation utilized the 364-day committed revolving credit facility by drawing $7,368 of the $75,000 available.

In addition to the above, the Corporation entered into a second unsecured credit facility agreement that provided for a committed line of credit of up to $150,000. This committed facility matures on February 12, 2015.

As at December 31, 2013, the Corporation had utilized $14,999 (2012 - $14,999) of the uncommitted Letter of Guarantee facility for a letter of credit that was provided to the IESO to mitigate the risk of default on energy payments. With the opening of Ontario's electricity market to wholesale and retail competition on May 1, 2002 ("Open Access"), the IESO requires all purchasers of electricity in Ontario to provide security to mitigate the risk of their default based on their expected purchases from the IESO administered spot market. The IESO could draw on the letter of credit if the Corporation defaults on its payment. Further, as at December 31, 2013, an additional $336 (2012 - $450) of the uncommitted Letter of Guarantee facility was utilized as security for operating projects.

(In thousands of dollars)

11. Short-term debt (continued)

(a) Credit facilities (continued)

The 364-day committed revolving credit facility can be drawn upon by direct advances, bearing interest at the lower of prime plus 0% or Bankers' Acceptance of a stamping fee plus 110 basis points (1.10% per annum). The uncommitted demand facility bears an interest rate at the lower of prime minus 0.30% or Bankers' Acceptance of a stamping fee plus 68 basis points (0.68% per annum). The Letter of Guarantee facility bears a charge of 50 basis points (0.50%) per annum.

The committed demand facility bears an interest rate at Bankers' Acceptance stamping fee plus 70 basis points (0.70% per annum), with commitment fee of 14 basis points applied to the unutilized balance.

The amount of short-term debt drawn on the available credit facilities consists of:

	2013	2012
	$	$
Uncommitted demand facility	**-**	25,000
Committed demand facility	**70,000**	-
	70,000	**25,000**

(b) Ontario Infrastructure and Lands Corporation ("Infrastructure Ontario") financing

On October 15, 2010 the Corporation secured financing with Infrastructure Ontario for its Permitted Generation Business unit. The funding is available for up to 5 years from the date that the agreement was signed.

As at December 31, 2013, the Corporation has utilized $48,315 (2012 - $8,523) of the $90,000 financing facility, of which $4,457 (2012 - $1,911) was transferred to a long-term debenture. Each advance bears interest at a floating rate per annum as determined by Infrastructure Ontario. The advance interest rate at December 31, 2013 was 1.79% (2012 - 1.74%) and interest expense on short-term debt for the year was $277 (2012 - $13).

A note in the amount of $980 bears interest at a rate of 4.09% per annum payable on May 15 and November 15 each year and matures on November 17, 2031.

A note in the amount of $964 bears interest at a rate of 3.54% per annum payable on February 15 and August 15 each year and matures on August 1, 2032.

A note in the amount of $2,709 bears interest at a rate of 3.85% per annum payable on March 1 and September 1 each year and matures on March 1, 2033.

The Corporation will pay Infrastructure Ontario a stand-by fee calculated at a rate of 25 basis points (0.25%) on the advanced balance of the committed amount should the Corporation fail to draw any funds pursuant to the agreement from Infrastructure Ontario during any period of 12 consecutive months commencing initially from October 15, 2010 and subsequently from the date of the draw of any such funds until the earlier of the facility termination date October 15, 2015 or the full advance of the committed amount. Infrastructure Ontario financing is secured by the assets of the Permitted Generation Business unit. The financial covenants require a debt service coverage ratio of 1:1 or higher, a debt to capital ratio of 70% or lower, and a current ratio of 1:1 or higher. See Note 18 on the compliance of the covenant.

(In thousands of dollars)

12. Long-term debt

(a) Bank term loan

The 5 year fixed rate term loan of $0 (2012 - $50,000) with a Canadian Chartered Bank had matured with repayment at the end of the contracted term, February 26, 2013.

(b) Debentures payable

	2013	2012
	$	$
3.958% unsecured debentures due July 30, 2042, interest payable in arrears semi-annually on January 30 and July 30	**198,221**	198,189

The debentures rank *pari passu* with all of the Corporation's other senior unsubordinated and unsecured obligations.

The debentures are subject to a financial covenant. This covenant requires that neither the Corporation nor any designated subsidiary may incur any funded obligation (other than non-recourse debt, capital lease obligations, intercompany indebtedness and purchase money obligations) unless the aggregate principal amount of the consolidated funded obligations does not exceed 75% of the total consolidated capitalization. As at December 31, 2013 the Corporation is in compliance with this covenant.

(c) Notes payable

	2013	2012
	$	$
Promissory note issued to the City of Vaughan	**78,236**	78,236
Deferred interest on promissory note issued to the City of Vaughan	**8,743**	-
Promissory note issued to the City of Markham	**67,866**	67,866
Deferred interest on promissory note issued to the City of Markham	**7,585**	-
Promissory note issued to the City of Barrie	**20,000**	20,000
Total long term notes payable	**182,430**	166,102
Less current portion:		
Deferred interest on promissory note issued to the City of Vaughan	**-**	8,743
Deferred interest on promissory note issued to the City of Markham	**-**	7,585
Total current notes payable	**-**	16,328
Total notes payable	**182,430**	182,430

On June 1, 2004 an unsecured 20 year term promissory note was issued to the City of Vaughan in the amount of $78,236. Interest thereon commenced on June 1, 2004 at an annual rate of 5.58%.

On June 1, 2004 an unsecured 20 year term promissory note was issued to the City of Markham in the amount of $67,866. Interest thereon commenced on June 1, 2004 at an annual rate of 5.58%.

(In thousands of dollars)

12. Long-term debt (continued)

(c) Notes payable (continued)

On December 31, 2008, an unsecured 16 year term promissory note was issued to the City of Barrie in the amount of $20,000. Interest thereon commenced on January 1, 2009 is at an annual rate of 5.58%.

The three promissory notes are repayable 90 days following demand by the City of Vaughan, the City of Markham, and the City of Barrie, with subordination and conditions. These notes have been classified as long-term, as the City of Vaughan, the City of Markham, or the City of Barrie, have indicated they will not demand repayment before January 1, 2015.

At the request of the City of Vaughan and the City of Markham, eight quarters of interest have been deferred commencing October 1, 2006 until October 31, 2013. In 2013, it has been further deferred so that the deferred interest will be repayable in full on October 31, 2018 and is subject to 4.03% interest rate.

13. Post-employment benefits

(a) Multi-employer defined benefit pension plan

During fiscal 2013, the expense recognized in conjunction with the OMERS plan, which is equal to contributions due for the year was $5,466 (2012 - $4,591). At December 31, 2013, $812 (2012 - $698) of contributions were payable to the OMERS plan and were included in accounts payable and accrued liabilities on the balance sheet.

As at December 31, 2013, OMERS had approximately 429,000 members, of whom approximately 550 are current employees of the Corporation. The accrued benefit obligation of the OMERS plan as shown in OMERS financial statements as at December 31, 2013 is $73,044 million, with a funding deficit of $8,641 million. The funding deficit will result in future payments by the participating employers.

The Corporation shares in the actuarial risks of the other participating entities in the OMERS plan and its future contributions may therefore be increased due to actuarial losses relating to the other participating entities. In addition, the withdrawal of other participating entities from the OMERS plan may also result in an increase to the Corporation's future contribution requirements.

(b) Non-pension defined benefit pension plans

A reconciliation of the obligation for the defined benefit plans is as follows:

	2013	2012
	$	$
Defined benefit obligation, beginning of the year	**18,048**	16,811
Amounts recognized in net income:		
Current service cost	**1,099**	1,051
Interest expense	**798**	744
Past service cost and gains/losses arising from settlements	**-**	-
	1,897	1,795
Payments from the plan	**(628)**	(558)
Defined benefit obligation, end of the year	**19,317**	18,048

(In thousands of dollars)

13. Post-employment benefits (continued)

The obligation for the defined benefit plans is presented in the balance sheet as post-employment benefits.

The significant actuarial assumptions used to determine the present value of the obligation for the defined benefit plans are as follows:

	2013	2012
	%	%
Discount rate	**4.50**	4.50
Rate of compensation increase	**3.50**	3.50
Medical benefits costs escalation	**5.00 - 7.25**	5.00 - 7.63
Dental benefits costs escalation	**5.00**	5.00

14. Share capital

The Corporation's authorized share capital is made up of an unlimited number of common shares, and an unlimited number of Class A non-voting common shares, all of which are without nominal or par value.

The share capital issued during the period is as follows:

	Common shares		Class A common shares		Total
	Shares issued	$	Shares issued	$	$
Balance at January 1, 2012	100,000	247,183	7,955	4,774	251,957
Issued for cash	-	-	47,240	28,344	28,344
Balance at December 31, 2012	100,000	247,183	55,195	33,118	280,301
Issued for cash	-	-	14,028	8,417	8,417
Balance at December 31, 2013	**100,000**	**247,183**	**69,223**	**41,535**	**288,718**

On November 23, 2010 a Subscription Agreement was signed between the Corporation and its Shareholders for new Class A common shares for the purposes of the Shareholders providing equity for the Corporation's Permitted Generation business unit. The articles of incorporation and shareholders agreement were amended in order to proceed with the subscription agreement. This Subscription Agreement expired on December 31, 2011 and as such, a revised Subscription Agreement was signed between the Corporation and its Shareholders on January 1, 2012 to extend the equity financing in respect of the Corporation's Permitted Generation Business unit.

The maximum amount of Class A common shares that are available under the subscription agreement is 100,000. During 2013, an additional 14,028 (2012 - 47,240) of the Class A common shares were issued for an amount of $8,417 (2012 - $28,344).

On November 1, 2013, a Unanimous Shareholders Agreement was signed between the Corporation and its Shareholders, superseding the existing revised Subscription Agreement. This ensured a reorganization of the Corporation becoming a wholly owned subsidiary of the newly established Group, PowerStream Holdings Inc. In effect, the total 100,000 common shares and 69,223 Class A common shares of the Corporation are wholly owned by PowerStream Holdings Inc.

14. Share capital (continued)

Dividends

The Corporation has established a dividend policy to pay a minimum of 50% of Modified IFRS ("MIFRS", framework used for reporting to the OEB) net income to PowerStream Holdings Inc., excluding the Permitted Generation Business unit income, with consideration given to the following:

- Cash position at the beginning of the current year;
- Working capital requirements for the current year; and
- Net capital expenditures required for the current year.

The Corporation paid a dividend of $149.16 per share (2012 - $160.87) on the common shares during the year, amounting to a total dividend of of $14,916 (2012 - $16,087). The Corporation is proposing to continue to follow the practice of proposing a dividend to be paid on common shares in 2014, representing 50% of the MIFRS net income. The proposed dividend would amount to $165.75 per share, resulting in a total dividend of $16,575. There is no tax affect as the dividends are paid out on an after tax basis.

The Corporation has also established a dividend policy for its Permitted Generation Business unit to distribute a dividend on the Class A common shares to PowerStream Holdings Inc. determined as follows:

- The Corporation will target an IRR of 10.5% on the Permitted Generation Business Unit.
  As each project is completed by the Permitted Generation Business Unit, the Corporation expects to make distributions calculated with reference to the Class A Common Shares equity injections made by the Shareholders from time to time, provided that the amount of each dividend will be at the discretion of the Board of Directors ("Board") and may be greater or lesser than the below having regard to the financial and operating results of the Corporation as a whole;
  - For purposes of the dividend declaration that follows receipt of the unaudited IFRS financial statements for the Permitted Generation Business unit at mid-year, such amounts shall be the greater of:
    - the amounts reported in the most recent unaudited year-end IFRS financial statements for the Permitted Generation Business unit, or
    - the sum of fifty percent (50%) of the amounts reported in the most recent unaudited year-end IFRS financial statements for the Permitted Generation Business unit plus 100% of the amounts reported in the most recent unaudited mid-year IFRS financial statements for the Permitted Generation Business unit (i.e. for a six-month period).
- In the Post-Construction Period or earlier as determined by the Board, the net free cash flow will be paid to the holders of the Class A Common Shares subject to the criteria listed below:
  - Dividends will be declared by the Corporation's Board of Directors after due consideration is given to the following:
    - All financial covenants on any debt issued by the Corporation.
    - Qualifications to meet external bond rating criteria and ensure no adverse impact on the current credit rating of the Corporation. The Corporation will advise the Shareholders of its credit rating from time to time (and at least on an annual basis).
    - Cash flow requirements of the Permitted Generation Business Unit of the Corporation to meet working capital requirements and short-term (2 year) plans of capital expenditures.
    - The maintenance of the planned 60/40 debt to equity ratio.

There have been no dividends on Class A common shares paid during the year (2012 - $Nil).

(In thousands of dollars)

15. Insurance

The Corporation maintains appropriate types and levels of insurance with major insurers. With respect to liability insurance, the Corporation is a member of the Municipal Electricity Association Reciprocal Insurance Exchange (“MEARIE”). A reciprocal insurance exchange may be defined as a group of persons formed for the purpose of exchanging reciprocal contracts of indemnity or inter-insurance with each other. MEARIE is licensed to provide general liability insurance to its members.

Insurance premiums charged to each member consist of a levy per thousands of dollars of service revenue subject to a credit or surcharge based on each member’s claims experience. The maximum coverage is $24,000 for liability insurance, $405,510 for property insurance, $15,000 for vehicle insurance, and $4,500 for credit insurance; plus $10,000 excess coverage on top of the regular liability and vehicle coverage.

16. Leases

(a) Finance leases

The Corporation leases its operations centre under a 25 year lease agreement. The lease agreement includes both land and building elements. Upon entering into this lease arrangement, the Corporation classified the building element of the lease as a finance lease since it was determined that substantially all of the benefits and risks incidental to ownership of the operation centre were transferred to the Corporation (the lessee). The component of the annual basic rent related to the land is classified and recorded as an operating lease and the component related to the building is classified as a finance lease.

			2013
	Future minimum lease payments (including interest)	**Interest**	**Present value of minimum lease payments**
	$	**$**	**$**
Less than one year	**1,430**	**1,115**	**315**
Between one and five years	**7,150**	**5,222**	**1,928**
More than five years	**23,566**	**8,702**	**14,864**
	32,146	**15,039**	**17,107**

			2012
	Future minimum lease payments (including interest)	Interest	Present value of minimum lease payments
	$	$	$
Less than one year	1,430	1,135	295
Between one and five years	7,150	5,344	1,806
More than five years	24,996	9,695	15,301
	33,576	16,174	17,402

(In thousands of dollars)

16. Leases (continued)

(a) Finance leases (continued)

Interest on the lease obligation during fiscal 2013 amounted to $1,135 (2012 - $1,153) based on the rate of 6.57% per annum (2012 - 6.57%). Amortization of the corresponding PP&E during fiscal 2013 amounted to $731 (2012 - $733) based on the straight-line method with a useful life equal to the term of the lease (25 years). The Corporation has the option to purchase within twelve months before the expiry of the original lease in 2034, or an option of three five year lease extensions.

(b) Operating leases

The Corporation is also committed to lease agreements for various vehicles, equipment, rooftops and the land portion of the finance lease for solar projects that have been classified as operating leases. The leases typically run for a period of 5 to 20 years.

The future minimum non-cancellable annual lease payments (including the land portion of the operating centre lease referred to in (a) above) are as follows:

	2013	2012
	$	$
Less than one year	**3,097**	1,612
Between one and five years	**15,351**	7,793
More than five years	**37,473**	24,599
	55,921	34,004

During the year ended December 31, 2013 an expense of $3,105 (2012 - $1,656) was recognized in net income in respect of operating leases.

17. Financial instruments and risk management

(a) Fair value of financial instruments

The Corporation's accounting policies relating to the recognition and measurement of financial instruments are disclosed in Note 3(d).

The carrying amount of cash, accounts receivable, unbilled revenue, amounts due from related parties, bank indebtedness, liability for subdivision development, short-term debt, short- term Infrastructure Ontario financing, customer deposits, accounts payable and accrued liabilities and amounts due to related parties approximates fair value because of the short maturity of these instruments. The carrying value and fair value of the Corporation's other financial instruments are as follows:

		2013		2012
Description	**Carrying value**	**Fair value**	Carrying value	Fair value
	$	**$**	$	$
Liabilities				
Notes payable	**182,430**	**206,990**	182,430	225,972
Debentures payable	**198,221**	**176,865**	198,189	199,000
Infrastructure Ontario	**-**	**-**	1,911	2,066
	380,651	**383,855**	382,530	427,038

The carrying amounts shown in the table are included in the balance sheet under the indicated captions. The fair value of the $4,457 long-term Infrastructure Ontario debenture which has been reclassified as a current liability (see Note 18) is $3,997 as at December 31, 2013.

(In thousands of dollars)

17. Financial instruments and risk management

(a) Fair value of financial instruments (continued)

Financial instruments which are disclosed at fair value are to be classified using a three - level hierarchy. Each level reflects the inputs used to measure the fair values disclosed of the financial liabilities, and are as follows:

- Level 1: inputs are unadjusted quoted prices of identical instruments in active markets,
- Level 2: inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly, and
- Level 3: inputs for the liabilities that are not based on observable market data (unobservable inputs).

The Corporation's fair value hierarchy is classified as Level 2 for notes and debentures payable. The classification for disclosure purposes has been determined in accordance with generally accepted pricing models, based on discounted cash flow analysis, with the most significant inputs being the contractual terms of the instrument discounted, and the market discount rates that reflects the credit risk of counterparties.

(b) Risk factors

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation's exposure to a variety of risks such as credit risk, interest rate risk and liquidity risk as well as related mitigation strategies have been discussed below. However, the risks described below are not exhaustive of all the risks nor will the mitigation strategies eliminate the Corporation's exposure to all risks listed.

(c) Credit risk

The Corporation's primary source of credit risk to its accounts receivable result from customer's failing to discharge their dues for electricity consumed and billed.

The Corporation has approximately 365,000 (2012 - 355,000) residential and commercial customers. In order to mitigate such potential credit risks, the Corporation has taken various measures in respect of its Energy customers such as collecting security deposits amounting to $14,830 (2012 - $15,216) in accordance with OEB guidelines, reviewing Dun & Bradstreet ("D&B") reports for the top 3000 commercial customers with an outstanding balance of $5 or more, in-house collection department as well as external collection agencies and a bad debt insurance policy for $4,500 (2012 - $4,500) related to energy receivables. Thus, the Corporation monitors and limits its exposure to such credit risks on an ongoing basis.

Pursuant to their respective terms, accounts receivable are aged as follows at December 31:

	2013		2012	
	Total		Total	
	$	**%**	$	%
Less than 30 days	**78,987**	**86**	70,205	84
30 - 60 days	**8,129**	**9**	9,151	11
61 - 90 days	**1,955**	**2**	2,218	3
Greater than 91 days	**2,902**	**3**	2,336	2
Total outstanding	**91,973**	**100**	83,910	100
Less: allowance for doubtful accounts	**(1,344)**	**(1)**	(1,487)	(2)
	90,629	**99**	82,423	98

As at December 31, 2013, there was no significant concentration of credit risk with respect to any financial assets.

(In thousands of dollars)

17. Financial instruments and risk management (continued)

(d) Interest rate risk

The Corporation manages its exposure to interest rate risk by issuing long term fixed rate debt in the form of debentures, promissory notes and bank loans. It also ensures that all payment obligations are met by adopting proper capital planning.

As part of the Corporations' revolving demand operating credit facility, the Corporation may utilize the line of credit for working capital and/or capital expenditure purposes. Such short-term borrowing may expose the Corporation to short-term interest rate fluctuations as follows:

	2013	2012
364 day revolving facility		
Prime based loans	**PR*+0.0% p.a.**	PR*+0.15% p.a.
Bankers Acceptances	**SF*+0.95% p.a.**	SF*+1.10% p.a.
Demand facility		
Prime based loans	**PR*–0.30% p.a.**	PR*–0.15% p.a.
Bankers acceptances	**SF*+0.68% p.a.**	SF*+0.85% p.a.
Bankers acceptances (Secondary)	**SF*+0.70% p.a.**	
Letter of guarantee facility	**0.50% p.a.**	0.50% p.a.
Infrastructure Ontario financing	**Floating rate p.a.**	Floating rate p.a.

Note: PR - Prime Rate, SF* - Stamping Fee*

A sensitivity analysis was conducted to examine the impact of a change in the prime rate or stamping fee on the short-term debt. A variation of 1% (100 basis points), with all other variables held constant, would increase or decrease the annual interest expense by approximately $700.

Cash balances that are not required for day to day obligations earn an interest of Prime minus 1.7% per annum. Fluctuations in this interest rate could impact the level of interest income earned by the Corporation.

(e) Liquidity risk

Liquidity risks are those risks associated with the Corporation's inability to meet obligations associated with financial liabilities such as repayment of principal or interest payments on debts.

The Corporation monitors its liquidity risks on a regular basis to ensure there is sufficient cash flow to meet the obligations as they fall due as well as minimize the interest expense. Cash flow forecasts are prepared to monitor liquidity risks. Liquidity risks associated with financial liabilities are as follows:

			2013			2012
Maturity period	**Principal***	**Interest**	**Total**	Principal*	Interest	Total
	$	**$**	**$**	$	$	$
Less than 1 year	**296,126**	**20,789**	**316,915**	238,685	19,098	257,783
1-5 years	**920**	**86,320**	**87,240**	365	85,753	86,118
6-10 years	**1,113**	**80,721**	**81,834**	441	85,822	86,263
Over 10 years	**366,600**	**138,328**	**504,928**	365,395	149,857	515,252
	664,759	**326,158**	**990,917**	604,886	340,530	945,416

*The principal includes $1,778 (2012 - $1,811) of deferred issuing cost amortization.

(In thousands of dollars)

17. Financial instruments and risk management (continued)

(f) Hedging/derivative risk

The Corporation has a swap and derivative transaction policy to enable the Corporation to enter into agreements such as interest rate swaps where 100% of the floating rate risk is hedged into a fixed rate. This is done for prudent risk management purposes and not speculative purposes.

The Corporation has not entered into any such transactions during the year current or prior years.

18. Capital structure

The Corporation's main objectives in the management of capital are to:

(i) Ensure that there is access to various funding options at the lowest possible rates for the various capital initiatives and working capital requirements necessary for the rate-regulated business;

(ii) Ensure compliance with various covenants related to its short-term debt, Infrastructure Ontario financing, bank term loan, debentures payable and Infrastructure Ontario debentures;

(iii) Consistently maintain a high credit rating for the Corporation;

(iv) Maintain a split of approximately 60% debt, 40% equity as recommended by the OEB;

(v) Ensure interest rate fluctuations are mitigated primarily by long term borrowings as well as capital planning; and

(vi) Deliver appropriate financial returns to shareholders.

The Corporation considers shareholders' equity, long-term debt and certain short-term debt as its capital. The capital structure as at December 31, 2013 is as follows:

	2013	2012 (Restated - Note 23)
	$	$
Short-term debt		
Short-term debt (Note 11)	**70,000**	25,000
Infrastructure Ontario financing (Note 11)	**48,315**	6,612
Bank term loan (Note 12)	**-**	50,000
Notes payable (Note 12)	**-**	16,328
Long-term debt		
Debentures payable (Note 12)	**198,221**	198,189
Notes payable (Note 12)	**182,430**	166,102
Infrastructure Ontario debentures (Note 11)	**-**	1,911
Total debt	**498,966**	464,142
Shareholders' equity		
Share capital (Note 14)	**288,718**	280,301
Accumulated other comprehensive income	**(739)**	(739)
Retained earnings	**123,157**	109,933
Total equity	**411,136**	389,495
Total	**910,102**	853,637

(In thousands of dollars)

18. Capital structure (continued)

As at December 31, 2013, the Corporation was in compliance with covenants related to its short-term debt, bank term loan and debentures payable. Subsequent to year-end, the Corporation received a waiver with respect to the current ratio covenant calculation as at December 31, 2013 on its Infrastructure Ontario financing covenants. As the waiver was received subsequent to year-end, the long-term Infrastructure Ontario debenture of $4,457 has been presented as a current liability. Details relating to covenants are disclosed in Note 11 and Note 12.

The Corporation is within the debt and equity requirements of the OEB. The Corporation's dividend policy is disclosed in Note 14.

19. Operating expenses

Operating expenses comprise:

	2013	2012
	$	$
Labour	**44,121**	43,775
Contract/consulting	**13,931**	14,052
Materials	**1,183**	1,124
Vehicle	**1,264**	1,392
Other	**25,084**	29,159
	85,583	89,502

20. Income taxes

(a) Income tax expense

PILs recognized in net income comprise the following:

	2013	2012
	$	$
Current tax expense		
Current year	**(995)**	(1,479)
Deferred tax expense		
Origination and reversal of temporary differences	**9,827**	11,161
Change in deferred tax rate	**-**	(2,397)
	9,827	8,764
Income tax expense	**8,832**	7,285

(In thousands of dollars)

20. Income taxes (continued)

(b) *Reconciliation of effective tax rate*

The PILs income tax expense differs from the amount that would have been recorded using the combined Canadian federal and provincial statutory income tax rates. The reconciliation between the statutory and effective tax rates is as follows:

	2013	2012
	$	$
Income before taxes	**36,972**	42,611
Statutory Canadian federal and provincial income tax rates	**26.50%**	26.50%
Expected tax provision on income at statutory rates	**9,798**	11,292
Increase (decrease) in income taxes resulting from:		
Permanent differences	**60**	484
Changes and differences in deferred tax rate	**-**	(2,397)
Scientific Research and Experimental Development tax credit	**(1,202)**	(762)
Other	**176**	(1,332)
Income tax expense	**8,832**	7,285

Statutory Canadian federal and provincial income tax rates for the current year comprise 15% (2012 - 15%) for federal corporate tax and a rate of 11.5% (2012 - 11.5%) for corporate tax in Ontario. There was no change in the federal corporate tax rate in 2013 (2012 - 16.5% to 15%) and no change in the provincial corporate tax rate in 2013 (no change in 2012).

(c) *Deferred tax assets*

Deferred tax assets are attributable to the following:

	2013	2012
	$	$
Employee future benefits	**5,509**	4,783
Property, plant and equipment	**18,316**	30,265
Intangible assets	**1,367**	1,484
Other deductible temporary differences	**559**	(2,450)
Balance at December 31	**25,751**	34,082

Movements in deferred tax balances during the year were as follows:

	2013	2012
	$	$
Balance at January 1	**34,082**	41,621
Recognized in net income	**(8,331)**	(7,539)
Balance at December 31	**25,751**	34,082

(In thousands of dollars)

20. Income taxes (continued)

(d) Deferred tax liabilities

Deferred tax liability of $3,214 at December 31, 2013 (2012 - $1,730) represents differences between book and tax values of property, plant and equipment from the Permitted Generation Business unit.

21. Net change in non-cash operating working capital

	2013	2012
	$	$
Accounts receivable	**(8,206)**	4,133
Unbilled revenue	**(19,453)**	(6,018)
Due from a related party	**275**	(841)
Inventories	**(10)**	321
Prepaids and other assets	**(61)**	(800)
Customer deposits	**293**	29
Accounts payable and accrued liabilities	**24,228**	(1,515)
Due to related parties	**1,825**	675
Liability for subdivision development	**1,349**	1,066
Capital accruals in prior year	**5,080**	-
Capital accrual in current year	**(10,122)**	(5,080)
	(4,802)	(8,030)

22. Contingencies, commitments and guarantees

(a) Contingencies- legal claims

The Corporation has been named as a defendant in several actions. No provision has been recorded in the financial statements for these potential liabilities as the Corporation expects that these claims are adequately covered by its insurance.

(b) Commitments

As at December 31, 2013, the Corporation has entered into agreements for capital projects and is committed to making payments of $80,619 in 2014.

(c) Guarantees

In the normal course of business, the Corporation enters into agreements that meet the definition of a guarantee as follows:

(i) The Corporation has provided indemnities under lease agreements for the use of various operating facilities. Under the terms of these agreements the Corporation agrees to indemnify the counterparties for various items including, but not limited to, all liabilities, loss, suits, and damages arising during, on or after the term of the agreement. The maximum amount of any potential future payment cannot be reasonably estimated.

(ii) Indemnity has been provided to all directors and/or officers of the Corporation for various items including, but not limited to, all costs to settle suits or actions due to association with the Corporation, subject to certain restrictions. The Corporation has purchased directors' and officers' liability insurance to mitigate the cost of any potential future suits or actions. The term of the indemnification is not explicitly defined, but is limited to the period over which the indemnified party served as a trustee, director or officer of the Corporation. The maximum amount of any potential future payment cannot be reasonably estimated.

(In thousands of dollars)

22. Contingencies, commitments and guarantees (continued)

(c) Guarantees (continued)

(iii) In the normal course of business, the Corporation has entered into agreements that include indemnities in favor of third parties, such as purchase and sale agreements, confidentiality agreements, engagement letters with advisors and consultants, outsourcing agreements, leasing contracts, information technology agreements and service agreements. These indemnification agreements may require the Corporation to compensate counterparties for losses incurred by the counterparties as a result of breaches in representation and regulations or as a result of litigation claims or statutory sanctions that may be suffered by the counterparty as a consequence of the transaction. The terms of these indemnities are not explicitly defined and the maximum amount of any potential reimbursement cannot be reasonably estimated.

The nature of these indemnification agreements prevents the Corporation from making a reasonable estimate of the maximum exposure due to the difficulties in assessing the amount of liability which stems from the unpredictability of future events and the unlimited coverage offered to counterparties. Historically, the Corporation has not made any significant payments under such or similar indemnification agreements and therefore no amount has been accrued in the balance sheet with respect to these agreements.

23. Correction of error

In the preparation of the Corporation's financial statements for the current year, management identified an error in PP&E (distribution assets category) for the year ended December 31, 2011. As a result, the Corporation has restated its financial statements from January 1, 2012.

The following table summarizes the impact of the restatement on the Corporation's previously reported amounts:

	Property, plant and equipment	Retained earnings
	$	$
As at December 31, 2012	820,923	116,410
Correction	(6,477)	(6,477)
As restated	814,446	109,933

PowerStream Inc.

Rating

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Senior Unsecured Debentures	A	Confirmed	Stable

Rating Update

DBRS has confirmed the Issuer Rating and the Senior Unsecured Debentures of PowerStream Inc. (PowerStream or the Company) at "A" with Stable trends. The ratings reflect the low business risk profile associated with PowerStream's stable regulated electricity distribution business, as well as its reasonable financial profile.

PowerStream's business risk profile is indicative of the "A" rating category, supported by distribution operations in a strong franchise area and a reasonable regulatory framework. The Company's regulated business is expected to continue to account for over 90% of total earnings and cash flows. Volatility from the non-regulated segments also remains manageable as power price risk has been effectively mitigated through long-term contracts with the Ontario Power Authority (OPA; rated A (high)). Given the Company's significant capital spending requirements, DBRS expects PowerStream to transition to Custom Incentive Rate-setting (CIR) under Ontario's Renewed Regulatory Framework (see Regulation section) from the current 3rd Generation Incentive Regulation Mechanism (IRM) when it next rebases. DBRS views CIR as appropriate for those distributors, such as PowerStream, with large, broad, multi-year capital expenditures (capex) that require certainty of funding in advance. DBRS notes that some concerns regarding key factors of the renewed framework, such as efficiency targets and the recovery and pass-through of capital costs to ratepayers, have eased after the late-2013 release of the Ontario Energy Board's (OEB) report on rate setting parameters and benchmarking. However, there remains uncertainty regarding what the OEB may approve under the renewed framework. Additionally, PowerStream may face moderately higher regulatory risk under CIR as this regime has a minimum term of five years versus four years under IRM, potentially resulting in greater regulatory lag. This is partially mitigated by the ability for the Company to initiate a regulatory review if actual return on equity (ROE) falls 300 basis points (bps) below the approved ROE.

PowerStream's financial risk profile is reflective of the "A" rating category, with all credit metrics in the "A" rating range. While large capital spending is planned for the medium-term, DBRS expects PowerStream to continue to fund free cash flow deficits through a mix of debt and equity in order to maintain its debt leverage in line with the regulatory capital structure.

Rating Considerations

Strengths
(1) Strong franchise area with good growth
(2) Second-largest local distribution company in Ontario
(3) Reasonable financial metrics

Challenges
(1) Managing capital expenditures
(2) Uncertain regulatory framework
(3) Limited access to equity markets

Financial Information

PowerStream Inc.	For the year ended December 31				
(CA$ millions)	**2013***	**2012***	**2011***	**2010**	**2009**
Total debt	523	482	427	415	396
Total debt in capital structure (1) (2)	59.5%	58.6%	58.8%	59.5%	60.4%
Cash flow/Total debt (1)	15.3%	15.3%	18.0%	20.7%	18.1%
EBIT gross interest coverage (times) (1)	2.53	2.14	2.77	2.57	2.32
Net income before non-recurring items	35.9	30.6	38.7	26.8	22.0
Cash flow from operations	83.2	74.9	78.1	87.1	73.9

(1) Includes operating leases. (2) Adjusted for accumulated other comprehensive income.

*Note: IFRS financial results have been adjusted by DBRS; values do not reflect Modified IFRS reporting required by the OEB.

Rating Considerations Details

Strengths

(1) **Strong franchise area with good growth.** PowerStream's franchise area is one of the strongest in Ontario, with relatively strong customer growth, averaging 2% over recent years. The customer mix is also favourable, with residential customers accounting for nearly 90% of total customers in 2013. This reduces the Company's exposure to economic conditions, as residential demand is very consistent.

(2) **Second-largest local distribution company (LDC) in Ontario.** With approximately 365,000 customers (as of December 31, 2013), the Company is the second-largest municipally-owned electricity utility in Ontario, behind only Toronto Hydro Corporation. The size of the customer base allows the company to operate more efficiently, taking advantage of economies of scale, especially under IRM.

(3) **Reasonable financial metrics.** PowerStream has continued to maintain a solid balance sheet and credit metrics for its current rating category. The Company's leverage, excluding debt and deferred interest owed to its parents, remains low at approximately 49%.

Challenges

(1) **Managing capital expenditures.** The Company has a large capex program to maintain the reliability of its system and expand its distribution networks. Additionally, the Company's Solar Generation unit will also require significant capex for the next two years ($51.5 million in 2014 and $24.5 million in 2015). The combined total capex will likely result in negative free cash flow over the near to medium term. DBRS expects the Company to remain prudent in its financing strategy to maintain its capital structure in line with the regulatory capital structure.

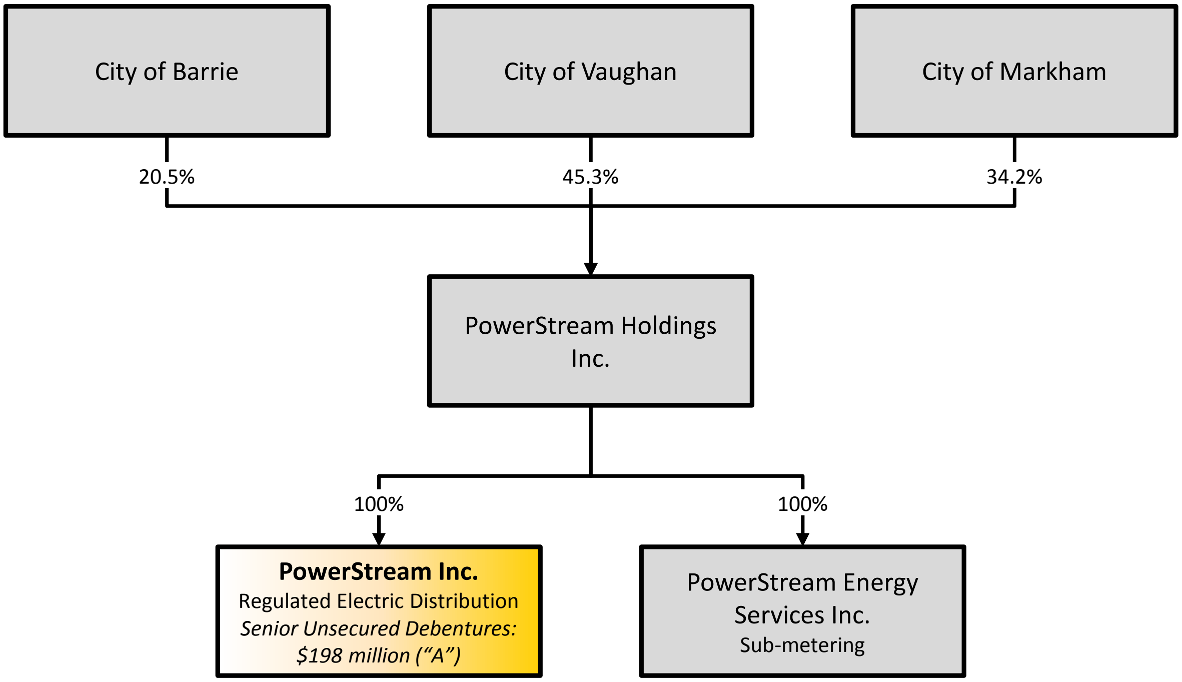
(2) **Uncertain regulatory framework.** PowerStream is expected to transition from IRM to CIR for its next rebasing period. While the OEB's report in November 2013 provided some parameters and benchmarking requirements under the Renewed Regulatory Framework, there is still uncertainty regarding what the OEB may approve. However, PowerStream will not be required to file its application until 2016 at the latest, at which point more clarity about the process should be available.

(3) **Limited access to equity market.** As a municipal owned electricity distributor, PowerStream has limited access to public equity markets. As such, funding requirements must be provided by the shareholders.

IFRS Conversion

PowerStream transitioned to IFRS on January 1, 2011. The OEB requires reporting under modified IFRS (MIFRS). Therefore, readers should use caution when interpreting financial results reported under IFRS, as MIFRS is used to calculate ROE and other key ratios. Additionally, PowerStream reports MIFRS results for its rate-regulated business (2013 MIFRS ROE: 9.9%) while it uses IFRS for the consolidated entity (2013 IFRS ROE: 6.8%).

Simplified Ownership Structure



- PowerStream Holdings Inc. (HoldCo) was incorporated in 2013 with two subsidiaries:
  - PowerStream Inc., which consists of the regulated electricity distribution business (approximately 96% of 2013 earnings) as well as the unregulated Solar Generation business
  - PowerStream Energy Services Inc., which was incorporated in 2013 to explore opportunities in unregulated businesses, such as unit sub-metering for condominiums, for both within and outside PowerStream's territory
- There is no debt at the HoldCo level. Going forward, DBRS does not expect any debt to be issued at this entity.

Earnings and Outlook

	For the year ended December 31				
(CA$ millions)	**2013***	**2012***	**2011***	**2010**	**2009**
Revenues	1,056.5	970.5	927.8	856.9	777.5
Net Sales	176.3	171.1	176.3	165.6	155.7
Operating expenses	84.8	85.7	73.4	59.7	61.5
EBITDA	91.5	85.4	103.0	105.9	94.2
EBIT	56.4	53.4	68.6	59.6	52.1
Gross interest expense	22.5	25.2	24.8	23.3	22.7
Net income before non-recurring items	35.9	30.6	38.7	26.8	22.0
Reported net income	28.1	35.3	25.6	26.5	21.1
Return on avg. common equity	9.0%	8.3%	12.2%	9.7%	9.0%
Rate base (CA$ millions)	832	795	760	688	639
Deemed common equity	40.0%	40.0%	40.0%	40.0%	40.0%
Allowed ROE	8.93%	8.01%	8.01%	8.01%	8.01%

*Note: IFRS financial results have been adjusted by DBRS; values do not reflect Modified IFRS reporting required by the OEB.

2013 Summary

- Distribution revenue of $157 million was in line with the revenue requirement approved in the 2013 cost-of-service (COS) application. This was lower than 2012 distribution revenue largely due to the harmonization of rates and management of costs which led to a 16% rate decrease for Barrie customers and a 3.5% rate decrease for other customers.
- Income from regulated operations increased modestly as a result of the rebasing in 2013 which added approximately $200 million to the rate base, and increased the allowed ROE to 8.93% from 8.01%. These positive earnings drivers more than offset the aforementioned decrease in distribution revenue.
- Reported net income fell as a result of a net loss at the Collus PowerStream joint venture, and storm costs related to the December 2013 North American ice storm.

2014 Outlook

- DBRS expects earnings from the core distribution business to remain relatively stable.
- Regulated earnings should continue to benefit from the larger rate base and higher allowed ROE.
- Going forward, all new unregulated activities will originate at PowerStream Energy Services Inc. DBRS expects unregulated earnings at PowerStream to remain at or below 10%.

Financial Profile and Outlook

	For the year ended December 31				
(CA$ millions)	**2013***	**2012***	**2011***	**2010**	**2009**
Net income before non-recurring items	35.9	30.6	38.7	26.8	22.0
Depreciation & amortization	38.9	35.2	36.1	49.1	44.7
Deferred income taxes/Other	8.3	9.1	3.3	11.3	7.2
Cash flow from operations	83.2	74.9	78.1	87.1	73.9
Dividends	(14.9)	(16.1)	(13.9)	(10.5)	(11.3)
Capex	(127.3)	(109.5)	(65.6)	(70.0)	(73.7)
Free cash flow before WC	(59.0)	(50.7)	(1.4)	6.6	(11.1)
Changes in working capital (WC)	(4.8)	(8.0)	(6.2)	(2.7)	(23.3)
Regulatory assets/Liabilities	(6.5)	4.2	(12.3)	(28.4)	(23.3)
Net free cash flow	(70.2)	(54.5)	(19.9)	(24.5)	(57.7)
Acquisitions/Mergers/Investments	0.0	(8.1)	0.0	0.0	0.0
Assets sales/Divestitures/Other	0.0	0.0	0.0	0.1	(19.6)
Net changes in equity	8.4	28.3	2.3	2.4	0.0
Net changes in debt	34.5	62.2	3.1	0.5	15.0
Other financing	0.0	0.0	(2.2)	(12.6)	21.2
Change in cash	(27.3)	28.0	(16.6)	(34.0)	(41.1)
Total debt (CA$ millions)	523	482	427	415	396
Total debt in capital structure (1) (2)	59.5%	58.6%	58.8%	59.5%	60.4%
Total debt excluding shareholder loans (1) (2)	49.3%	48.4%	45.2%	45.5%	45.8%
Cash flow/Total debt (1)	15.3%	15.3%	18.0%	20.7%	18.1%
EBIT gross interest coverage (times) (1)	2.53	2.14	2.77	2.57	2.32
Dividend payout ratio	41.5%	52.6%	35.8%	39.2%	51.2%

(1) Includes operating leases. (2) Adjusted for accumulated other comprehensive income.

*Note: IFRS financial results have been adjusted by DBRS; values do not reflect Modified IFRS reporting required by the OEB.

2013 Summary

- Overall, key credit metrics remained stable, and support the current rating category.
- Cash flow from operations improved largely as a result of higher earnings. Capex continued to increase which led to a significant free cash flow deficit. This deficit was largely funded through cash on hand, and incremental debt.
- The slight deterioration in the cash flow-to-debt ratio is the result of total debt growing faster than cash flow during this period of large capex.
- PowerStream's dividend policy remain unchanged and the Company paid out 50% of 2012 MIFRS income to its shareholders in 2013. Dividend payout is also dependent on the Company's cash position, working capital requirements and net capital expenditures required.
- Excluding debt and deferred interest owed to its parents, the debt leverage was low, at approximately 49%.

2014 Outlook

- Capex is expected to remain elevated at over $100 million over the near to medium term. Combined with estimated dividends of approximately $17 million, DBRS anticipates a free cash flow deficit of $20 to $30 million in 2014.
- DBRS expects the Company to fund free cash flow deficits with a mix of debt and equity injections, to continue to maintain its debt leverage at around 60% (the OEB approved deemed capital structure).
- Interest coverage and cash flow metrics are expected to remain supportive of the "A" rating.

Long-Term Debt and Bank Lines

Liquidity

Credit facilities as at Dec. 31, 2013

(CA$ millions)	Amount	Drawn/LOC	Available	Maturity
Committed line of credit	150.00	70.00	80.00	Feb. 2015
364-day committed revolving credit facility	75.00	7.37	67.63	N/A
Uncommitted demand facility	25.00	-	25.00	N/A
Uncommitted Letter of Guarantee facilities	15.34	15.34	0.00	N/A
Total consolidated credit facilities	**265.34**	**92.70**	**172.63**	

As of December 31, 2013, the Company had the following facilities:

- A $150 million committed operating line, of which $80 million was available.
- A 364-day committed credit facility of $75 million, of which $68 million was available.
- A $25 million uncommitted demand facility for specific purposes, which was undrawn.
- Uncommitted Letter of Guarantee facilities of $15 million and $0.3 million, both of which have been completely drawn.

Long-Term Debt

Long-Term Debt Maturity as at Dec. 31, 2013

(CA$ millions)	Amount	Rate	Maturity
3.958% Senior unsecured debentures	198.22	3.958%	Jul. 2042
Promissory note issued to the City of Vaughan	78.24	5.580%	Jun. 2024
Promissory note issued to the City of Markham	67.87	5.580%	Jun. 2024
Promissory note issued to the City of Barrie	20.00	5.580%	Jun. 2024
Infrastructure Ontario debenture	2.71	3.850%	Mar. 2033
Infrastructure Ontario debenture	0.98	4.090%	Nov. 2031
Infrastructure Ontario debenture	0.96	3.540%	Aug. 2032
Total	**368.98**		
Deferred interest on promissory notes	16.33		
Total long-term debt	**385.30**		

- PowerStream's long-term debt currently consists of the following:
  - Senior unsecured debentures totalling $198.22 million, maturing on July 30, 2042. The senior unsecured debentures were issued in July 2012 through a private placement offering. The net proceeds were used to repay outstanding indebtedness, including a $125 million debenture owed to the Electricity Distributors Finance Corporation and for general corporate purposes.
  - Subordinate debt to shareholders (promissory notes) totalling $166.1 million.
  - – $78.24 million, 5.58%, due 2024, held by the City of Vaughan plus deferred interest of $8.7 million.
  - – $67.87 million, 5.58%, due 2024, held by the City of Markham plus deferred interest of $7.5 million.
  - – $20.00 million, 5.58%, due 2024, held by the City of Barrie.
  - The three promissory notes are repayable as of 90 days following demand from its owners. These notes have been classified as long-term by PowerStream, as it is not the intent of any of its owners to demand repayment within the following year.
  - $4.65 million of construction financing from Infrastructure Ontario through three separate notes.
  - The Company repaid its $50 million term loan by drawing on its committed line of credit.

Regulation

- PowerStream is regulated by the OEB under the Ontario Electricity Act, 1998.
- PowerStream currently operates under the IRM framework, under which the Company is subject to a formula price cap that allows for an annual increase in distribution rates based on inflation less a productivity factor, which can be reset annually.
- Under the IRM framework, if the Company's actual ROE is 300 bps above or below the allowed ROE, the OEB will undertake a review, and earnings over 300 bps may be shared with customers.
- PowerStream is allowed to fully recover its purchased power costs (except doubtful accounts on power cost, which are manageable) in a timely fashion, eliminating its exposure to power price risk. DBRS views this as a positive factor in the current regulatory system in Ontario (regardless of whether the Company operates under IRM or COS).
- In addition to IRM, the Company is allowed to file a COS application, which is expected every four to five years. PowerStream last rebased in 2013.
- In December 2012, the OEB issued a decision on PowerStream's COS application, which approved the following:
  - Rate base of approximately $832 million (applied for $842 million).
  - ROE of 8.93% (8.01% for 2012).
  - Allowed equity component of 40% and debt component of 60%, which is composed of 56% long-term debt and 4% short-term debt.
- PowerStream filed its 2014 IRM application in September 2013. The OEB released its decision in February 2014, approving additional funding for the 2014 capital program through the Incremental Capital Module (ICM). Revenue under the ICM will be deferred until the next rebasing.
- Under the OEB's new rate-setting policy, electricity distribution companies in Ontario will transition from the current IRM framework to the Renewed Regulatory Framework, where distributors can choose between three rate-setting options: (1) 4th Generation Incentive Rate-setting; (2) Custom Incentive Rate-setting; or (3) Annual Incentive Rate-setting Index (see *DBRS Commentary: No Real Credit Substance in the Ontario Energy Board's Report on Renewed Regulation Framework for Electricity Distributors*, dated October 19, 2012).
- Given PowerStream's large capex program, DBRS expects the Company to apply for CIR to take effect for as early as January 1, 2016. While the IR period will be longer under CIR than under the 3rd Generation IRM (five years versus three years), the current 300 bps "off ramp" will continue and pre-approved capital spending will be added to the rate base every year.
- The chart below reflects DBRS's assessment of the regulatory environment for PowerStream based on DBRS's methodology guideline.

Criteria	Score	Analysis
(1) Deemed Equity	Excellent Good **Satisfactory** Below Average Poor	The OEB allows PowerStream to have a deemed equity of 40%, which is consistent with the other electricity distribution companies in Ontario. As a result of the need to maintain the regulatory capital structure, PowerStream's leverage has been in line with the "A" rating range.
(2) Allowed ROE	Excellent Good **Satisfactory** Below Average Poor	PowerStream has an allowed ROE of 8.93% for 2014. This is largely in line with other distribution companies in Ontario. Any difference in ROE between PowerStream and other distribution companies is mainly due to the timing of the regulatory filings and the interest environment prevalent at that time.

Criteria	Score	Analysis
(3) Energy Cost Recovery	**Excellent** Good Satisfactory Below Average Poor	There is no power price risk for PowerStream, as it is not responsible for purchasing power from generation facilities or the wholesale market. Power costs are passed on to ratepayers at rates set by the OEB and PowerStream collects the payments from its customers on a bi-monthly basis.
(4) Capital Cost Recovery	Excellent **Good** Satisfactory Below Average Poor	Under IRM, some capital costs are pre-approved at the time of the COS application. Subsequent capital spending after the base year will not be approved until the next rate application and approval of the rate base. If incremental capital costs are significant, non-discretionary and prudent, PowerStream can file under ICM to request for the recovery of the costs.
(5) COS vs. IRM	Excellent Good **Satisfactory** Below Average Poor	PowerStream is currently regulated under an IRM framework, with three years in between COS rebasing years. PowerStream rebased in 2013 and was allowed to recover prudently spent capex from 2009 to 2012. During the IRM period, PowerStream can file an ICM if there are significant, non-discretionary and prudent incremental capital needs between rebasing years. Going forward, DBRS expects the Company to remain on IRM for the remaining term or apply for CIR under the Renewed Regulatory Framework to take effect as early as January 1, 2016.
(6) Political Interference	Excellent Good Satisfactory **Below Average** Poor	The government of Ontario plays a significant role in the electricity sector in Ontario, given that the majority of the utilities are government-owned (PowerStream is owned by the City of Barrie, the City of Vaughan and the City of Markham). Furthermore, stakeholders, such as the Ontario Power Authority (rated A (high)) and the Independent Electricity System Operator, are also government-owned. As a result, the government has direct and indirect influence on Ontario’s electricity industry.
(7) Retail Rate	Excellent Good **Satisfactory** Below Average Poor	The cost of power in PowerStream’s service territory is set by the OEB. On average, electricity prices for PowerStream’s residential customers are approximately 13 cents per kWh. This is on par with other service territories in Ontario.
(8) Stranded Cost Recovery	Excellent **Good** Satisfactory Below Average Poor	Minimal stranded costs exist in the Ontario market. DBRS notes that the recovery of the costs is also subject to some regulatory lag. Although stranded costs have been fully recovered in the past years, assets could potentially be written down if the OEB does not approve the recovery of the costs.

Criteria	Score	Analysis
(9) Rate Freeze	Excellent Good **Satisfactory** Below Average Poor	Distribution rates were frozen for a short time in the early 2000s, but this did not have a material impact on PowerStream's financial profile. Since distribution costs represent 20% to 30% of a customer's overall electricity bill, an increase in rates would have a greater nominal impact on customers' bills. This could increase the risk of potential rate freezes.
(10) Market Structure (Deregulation)	Excellent **Satisfactory** Poor	Following the restructuring of Ontario Hydro in 1999, Ontario's electricity market became partially deregulated, specifically for the generation segment. Distribution (including PowerStream) and transmission remains fully regulated under the OEB. DBRS notes that no single utility in Ontario is fully integrated.

PowerStream Inc.

(CA$ millions) **Assets**	**Dec. 31 2013***	**Dec. 31 2012***	**Dec. 31 2011***	**Liabilities & Equity**	**Dec. 31 2013***	**Dec. 31 2012***	**Dec. 31 2011***
Cash & equivalents	0	20	0	S.T. borrowings	77	25	48
Accounts receivable	91	82	87	Accounts payable	120	99	97
Inventories	3	3	3	Current portion L.T.D	44	73	3
Others	122	103	96	Others	53	48	52
Total Current Assets	**216**	**209**	**185**	**Total Current Liabilities**	**294**	**245**	**201**
Net fixed assets	926	814	719	Long-term debt	402	383	375
Future income tax assets	23	32	42	Deferred income taxes	0	0	1
Goodwill & intangibles	56	55	52	Other L.T. liabilities	101	83	56
Regulatory assets	0	0	0	Provisions	19	18	17
Deferred Charges & Other	7	8	0	Shareholders' equity	411	389	348
Total Assets	**1,228**	**1,119**	**998**	**Total Liab. & SE**	**1,228**	**1,119**	**998**

Balance Sheet & Liquidity & Capital Ratios	For the year ended December 31 **2013***	**2012***	**2011***	**2010**	**2009**
Current ratio	0.73	0.85	0.92	1.03	1.24
Total debt in capital structure (1) (2)	59.5%	58.6%	58.8%	59.5%	60.4%
Cash flow/Total debt	15.9%	15.6%	18.3%	21.0%	18.7%
Cash flow/Total debt (1)	15.3%	15.3%	18.0%	20.7%	18.1%
(Cash flow - dividends)/Capex	0.54	0.54	0.98	1.09	0.85
Deemed common equity	40.0%	40.0%	40.0%	40.0%	40.0%
Dividend payout ratio	41.5%	52.6%	35.8%	39.2%	51.2%
Coverage Ratios (times)					
EBIT gross interest coverage	2.51	2.12	2.77	2.56	2.30
EBIT gross interest coverage (times) (1)	2.53	2.14	2.77	2.57	2.32
EBITDA gross interest coverage	4.07	3.39	4.16	4.55	4.15
Fixed-charges coverage	2.51	2.12	2.77	2.56	2.30
Debt/EBITDA	5.72	5.64	4.14	3.92	4.20
Profitability Ratios					
EBITDA margin	51.9%	49.9%	58.4%	63.9%	60.5%
EBIT margin	32.0%	31.2%	38.9%	36.0%	33.5%
Profit margin	20.4%	17.9%	21.9%	16.2%	14.1%
Return on equity	9.0%	8.3%	12.2%	9.7%	9.0%
Return on capital (2)	5.9%	6.2%	7.8%	6.0%	6.0%
Allowed base ROE	8.93%	8.01%	8.01%	8.01%	8.01%

(1) Includes operating leases. (2) Adjusted for accumulated other comprehensive income.

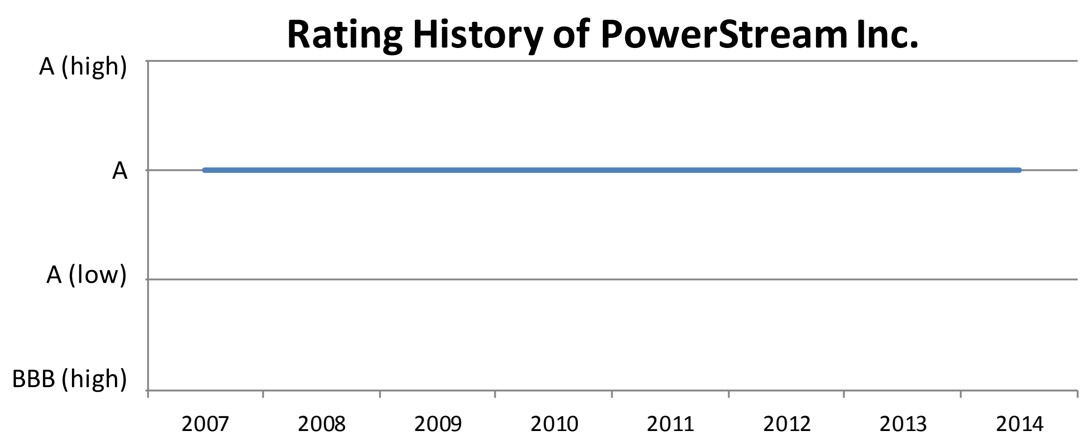
*Note: IFRS financial results have been adjusted by DBRS; values do not reflect Modified IFRS reporting required by the OEB.

Rating

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Senior Unsecured Debentures	A	Confirmed	Stable

Rating History

	Current	2013	2012	2011	2010	2009
Issuer Rating	A	A	A	A	A	A
Senior Unsecured Debentures	A	A	A	NR	NR	NR



All figures are in Canadian dollars unless otherwise noted.

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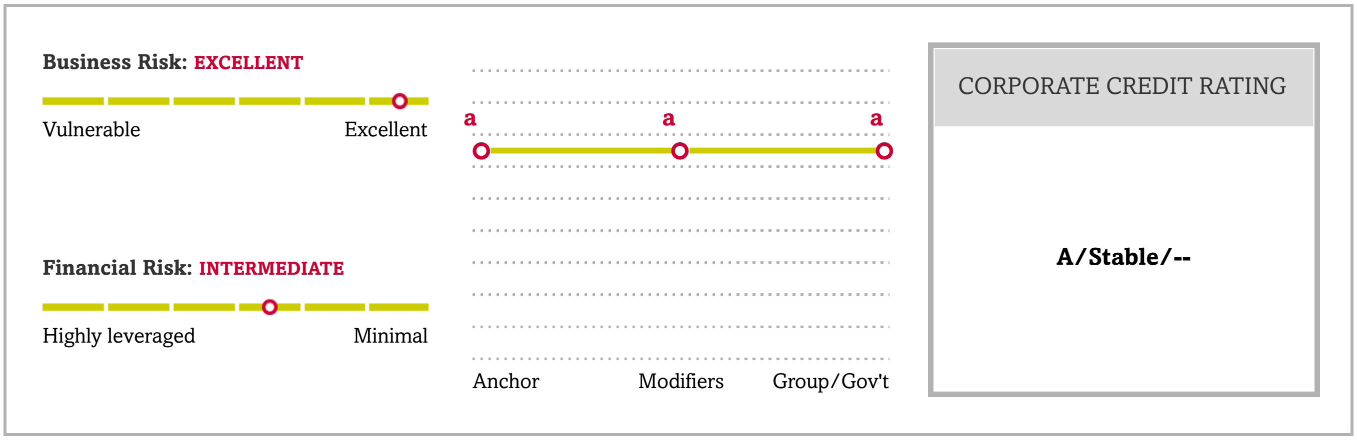
Summary:

PowerStream Inc.



Rationale

Business Risk: Excellent	Financial Risk: Intermediate
• Transparent, predictable and stable regulatory regime • Tariff includes a pass-through mechanism for major expenses such as commodity cost, effectively shielding the utility from input cost risk • A large, diverse customer base with minimal customer concentration risk	• Stable, regulated cash flow • Transparent financial policies

Outlook: Stable

The stable outlook reflects Standard & Poor's Ratings Services' assessment of PowerStream Inc.'s predictable and stable cash flows from its low-risk, regulated distribution business. The outlook also reflects our expectation that management will continue to focus on its core regulated business during our two-year outlook horizon.

Downside scenario

Although we don't expect it, a material, adverse regulatory ruling or a significant and sustained increase in leverage leading to deterioration in forecast adjusted funds from operations (AFFO)-to-debt to below 13% could trigger a review and could lead to a downgrade.

Upside scenario

If the company deleverages leading to forecast sustained AFFO-to-debt of range of 20%-23%, we could raise the ratings. We don't expect this to happen during our outlook horizon.

Standard & Poor's Base-Case Scenario

PowerStream is an Ontario-based local electricity distribution company (LDC) serving several small municipalities, mostly in the Greater Toronto Area. The rating's key driver continues to be the Ontario Energy Board's (OEB) regulatory framework and the utility's performance within it.

Assumptions

- The regulatory regime will remain relatively stable, and PowerStream will not experience any material, adverse regulatory decisions
- The company will continue to earn close to its allowed return on equity (ROE) on its deemed capital structure
- It will not make any material, debt-financed unregulated investments
- Rates for 2014 and 2015 will be established using the incentive-rate mechanism (IRM)

Key Metrics

	2013A	2014E	2015E
AFFO/debt	13.2%	13%-16%	13%-17%
Debt-to-debt and equity	58.3%	57%-62%	57%-62%

AFFO--Adjusted funds from operations. A--Actual. E--Estimated.

Business Risk: Excellent

We view PowerStream's business risk profile as excellent, reflecting our assessment of the OEB regulatory framework. We view the OEB regulatory process as transparent, consistent, and predictable. The board publishes details of all hearings and the rationale supporting its decisions. Supporting consistency and predictability is the use of standard methodology for all utilities in its jurisdiction, including a transparent formula for allowed returns, and a consistent deemed capital structure that has not changed for many years. In addition, during times of change, the regulator follows a public process of study and consultation that allows management to adjust to new regulatory or market developments.

The OEB's mandate is to balance the needs of the customer and utility investors. To date, the regulator has not imposed any penalties, although it does monitor performance standards.

Rates are typically determined in a timely fashion and allow for the recovery of prudently incurred costs and the opportunity to earn a modest return. Furthermore, several mechanisms support timely recovery of material and unexpected capital costs, including rate riders, specific adjustments under incentive-based ratemaking, and (in some circumstances) an ability to request a rate-reset hearing.

The LDC has no obligation to ensure an adequate supply of electricity and is not burdened with the procurement process or power purchase agreements which reduce operating risk. Furthermore, commodity costs flow through rates, limiting the LDC's exposure to commodity risk and associated cash flow volatility.

We expect PowerStream's customer profile to be stable, and dominated by residential customers who are less sensitive to macroeconomic stresses and business cycles. The service area's well-diversified economy and limited customer concentration support our view. The company continues to have some sensitivity to volume fluctuations, primarily weather-driven, although we do not believe fluctuations would pressure credit metrics at the rating. PowerStream's operating efficiency, as measured by standard industry reliability measures, is above average because of its newer assets compared with those of its peers, although there are no penalties or incentives associated with performance. The company's unregulated cash flow is not material to our analysis.

Financial Risk: Intermediate

We assess PowerStream's stand-alone financial risk profile as intermediate. For the company, we use the low volatility table, reflecting the "very low" industry risk associated with regulated utilities and the supportive regulatory framework. The OEB established rates for 2013 using a cost-of-service approach. We have assumed that rates in 2014 and 2015 will be established under the OEB's relatively new IRM. We do not expect the company to undergo another cost-of-service hearing and rate reset until 2016. During this IRM period, we expect the regulator to adjust rates annually by inflation minus a productivity factor. The relatively low inflation environment, combined with the productivity and stretch factors, might challenge PowerStream's ability to earn the allowed ROE in the long term. Nevertheless in our base-case scenario, we expect PowerStream will maintain its adjusted funds from operations (AFFO)-to-debt above the 13% threshold, in the 13%-17% range.

Liquidity: Adequate

The company's liquidity is "adequate," in our view. We expect that liquidity sources will be sufficient to cover uses more than 1.1x in the next 12 months. We expect that in the event of a 10% decline in earnings, sources of funds would still exceed uses. In our view, PowerStream has sound relationships with its banks and generally prudent financial risk management.

Principal Liquidity Sources	Principal Liquidity Uses
• Projected FFO of C$85 million-C$90 million in 2014 • Committed operating line, which expires in February 2015, with C$50 million available as of March 2014	• Nondeferrable capital expenditure of approximately C$38 million in 2014 • Dividends of approximately C$16 million in 2014

Government Influence

We believe there is a "low" likelihood that PowerStream's three municipal owners would provide timely and sufficient extraordinary support in the event of financial distress. We base this on what we view as a "limited" link and "limited importance" role as our government-related entity criteria define these terms.

Ratings Score Snapshot

Corporate Credit Rating

A/Stable/--

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Strong

Financial risk: Intermediate

- **Cash flow/Leverage:** Intermediate

Anchor: a

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Financial policy:** Neutral (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a

- **Likelihood of government support:** Low (no impact)

Related Criteria And Research

Related Criteria

- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Jan 2, 2014
- Corporate Methodology, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- Rating Government-Related Entities: Methodology And Assumptions, Dec. 9, 2010
- 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	**Intermediate**	Significant	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	**a+/a**	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

By 2020 we intend to achieve the following results in order to successfully pursue our Strategy:

1. ***Health and Safety*** **(Zero Serious Injuries)** - Achieve Zero serious injuries in each year until 2020.

2. ***Employee Satisfaction*** **(95% Level of Employee Satisfaction)** - Maintain an overall score of 95% on the combined average of the five key employee engagement on the Employee Survey and achieve 70% top box score (strongly agree)

3. ***Business Excellence*** **(Excellence Canada Order of Excellence Achievement)** - Achieve Order of Excellence status in Excellence Canada's Progressive Excellence Program based on external third party assessment

4. ***Customer Satisfaction***

a) 95% Level of Customer Satisfaction - Achieve an overall Customer Satisfaction score of 95%

b) Achieve an average of 40 Customer minutes of Interruption per customer per year

c) Reliability Centers of Focus - Defined sub-set of geographic areas that have reliability concerns based on outage history or sensitive loads where a specific improvement program is in place to ensure reliability performance is at least equal to or greater than the overall system wide average

5. ***Corporate Social Responsibility***

a) Reduce PowerStream's Environmental footprint

b) Meet or exceed mandated CDM targets

6. ***Shareholder Value***

Achieve a consolidated ROE that Exceeds OEB approved rate by 100 basis points.

7. ***Profitable New Growth*** **(15-20% of Net Income from New Businesses)** - Grow annual revenues to approximately $2-3 billion and achieve 15-20 % of annual Net Income from new businesses to include mergers and acquisitions, Renewable Generation, sub metering, c0-generation, and other allowable business activities, including the achievement of growth in customer base to 600,00 to 750,000.

(DRAFT)

Five Year Work Reliability Work Plan

Prepared by: Riaz Shaikh

Date: Dec 2013

Contents

1. Executive Summary

In 2010, as a part of "Strategic Direction - Five Years Critical Success Factors" PowerStream has targeted to achieve the "Five 9's" reliability target by the year end 2015.

This reliability improvement initiative exceeded the minimum regulatory service quality standard expected of PowerStream. With respect to service quality standards pertaining to reliability, the Ontario Energy Board (OEB) expects that a distributor's current reliability performance (SAIDI, SAIFI, CAIDI) should, at minimum, remain within the range of its historical previous 3 year performance.

According to the Five 9's target, by year end 2015, PowerStream was aiming to achieve a minimum monthly Reliability index of 0.99990 (excluding Loss of Supply and Major Event Days) and a monthly Reliability Index of 0.99999 (excluding Loss of Supply and Major Event Days) for a minimum 9 of 12 months by year end 2015.

A reliability work plan was developed to provide a general road map for moving towards the Five 9's reliability target by year 2015.

The Base Line or "Starting Point" CMI (Customer Minutes of Interruption) selected for reliability improvement was the 2010 Reliability Target, 20,869,218 CMI. Subsequent improvements due to the capital and other reliability projects were subtracted to portray the CMI targets each year.

The annual reliability improvement projections and final 2015 target did take into account annual customer growth. For purposes of projecting the number of customer serviced each year, the System customer count was assumed to increase by 7,000 each year, from 325,000 in 2010 to 360,000 in 2015.

To achieve the Five 9's target, it was determined that the PowerStream was to achieve a saving of 14,919,218 CMI over the 5 years to achieve the target of 17 minutes.

It was acknowledged from the onset that the plan would require changes as more information and data become available.

PowerStream's 2010 reliability performance was better than expected. However it was still selected as a baseline as too early to determine with certainty and accuracy as to what contributed to the improvement. Today, we can conclude that the performance achieved was indicative of a fortuitous correlation of mild weather and low equipment failure rates.

In addition to the above reason, it is also now noted that couple of reliability improvement and capital projects were too optimistic in CMI savings prediction. Hence there is a need to adjust the projections and targets moving forward. This report outlines the Five Year Reliability Target with the projects that are in place. CMI savings have been adjusted for the various capital and reliability improvement efforts.

It is now seen that with the programs that are in place PowerStream at the best can achieve a SAIDI of 38.78 minutes in 2018. This represents a 34% reduction from the 2014 target of 59.31 minutes which can be considered a drastic improvement in reliability over the five year period.

It is to be noted that the reliability improvement goal (Five 9's) is very challenging because of the following reasons:

1. PowerStream has significant quantity of assets that are getting older. PowerStream has asset condition assessment and replacement program in place however it these do not match the aging profile.

2. There are some limitations as to which reliability drivers PowerStream can exercise control over in its effort to improve reliability. The uncontrollable factors like weather, vehicle contacts have a significant impact on the reliability and PowerStream has no control over them. In fact, the recent weather phenomena suggest that the event duration is longer and more impactive (For e.g. Hurricane Sandy, 2013 July Flood Storm in GTA). Based on previous five year outage if PowerStream were to eliminate all of the controllable outages i.e. not to have a single equipment failure and no tree contact the annual SAIDI would still be 25.44 minutes.

3. There are existing budget and resource constraints in PowerStream operations. These constraints may prevent PowerStream from fully implementing all work programs it needs to carry out to achieve the reliability target.

4. There are some limitations on the effectiveness of incremental reliability improvement, especially after the system has been "optimized", and a high level of reliability has already been achieved. This is the reality of diminishing returns where the cost of the next incremental improvement would be prohibitively high and not justifiable.

5. The increased capital spending has resulted in increased scheduled outages. It is projected that the scheduled outages will add 945,674 CMI (2.73) minutes to the SAIDI in the next year.

This report discusses the following related issues that have impact on the CMI target:

- Reliability Performance
- The Approach to Reliability
- Base Line for Reliability Improvement
- Incremental Improvement
- Budget Constraints
- Controllable versus Uncontrollable Factors
- Increase in scheduled Outages
- Diminishing Return
- Reliability Metrics
- Reliability Performance by Outage Cause Codes
- Hydro One's Reliability Impacting PowerStream

This report highlights the work programs that are in place to improve reliability and identifies programs for implementation over the next few years.

In general, it is difficult to determine accurately the cost and the expected reliability improvement for each work program. In most cases, the cost and benefit of each work program are estimated based on available information. Some program benefits can be quantified, while others can only be given a qualified estimate ("rough" and "ball park figure"). Attempts have been made to validate the projected CMI savings by business units that will be implementing the project. It is expected that the reliability improvement estimates will be updated on the annual basis.

The recommended overall annual cost of the programs and reliability improvement projections are shown in Table A, Chart A, and Chart B.

The recommended ownership of the various work plans are shown in Table B.

The details of annual cost and benefit of individual work programs are shown in Table C.

The reliability work plan will be revisited annually, and adjustments (planned vs. actual, activity changes, etc.) will be made as required.

The Reliability Committee will take the key role in overseeing the implementation of the reliability work plan. The work plan will be a standing agenda item in the Reliability Committee meetings.

Table A - Annual Cost and Reliability Projection					
	2014	**2015**	**2016**	**2017**	**2018**
CMI - Base Line (A)	22,804,860	21,034,292	19,757,342	16,257,149	15,448,624
CMI Savings during the year (B)	2,284,397	1,276,133	3,893,768	1,232,094	1,080,594
CMI - end of year (C = A - B)	20,520,463	19,758,159	15,863,573	15,025,055	14,368,030
System Customers (D)	346,000	354,650	363,516	372,604	381,919
SAIDI (minutes)	59.31	55.71	45.00	41.69	38.78
IOR	0.9998872	0.999894	0.9999144	0.9999207	0.9999262
Annual Cost ($) (G)	35,776,766	32,443,883	34,216,837	34,016,088	33,684,808
Annual Cost/CMI Saving (H = G/B)	15.66	25.42	8.79	27.61	31.17

Chart A – SAIDI Projection

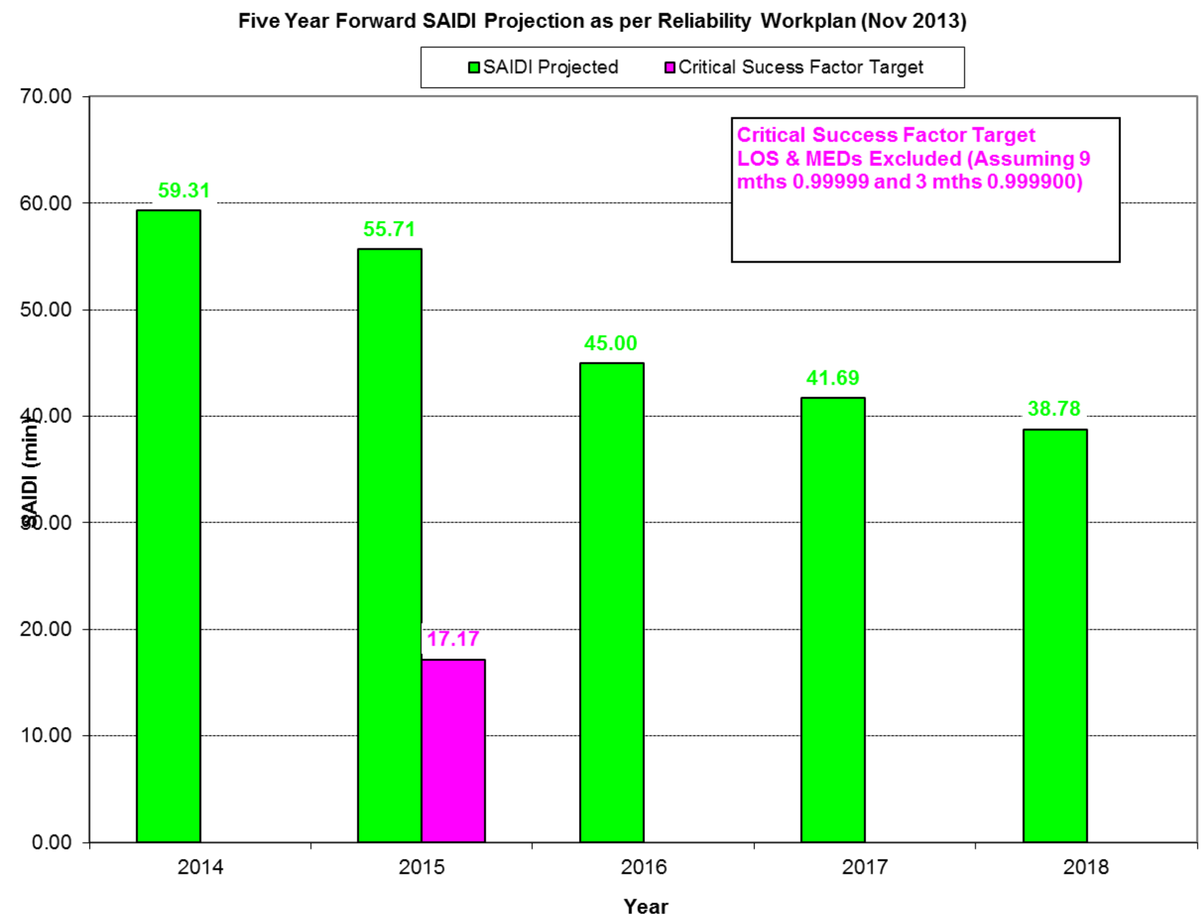


Chart B – IOR Projection

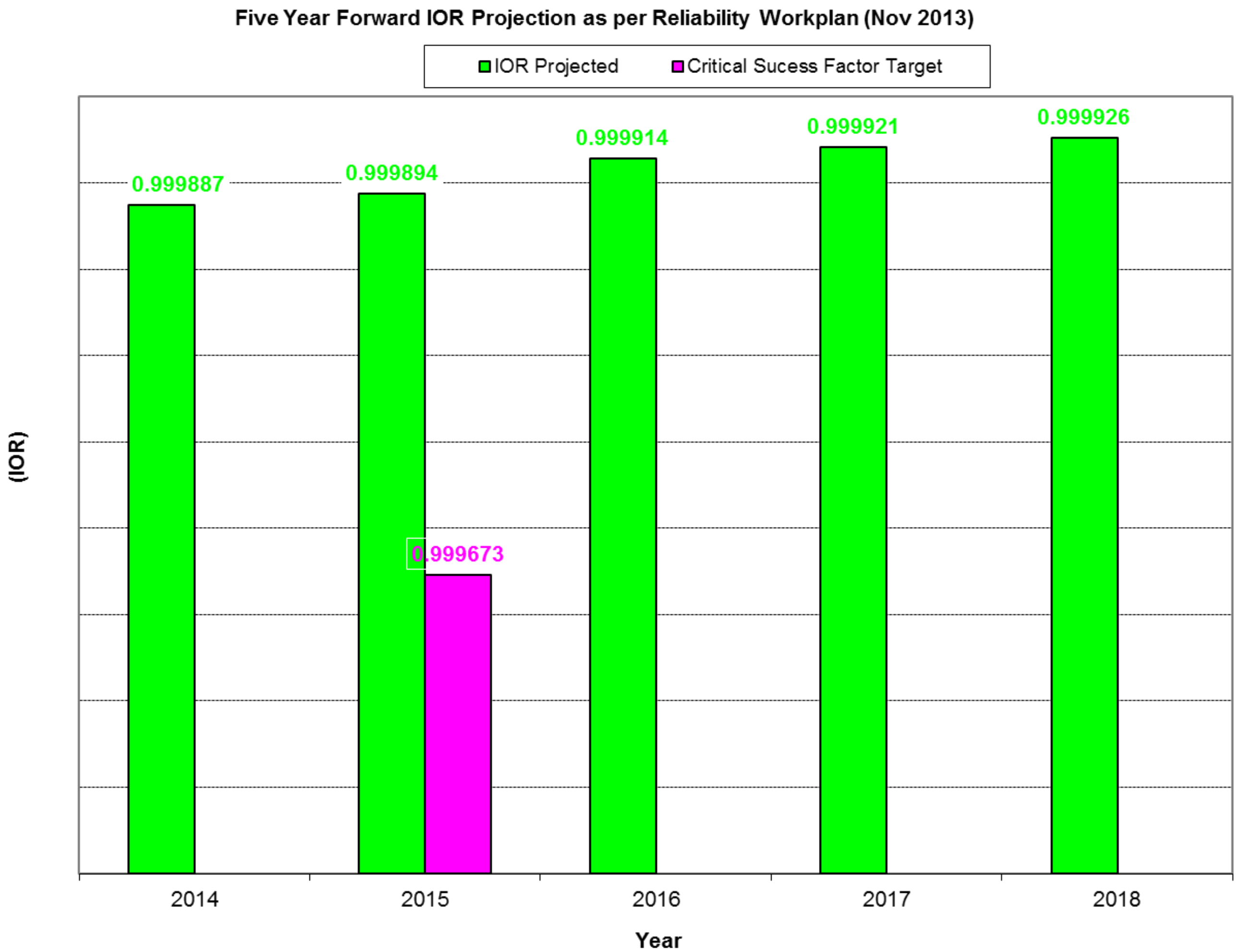


Table B - Implementation Responsibilities - Program Owners

	Program Description	Responsibility	Date
1	**Trouble Crew Coverage on 24/7 Basis, Improve Trouble Response Times, Process & Procedure** •Operations to lead the implementation of the project. Report to the Reliability Committee on the outcomes and recommendations of the Outage Performance Group. • Continue to implement process that result in reducing outage response times.	Lines, Operations	Q4 2015
2	**FDIR (Fault Detection, Isolation and Restoration)** • Confirm positive net benefit of 2013 project.	Operations	Annual
3	**Worst Performing Feeders (WPF)** • Assign resources to carry out the required maintenance work	Lines	Annual
4	**Automatic Fault Restoration** Report on the benefits of the pilot completed in 2013 Continue to propagate AFR schemes on 27.6 kV feeders	Station Design, SP&S	Annual
5	**44 kV Tie in Penetanguishene** • Follow up with budget approval and implementation of the project.	SP&S	Q4 2013
6	**Inspection & Maintenance Program** Ensure the existing tree trimming program adequately addresses actual vegetation growth rates. • Emphasize feeder patrols to identify potential vegetation problems to aid in proactively prioritizing tree trimming work. Continue the implement the inspection and maintenance work program and activities	Lines, Stations Sustainment	Annual
7	**Wood Pole Replacement** • Continue the inspection and annually refine the ACA program and manage the annual pole replacement program.	SP&S	Annual
8	**Distribution Automation Switch/Recloser Installation** • Increase the annual installation of automated switches to 30 units per year starting 2014.	SP&S	Annual
9	**Underground Cable Replacement** • Continue to inject and replace 107 km of cable each year.	SP&S	Annual
10	**Distribution Switchgear Replacement** • Continue the annual switchgear replacement program each year.	SP&S	Annual
11	**Submersible Transformer & Vault Replacement/Retrofit** • Proceed with the proposed replacement under the asset replacement program.	SP&S, Lines	Annual
12.	**Installing Intellirupters on MS835 F3 and F4** • Proceed with the proposed installation and verify CMI savings at the end of 2014	SP&S	Q4 2014
13.	**Fault Indicator Program** • Proceed with the annual installation program	Lines	Annual
12	**Other Initiatives:** **Rear Lot Construction Elimination** • Produce report on impact on reliability and resources required for implementation. **Asset Condition Assessment Program (Station and Distribution Assets)** • Continue to refine the asset condition assessment program and ensure that the condition data is updated with the current data from the inspection and maintenance programs for the Station as well as Distribution Assets. **Contingency, Spare Equipment and Materials** •Ensure adequate spare equipment are available.	SP&S SP&S SP&S, Supply chain	Q4 2013 Annual Q4 2014

Table C - Summary of Five Year Reliability Work Plan

Program	Program Description	Responsibility	Program Type	Cost A	CMI Saving B	Cost per CMI C = A/B	2014 346,000 Customers			2015 354,650 Customers			2016 363,516 Customers			2017 3 72,604Customers			2018 381,919 Customers			Five Years Acc Cost (2010 Dollar)	Five Years Acc CMI Savings
							Cost	CMI Saving	SAIDI Saving (Minutes) 332,000 Cust	Cost	CMI Saving	SAIDI Saving (Minutes) 354,650 Cust	Cost	CMI Saving	SAIDI Saving (Minutes) 363,516 Cust	Cost	CMI Saving	SAIDI Saving (Minutes) 371,604 Cust	Cost	CMI Saving	SAIDI Saving (Minutes) 381,919 Cust		
1	Trouble Crew Coverage on 24/7 Basis (Days-Weekend Option)	Lines,Ops	OM&A	1,000,000	2,459,022	$0.41	0	0	0.0	0	0	0.00	1,000,000	2,617,315	7.20	1,000,000	0	0.00	1,000,000	0	0.00	3,000,000	7.20
2	FDIR (Fault Detection, Isolation and Restoration)	Operations	Capital	200,000	375,000	$0.53	100,000	100,000	0.3	0	0	0.00	0	0	0.00	0	0	0.00	0	0	0.00	100,000	0.29
3	Worst Performing Feeders (WPF)	Lines	OM&A	250,000	250,000	$1.00	250,000	220,000	0.6	250,000	250,000	0.70	250,000	250,000	0.69	250,000	250,000	0.67	250,000	250,000	0.65	1,250,000	3.35
4	Automatic Fault Restoration	SP&S,Ops, Station Sustainment	OM&A	400,000	50,000	$8.00	400,000	190,000	0.5	400,000	50,000	0.14	400,000	50,000	0.14	400,000	50,000	0.13	400,000	50,000	0.13	2,000,000	1.09
5	44 kV Tie in Penetanguishene	SP&S	Capital	587,491	607,000	$0.97	0	547,370	1.6	0	0	0.00	0	0	0.00	0	0	0.00	0	0	0.00	0	1.58
6	Inspection & Maintenance Procedures	Lines, Station Sustainment	OM&A	3,000,000	309,498	$9.69	3,000,000	309,498	0.9	3,000,000	139,125	0.39	3,000,000	139,125	0.38	3,000,000	139,125	0.37	3,000,000	139,125	0.36	15,000,000	2.41
7	Wood Pole Replacement	SP&S	Capital	4,956,094	720	$6,883.46	4,956,094	27,312	0.1	5,071,697	27,312	0.08	5,188,949	27,312	0.08	5,307,899	27,312	0.07	5,428,597	27,312	0.07	25,953,236	0.38
8	Distribution Automation Sw itch/Recloser Installation	SP&S	Capital	2,419,883	122,866	$19.70	2,419,883	122,866	0.4	2,475,169	122,866	0.35	2,530,758	122,886	0.34	2,585,744	122,866	0.33	2,194,590	122,866	0.32	12,206,144	1.69
9	Underground Cable Replacement and Rejuvenation	SP&S	Capital	20,948,153	547,497	$38.26	20,948,153	547,497	1.6	18,153,650	547,497	1.54	18,670,969	547,797	1.51	18,063,953	383,458	1.03	18,409,383	383,458	1.00	94,246,108	6.67
10	Distribution Sw itchgear Replacement	SP&S	Capital	2,323,235	100,033	$23.22	2,390,636	55,574	0.2	2,459,927	100,033	0.28	2,531,161	100,033	0.28	2,604,401	100,033	0.27	2,604,401	100,033	0.26	12,590,526	1.25
11	Submersible Transformer & Vault and Pad Mount Transformer Replacement	SP&S,Lines	Capital	82,000	1,800	$45.56	1,312,000	10,080	0.0	363,440	7,800	0.02	375,000	7,800	0.02	386,250	7,800	0.02	397,837	7,800	0.02	2,834,527	0.11
12	Installing Intellirupters on MS835F3 & MS835F4	SP&S	Capital	147,841	44,000	$3.36	0	84,000	0.2	0	0	0.00	0	0	0.00	147,841	120,000	0.32	0	0	0.00	147,841	0.56
13	Fault Indicator Program	Lines	OM&A	270,000	31,500	$0.12	0	70,200	0.2	270,000	31,500	0.09	270,000	31,500	0.09	270,000	31,500	0.08	270,000	31,500	0.08	1,080,000	0.55
	TOTAL PROGRAM	Total Program					35,776,766	2,284,397	6.60	32,443,883	1,276,133	3.60	34,216,837	3,893,768	10.71	34,016,088	1,232,094	3.31	33,684,808	1,080,594	2.91	170,138,382	27.13
	Reliability Projection= SAIDI (Minutes) Base Line- SAIDI Improvements + Increase in schedule	SAIDI Projected						65.91	59.31		55.71	55.71		45.00	45.00		41.69	41.69		38.78	38.78		
	Reliability Projection - IOR Baseline IOR = 0.999878	IOR Projected						0.999875	0.999887		0.999894	0.999894		0.999914	0.999914		0.999921	0.999921		0.999926	0.999926		

2. Background and Purpose

In the spring of 2010, PowerStream developed the "**Strategic Direction - Five Years Critical Success Factors**" to support the corporate strategy over the next five years 2010 – 2015.

One of the Critical Success Factors proposed by the executives and approved by the Board is the 95% Level of Customer Satisfaction & 0.99% Reliability.

The Reliability work plan was developed to addresses the specifically the target of achieving 99.999% Reliability ("Five 9's") by the end of 2015. However it was acknowledged that this target would be adjusted based on success of the projects and it that it was very challenging to achieve five 9's by 2015 and the target year may be adjusted.

This document will review the current reliability performance level, discuss the related issues that have impacts on reliability, discuss the initiatives that were proposed in the initial plan and recommend changes to the projected CMI savings that were proposed in the initial plan. It will also include additional projects that will improve reliability over the next few years.

The work programs proposed span across many business units and include continuous improvements and best practice implementation in the following areas:

- Planning
- Design
- Construction
- Inspection & Maintenance
- Operations
- Distribution Automation
- Smart Grid Technologies
- Outage Response & Outage Management
- Records System
- Coordination of Work Programs
- Hydro One's System Performance impacting PowerStream
- Contingency Plans

3. Plan Development

This section will describe the approach that has been taken to develop the five year reliability work plan. The plan will be developed in consideration with the following reliability drivers and influencers.

- Base Line Determination
- Incremental Improvement Work Programs
- Budget Constraints
- Controllable vs. Uncontrollable Events
- Diminishing Return of Work Programs
- Reliability Metrics to be Measured
- Increase in Scheduled Outages

3.1 Base Line for Reliability Improvement

The Ontario Energy Board (OEB) expects that a distributor's current reliability performance (SAIDI, SAIFI, CAIDI) should, at minimum, remain within the range of its historical previous 3 year performance. This concept can be extended to the Index of Reliability (IOR) performance.

During 2010, the actual reliability performance of the PowerStream was better than the 2010 targets. The performance achieved is attributed to fortuitous correlation of mild weather and low equipment failure rates in 2010.

Going forward, System Planning is recommending that the baseline reliability number should be based on the contribution of each of the factors which include controllable and non –controllable or based on the average of at least five years of data.

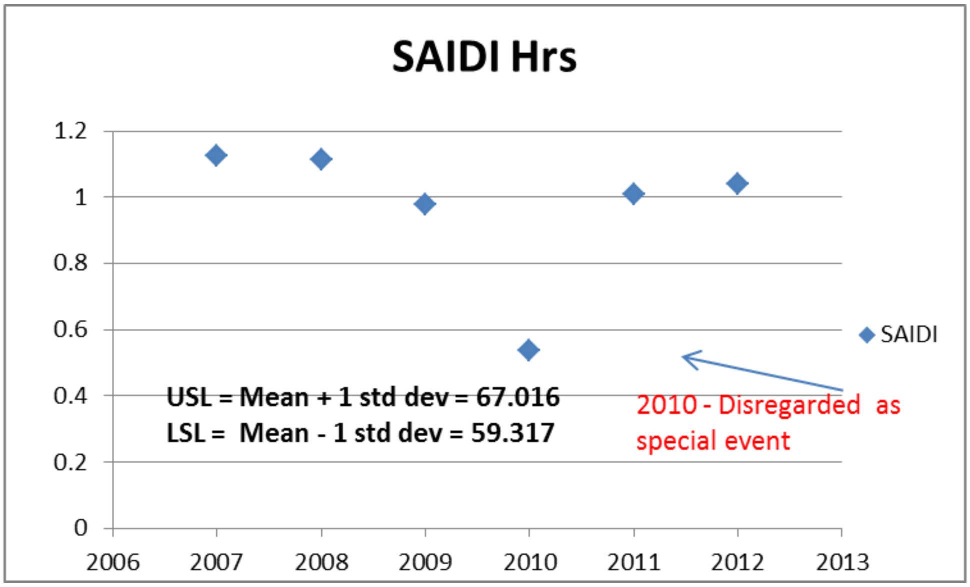


Fig-1: SAIDI by Year

Fig- 1 shows the SAIDI excluding LOS/MED events for the year 2006-2012. SAIDI values in the previous years can be plotted to establish a control chart. Using the methods from the process control world; a year with anomaly can be removed. (Justification special year with good weather as in 2010 which lead to skewed metrics can be removed as it is on outlier).

A mean SAIDI value of 63.16 has been established as a baseline for year 2014.

3.2 Incremental Improvement

Among the recommended work programs, there are two types of incremental improvement:

- **One time only incremental improvement:** the CMI (Customer Minutes of Interruption) saving is achieved only in one year and not repeated in future years. For example, when an old switch (high probability of failure within the next 5 years) is replaced with a new switch, the CMI saving is achieved for one year only. In this case, the CMI saving will be counted for one year only.

- **Repeating incremental improvement:** the CMI saving is repeated in future years. For example, tracking and reducing the trouble response procedure is revised and implemented, resulting in a reduction of the outage response time by 10 minutes every time the crew respond to an outage. In this case, the CMI saving will be counted for all future years.

  CMI Avoidance vs. CMI Savings: It is acknowledged that the capital programs are CMI avoidance for future years and not necessarily a CMI savings from the present situation and hence need to be quantified in a different way. It is suggested that the data should be obtained by looking at the actual CMI attributed in the system for failure of the particular asset class in the last 5 years and then assigning a savings based on those numbers. This approach has been used in the report.

3.3 Budget Constraints

It is very difficult to establish a one-to-one relationship between budget spending and reliability. PowerStream is taking concentrated efforts to identify and establish projects that will improve reliability and implement capital programs that match the aging profile of the plant. At an overall level it is reasonable to assume that the current level of budget capital spending is sufficient to sustain the current level of reliability and achieve modest reliability improvement. For significant reliability improvements additional capital and OM&A funds will be required.

This is a reasonable assumption, considering that the distribution asset components are getting older, and therefore becoming less reliable as time goes by.

3.4 Controllable vs. Uncontrollable Factors

Among the factors that impact reliability, there are factors that usually considered “Controllable” and others considered “Uncontrollable”.

Although there is no universally accepted definitive classification, and there will be events that could be debated as either controllable or uncontrollable, for practical purpose, at PowerStream we consider the following grouping:

1. Controllable factors include:
    - Code 1 – Scheduled Outage
    - Code 3 - Tree Contact
    - Code 5 - Defective Equipment
    - Code 8 – Human Element

2. Uncontrollable factors include:
    - Code 0 – Unknown/Other
    - Code 2 – Loss of Supply
    - Code 4 – Lightning
    - Code 6 – Adverse Weather
    - Code 7 – Adverse Environment
    - Code 9 – Foreign Interference

Table 1 – Controllable vs. Uncontrollable Factors

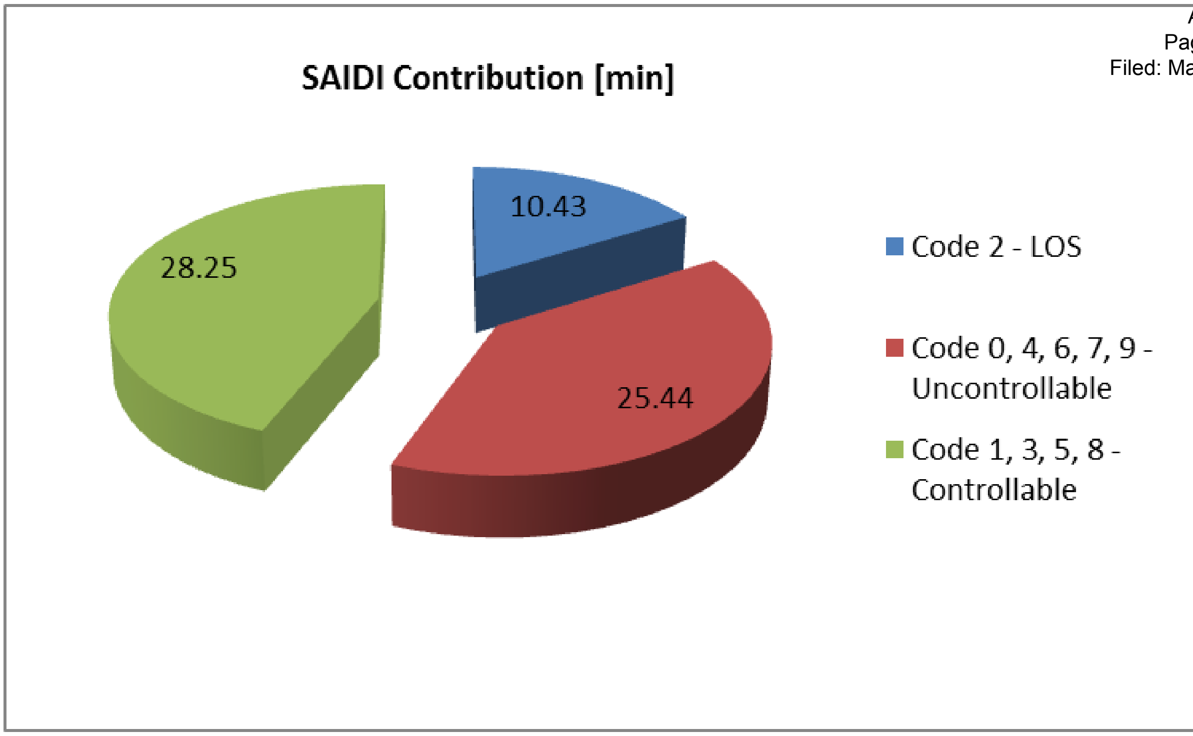
PowerStream SAIDI - By Cause Codes (Ranking)		
Code/Year	**Cumulative from 2007 to 2012**	
	SAIDI	**%**
Code 5 - Defective Equipment	18.26	28.31
Code 6 - Adverse Weather	13.46	20.87%
Code 3 - Tree Contact	5.70	8.85%
Code 9 - Foreign Interference	4.71	7.30%
Code 4 - Lightning	4.05	6.29%
Code 2 - Loss of Supply	10.43	16.17%
Code 1 - Scheduled Outage	3.59	5.57%
Code 0 - Unknown/Other	2.82	4.30%
Code 7 - Adverse Environment	0.40	0.63%
Code 8 - Human Element	0.70	1.09%
Total		100.00%

Code 2 - LOS	10.43	16.17%
Code 0, 4, 6, 7, 9 - Uncontrollable	25.44	39.39%
Code 1, 3, 5, 8 - Controllable	28.25	43.82%

The SAIDI contributions of the cause codes over the past 7 years are listed in Table 1. To put things in perspective, the total contributions to PowerStream SAIDI comprise of:

- Loss of Supply (Code 2): 16.17%, Average SAIDI contribution- 10.43 min
- Uncontrollable Factors (Code 0, 4, 6, 7, and 9): 39.39%, Average SAIDI contribution – 25.44 min
- Controllable Factors (Code 1, 3, 5 and 8); 43.82%, Average SAIDI contribution- 28.25 min

Fig -2: Average Annual SAIDI Contribution



As seen in Fig- 2, it noted that the average SAIDI contribution over the past seven years from un- controllable factors is approximately 25.44 min which means that the even if PowerStream were to eliminate all of the controllable factors there are limitations on the SAIDI improvement with the current processes and system in place. For very significant reliability improvement PowerStream will have to implement revolutionary change in the operating processes (like 24x7 coverage), and radical change in current installation practices (underground vs. overhead) and system configuration options (sky wire in areas significantly affected by lightning). Although PowerStream will put effort on all available opportunities to improve reliability, the reliability work plan will place more emphasis on controllable factors.

3.5 Economic Cost and Diminishing Return

There are limitations as to what reliability improvements can be achieved with the present system configuration. In order to achieve significant reliability improvement revolutionary changes to the system and operating procedures will be required which will not be economically feasible.

Depending on the current level of reliability, the subsequent incremental reliability improvement works may or may not be cost effective. The reason is that when the system has already been “optimized” and a high level of reliability has already been achieved incremental efforts will reach a “saturation point”. After that point, any incremental efforts will yield very little results.

One example to illustrate the point of diminishing return is the installation of distribution automation Scada-Mate switches on a long feeder that has customers evenly uniformly distributed.

To reflect the impact of diminishing return on the reliability work plan, for some work programs, the projected CMI savings are reduced in the latter years. This was achieved by multiplying the early year’s CMI by a factor of 0.70 (scale down by 30%) in 2017.
As more details are available, the diminishing return factors will be validated and adjusted.

3.6 Reliability Metrics

PowerStream is using the following 8 reliability metrics to monitor and report reliability.

- SAIDI
- SAIFI
- CAIDI
- IOR
- MAIFI
- FAIDI
- FAIFI

The details of the definitions are shown in Appendix A.

3.7 Scheduled Outages

Increase in capital budget has almost doubled the number of scheduled and associated CMI. Opportunities should be explored to reduce impact to customer.
Since 2013 was the first year with the increase in capital spending the annual CMI attributed until Nov 2013 has been used to predict the increase in CMI for the future years.

- In 2013 scheduled outages contributed to 6.33 min’s of SAIDI vs. the 3.60 minutes from previous year’s average 2007-2012 (before the capital budget was increased).

Starting in 2014 an additional 2.73 minutes will be added to account for increase in scheduled outages.

4. Reliability Performance & Target

4.1 System Reliability & Target

PowerStream’s system reliability performance over the last 3 years (2012, 2011, and 2010), are shown in Table 2, 3, 4, and 5. The reliability targets for the year (2014) are shown in Table 6.

Reliability performance is monitored by the PowerStream Reliability Committee which comprises members from various business units across the organization, and has the mandate to manage and improve reliability.

Table 2 – PowerStream Reliability Stats.

	PowerStream All Events			PowerStream Total Excluding LOS			PowerStream Total Excluding LOS & MED		
Index	**2010**	**2011**	**2012**	**2010**	**2011**	**2012**	**2010**	**2011**	**2012**
SAIFI	0.923	1.231	1.703	0.801	1.003	1.529	0.800	0.959	1.529
CAIDI	0.881	0.976	0.679	0.670	1.043	0.681	0.668	1.051	0.681
SAIDI	0.813	1.201	1.156	0.537	1.046	1.041	0.535	1.008	1.041
IOR	0.999907	0.999863	0.999775	0.999939	0.999881	0.999819	0.999939	0.999885	0.999888

PowerStream reliability target is obtained by subtracting the projected improvement from the baseline. Accordingly the 2014 Target is obtained as follows:

Baseline: SAIDI – 63.18 minutes
Increase in Schedule Outage- 2.73 minutes
Reliability Improvement- 6.60 minutes

Target = Baseline SAIDI+ Increase in scheduled Outages – Reliability Improvements

Table 3 – PowerStream 2014 Reliability Targets

2014 Target (Baseline)	SAIDI (Min)	IOR
Excluding LOS and MED	59.34	0.99988

4.2 Feeder Reliability – Worst Performing Feeders (WPF)

On an annual basis, PowerStream will identify a total of 20 WPF (typically) based on feeder reliability data over the previous 3 years (i.e. in the spring of 2012, the “2012 WPF” will be designated using annual reliability data for 2011, 2010, and 2009). Statistical feeder interruption duration and feeder interruption frequency will be taken into consideration. All customer outages downstream of a feeder will be counted against that feeder. Qualitative input from Lines, Operations, Customer Services and System Planning will also be considered in selecting annual WPF.

WPF management is a joint effort by many business units including Operations, Lines, Design, System Planning, Stations, and the Reliability Committee.

Feeders that have the highest Feeder Scores are considered less reliable and will be targeted for detailed reviews and corrective actions. Each spring, System Planning will issue the Worst Performing Feeder report outlining the recommended actions on each identified feeder.

Remediation efforts will include feeder patrol, inspection, maintenance work, and any present or future capital work. System Planning in conjunction with Control Room will monitor the Feeder performance and report regularly for a period of 3 years following WPF identification, to confirm remediation efforts have been implemented and feeder reliability improvement has been achieved.

10 Feeders will be selected based on the feeder score obtained by the FAIDI/FAIFI methodology and 10 Feeders will be selected based on feeder scores obtained by the CMI/CI/No of Outages Methodology as outlined below:

Step 1: Compile Feeder Reliability Data and Determine WPF

1. Operations (System Control) to compile feeder reliability data. The following data is required for the previous 3 years

- FAIDI (annual)
- FAIFI (annual)
- CMI (Customer Minutes of Interruption)
- CI (Customers Interrupted on a Feeder)
- Number of Outages including momentary Outages
- Cause Code
- 3-Year Average FAIDI
- 3-Year Average FAIFI

Note 1: Feeder reliability performance will be ranked based on the following formula:

Step 2. System Planning will determine the Worst Performing Feeder based on the following:

1) Ten Feeders from the FAIDI/FAIFI methodology and will be computed as follows:
Feeder Score = 0.5 *FAIDI + 0.5*FAIFI

Where:
FAIDI = Feeder Average Interruption Duration Index (3-Year Average, excluding Loss of Supply and Major Event Day)
FAIFI = Feeder Average Interruption Frequency Index (3-Year Average, excluding Loss of Supply and Major Event Day)

2) Ten Feeders from the CMI/CI/No of Outages methodology which will be computed as follows:

Feeder Score = 0.5* Normalized CMI + 0.25* Normalized Customers Interrupted+ 0.25 * Normalized Total No of Outages Including Momentary Outages

- Min- Max Normalization will be used to Normalize the data set
- Normalization = (A- minimum value of A)/(Max Value of A-Min Value of A)

Where CMI: Customer Minutes of Interruption (3-Year Average, excluding Loss of Supply and Major Event Day)

CI: Total Customer Interrupted (3-Year Average, excluding Loss of Supply and Major Event Day)
Outages: Total Number of Outages including Momentary Outages (Excluding Loss of Supply and Major Event Days)

4.3 Hydro One's Feeders impacting PowerStream's Reliability

In PowerStream North service territory, there are a number of 44 kV feeders owned and operated by Hydro One. The reliability of these Hydro One's feeders has a direct impact on PowerStream's customers.

Each year the outage information in PowerStream North based on last 3 years data is studied and Hydro One's feeders that exhibit operational performance issues that merit review and potential corrective actions ate identified. As a result, the PowerStream SP&S has initiated discussion with Hydro One to improve reliability performance for these feeders.

4.4 Reliability Performance by Outage Cause Codes

PowerStream uses outage cause codes to categorize the causes of the outages.
Outages can be resulted from "uncontrollable" factors such as storm, snow, and vehicle accident, to "controllable" factors such as defective equipment, error in installation/operation/maintenance of the system, and tree contact.

The outage cause codes information is helpful for Reliability Committee to have an overview of the situation and prioritize reliability improvement efforts.

Based on the cumulative results over the past 5 years, the top 5 cause codes are:

1. Code 5 - Defective Equipment: accounts for 28.31% of SAIDI
2. Code 6 – Adverse Weather: accounts for 20.87% of SAIDI
3. Code 3 – Tree Contact: account for 8.85% of SAIDI
4. Code 9 – Foreign Interference: accounts for 7.3% of SAIDI
5. Code 4 – Lightning: accounts for 6.29% of SAIDI

It is suggested that the individual cause codes should be analyzed to determine:
1. Contribution to SAIDI
2. Contribution to SAIFI
3. Outage Cause details from root cause analysis/post-mortem investigation reports
4. Outage Code Trending
5. Gaps in data base, records, consistency of data collection
6. Determination of annual targets to reduce the impact to reliability

4.5 Establishing a Base Line for Reliability Improvement

In this section, we establish a reliability base line, upon which future reliability improvement can be made.

As seen from Fig-1, the baseline 2014 Target can be expected to fall between (55.47-63 min). A mean target of SAIDI 63.18 minutes is selected as baseline for 2014.

The base line contributions to SAIDI and to CMI of the cause codes have been calculated as follows:

1. The 2014 SAIDI reliability target for 2014(1.053 hours = 63.18 minutes).
2. 2014 IOR Target (Base Line) = 0.99988
3. CMI = Customers x SAIDI = 346,401 x 63.18 = 21,885,615
4. Increase in scheduled Outages: 2.36* 346,401= 817,506

4.6 MED Methodology

PowerStream has adopted in principle the IEEE B2.5 methodology for the MED calculations. However there are number of drawbacks in this method which results in some days being not counted as MED days hence affecting the system reliability numbers. The Distribution assumes Log – normal distribution which is not a characteristic distribution for SAIDI. On an average 3 days in a year would be classified as MED according to this methodology however there have been no MED days in 2012.

If a weather event exceeds normal 24 hour window in which either of the days don't exceed the MED threshold than those days will not be accounted as MED as per IEEE B2.5 methodology. Recent example is Hurricane Sandy; the total system contribution was 7.32 minutes of SAIDI in 2012 however since the event was spread over 2 days the event was not included as MED.

For example: 2012 T (med) threshold – 7.13 min

No of days exceeded threshold – 0.

Average three year SAIDI 2009-2012 (LOS excluded) – 63.87 min

It is suggested that PowerStream continue to explore the use of variation of this methodology or adapt a different methodology (10% rule) which has been adopted by Hydro one.

5. Work Plan to Improve Reliability

Over the last year, there have been numerous internal discussions on initiatives to improve reliability at PowerStream. There have been extensive discussions on the programs and process improvement projects and the reliability improvement efforts.

In general, it is difficult to determine accurately the cost and the expected reliability improvement for each work program. The cost and benefit of each work program are estimated based on available information and have been further validated by business leads implementing the projects. Some program benefits can be quantified, while others can only be given a qualified estimate (“rough” and “ball park figure”).

Going forward, SP&S will monitor the savings realized for each of the program where ever possible ; for e.g. for cable rehab projects looking at the outage history for 3 consecutive years and comparing a year after the capital programs are implemented.

The recommended overall annual cost of the programs and reliability improvement projections are shown in Table A, Chart A, and Chart B.

The recommended ownership of the various work plans are shown in Table B.

The details of annual cost and benefit of individual work programs are shown in Table C.

The reliability work plan will be revisited annually, and adjustments (planned vs. actual, activity changes, etc.) will be made as required.

The 13 initiatives are discussed below.

5.1 Trouble Crew Coverage (Days-Weekend Option), Improve Trouble Response Times, Process & Procedure

A. Trouble Crew Coverage

In 2010, it was proposed that Trouble Crew coverage be extended to 24 hours per day, 7 days per week. It was projected this initiative will have a significant impact on power restoration duration, and therefore improve reliability. It was estimated that the CMI savings of 1,129,800 could be achieved. System Control was tasked with the preparation of the report on 24x7 coverage. System control has submitted an initial report “ Business case- 24/7 Trouble Crew” and recommended the days- week end option.

The report proposes the following CMI savings for the days- weekend option.

Table-4: CMI Savings Projections for Days- Weekend Option

Period	Scenario	Average Number of Customers during Outages	Estimated Response (Outage) Savings (mins)	Number of Outages	CMI Savings	Apply to 50% of outages	Divided by # customers= Minutes of Interruption saved (from annual total)
Sat/Sun Days	#1	420	15	400	2,520,000	1,260,000	3.8
	#2	420	30	400	5,040,000	2,520,000	7.6
	#3	420	45	400	7,560,000	3,780,000	11.5
Weeknights	#1	420	15	246	1,549,800	774,900	2.3
	#2	420	30	246	3,099,600	1,549,800	4.7
	#3	420	45	246	4,649,400	2,324,700	7.0
Weekend Nights	#1	420	15	118	743,400	371,700	1.1
	#2	420	30	118	1,486,800	743,400	2.3
	#3	420	45	118	2,230,200	1,115,100	3.4

Best (Scenario 1) – 21.9 minutes
Average (Scenario 2) – 14.6 minutes
Least (Scenario 3)- 7.2 minutes

The target implementation date of 2013 was proposed in 2010 however due to resource and other consideration the project was not implemented. A new target implementation date is required to be able to predict the CMI savings.

In this report a target implementation year of 2015 and least savings of 7.2 minutes have used for 2016.

- It is recommended that Reliability Committee decide the next steps for this key reliability initiative.
- Operations continue to refine and improved process and procedure to reduce the response times.

5.2 FDIR (Fault Detection, Isolation and Restoration)

FDIR Survelant Technologies pilot project at Richmond Hill TS#1 has been in operation since 2012. This project uses the SCADA system and existing field devices to provide automatic and/or manual system restoration after a fault. This is a promising technology that could significantly reduce FAIDI on distribution feeders.

The estimated CMI savings are calculated on per feeder basis. Lockout events at RTS # 1 and RTS # 2 average 4-10 occurrences annually. Under FDIR semi-automatic mode, Control room has anticipated a CMI savings of 100,000 per year.

5.3 Worst Performing Feeders (WPF)

In year 2012, PowerStream revised the WPF methodology using a blended approach (5 Feeders from the FAIDI+ FAIFI list and 5 Feeders from the CMI+CI+MI list for North and South). This ensured that we are directing resources at Feeder which are really worst at Feeder level and also at Feeder's which are impacting the system level reliability.

The selected Feeders contribute to approximately 30-40 % of annual SAIDI excluding LOS and MED.

- In 2012, Worst Performing Feeder contributed to 4.39 M CMI in 2013.

With targeted efforts SP&S and Line aim to reduce the CMI by 5% on these feeders.

It is proposed to reduce 5% of the total annual CMI per year on these 20 WPF (approx. 15% over 3 years). This can be achieved by implementing the WPF procedure which requires the WPF be monitored closely for 3 years, and the following work be carried out as needed:

- Feeder Patrol
- Tree Trimming
- Wildlife Guard
- Infrared Inspection
- Insulator Washing
- Lightning Arrestor
- Fault Indicator
- Feeder Re-configuration
- Feeder Protection Review

CMI Saving = 220,000 CMI

It is recommended that PowerStream (Operations):

- Assign resources to carry out the required maintenance work.

5.4 Automatic Feeder Restoration Program

In 2013, Station Design in conjunction with Planning has implemented a pilot project for an automated Feeder restoration scheme. The plan is to automate 4 feeders out of Greenwood TS, Jackson TS & Lazenby TS.

The basic features of Automatic Feeder Restoration scheme:

- Only faulted feeder section is tripped, upstream sections unaffected
- Power rerouted to unfaulted feeder sections downstream of permanently faulted section within 6 cycles
- Reclosers readily reconfigurable to adapt for changes in feeder configuration
- Number of Interconnect able feeders is scalable so that several feeders can work as a network

It is expected that with successful results of the pilot additional feeders will be added to participate in the AFR scheme. The annual distribution automation program should be coordinated with the AFR program.

In 2014, a savings of 190,000 CMI's are expected by automating the 4 feeders (20M12, 5122M11, 20M22 & 36M3)

5.5 44 kV Tie in Penetanguishene

44 kV tie in Penetanguishene has been provided along Robert St. The town of Penetanguishene was being supplied by a 44 kV Hydro One feeder (98M3) from Waubashene. During a feeder outage, 98M7 could not be used to restore the town's load as there is no feeder tie within PowerStream's North Service area. The proposed 1.4 km tie line and three automated switches now provide a means of remotely restoring the town's load with the 98M7.

This project has been competed in 2013. The benefits of this project in terms of CMI will be realized in year 2014.

Outages per year = 10
CMI Saving = 607,000

5.6 Inspection & Maintenance Programs

PowerStream has been maintaining the system reasonably well, especially to station equipment. PowerStream has streamlined the inspection and maintenance procedure on distribution assets which will have a positive impact on the reliability.

Effective inspection and maintenance programs help to identify potential reliability problem, and initiate remedial actions to prevent or reduce the extent of outages.

- Tree Trimming- Over the past five years Tree contacts attributed to over 1.6M CMI each year. It is proposed to achieve a 3 year tree trimming cycle across all service areas. Since we are not yet close to the 3 year cycle we are projecting a reduction of 15 percent (80,000 CMI) with the targeted tree trimming efforts.
- Transformer - Over the past five year Transformer attributed on average 677,484 CMI per year. With the inspection program and subsequent change out we are projecting that we can save 10% (67,748 CMI)
- With Switchgear inspection + dry ice cleaning- Over the past five year Switchgear attributed to annual average 695,000 CMI. We are projecting a savings of 5% (34,750CMI)
- The insulator, arrestor + elbow failures account to over 1.27 M CMI. With the infrared and washing program SP&S is estimating a CMI savings of 10% (127,000) from the total CMI's attributed to elbow and arrestor failures.

- Total CMI savings – 309,498 (Estimated by SP&S based on outage data and in consultation with Lines)

It is recommended that PowerStream Lines:

- Leverage the information from the pole testing program and overhead inspection for maintenance work. Examples are the field notes on the condition of various components that are attached to the pole such as: bracket, insulator, guy, anchor, grounding, clearance, and sagging. Take follow-up actions (such as follow-up field verification to determine the severity and urgency of the deficiencies), and schedule corrective maintenance work as required.
- Provide refresher training for staff on cable splicing theory and technique. According to cable splice manufacturer who has conducted post failure analysis, the vast majority of splice failures were attributed to workmanship (in the high 90%).

Estimated CMI Saving = 309,498 CMI
Total CMI Savings from Tree Trimming over the next five years (25%) - 400,000
Total CMI Savings from Transformer and Switchgear Inspection (20%) –135,498+ 139,000= 274,498
Total CMI Savings from Insulator, Elbow, and Arrestor program (15%) – 190,500

As the inspection and maintenance process are improved and optimized, a reduction of 25% in the CMI attributed to tree contacts over the next five is estimated. It is also estimated that 10% CMI savings will be realized through the transformer and switchgear inspection and 5% on other inspection programs (overhead, underground, vaults).

5.7 Underground Primary Cable Rehabilitation (Cable Replacement and Injection)

PowerStream has significantly increased the capital for cable replacement and injection. Cable and Splice failures contributes 36% to the defective equipment category. PowerStream has a targeted cable replacement and injection program.

In 2013, PowerStream has changed its strategy and will be replacing splices in the areas where the cable is injected. This will have a very positive contribution to reliability as splice failures is the leading cause of outage in the defective equipment category.

Using a typical residential subdivision as a unit for cable injection, the potential CMI saving for each unit replacement is estimated as follows:

Frequency of interruption:	0.6 failures per km of cable
- Duration of interruption:	3 hours
- Number of transformers:	12 transformers
- Number of customers in the residential loop:	120 customers

- Number of customers affected in an outage: 120/2 = 60 customers (half loop)
- Number of Customer in the industrial loop: 4 customers
- Number of Customers affected in an outage: 2 customers (half loop)

The customer service reliability impact resulted by cable failures is expressed in CMI (Customer Minutes of Interruption). A mixture of 70% residential and 30% industrial has been used for calculation.

The CMI is calculated as follows:
Residential Customers:
CMI = 60 customers x 3 hours x 60 minutes x 0.6 x 119 x 0.70 = 539,784 CMI
Industrial Customers:
CMI: 2 x 3 x 60 x 0.6 x 119 x0.30 = 7711 CMI
Total CMI = 547, 495

5.8 Wood Pole Replacement

PowerStream has approx. 44,000 wood poles in service. As the poles get older and their structural integrity deteriorates, they are proposed to be replaced. Replacement in advance of failure will result in CMI avoidance rather than CMI savings.

- On Average wood pole contributed to 54,623 CMI per year (2 Outages/per year). With the budget increased to accommodate 400 pole replacement a 50% reduction in CMI can be expected
- Total CMI- 54,623
- CMI savings- 27311 (Estimated by SP&S based on past outage data and Failure History)
- Unit cost = $7,400
- Cost/CMI = $7,400 / 720 CMI = 10.27

The annual number of units budgeted in 2013 onwards is 400 units per year.

5.9 Distribution Automation

Distribution automation switches/reclosers are proposed to be installed at strategic locations to achieve the following 2 objectives:

1. To reduce feeder down time in case of outages
2. To reduce number of customers affected by outages

It is estimated that there is an incremental outage time saving of 30 minutes between manual switching versus remote automatic switching.

In 2012, DA report was published which recommended feeder automation feeders. The report recommended:

- 70 N.C RTU switches/Reclosers on selected feeders for year 2013 to 2018.
- 67 N.O RTU switches or tie- reclosers on selected feeders for year 2013 to 2018.
- The expected CMI savings by installing these automated devices is 1.5M (Five year period)
- Total CMI savings – 1,500,000
- CMI savings (2014) -122,866 (Estimated by SP&S based on the Feeder SAIDI and expected improvement following a 3 ½ switch strategy)

The annual number of units budgeted in 2014 is 22 units per year.

5.10 Distribution Switchgear Replacement

PowerStream has approx. 1,900 distribution switchgear units in service. As the units get older and their functionality and reliability deteriorates they are proposed to be replaced. The units that are located in residential subdivisions will have more impact on CMI savings than those located in commercial/industrial areas.

- Total CMI contributed to Switchgear failure = 694,980.
- No of Failures – 25, Average CMI = 27787
- CMI savings- 0.10 X 36X27787 = 100,033 (Estimated by SP&S based on past outage data and failure of 1 unit in 10 years for the switchgear being replaced)

The annual number of units budgeted in 2014 onward is 36 units per year.

5.11 Submersible Transformer and Pad Mount Transformer Replacement

PowerStream had approx. 30 locations in South (“Submersible”) and 57 locations in North (“Rocket Ship”).

All the 30 locations in South were replaced by 2012. Out of 57 units in North, 48 units have been replaced until 2013. The project to replace the submersible transformer will be completed in 2014.

In addition each year PowerStream replaces 50 pad mount transformers in the South which are identified through the inspection and maintenance program.

- PowerStream has approx. 30 locations in South (“Submersible”) and 57 locations in North (“Rocket Ship”). In 2013, 24 transformers are being replaced.
- CMI Savings:
- Number of customers affected in an outage: 35 customers (half loop)
- Frequency of interruption: 0.1 outage per year (1 failure in 10 years, for those units under consideration)
- Duration of interruption: 3 hours = 180 minutes
- Incremental CMI saving = 35 customers x 180 minutes x 0.1 failure/year = 630 CMI / year
- CMI Savings: 15,120 (Estimated by SP&S)

5.12 Installing Intellirupters on MS835 F3 and F4

The implementation of this project will improve reliability by decreasing the restoration time and will offer remote switching capability for the feeders.

The station is at the very end of PowerStream service territory and existing protection consists of fuses. The duration of outage is prolonged due to the travel time and manual restoration of the fuses.

Over the last 3 years customers have experienced an average of 2 outages per year mostly due to fuse operation.

- Average CMI during the past three year- 168,000

It is estimated that savings of 84,000 CMI’s can be achieved by implementing the project. The project will be completed in 2013 hence the savings are recorded for 2014.

5.13 Fault Indicator Program

PowerStream has an ongoing program to install additional fault indicators. Each year an additional 3000 fault indicators will be installed.

The CMI Savings have been calculated as follows:

- Failure rate = 0.026 (1 Failure in 38 years)
- No of customers per half loop = 100 (10 Transformer, No of customers on each transformer = 10, 5kVA of each customer load)
- CMI savings= 100*45*0.026 = 117 per fault indicator
- CMI Savings – 70,000

5.14 Other Initiatives

The following are the other initiatives that are believed to a have a positive impact on the CMI however no CMI savings have been attached to the program as it is very difficult to quantify the CMI savings.

Rear Lot Construction Elimination

Existing Rear Lot construction locations present some operational and reliability issues:

- Pole line deteriorated conditions
- Access problems for maintenance and trouble response
- Risk to staff health and safety
- High cost to remove rear lot pole line to the front

Cost and CMI saving are not estimated at this time.

It is recommended that PowerStream (System Planning & Standards):

- Review the issue and produce report detailing expected impact on reliability and resources required for implementation.

Asset Condition Assessment (ACA) Program (Station and Distribution Assets)

An effective ACA process will assist PowerStream to make the right decisions on the short term and long term plans for various distribution and station assets. Currently there are some new initiatives to enhance the existing ACA models:

- Review and update existing models
- Model additional assets – Mini-rupter switches, 230 kV switches
- Enhancements to existing models to achieve the following 4 objectives:
  1. Projection for customer interruption, CMI, system risk, and reactive capital
  2. Project creation module
  3. Repair versus replacement decision
  4. Business Case Evaluation

Cost and CMI saving are not estimated at this time.

It is recommended that PowerStream (System Planning & Standards and Station Sustainment):

- Continue development of the ACA program to accurately assess the condition and the risk of failure of various distribution asset classes and tie the inspection and maintenance results to the ACA condition assessment.
- Continue to refine the station asset condition assessment program and ensure that the current condition f the assets are accurately captured in the model. For e.g. the current TS/MS Transformer DGA results to be used for condition assessment in the TS/MS model.

Contingency Plan, Spare Equipment & Materials

Contingency Plans are required to deal with any asset related event that affects the proper functioning of the distribution system. Contingency planning will deal with potential high impact low probability (HILP) events that can have major repercussions on the distribution system and our customers. All other events that occur regularly, have low impact, and have established processes to deal with, are not part of this Contingency Plant. The HILP events considered here are shown in the Table 13.

Table 5 - Contingency Plans

Asset Class	Contingency Event	Contingency Plan
TS Power Transformers	Transformer failure requiring off-site servicing	1. Spare Transformer 2. Storage location for spare 3. Individual plans to move spare to affected TS 4. Individual connection plans for each TS configuration
TS Switchgear Cell(s)	Cell or multi-cell failure	1. Spares – Critical parts list 2. Contact plan for manufacturer repair support 3. Spare cell 4. Feeder emergency loading capability
230kV switches	Switch failure – non-repairable	1. Spare switch(s)/parts 2. Storage location for spare(s) 3. Individual mounting plan(s) for each TS structure
TS Feeder cables	Failure of one or more underground cables	1. Spare cable reel
TS Capacitor banks	Failure of significant portion of capacitor bank	1. Spare Capacitor cans 2. Contact plan for manufacturer repair support
TS Reactor failure	Failure of reactor	1. Spare reactor
Station RTU	Failure of RTU leading to loss of station control	1. Standby staff to man station 2. Contact plan for manufacturer repair support
Station Protective Devices	Device failure leading to full/partial loss of station	1. Spare – Critical Parts list
Poles	Loss of high number of pole structures through high impact event (severe weather, etc.)	1. Stock poles 2. Supplier stock 3. Neighbouring LDC stock

In all cases if available contingency measures prove insufficient, rotating load shedding may be required to ensure equipment is not loaded beyond approved tolerances.
Sufficient spare equipment and materials are essential for PowerStream to manage power outages.

Cost and CMI saving are not estimated at this time.

It is recommended that PowerStream (System Planning & Standards):

- Procurement, Operations, Lines and Planning review, as required, emergency stock levels to ensure that adequate stock is on hand to deal with the various component failure/replacement rates.

6. Recommendations - Overall Reliability Work Plan

Target:

The IOR Target according to critical success factor is set as:
Four 9's for 3 months and five 9's for 9 months
3 months x IOR 0.99990
9 months x IOR 0.99999

Per month IOR = (730 – SAIDI per month) / 730

IOR = 0.99990 per month is equivalent to SAIDI = 0.073 hours per month = 4.38 minutes per month

IOR = 0.99999 per month is equivalent to SAIDI = 0.0073 hours per month = 0.438 minutes per month

Therefore SAIDI Target:

SAIDI = 4.38 minutes x 3 months + 0.438 minutes x 9 months = 17 minutes per year = 0.283333 hours per year

IOR Target for critical success factor is:
IOR = (8760 – SAIDI) / 8760 = (8760 – 17/60) / 8760 = 0.999967656

Base Line

Base Line CMI (2014) = 21,885,615 CMI

CMI Saving Required

Total CMI Saving Required = Base Line CMI – Target CMI
Total CMI Saving Required = 21,885,615 CMI – 6,604,398 CMI = 15,281,217 CMI

Table 6: Baseline, Target and Actual Performance

Base Line vs. Target and Projected Performance				
	Base Line	**IOR Target (Five 9's)**	**Required Improvement**	**Projected Improvement (By end 2018)**
CMI	**21,885,615**	**6,604,398**	**15,281,217**	**10,361,462**
SAIDI (Minutes)	**63.18**	**17.00**	**46.18**	**27.13**
IOR	**0.99988**	**0.99996**	**0.000087**	**0.000069**

From table 6 it is established that work programs are **REQUIRED** to produce 15,281,217 CMI savings to reach the Five 9s' target.

This report recommends 13 work programs that can be implemented over the next few years. The work programs are projected to deliver a savings of 27.13 minutes instead of the required 46.18 within the next five years.

The recommended overall annual cost of the programs and reliability improvement projection are shown in Table A, Chart A, and Chart B.

The recommended ownership of the various work plans are shown in Table B.

The details of annual cost and benefit of individual work programs are shown in Table C.

The reliability work plan will be revisited annually, and adjustments (planned vs. actual, activity changes, etc.) will be made as required.

The Reliability Committee will take the key role in overseeing the implementation of the reliability work plan. The work plan will be a standing agenda item in the Reliability Committee meetings.

Recommendations:

1. The Reliability Committee approve the reliability work plan shown on Table B, and Table C.

2. The Reliability Committee take the key role of overseeing the implementation of the reliability work plan, which will be a standing agenda item in the Reliability Committee meetings.

3. The business units referred to under each work program to continue to work on implementing or refining the respective work program according to Table B.

4. SP&S to review the outage data, individual cause code contribution and model the reliability performance considering various weather pattern, scenarios and available project funding.

Table A - Annual Cost and Reliability Projection					
	2014	**2015**	**2016**	**2017**	**2018**
CMI - Base Line (A)	22,804,860	21,034,292	19,757,342	16,257,149	15,448,624
CMI Savings during the year (B)	2,284,397	1,276,133	3,893,768	1,232,094	1,080,594
CMI - end of year (C = A - B)	20,520,463	19,758,159	15,863,573	15,025,055	14,368,030
System Customers (D)	346,000	354,650	363,516	372,604	381,919
SAIDI (minutes)	59.31	55.71	45.00	41.69	38.78
IOR	0.9998872	0.999894	0.9999144	0.9999207	0.9999262
Annual Cost ($) (G)	35,776,766	32,443,883	34,216,837	34,016,088	33,684,808
Annual Cost/CMI Saving (H = G/B)	15.66	25.42	8.79	27.61	31.17

Chart A – SAIDI Projection

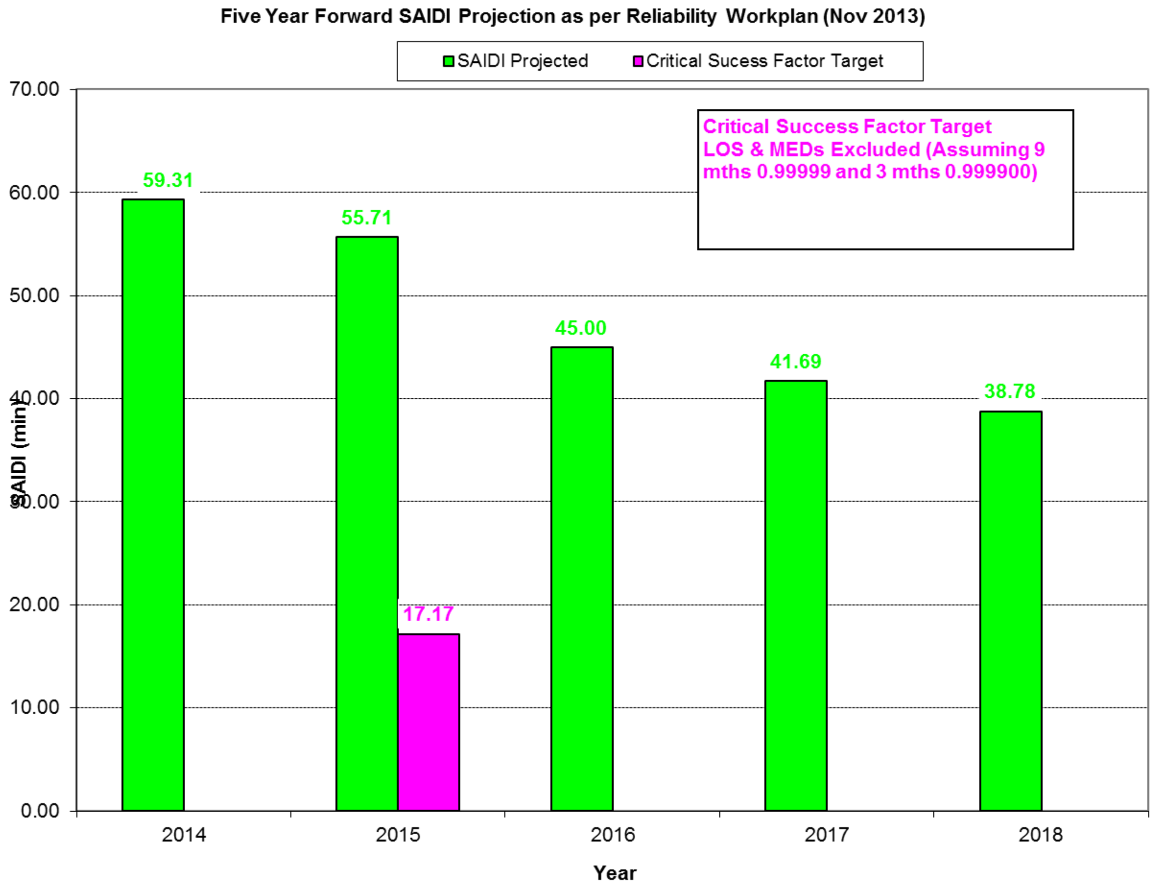


Chart B – IOR Projection

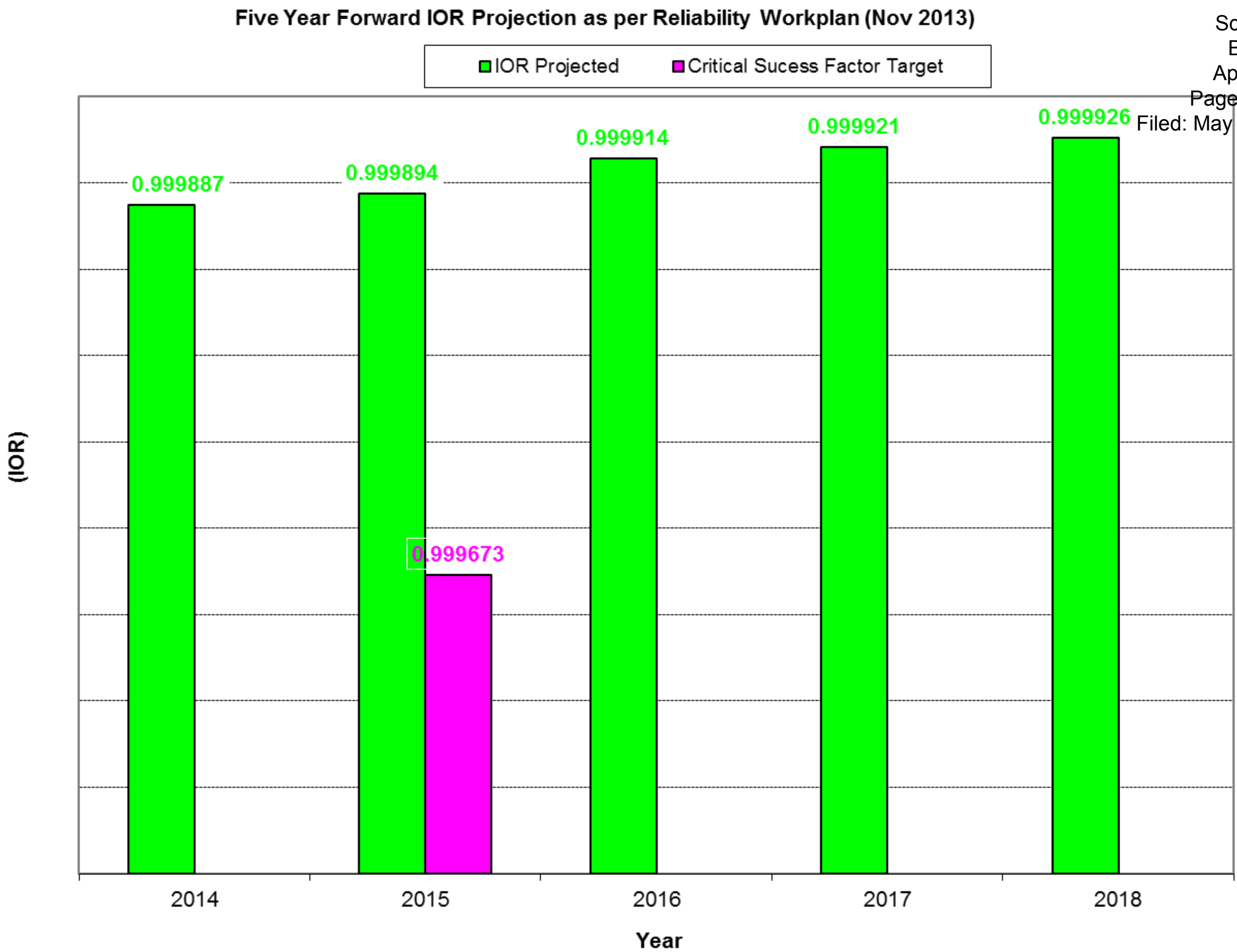

Five Year Forward IOR Projection as per Reliability Workplan (Nov 2013)
IOR Projected
Critical Sucess Factor Target
0.999887
0.999894
0.999914
0.999921
0.999926
0.999673
(IOR)
2014
2015
2016
2017
2018
Year

Table B - Implementation Responsibilities - Program Owners

	Program Description	Responsibility	Date
1	**Trouble Crew Coverage on 24/7 Basis, Improve Trouble Response Times, Process & Procedure** •Operations to lead the implementation of the project. Report to the Reliability Committee on the outcomes and recommendations of the Outage Performance Group. • Continue to implement process that result in reducing outage response times.	Lines, Operations	Q4 2015
2	**FDIR (Fault Detection, Isolation and Restoration)** • Confirm positive net benefit of 2013 project.	Operations	Annual
3	**Worst Performing Feeders (WPF)** • Assign resources to carry out the required maintenance work	Lines	Annual
4	**Automatic Fault Restoration** Report on the benefits of the pilot completed in 2013 Continue to propagate AFR schemes on 27.6 kV feeders	Station Design, SP&S	Annual
5	**44 kV Tie in Penetanguishene** • Follow up with budget approval and implementation of the project.	SP&S	Q4 2013
6	**Inspection & Maintenance Program** Ensure the existing tree trimming program adequately addresses actual vegetation growth rates. • Emphasize feeder patrols to identify potential vegetation problems to aid in proactively prioritizing tree trimming work. Continue the implement the inspection and maintenance work program and activities	Lines, Stations Sustainment	Annual
7	**Wood Pole Replacement** • Continue the inspection and annually refine the ACA program and manage the annual pole replacement program.	SP&S	Annual
8	**Distribution Automation Switch/Recloser Installation** • Increase the annual installation of automated switches to 30 units per year starting 2014.	SP&S	Annual
9	**Underground Cable Replacemen**t • Increase the annual cable replacement budget to $8 M per year starting 2013	SP&S	Annual
10	**Distribution Switchgear Replacement** • Increase the annual switchgear replacement to 30 units per year starting 2013	SP&S	Annual
11	**Submersible Transformer & Vault Replacement/Retrofit** • Proceed with the proposed replacement under the asset replacement program.	SP&S, Lines	Annual
12.	**Installing Intellirupters on MS835 F3 and F4** • Proceed with the proposed installation and verify CMI savings at the end of 2014	SP&S	Q4 2014
13.	**Fault Indicator Program** • Proceed with the annual installation program	Lines	Annual
12	**Other Initiatives:** **Rear Lot Construction Elimination** • Produce report on impact on reliability and resources required for implementation. **Asset Condition Assessment Program (Station and Distribution Assets)** • Continue to refine the asset condition assessment program and ensure that the condition data is updated with the current data from the inspection and maintenance programs for the Station as well as Distribution Assets. **Contingency, Spare Equipment and Materials** •Ensure adequate spare equipment are available.	SP&S SP&S SP&S, Supply chain	Q4 2013 Annual Q4 2014

Table C - Summary of Five Year Reliability Work Plan

Program	Program Description	Responsibility	Program Type	Cost A	CMI Saving B	Cost per CMI C = A/B	2014 346,000 Customers			2015 354,650 Customers			2016 363,516 Customers			2017 3 72,604Customers			2018 381,919 Customers			Five Years Acc Cost (2010 Dollar)	Five Years Acc CMI Savings
							Cost	CMI Saving	SAIDI Saving (Minutes) 332,000 Cust	Cost	CMI Saving	SAIDI Saving (Minutes) 354,650 Cust	Cost	CMI Saving	SAIDI Saving (Minutes) 363,516 Cust	Cost	CMI Saving	SAIDI Saving (Minutes) 371,604 Cust	Cost	CMI Saving	SAIDI Saving (Minutes) 381,919 Cust		
1	Trouble Crew Coverage on 24/7 Basis (Days-Weekend Option)	Lines,Ops	OM&A	1,000,000	2,459,022	$0.41	0	0	0.0	0	0	0.00	1,000,000	2,617,315	7.20	1,000,000	0	0.00	1,000,000	0	0.00	3,000,000	7.20
2	FDIR (Fault Detection, Isolation and Restoration)	Operations	Capital	200,000	375,000	$0.53	100,000	100,000	0.3	0	0	0.00	0	0	0.00	0	0	0.00	0	0	0.00	100,000	0.29
3	Worst Performing Feeders (WPF)	Lines	OM&A	250,000	250,000	$1.00	250,000	220,000	0.6	250,000	250,000	0.70	250,000	250,000	0.69	250,000	250,000	0.67	250,000	250,000	0.65	1,250,000	3.35
4	Automatic Fault Restoration	SP&S,Ops, Station Sustainment	OM&A	400,000	50,000	$8.00	400,000	190,000	0.5	400,000	50,000	0.14	400,000	50,000	0.14	400,000	50,000	0.13	400,000	50,000	0.13	2,000,000	1.09
5	44 kV Tie in Penetanguishene	SP&S	Capital	587,491	607,000	$0.97	0	547,370	1.6	0	0	0.00	0	0	0.00	0	0	0.00	0	0	0.00	0	1.58
6	Inspection & Maintenance Procedures	Lines, Station Sustainment	OM&A	3,000,000	309,498	$9.69	3,000,000	309,498	0.9	3,000,000	139,125	0.39	3,000,000	139,125	0.38	3,000,000	139,125	0.37	3,000,000	139,125	0.36	15,000,000	2.41
7	Wood Pole Replacement	SP&S	Capital	4,956,094	720	$6,883.46	4,956,094	27,312	0.1	5,071,697	27,312	0.08	5,188,949	27,312	0.08	5,307,899	27,312	0.07	5,428,597	27,312	0.07	25,953,236	0.38
8	Distribution Automation Sw itch/Recloser Installation	SP&S	Capital	2,419,883	122,866	$19.70	2,419,883	122,866	0.4	2,475,169	122,866	0.35	2,530,758	122,886	0.34	2,585,744	122,866	0.33	2,194,590	122,866	0.32	12,206,144	1.69
9	Underground Cable Replacement and Rejuvenation	SP&S	Capital	20,948,153	547,497	$38.26	20,948,153	547,497	1.6	18,153,650	547,497	1.54	18,670,969	547,797	1.51	18,063,953	383,458	1.03	18,409,383	383,458	1.00	94,246,108	6.67
10	Distribution Sw itchgear Replacement	SP&S	Capital	2,323,235	100,033	$23.22	2,390,636	55,574	0.2	2,459,927	100,033	0.28	2,531,161	100,033	0.28	2,604,401	100,033	0.27	2,604,401	100,033	0.26	12,590,526	1.25
11	Submersible Transformer & Vault and Pad Mount Transformer Replacement	SP&S,Lines	Capital	82,000	1,800	$45.56	1,312,000	10,080	0.0	363,440	7,800	0.02	375,000	7,800	0.02	386,250	7,800	0.02	397,837	7,800	0.02	2,834,527	0.11
12	Installing Intellirupters on MS835F3 & MS835F4	SP&S	Capital	147,841	44,000	$3.36	0	84,000	0.2	0	0	0.00	0	0	0.00	147,841	120,000	0.32	0	0	0.00	147,841	0.56
13	Fault Indicator Program	Lines	OM&A	270,000	31,500	$0.12	0	70,200	0.2	270,000	31,500	0.09	270,000	31,500	0.09	270,000	31,500	0.08	270,000	31,500	0.08	1,080,000	0.55
	TOTAL PROGRAM	Total Program					35,776,766	2,284,397	6.60	32,443,883	1,276,133	3.60	34,216,837	3,893,768	10.71	34,016,088	1,232,094	3.31	33,684,808	1,080,594	2.91	170,138,382	27.13
	Reliability Projection= SAIDI (Minutes) Base Line- SAIDI Improvements + Increase in schedule	SAIDI Projected						65.91	59.31		55.71	55.71		45.00	45.00		41.69	41.69		38.78	38.78		
	Reliability Projection - IOR Baseline IOR = 0.999878	IOR Projected						0.999875	0.999887		0.999894	0.999894		0.999914	0.999914		0.999921	0.999921		0.999926	0.999926		

Appendix A – Reliability Metrics

PowerStream is using the industry-accepted metrics to monitor and report the system reliability. The Reliability metrics are described below.

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.
“Sustained interruption” means an interruption of one minute or more.

SAIDI is defined as the total customer-hours of sustained interruptions normalized per customer served, and is expressed as follows:

$$\text{SAIDI} = \frac{\text{Total Customer-Hours of Sustained Interruptions}}{\text{Total Number of Customers Served}}$$

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.

SAIFI is defined as the number of sustained interruptions normalized per customer served, and is expressed as follows:

$$\text{SAIFI} = \frac{\text{Total Customer Sustained Interruptions}}{\text{Total Number of Customers Served}}$$

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.

CAIDI is defined as the total customer-hours of sustained interruptions normalized per customer sustained interruption, and is expressed as follows:

$$\text{CAIDI} = \frac{\text{Total Customer-Hours of Sustained Interruptions}}{\text{Total Customer Sustained Interruptions}}$$

IOR – Index of Reliability

IOR is an indicator of system reliability that expresses the per unit annual customer-hours that service is available. This is another way of expressing SAIDI. All planned and unplanned sustained interruptions are used to calculate this index.

$$\text{IOR} = \frac{\text{8,760 hours/year - SAIDI}}{\text{8,760 hours/year}}$$

When SAIDI = 0 (i.e. no interruption in the year), IOR = 1 (i.e. the system is available at all time).

Example:
In order to achieve an IOR = 0.99999 (Five 9's), PowerStream must achieve a SAIDI = 5.3 minutes, as calculated below:
IOR = (8760 – SAIDI) / 8760
Therefore:
SAIDI = 8760 (1 – IOR)
SAIDI = 8760 (1 – 0.99999) = 8760 x 0.00001 = 0.0876 hours
SAIDI = 0.0876 hours x 60 minutes/hour = 5.3 minutes

MAIFI – Momentary Average Interruption Frequency Index

MAIFI is an indicator that expresses the average number of momentary interruptions each customer experiences in a year. All planned and unplanned momentary interruptions are used to calculate this index. "Momentary interruption" means an interruption of less than one minute.

MAIFI is defined as the number of momentary interruptions normalized per customer served, and is expressed as follows:

$$\text{MAIFI} = \frac{\text{Total Number of Momentary Customer Interruptions}}{\text{Total Number of Customers Served}}$$

FAIDI – Feeder Average Interruption Duration Index

FAIDI is an indicator of feeder 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.

FAIDI is defined as the total customer-hours of sustained interruptions on the feeder normalized per customer served on the feeder, and is expressed as follows:

$$\text{FAIDI} = \frac{\text{Total Customer-Hours of Sustained Interruptions on the Feeder}}{\text{Total Number of Customers Served on the Feeder}}$$

FAIFI – Feeder Average Interruption Frequency Index

FAIFI is an indicator of feeder reliability that expresses the average number of sustained interruptions that each customer experiences in a year. All planned and unplanned sustained interruptions should be used to calculate this index.

FAIFI is defined as the number of sustained interruptions on the feeder normalized per customer served on the feeder, and is expressed as follows:

$$\text{FAIFI} = \frac{\text{Total Customer Sustained Interruptions on the Feeder}}{\text{Total Number of Customers Served on the Feeder}}$$

FESI-x – Feeder Experiencing Sustained Interruption x times or more during a 12-month rolling period. This can be adopted to highlight Feeders that experience multiple sustained outages in a year.

FESI-x is an indicator of feeder reliability that expresses how many feeders (out of the total feeder population in the system) experience x outages or more over the past 12 months.

FESI-x is described below, via an example.

Example:
FESI-8 : Feeder that has 8 or more sustained interruptions during the past 12 months.
Say by December 31, 2013, feeder JOHF5 has accumulated a total of 9 sustained interruptions during 2013 (i.e. in the past 12 months). Because 9 is greater than the threshold 8, feeder JOHF5 is classified as one of FESI-8 group.

PowerStream can set a target such as follows:
In any one year, there will be less than 10% of the total number of feeders will fall into the FESI-8 group. Another interpretation of the above is: how many feeders have 8 or more sustained interruptions in the past 12 months?

The above 8 metrics will be compiled and reported according to the 4 categories:

- All Events: data is inclusive of all outage cause codes.

- Excluding Loss of Supply (LOS): outages that resulted because of Hydro One's feeder or transmission outage are excluded from the calculation.

- Excluding Loss of Supply (LOS) and Major Event Days (MED):
  Outages that resulted because of a loss of supply from Hydro One's system or Major Event Days are excluded from the calculation.

Five Year Work Reliability Work Plan

2015-2019

Prepared by: System Planning

Date: Dec 2014

Contents

1. Executive Summary

PowerStream is required by the Ontario Energy Board (OEB), to report two system-wide reliability indices, the system average interruption frequency index ("SAIFI") and the system average interruption duration index ("SAIDI"). These results are used to ensure that distributors are achieving the OEB's desired outcomes for customers, and are published as part of each utilities performance scorecard. At a minimum, Distributors are expected to maintain a three-year moving average of their system reliability performance within historical levels.

As such, reliability has become a significant focus within the working culture at PowerStream and has led to many innovations in terms of technical, maintenance, and process improvements. The general target continues to be to lower our overall SAIDI or at least perform better than the minimum requirements set out by the OEB.

In 2010, a *Five Year Reliability work Plan* was developed and subsequently updated in 2013. The report captures the efforts of many departments, quantifies the reliability savings of each project in terms of CMI savings, and creates a 5 year projection of reliability to measure performance against.

Although the Five Year Reliability Work Plan has been an effective tool to capture programs and projects that have a positive impact on reliability, there is the need to further improve the accuracy of forecasting future performance and achieving the projected targets.

In response, an initiative was created in 2014 to review and revise the methodology for setting annual reliability targets and as a solution; a Reliability Model is being proposed to forecast future reliability projections.

<u>Reliability Model:</u>

The Reliability Model is designed to output a 5 year Reliability Projection in terms of SAIDI performance based on the past 5 years of reliability history and future planned Reliability improvements.

The Model breaks down SAIDI into its controllable and uncontrollable factors and identifies contributions made by factors tied directly or indirectly to weather. Weather has been shown to make a significant impact on reliability and makes up most of the SAIDI from the uncontrollable factors.

Among the uncontrollable factors, three codes were dedicated specifically to weather outages namely: Adverse Environment, Adverse Weather and Lightning.

The controllable and uncontrollable factors are listed below:

Controllable factors	**Uncontrollable factors**
Defective Equipment	Foreign Interference
Scheduled Outage	Unknown
Tree Contact	Adverse Environment *(Weather Dependent)*
Human Element	Adverse Weather *(Weather Dependent)*
	Lightning *(Weather Dependent)*

The model 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

The first variable in the equation, '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. The second variable 'Weather Outages', is calculated by averaging the SAIDI performance due to weather related outages over the past five years. The third variable 'Increase in Scheduled Outages', is calculated using the yearly increase in capital spend as a proportional guideline. The fourth variable '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 complete list of the technical projects and work programs included in the 2015 to 2019 Reliability Work Plan are listed below:

1	Worst Performing Feeders (WPF)
2	Automatic Fault Restoration
3	Inspection and Maintenance
4	Wood Pole Replacement
5	Distribution Automation Switch/Recloser Installation
6	Underground Cable Replacement and Rejuvenation
7	Distribution Switchgear Replacement
8	Submersible Transformer & Vault and Pad Mount Transformer Replacement
9	Fault Indicator Program
10	44kV Insulators Replacement Program
11	Mini-Rupter Switch Replacement Program
12	Ice Storm Hardening
13	Rear Lot Supply Remediation

Table 1: 2015 to 2019 Reliability based projects and programs

Based on the Reliability Model calculations, the 5 year reliability forecast for 2015 to 2019 is as follows:

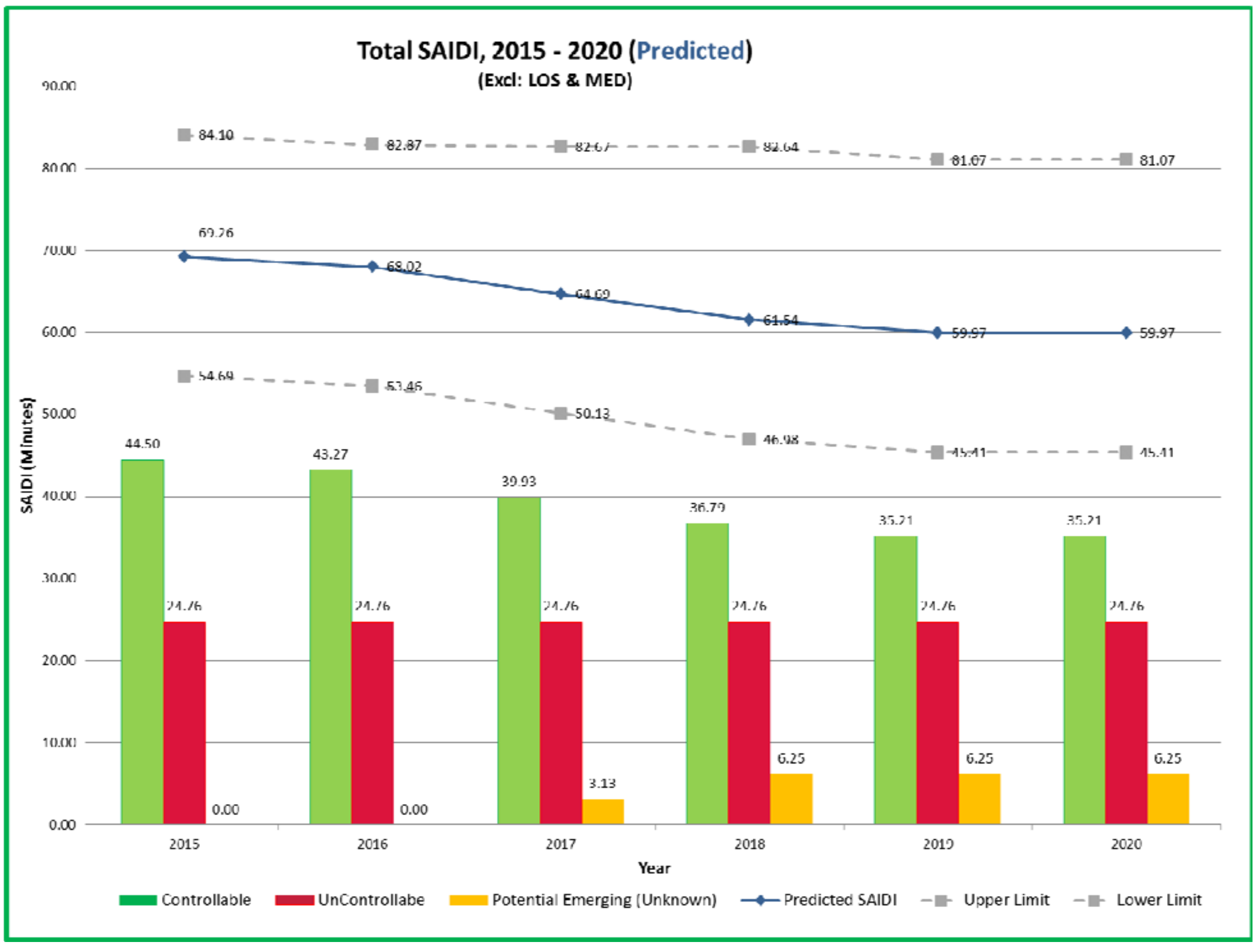


Figure 1: 2015 to 2019 Reliability based projects and programs

Figure 1 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 years 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.

Recommendations:

Based on the calculations of the Reliability Model, it is recommended to use to following Five Year Reliability projection for 2015 to 2019, utilizing a SAIDI threshold value that is bound by an upper weather limit:

Year	2015	2016	2017	2018	2019	2020
SAIDI Upper Limit (Minutes)	(84.10)	(82.87)	(82.67)	(82.64)	(81.07)	(81.07)
SAIDI target (Minutes)	69.26	68.02	64.69	61.54	59.97	59.97

Table 2: Five year Reliability Targets

Attachments:

Appendix A – 5 Year Reliability Work Plan
Appendix B – Implementation Responsibilities
Appendix C – Reliability Metrics

2. Purpose

In an effort to support PowerStream's mission to deliver reliable power to its customers, System Planning issues an annual five-year Reliability Work Plan that identifies which planned capital projects are expected to have a positive impact on Reliability, quantifies each of said project's effectiveness in the form of CMI (Customer Minutes of Interruption) reduction, and estimates a 5 year projection of overall reliability performance for PowerStream going forward.

This document will review the current reliability performance level, discuss related issues that have an impact on reliability, discuss existing initiatives that are in progress and update their projected CMI savings, and introduce new initiatives that will result in additional CMI reductions.

The Five Year Reliability Work Plan primarily focuses on the future five year capital budget plans for the Asset Management and Operations departments. The plan identifies the project lead for each undertaking and creates the frame work necessary for reporting to the Reliability Committee in the year ahead.

The work programs proposed span across many technical fields and include continuous improvements and best practice implementation in the following areas:

- Planning
- Design
- Construction
- Inspection & Maintenance
- Operations
- Distribution Automation
- Smart Grid Technologies
- Outage Response & Outage Management
- Records System
- Coordination of Work Programs
- Hydro One's System Performance impacting PowerStream
- Contingency Plans

3. Background

Electricity distributors in Ontario annually report two system-wide reliability indices to the OEB (Ontario Energy Board):

- System Average Interruption Frequency Index ("SAIFI") and;
- System Average Interruption Duration Index ("SAIDI").

Distributors have been reporting these system reliability indicators to the Board since 2002. Distributors are expected to maintain, at a minimum, a three-year moving average of their system reliability performance within historical levels.

For example, PowerStream's SAIDI results including all weather events for 2010, 2011, and 2012 were 32.4min, 63.0min, and 62.4min respectively. Therefore, the expectation was to maintain an average SAIDI performance of 52.6min for 2013. Unfortunately, due to the significant ice storms experienced in December 2013, PowerStream's reported performance for 2013 was an inflated 9.77min.

PowerStream's reliability indicators are published each year by the OEB as part of the 'Distributor Scorecard'. The publically available scorecard is intended to measure how well PowerStream is performing each year, relative to other Ontario electricity distributors. It is designed to encourage electricity distributors to operate effectively, continually seek ways to improve productivity and focus on improvements that their customers value.

The complete 2013 list of Ontario's Electricity Distributors scorecards, including PowerStream's, can be found using the following link:

www.ontarioenergyboard.ca/OEB/ElectricityDistributorScorecards

For the next five years, PowerStream will aim to at least maintain its system average and work towards making a modest improvement in system reliability. It will achieve this goal by identifying, implementing, and optimizing new work methods and technology innovations.

4. Reliability Considerations

This section describes the approach taken to develop the five year reliability work plan. The plan will be developed in consideration with the following reliability drivers and influencers:

- Reliability Metrics to be Measured
- Base Line Determination
- Incremental Improvement Work Programs
- Budget Constraints
- Controllable vs. Uncontrollable Events
- Diminishing Return of Work Programs
- Loss of Supply & Major Event Days

a. Reliability Metrics

PowerStream uses the following reliability metrics to monitor and report reliability.

- SAIDI
- SAIFI
- CAIDI
- IOR
- MAIFI
- FAIDI
- FAIFI
- CELID
- CEMI

Full definitions for the above reliability metrics are listed in Appendix C.

b. Base Line for Reliability Improvement

The Ontario Energy Board (OEB) expects that a distributor's current reliability performance (SAIDI, SAIFI, CAIDI) should, at minimum, remain within the range of its historical previous 3 year performance. This concept can be extended to the Index of Reliability (IOR) performance.

Going forward, System Planning is recommending that the baseline reliability number should be generated based on the on the average of at least five years of past data. This will ensure that various years of past performance are considered when predicting a baseline starting value for the following year.

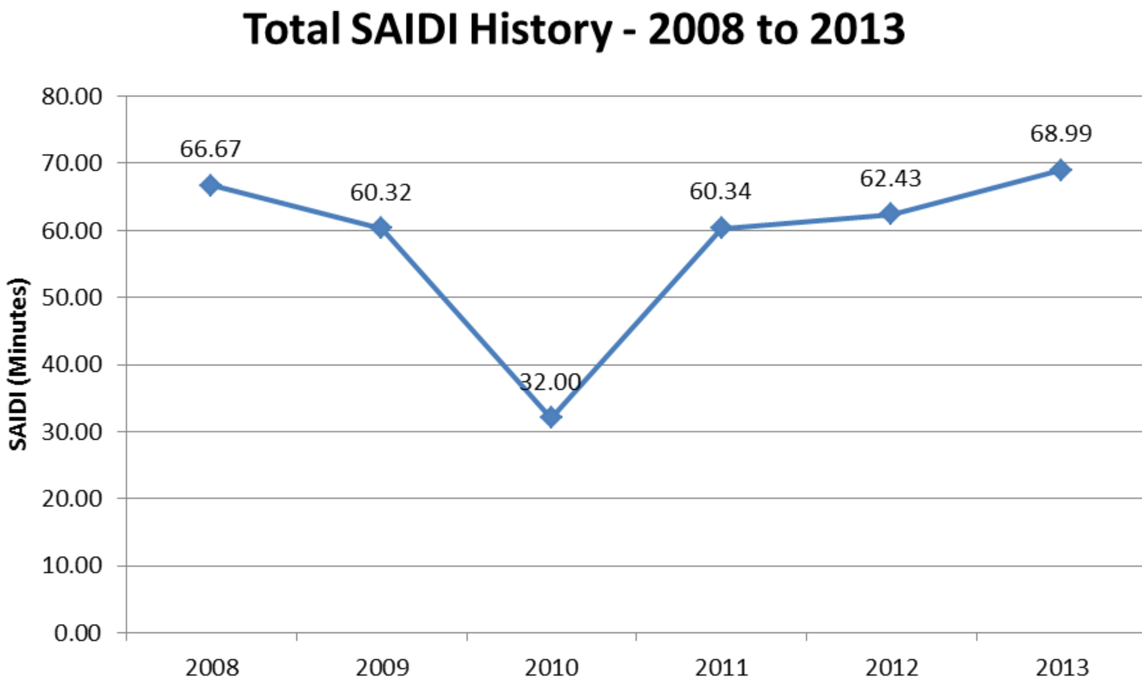


Figure 2: SAIDI History by Year (Excluding LOS & MED)

Figure 2 shows the total SAIDI in minutes for the years 2008 to 2013 excluding LOS & MED events. SAIDI values in the previous five years can be plotted to establish a control chart. Using the methods from the process control world; a year with obvious inconsistency can be considered an anomaly and can be removed from the data set. For example, a special year with good weather as in 2010, which may lead to skewed metrics, is considered an anomaly and can be removed.

A mean SAIDI value of **57.4 minutes** has been established as a baseline for year 2015. Baseline is discussed in further detail in section 6.

c. Incremental Improvement

Among the recommended work programs, there are two types of incremental improvement:

- **One time only incremental improvement:** the CMI savings are achieved in one year only and not repeated in future years. For example, when an old switch (high probability of failure within the next 5 years) is replaced with a new switch, the CMI savings are achieved for one year. In this case, the CMI saving will be counted for one year only.

- **Repeating incremental improvement:** the CMI saving is repeated in future years. For example, tracking and reducing the trouble response procedure is revised and implemented, resulting in a reduction of the outage response time by 10 minutes every time the crew respond to an outage. In this case, the CMI saving will be counted for all future years.

  CMI Avoidance vs. CMI Savings: It is acknowledged that the capital programs are CMI avoidance for future years and not necessarily a CMI savings from the present situation, and hence need to be quantified in a different way. It is suggested that the data should be obtained by looking at the actual CMI attributed in the system for failure of the particular asset class in the last 5 years and then assigning a savings based on those numbers. This approach has been used in the report.

d. Budget Constraints

It is very difficult to establish a one-to-one relationship between budget spending and reliability. PowerStream is taking concentrated efforts to identify and establish projects that will improve reliability and implement capital programs that match the aging profile of the plant. At an overall level it is reasonable to assume that the current level of budget capital spending is sufficient to sustain the current level of reliability and achieve modest reliability improvement.

For significant reliability improvements additional capital and OM&A funds will be required. This is a reasonable assumption, considering that the distribution asset components are getting older, and therefore becoming less reliable as time goes by.

e. Controllable vs. Uncontrollable Factors

Among the factors that impact reliability, there are factors that are considered “Controllable” and others that are considered “Uncontrollable”.

PowerStream uses outage cause codes to categorize the causes of the outages. Outages can be resulted from “uncontrollable” factors such as storm, snow, and vehicle accident, to “controllable” factors such as defective equipment, error in installation/operation/maintenance of the system, and tree contact.

The outage cause code information is helpful for Reliability Committee to have an overview of the situation and prioritize reliability improvement efforts.

Although there is no universally accepted definitive classification for controllable and uncontrollable, and there will be events that could be debated as either, a general means of distinction must be derived in order to allow for meaningful analysis.

For practical purpose, based on the ten outage cause codes that the control room currently classifies outages under, PowerStream will consider the following groupings of Controllable and Uncontrollable factors:

1. Controllable factors include:
   - Code 1 – Scheduled Outage
   - Code 3 – Tree Contact
   - Code 5 – Defective Equipment
   - Code 8 – Human Element

2. Uncontrollable factors include:
   - Code 0 – Unknown/Other
   - Code 2 – Loss of Supply
   - Code 4 – Lightning
   - Code 6 – Adverse Weather
   - Code 7 – Adverse Environment
   - Code 9 – Foreign Interference

The SAIDI contributions for Controllable, Uncontrollable and Loss of Supply over the past 5 years are illustrated further in Figure 3.

PowerStream SAIDI breakdown by Controllable, Uncontrollable, and Loss of Supply (2008-2013, excluding 2010 and MED)

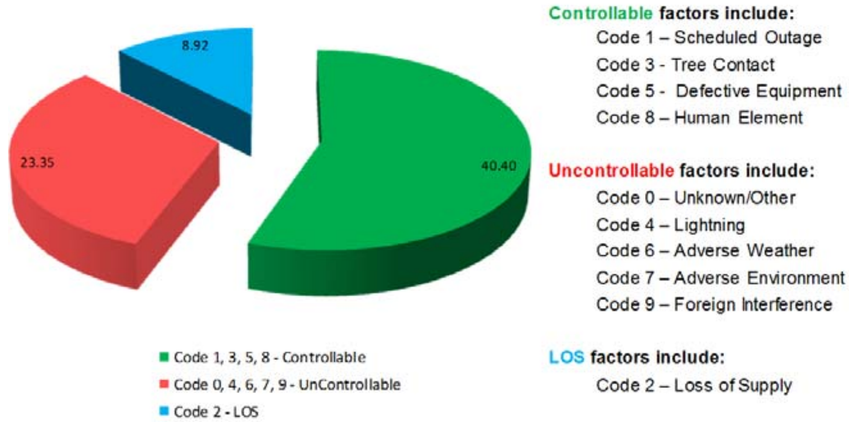


Figure 3: Average Annual SAIDI Contribution by factor

The SAIDI contributions for each of 10 cause codes over the past 5 years are broken down further in the following table:

PowerStream SAIDI breakdown by Cause Codes (Cumulative from 2008-2013, excluding 2010 and MED)

Code	Cause	SAIDI(min)	Total Controllable(min)	% of Total SAIDI
1	SO - Scheduled Outage	6.27	40.40	55.59
3	TC - Tree Contact	4.42		
5	DE - Defective Equipment	28.66		
8	HE - Human Element	1.05		
Code	Cause	SAIDI(min)	Total UnControllable(min)	% of Total SAIDI
0	UK - Unknown	2.63	23.35	32.13
4	LT - Lightning	2.95		
6	AW - Adverse Weather	9.82		
7	AE - Adverse Environment	0.67		
9	FI - Foreign Interference	7.27		
Code	Cause	SAIDI(min)	Total Loss of Supply(min)	% of Total SAIDI
2	LS - Loss of Supply	8.92	8.92	12.28

Table 3 – Controllable vs. Uncontrollable Factors

From the table, we can see that the total contributions to PowerStream SAIDI comprise of:

- Controllable Factors (Code 1, 3, 5 and 8); Average SAIDI contribution = 40.40min; 55.59%
- Uncontrollable Factors (Code 0, 4, 6, 7, and 9): Average SAIDI contribution = 23.35 min; 32.13%
- Loss of Supply (Code 2): Average SAIDI contribution = 8.92 min;12.28%

As seen in figure 3, it can be noted that the average SAIDI contribution over the past five years from un-controllable factors is approximately 23.35 min per year. This means, that even if PowerStream were to eliminate all SAIDI contribution from controllable factors, 23.35min of un-controllable SAIDI would still remain. This illustrates that there are limitations to the overall effectiveness of our work efforts on total SAIDI reduction, and that the impact of uncontrollable factors needs to be managed in a different manner as part of the overall reliability improvement strategy going forward.

To achieve significant reliability improvement with uncontrollable factors PowerStream will have to implement revolutionary changes in the operating processes (like 24x7 coverage), and radical change in current installation practices (underground vs. overhead) and system configuration options (sky wire in areas significantly affected by lightning). Although PowerStream will put effort on all available opportunities to improve reliability, the reliability work plan will place more emphasis on controllable factors.

Based on the Controllable, Uncontrollable, and LOS cumulative results over the past 5 years, the top 5 cause codes are as follows:

1. Code 5 - Defective Equipment: accounts for 39.44% of SAIDI (Controllable)
2. Code 6 – Adverse Weather: accounts for 13.51% of SAIDI (Uncontrollable)
3. Code 9 – Foreign Interference: account for 10.00% of SAIDI (Uncontrollable)
4. Code 1 – Scheduled Outage: accounts for 8.63% of SAIDI (Controllable)
5. Code 3 – Tree Contact: accounts for 6.08% of SAIDI (Controllable)

It is suggested that the individual cause codes should be analysed to determine:

1. Contribution to SAIDI
2. Contribution to SAIFI
3. Outage Cause details from root cause analysis/post-mortem investigation reports
4. Outage Code Trending
5. Gaps in data base, records, consistency of data collection
6. Determination of annual targets to reduce the impact to reliability

f. Economic Cost and Diminishing Return

There are limitations as to what reliability improvements can be achieved with the present system configuration. In order to achieve significant reliability improvement, revolutionary changes to the system and operating procedures will be required which are not economically feasible at present time.

Depending on the current level of reliability, the subsequent incremental reliability improvement works may or may not be cost effective. The reason is that when the system has already been “optimized” and a high level of reliability has already been achieved, incremental efforts will reach a “saturation point”. After that point, any incremental efforts will yield very little results.

One example to illustrate the point of diminishing return is the installation of distribution automation Scada-Mate switches on a long feeder that has customers evenly distributed.

To reflect the impact of diminishing return on the reliability work plan, for some work programs, the projected CMI savings are reduced in the latter years. As more details become available, the diminishing return factors in future years will be validated and adjusted.

g. Loss of Supply - Hydro One's Feeders impacting PowerStream's Reliability

In PowerStream North service territory, there are a number of 44 kV feeders owned and operated by Hydro One. The reliability of these Hydro One feeders has a direct impact on PowerStream's customers.

Each year, the outage information in PowerStream North is reviewed based on the last 3 year's performance. Hydro One feeders that exhibit operational performance issues that merit review and potential corrective actions are identified. As a result, the PowerStream Planning has initiated discussion with Hydro One to improve reliability performance for these feeders.

h. Major Event Days - MED Methodology

Major Event Days (MED) are events that occur rarely but have a significant impact on the reliability of the Distribution system, such as ice or wind storms. Normalizing reliability data to remove the impact of major event days allows distributors to be able to better determine year to year comparisons of reliability performance.

PowerStream has adopted in principle the IEEE B2.5 methodology for the MED calculations. However, there are a number of drawbacks in this method which results in some poor weather days not being counted as MED days, and hence contributing to the overall system reliability numbers. The methodology assumes Log – normal distribution which is not a characteristic distribution for SAIDI. On average, three days in a year would be classified as MED according to this methodology. However, over the course of the 5 years of 2008, 2009, 2010, 2011, and 2012, PowerStream recorded 0, 2, 1, 1, and 0 respectively.

If a weather event exceeds the normal 24 hour window in which either of the days don't exceed the MED threshold than those days will not be accounted as MED as per IEEE B2.5 methodology.

It is suggested that PowerStream continue to explore the use of a variation of this methodology or adapt a different methodology which more accurately reflects Major Event Days. One possibility is the '10% rule', which has been adopted by Hydro one. PowerStream is currently working with CEA (Service Continuity Committee) members to validate and adapt a variation of the IEEE methodology.

5. Reliability Performance

a. System Reliability

Reliability performance is monitored by the PowerStream Reliability Committee which comprises members from various business units across the organization, and has the mandate to manage and improve reliability.

PowerStream's system reliability performance over the last 7 years (2007 to 2013), is shown in Table 4 and Figure 4.

	PowerStream - All Events			PowerStream Total Excluding LOS			PowerStream Total Excluding LOS & MED		
	CAIDI	SAIFI	SAIDI	CAIDI	SAIFI	SAIDI	CAIDI	SAIFI	SAIDI
2013	4.202	2.542	10.679	4.368	2.237	9.771	0.881	1.309	1.153
2012	0.679	1.703	1.156	0.681	1.529	1.041	0.681	1.529	1.041
2011	0.976	1.231	1.201	1.043	1.003	1.046	1.051	0.959	1.008
2010	0.881	0.923	0.813	0.670	0.801	0.537	0.668	0.800	0.535
2009	1.603	1.232	1.975	1.484	1.068	1.585	1.120	0.873	0.978
2008	0.964	1.463	1.409	0.968	1.148	1.112	0.968	1.148	1.112
2007	1.152	1.923	2.216	1.168	1.801	2.105	0.750	1.500	1.125

Table 4: PowerStream Reliability Statistics

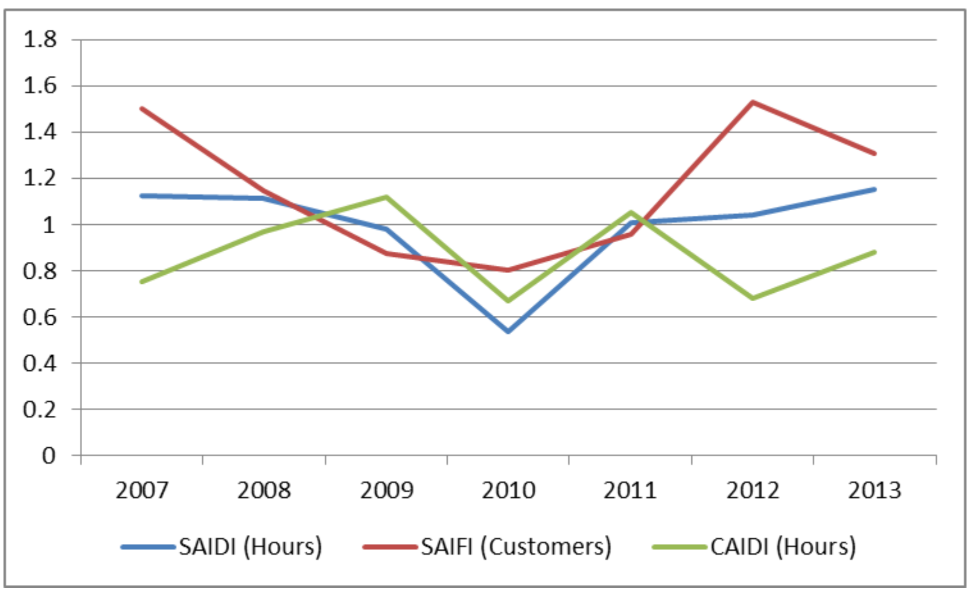


Figure 4: 2007-2013 SAIDI, SAIFI, and CAIDI Contribution, excluding LOS & MED

Table 4 contains the performance indices CAIDI, SAIFI, and SAIDI, for all events (including LOS&MED), excluding LOS, and excluding both LOS & MED. These three methods for reviewing reliability statistics are common in order to understand the specific impact of LOS and/or MED.

For example, PowerStream's SAIDI performance in 2013 was 1.153hrs excluding LOS&MED. If all MED events were included the value would rise to 9.771hrs which is an increase of 8.618hrs or 750%. This example is intended to illustrate the potential increase in outage durations that are attributed to Major Event Days and the ability of MEDs to skew yearly reliability performance if they are not separated from the total yearly data.

6. Plan Development

In 2014, an initiative was undertaken to review and assess the methodology for developing 5 year reliability targets. Based on a review of PowerStream's past performance and an in depth look at the variables impacting reliability, it was decided that future performance predictions would include the variables outlined in the following equation:

$$\text{Predicted SAIDI} = \underset{\text{(Avg last 5 yr)}}{\text{Baseline SAIDI}} + \text{Weather Outages} + \text{Increase in Scheduled Outages} - \text{Reliability Improvements}$$

Equation 1: Reliability Predictive Model

The following sections outline the steps to develop each variable of the Reliability Predictive Model.

a. Baseline SAIDI

As discussed earlier, it has been decided that beyond 2014, baseline reliability numbers should be generated based on the average of at least the five years of past data. This will ensure that various years of past performance are considered when predicting a baseline starting value for the following year.

Figure 2 shows the total SAIDI in minutes for the years 2006 to 2013 excluding LOS & MED events. From Figure 2, the total SAIDI results for the past five years excluding LOS and MED are listed in Table 5. To improve accuracy, the 2010 data has been excluded, and 2014 projected values have been included.

Year	SAIDI (Minutes)
2008	66.67
2009	60.32
2011	60.34
2012	62.43
2013	68.99
2014 projected	76.98

Table 5: PowerStream SAIDI performance (2008 -2013)

Table 6 breaks down the total SAIDI contribution from the Controllable, Uncontrollable, and Weather components.

Year	Total SAIDI (Min)	Controllable Contribution (Min)	Uncontrollable Contribution (Min)	Weather Contribution (Min)
2008	66.67	37.75	15.43	13.49
2009	60.32	36.79	6.61	16.92
2011	60.34	36.75	7.79	15.80
2012	62.43	38.51	9.37	14.55
2013	68.99	52.20	10.30	6.50
2014 YTD	76.98	45.20	10.18	21.60

Table 6: (2008 -2014) Controllable, Uncontrollable, and Weather contribution to total SAIDI

A baseline value can be created by averaging the SAIDI performance experienced in 2008, 2009, 2011, 2012, 2013, and 2014. In order to account for the varying equipment failure rate, an adder of one sigma is included with the controllable SAIDI contribution. The baseline contributions for Controllable, Uncontrollable, and Weather are seen below:

Year	--	**Controllable Contribution (Min)**	**Uncontrollable Contribution (Min)**	**Weather Contribution (Min)**
5yr Average (08-14)	--	41.20	9.95	14.81
+1Sigma	--	+6.25	--	--
2015 Base		**47.45**	**9.95**	**14.81**

Table 7: 2015 Baseline Values

Total Base line SAIDI for 2015, excluding any contribution from weather, is predicted to be **57.4 minutes.**

b. Weather

Weather has a significant impact on the reliability performance of the distribution system in Ontario. As Extreme weather is becoming more common in southern Ontario, more weather related outages are incurred and thus have a direct impact on total SAIDI performance.

Adverse weather events such as rain, snow and ice all have a significant negative impact on System Reliability. During these events moisture often impedes insulating efforts on the distribution lines and flashovers can occur.

Adverse environment is a second factor caused by weather that creates challenging environmental contamination. For example, the salt used on city streets during snow storms often gets on equipment and insulators and can cause flashovers.

Lightning is another weather event that causes significant outages. Although the bare wire conductors are strategically protected with lightning arrestors, there are still occurrences of blown fuses, overvoltage on equipment, and direct lightning strikes that affect customer reliability.

In the case of extreme weather, there is potential that the weather event may be classified as a Major Event Day(s) and any outages experienced during the MED timeframe would not be counted against PowerStream's total SAIDI performance. However, in this case, there are still lingering issues caused by the environmental strain on the system, that don't surface until well after the event has subsided. For example, contamination from weather and equipment stain from numerous faults, often take various amounts of time before they emerge.

PowerStream has experienced two extreme weather events over the past 12 months as outlined below:

1. On **December 21-22, 2013**, a significant ice storm moved through Southern Ontario causing over 500,000 customers to lose power including 92,000 in PowerStream's service territory.

2. On **June 17th 2014**, 12 poles came down on Warden Ave in Markham during an intense thunderstorm. Four 27.6kV circuits were brought to the ground during the event and the broken poles and wires caused damage to approximately 20 cars on the roadway below.

The following chart breaks down controllable and uncontrollable components of PowerStream total SAIDI performance since 2006.

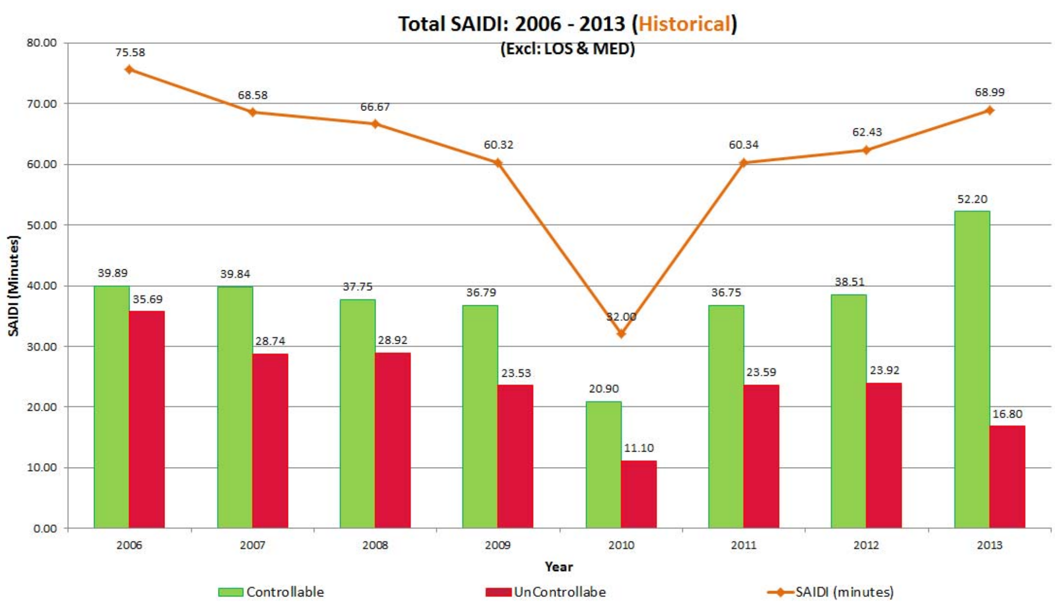


Figure 5: Controllable vs Uncontrollable Performance (2006-2013) (Excluding LOS & MED)

By looking at the controllable and uncontrollable performance we can make the following observations:

- Years 2006 to 2011 follow a similar ratio of controllable vs uncontrollable contribution
- 2010 was a good weather year that resulted in a significant drop in controllable and uncontrollable totals

- 2013 was a poor weather year, however, controllable outages spiked while uncontrollable outages dropped (opposite to what is expected)
- Although 2014 is not captured on the chart, year to date performance has showed that uncontrollable outages due to weather are way up in comparison to 2013 while controllable outages are falling.

Based on past performance and experience we can conclude that total SAIDI *is* a function of weather. However, based on the limited data we currently have available, we are unable to clearly identify the relationship between weather and total SAIDI, and therefore are unable to successfully use weather as an accurate variable in the prediction of future performance. Unfortunately, weather appears relatively unpredictable based on previous years.

For the purpose of the Reliability Model, weather impact will be compiled using historical averages of the uncontrollable SAIDI contribution from the following weather related outage types:

- *Adverse Environment (weather dependent)*
- *Adverse Weather (weather dependent)*
- *Lightning (weather dependent)*

The average weather contribution from 2008 to 2014 is included in Tables 6 and 7.

In addition to the average contribution from weather dependent outages in past years, the 2015-2019 predictions will include an upper and lower sideband to account for the potential variance in performance caused by good and bad weather

Severe weather has both short and long term effects on the reliability system and needs to be factored into the equation.

c. Scheduled Outages

An increase in capital budget since 2010 has continually increased the number of scheduled outages and associated CMI. These outages are necessary to ensure the safety of workers when performing construction work and are generally accepted as an unavoidable part of the process. Unfortunately, it is understood that reconfiguring the system to accommodate scheduled outages often increases the exposure of the system by moving away from standard operating configurations and limiting the availability of sound redundant paths. Opportunities for innovative work practices and technology should be explored in order to find ways to reduce the significant impact of scheduled outage minutes to the customer.

In 2014, scheduled outages are projected to contribute 8.43 minutes of total SAIDI by year end. This is an increase of 0.91min since 2013 which contributed a total of 7.52 min to system SAIDI. The growth in scheduled outages has resulted in additional 5.17 min since 2010 when the contribution was only 3.26 min.

Using the progression of the capital budget as a guideline, an additional 0.14 minutes will be added in 2015 to account for the necessary outages required to complete 2015 capital projects. In 2016, an additional 1.67min will be added, at which time scheduled outages are expected to level out moving forward.

As over 10% of total SAIDI currently comes from scheduled outages, future consideration must be given to improved work practices and scheduling.

d. Reliability Improvement

This section outlines the projects proposed to increase system reliability. The work programs proposed span across many business units and include continuous improvements and best practice implementation in the following areas:

- Planning
- Design
- Construction
- Inspection & Maintenance
- Operations
- Distribution Automation
- Smart Grid Technologies
- Outage Response & Outage Management
- Records System
- Coordination of Work Programs
- Hydro One's System Performance impacting PowerStream
- Contingency Plans

The following list summarizes each projects cost, CMI savings, SAIDI savings and cost/CMI. A complete list can be found in Appendix A. Refer to section 8 for full details of each Reliability Improvement:

Program	Program Description	2015 362,122 Customers				2016 369,822 Customers				2017 377,522 Customers				2018 385,222 Customers				2019 392,922 Customers			
		Cost ($)	CMI Saving	SAIDI Saving (Minutes) 362,122 Cust	Cost per CMI ($)	Cost ($)	CMI Saving	SAIDI Saving (Minutes) 369,822 Cust	Cost per CMI ($)	Cost ($)	CMI Saving	SAIDI Saving (Minutes) 377,522 Cust	Cost per CMI ($)	Cost ($)	CMI Saving	SAIDI Saving (Minutes) 382,000 Cust	Cost per CMI ($)	Cost ($)	CMI Saving	SAIDI Saving (Minutes) 392,922 Cust	Cost per CMI ($)
1	Worst Performing Feeders (WPF)	250,000	220,000	0.61	1.14	250,000	200,000	0.54	$1.25	250,000	180,000	0.48	1.39	250,000	150,000	0.39	1.67	250,000	50,000	0.13	5.00
2	Automatic Fault Restoration	400,000	50,000	0.14	8.00	400,000	50,000	0.14	$8.00	400,000	50,000	0.13	8.00	400,000	50,000	0.13	8.00	400,000	25,000	0.06	16.00
3	Inspection and Maintenance	3,000,000	139,125	0.38	21.56	3,000,000	139,125	0.38	$21.56	3,000,000	139,125	0.37	21.56	3,000,000	139,125	0.36	21.56	3,000,000	69,563	0.18	43.13
4	Wood Pole Replacement	4,643,377	27,312	0.08	170.01	4,757,432	27,312	0.07	$174.19	5,163,139	27,312	0.07	189.04	5,280,548	27,312	0.07	193.34	5,399,708	13,656	0.03	395.41
5	Distribution Automation Switch/Recloser Installation	1,850,276	91,847	0.25	20.15	1,530,249	74,304	0.20	$20.59	2,080,457	122,866	0.33	16.93	2,283,805	122,866	0.32	18.59	2,354,895	122,866	0.31	38.33
6	Underground Cable Replacement and Rejuvenation	15,738,066	188,800	0.52	83.71	16,237,719	188,800	0.51	$86.37	17,251,397	188,800	0.50	91.76	17,779,521	188,800	0.49	94.57	18,322,521	94,400	0.24	116.58
7	Distribution Switchgear Replacement	2,000,437	81,348	0.22	24.59	2,063,837	81,564	0.22	$25.30	2,462,129	52,853	0.14	46.58	2,533,373	53,931	0.14	46.97	2,606,624	39,292	0.10	66.34
8	Submersible Transformer & Vault and Pad Mount Transformer Replacement	1,534,405	32,931	0.09	46.59	1,137,763	23,665	0.06	$48.08	521,766	7,800	0.02	66.89	536,122	7,800	0.02	68.73	550,844	3,900	0.01	141.24
9	Fault Indicator Program	270,000	31,500	0.09	8.57	270,000	31,500	0.09	$8.57	270,000	31,500	0.08	8.57	270,000	31,500	0.08	8.57	270,000	15,750	0.04	17.14
10	44kV Insulators Replacement Program	66,000	50,000	0.14	1.32	68,000	50,000	0.14	$1.36	69,000	50,000	0.13	1.13	71,000	50,000	0.13	1.16	71,000	50,000	0.13	1.62
11	Mini-Rupter Switch Replacement Program	577,736	7,200	0.02	80.24	592,267	7,200	0.02	$82.26	607,090	7,200	0.02	84.32	622,214	7,200	0.02	86.42	637,649	3,600	0.01	177.12
12	Ice Storm Hardening	0	0	0.00	0.00	6,675,344	0	0.00	$0.00	6,872,001	188,761	0.50	36.41	7,074,617	173,350	0.45	40.81	7,283,370	98,231	0.25	74.15
13	Rear Lot Supply Remediation	3,348,998	200,000	0.55	16.74	3,429,673	200,000	0.54	$17.15	3,549,751	200,000	0.53	17.75	3,595,217	200,000	0.52	9.25	3,680,170	100,000	0.25	18.97
		33,679,295	1,120,062	3.09		40,412,284	1,073,471	2.90		42,496,731	1,246,217	3.30		43,696,416	1,201,884	3.12		44,826,781	686,258	1.75	

Table 8: Five year Reliability Improvement Savings

7. Projected Targets

a. Reliability Target: 2015-2020

Based on the Reliability Predictive Model outlined in Equation 1, the 6 year forward looking prediction for years 2015 to 2020 is outlined below:

$SAIDI_{Year}$ = $SAIDI_{Base}$ + Weather + Change in Schedule Outages - Reliability Improvement

Year	$SAIDI_{Base}$			+	Weather	+	Scheduled Outages Increase (Over Previous year)	-	Reliability Improvements	=	Predicted SAIDI	Upper Limit	Lower Limit
	Controllable	Un-Controllable (not including weather)	Total										
2015	47.45	9.95	57.40		14.81		0.14		3.09		69.26	84.10	54.69
2016	44.50	9.95	54.45		14.81		1.67		2.90		68.02	82.87	53.46
2017	43.27	9.95	53.21		14.81		0.00		3.33		64.69	82.67	50.13
2018	39.93	9.95	49.88		14.81		0.00		3.15		61.54	82.64	46.98
2019	36.79	9.95	46.73		14.81		0.00		1.57		59.97	81.07	45.41
2020	35.21	9.95	45.16		14.81		0.00		0.00		59.97	81.07	45.41

Table 9: Reliability Prediction Breakdown 2015-2020

The target for each year will be determined by the Predicted SAIDI value, bound by the projected Upper Limit. The following chart outlines the expected reliability targets for years from 2015 to 2020:

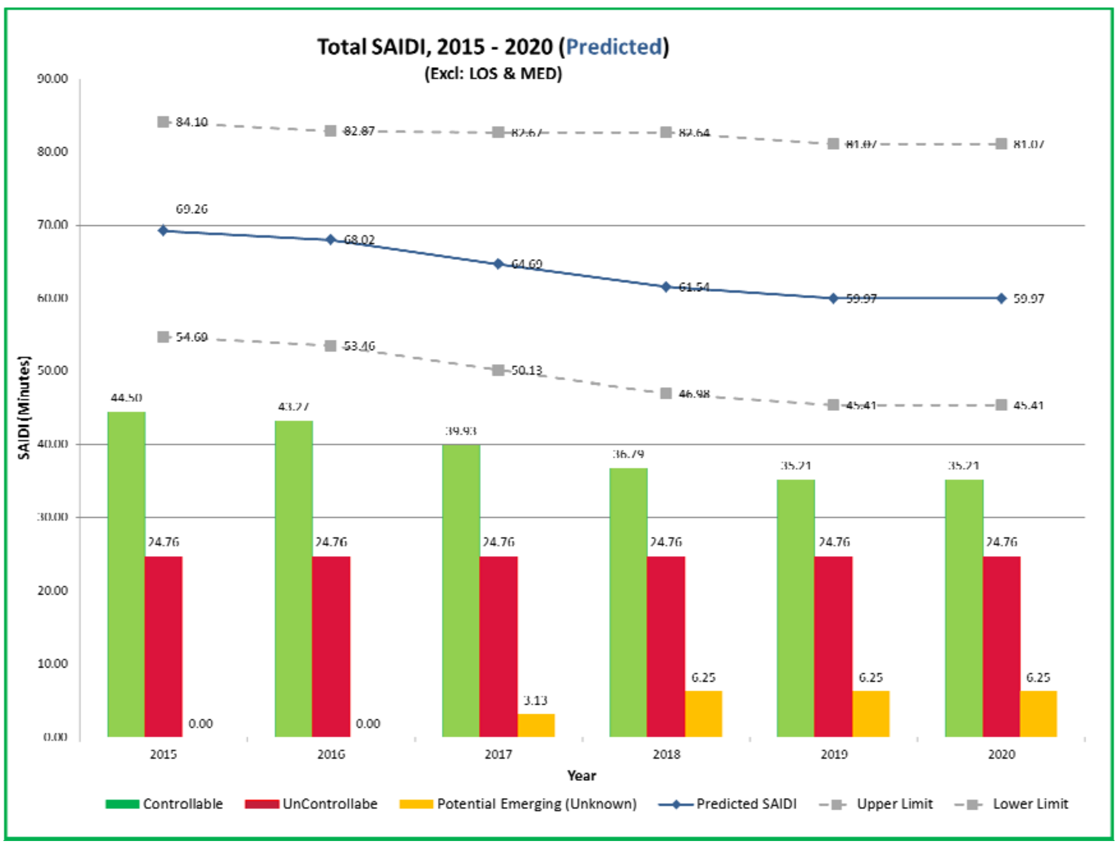


Figure 6: Controllable vs Uncontrollable Performance (2015-2020)

b. 2015 Target

For the year 2015, as per Table 9 and Figure 6, the Predicted SAIDI Reliability Target for all outages excluding LOS/MED will be 69.26 min based on an average weather pattern year. However, in the case of a year with severe weather, the upper limit threshold will be 84.10 min.

The following table outlines the expected reliability target for 2015:

2015 Reliability Target	
Upper Limit	= 84.10 min
Target	**= 69.26 min**
Lower Limit	= 54.69 min

Table 10: 2015 Reliability Targets

The controllable SAIDI will be 47.45 min which includes Scheduled Outage, Tree Contact, Defective Equipment and Human element. The uncontrollable SAIDI will be 24.76 min which includes Unknown, Lightning, Adverse Weather, Adverse Environment, and Foreign Interference.

A breakdown of the predicted Controllable and Uncontrollable contributions for 2015 is seen in fig 7. The top 5 causes are similar to those occurring over the last 5 years.

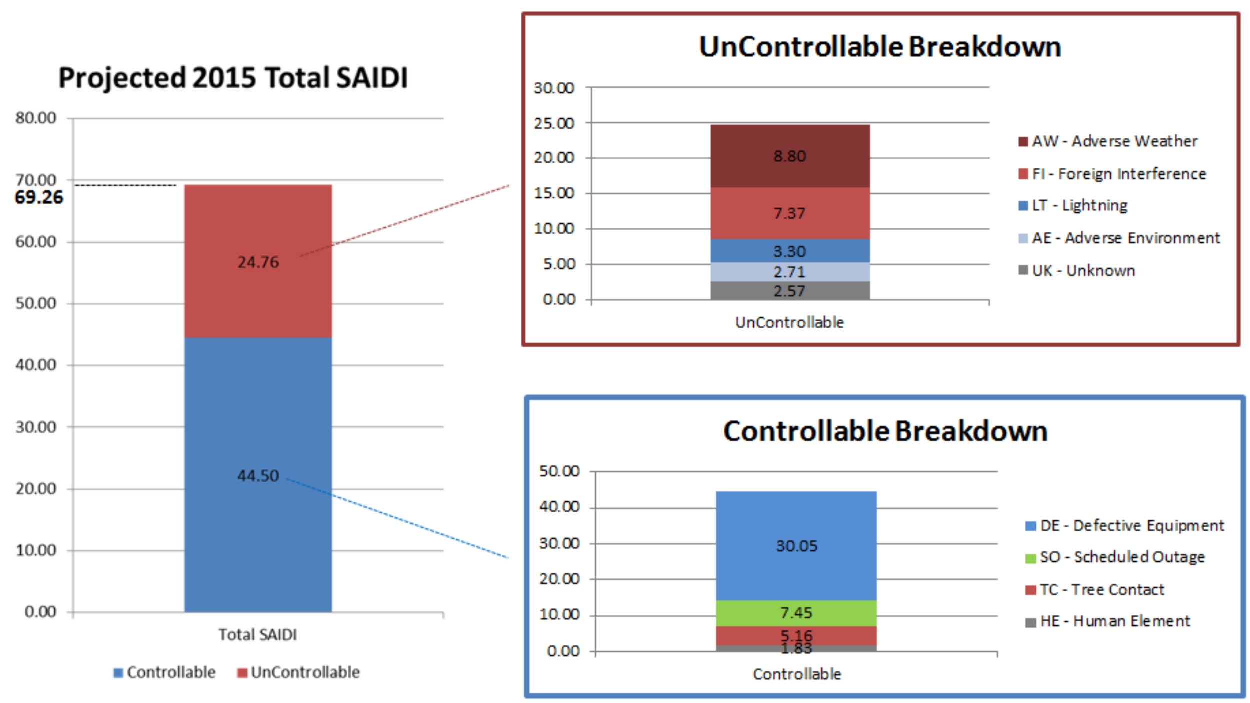


Figure 7: 2015 Projected SAIDI Breakdown

Each year System Planning will breakdown the predicted Controllable and Uncontrollable contributions as part of the projected Reliability Target.

8. Work Plan to Improve Reliability

There have been numerous internal discussions on reliability initiatives at PowerStream and the ability of each initiative to impact reliability performance. These discussions have included program and process improvement projects in addition to technology improvement efforts.

In general, it is difficult to determine accurately the cost and the expected reliability improvement for each work program. The cost and benefit of each work program are estimated based on available information and have been further validated by business leads implementing the projects. Some program benefits can be quantified, while others can only be given a qualified estimate (“rough” and “ball park figure”).

Going forward, System Planning will continue to monitor the savings realized for each of the program where ever possible. For example, cable rehabilitation projects will continue looking at the outage history for 3 consecutive years and compare to the outage trend a year after the capital program is implemented.

The recommended overall annual cost of the programs and reliability improvement projections are shown in Table 8 and Appendix A. Implementation Responsibilities are outlined in Appendix B.

The reliability work plan will be revisited annually, and adjustments (planned vs. actual, activity changes, etc.) will be made as required.

The 13 initiatives are discussed below.

8.1 Worst Performing Feeders (WPF)

On an annual basis, PowerStream will identify a total of 20 WPF (typically) based on feeder reliability data over the previous 3 years (i.e. in the spring of 2015, the “2014 WPF” will be designated using annual reliability data for 2014, 2013, and 2012). Statistical feeder interruption duration and feeder interruption frequency will be taken into consideration. All customer outages downstream of a feeder will be counted against that feeder. Qualitative input from Lines, Operations, Customer Services and System Planning will also be considered in selecting annual WPF.

WPF management is a joint effort by many business units including Operations, Lines, Design, System Planning, Stations, and the Reliability Committee.

Feeders that have the highest Feeder Scores are considered less reliable and will be targeted for detailed reviews and corrective actions. Each spring, System Planning will issue the Worst Performing Feeder report outlining the recommended actions on each identified feeder.

Remediation efforts will include feeder patrol, inspection, maintenance work, and any present or future capital work. System Planning in conjunction with Control Room will monitor the Feeder performance and report regularly for a period of 3 years following WPF identification, to confirm remediation efforts have been implemented and feeder reliability improvement has been achieved.

10 Feeders will be selected based on the feeder score obtained by the FAIDI/FAIFI methodology and 10 Feeders will be selected based on feeder scores obtained by the CMI/CI/No of Outages Methodology as outlined below.

Step 1: Compile Feeder Reliability Data and Determine WPF

1. Operations (System Control) to compile feeder reliability data. The following data is required for the previous 3 years

- FAIDI (annual)
- FAIFI (annual)
- CMI (Customer Minutes of Interruption)
- CI (Customers Interrupted on a Feeder)
- Number of Outages including momentary Outages
- Cause Code
- 3-Year Average FAIDI
- 3-Year Average FAIFI

Note 1: Feeder reliability performance will be ranked based on the following formula:

Step 2. System Planning will determine the Worst Performing Feeder based on the following:

1) Ten Feeders from the FAIDI/FAIFI methodology and will be computed as follows:
Feeder Score = 0.5 *FAIDI + 0.5*FAIFI

Where:
FAIDI = Feeder Average Interruption Duration Index (3-Year Average, excluding Loss of Supply and Major Event Day)
FAIFI = Feeder Average Interruption Frequency Index (3-Year Average, excluding Loss of Supply and Major Event Day)

2) Ten Feeders from the CMI/CI/No of Outages methodology which will be computed as follows:

Feeder Score = 0.5* Normalized CMI + 0.25* Normalized Customers Interrupted+ 0.25 * Normalized Total No of Outages Including Momentary Outages

- Min- Max Normalization will be used to Normalize the data set
- Normalization = (A- minimum value of A)/(Max Value of A-Min Value of A)

Where CMI: Customer Minutes of Interruption (3-Year Average, excluding Loss of Supply and Major Event Day)

CI: Total Customer Interrupted (3-Year Average, excluding Loss of Supply and Major Event Day)
Outages: Total Number of Outages including Momentary Outages (Excluding Loss of Supply and Major Event Days)

WPF feeders contribute to approximately 20-30% of annual SAIDI excluding LOS & MED.

In 2013, Worst Performing Feeders contributed a total of 4,677,020 CMI. This is approximately 21% of annual system wide SAIDI.

With targeted efforts, System Planning and Lines aim to reduce the CMI by approximately 6% over the next five years on these feeders.

It is proposed to reduce 5% of the total annual CMI per year on these 20 WPF (approx. 15% over 3 years). This can be achieved by implementing the WPF procedure which requires the WPF be monitored closely for 3 years, and the following work be carried out as needed:

- Feeder Patrol
- Tree Trimming
- Wildlife Guard
- Infrared Inspection
- Insulator Washing
- Lightning Arrestor
- Fault Indicator
- Feeder Re-configuration
- Feeder Protection Review

In order to estimate realistic CMI savings achieved from the proposed remediation plan it is essential to apply the principle of diminishing return. For example, after the initial tree trimming cycle, future cycles will maintain the system and will not be a significant source of CMI savings. This is reflected in the table below:

Table 11: CMI Savings from WPF

Year	2015	2016	2017	2018	2019	2020
CMI Saving	220,000	200,000	180,000	150,000	50,000	0

It is recommended that PowerStream (Operations):

- Assign necessary resources to carry out maintenance work required by the WPF program.

8.2 Automatic Feeder Restoration Program

In 2013, Station Design in conjunction with Planning and Smart Grid began implementing a pilot project for an automated Feeder restoration scheme. The plan automated 2 feeders out of Greenwood TS and Jackson TS & Lazenby TS.

The basic features of Automatic Feeder Restoration scheme:

- Only faulted feeder section is tripped, upstream sections unaffected
- Power rerouted to unfaulted feeder sections downstream of permanently faulted section within 6 cycles
- Reclosers readily reconfigurable to adapt for changes in feeder configuration
- Number of Interconnect able feeders is scalable so that several feeders can work as a network

It is expected that additional feeders will be continually added to participate in the AFR scheme. The estimated CMI savings achieved from the AFR program are 225,000 over the next six years. The CMI's savings will be observed as follows:

Table 12:CMI savings from AFR

Year	2015	2016	2017	2018	2019	2020
CMI Saving	50,000	50,000	50,000	50,000	50,000	0

The annual Distribution Automation program should be coordinated with the AFR program to ensure that new switch locations will support future AFR growth.

8.3 Inspection & Maintenance Programs

PowerStream has been maintaining the distribution system reasonably well for the past 3 years. The inspection and maintenance procedure has been streamlined for distribution assets which is having a positive impact on the reliability.

Effective inspection and maintenance programs help to identify potential reliability problems, and initiate remedial action to prevent or reduce the extent of outages.

- Tree Trimming - Over the past five years (2009 – 2013), tree contacts have attributed to over 5.8M CMI each year. This is approximately 1.16M CMI each year. Tree trimming currently follows a 3-year cycle. Since 2014 was the start of a new tree trimming cycle we are projecting 58,000 CMI Savings (5% of 1.16M) from 2015 onwards
- Transformers - Over the past five year (2009 – 2013) Underground and Overhead Transformers combined, have attributed to over 3.8M CMI. This is on average, 760,000 CMI each year. Transformer inspection follows a 3-year cycle. As the inspection cycle identifies units that are on the verge of failing, we can save CMI by selecting appropriate units to replace in the Transformer Replacement Program. We are projecting 22,800 CMI Savings (3% of 760,000).
- Switchgear inspection and dry ice cleaning - Over the past five years, switchgear has annually contributed an average of 940,000 CMI. We are projecting 28,200 CMI Savings (3% of 940,000).
- Insulator, arrestor and elbow failures – These have attributed an annual average of 1.432M CMI. . With the infrared and washing program, Planning is estimating 30,125 CMI savings (2% of 1.432M).
- Total CMI savings – 139,125 (Estimated by Planning based on outage data and feedback from the reliability committee)

It is recommended that PowerStream Lines:

- Leverage the information from the pole testing program and overhead inspection for maintenance work. Examples are the field notes on the condition of various components that are attached to the pole such as: bracket, insulator, guy, anchor, grounding, clearance, and sagging. Take follow-up actions (such as follow-up field verification to determine the severity and urgency of the deficiencies), and schedule corrective maintenance work as required.
- Provide refresher training for staff on cable splicing theory and technique. According to cable splice manufacturers who have conducted post failure analysis, the vast majority of splice failures were attributed to workmanship (in the high 90%).

The CMI Savings achieved via the program will decrease as the system is maintained on a regular basis. The program would result in avoiding CMI rather than saving. This will result in fewer CMI Savings after certain years. The CMI savings projected over the next 6 years are as follows:

Table 13: CMI Saving from Inspection and Maintenance

Year	2015	2016	2017	2018	2019	2020
CMI Saving	139,125	139,125	139,125	139,125	69,563	0

8.4 Wood Pole Replacement

PowerStream has approx. 46,000 wood poles in service. As the poles get older and their structural integrity deteriorates, they are proposed to be replaced. Wood pole failures are very rare due to PowerStream's comprehensive replacement programs. Contractors test the company's wooden poles, and make replacement recommendations based on test results and minimum physical life remaining. Program recommendations are based on the pole testing results and PowerStream's pole replacement prioritization indices. The annual number of units budgeted for replacement and reinforcement from 2015 onwards is approximately 400 poles. Each year the failure rate of the poles will be reassessed to determine the annual number of poles that require replacement and reinforcement.

- On Average wood pole contributed to 54,623 CMI per year (2 Outages/per year). With the budget to accommodate 400 pole replacement and reinforcement, a 50% reduction in CMI can be expected.
- Total CMI - 54,623
- CMI savings - 27,312 (Estimated by Planning based on past outage data and Failure History)

The estimated CMI savings projected over the next six years are as follows:

Table 14: CMI Savings from Wood Pole Replacement Program

Year	2015	2016	2017	2018	2019	2020
CMI Saving	27,312	27,312	27,312	27,312	13,656	0

8.5 Distribution Automation

Distribution automation switches/reclosers are proposed to be installed at strategic locations to achieve the following 2 objectives:

1. To reduce feeder down time in case of outages
2. To reduce number of customers affected by outages

It is estimated that there is an incremental outage time saving of 30 minutes between manual switching versus remote automatic switching.

In 2012, a Distribution Automation report was published which recommended feeder automation feeders. The report recommended:

- 70 N.C RTU switches/Reclosers on selected feeders for year 2013 to 2018.
- 67 N.O RTU switches or tie- reclosers on selected feeders for year 2013 to 2018.
- The expected CMI savings by installing these automated devices is 1.5M (Five year period)
- Total CMI savings – 1,500,000
- CMI savings - 122,866 (Estimated by Planning based on the Feeder SAIDI and expected improvement following a 3 ½ switch strategy)

The annual number of units budgeted for 2015 is 17 units. Based on the information above and budget constraints, Planning projects the following CMI Savings for the next six years:

Table 15: CMI Savings from Distribution Automation

Year	2015	2016	2017	2018	2019	2020
CMI Saving	91,847	74,304	122,866	122,866	122,866	122,866

The latest Distribution Automation report will be completed in late 2014. With the new report, the updated plan will provide a clearer picture of the CMI Savings that can be achieved through this program.

8.6 Underground Primary Cable Rehabilitation (Cable Replacement and Injection)

PowerStream has recently revised the Primary Cable Replacement and Injection program for the following key reasons:

- Budget for 2015 is reduced ($15.74M in 2015 vs $16.74M in 2014)
- Cable Injection has become more cost effective than Cable Replacement
- Age bracket for Cable Injection candidates can be expanded (40 to 21 year old in 2015 vs 30 to 26 year old previously)
- All splices are now being replaced during injection, therefore it is expected that additional CMI savings are associated with the activity.

The old and new approaches are shown in the tables below:

Old Approach	
Activity	Cable Length (km)
Injection	57
Replacement	47
Total	104

New Approach	
Activity	Cable Length (km)
Injection	100
Replacement	30
Total	130

Table 16: Cable Replacement and Injection Improvements

Over the past 5 years primary cable and splice failures contributed to an annual average of 3.37M CMI. This contributes to roughly 17.7% of the previous 5 years average of the total CMI. PowerStream targets the worst areas for injection and replacement and hence, it is expected that annual CMI attributed from cable and splice failures will be reduced. Based on the available budget, past outage data and feedback from the reliability committee the CMI savings for the next six years are as follows:

Table 17:CMI Savings from Cable Replacement and Injection Program

Year	2015	2016	2017	2018	2019	2020
CMI Saving	188,800	188,800	188,800	188,800	94,400	0

8.7 Distribution Switchgear Replacement

PowerStream has approx. 1,900 distribution switchgear units in service. Switchgear units are utilized to isolate/control other equipment, and to reconfigure the loops for maintenance, restoration or other operating requirements. As the units get older and their functionality and reliability deteriorates they are proposed to be replaced. The units that are located in residential subdivisions will have more impact on CMI savings than those located in commercial/industrial areas.

- Average CMI/year contribution from Switchgear failure over the past 5 years = 943,909
- Average Number of Failures per year – 24
- Average CMI per Failure = 39,330

The annual number of units planned to be replaced for 2015 is 31 units. The estimated CMI saving for 2015 is 81,348. The CMI savings for 2015 and the future years is estimated based on available budget, the improving condition of the distribution switchgears in the system, past outage data and feedback from the reliability committee. The projected CMI savings for the next six years are as follows:

Table 18: CMI savings from Distribution Switchgear Replacement Program

Year	2015	2016	2017	2018	2019	2020
CMI Saving	81,348	81,564	52,853	53,931	39,292	0

8.8 Submersible Transformer and Pad Mount Transformer Replacement

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 non-existent.

There are 8 submersible transformers and 60 pad mount transformers planned to be replaced in 2015. The submersible transformer replacement will be completed in 2016. All the pad mount transformer replacements are identified through the inspection and maintenance program.

Submersible Transformers have the greatest chance of failing due to the nature of their installation. These assets are continuously exposed to sources of contamination, including dirt, road salt, water etc. The accumulation of dirt can cause corrosion and lead to transformer failure.

Pad Mount and Vaults possess lower risk of failures due to better shielding from the contaminations.

CMI savings from Submersible Transformers:

- For 1 transformer, the frequency of failure is considered: 0.2 failure per year (1 in 5 years)
- Therefore, for 8 transformers, the frequency of failure is: 0.2 failure x 8 = 1.6 failures

Using 2012 Control Room data, there were 4 Submersible Transformer failures affecting 144 customers and creating 33,434 CMI.

- Average CMI for 1 failure is: 33,434/4 = 8,359 CMI
- Projected CMI for 1.6 failures is: 8,359 x 2.4 = 13,374 CMI

Estimated CMI savings from replacing 60 Pad Mount Transformers – 19,557 (Estimated by Planning based on past outage data and feedback from the reliability committee).

Total CMI saving = 13,374 + 19,557 = 32,931

The CMI saving for the next six year varies due to diminishing returns and the submersible transformer replacement program coming to end in 2016. The projected CMI Saving over the next six years is as follows:

Table 19:CMI savings from Transformer Replacement Program

Year	2015	2016	2017	2018	2019	2020
CMI Saving	32,931	23,665	7,800	7,800	3,900	0

8.9 Fault Indicator Program

PowerStream has an ongoing program to install additional fault indicators. Fault Indicators provide remote indication of a fault on the system. The device is used as a means of automatically detecting and identifying faults to reduce outage time.

Based on the feedback from the reliability committee the CMI Savings over the next 6 years are as follows:

Table 20:CMI Savings from the Fault Indicator Program

Year	2015	2016	2017	2018	2019	2020
CMI Saving	31,500	31,500	31,500	31,500	15,750	0

8.10 44kV Insulators Replacement Program

This is a six year program beginning 2015 to cope with the rising failure rate of 44kV porcelain insulators. Electrically conducting films deposited on the insulators of power lines are frequently regarded as responsible for the failures. Under the condition of high air humidity, especially fog, electrically conducting films may deposit on the insulators, which even at nominal operating voltage, may lead to flashover and fail. The porcelain insulators are prone to damage due to moisture ingress.

There are approximately 277 units planned to be replaced every year for the next six years. The CMI savings for the next six years, estimated based on the past outage data and feedback from the reliability committee is as follows:

Table 21: CMI savings from the 44kV insulator program

Year	2015	2016	2017	2018	2019	2020
CMI Saving	50,000	50,000	50,000	50,000	50,000	50,000

8.11 Mini-Rupter Switch Replacement Program

In the near-term, PowerStream expects to replace on average 15 units per year under the planned mini-rupter replacement program. This is in addition to those units that will be replaced under emergency due to unit failure. Rate of change of failure in future years is expected to be moderate and manageable. Any emerging significant deviations from expected spending would trigger a program review.

The CMI Savings have been calculated as follows:

- For 1 Mini-Rupter switch unit, frequency of failure is: 0.2 failure per year (1 in 5 years)
- For 15 Mini-Rupter switch units, frequency of failure is: 0.2 failure x 15 = 3 failures

It is estimated that Mini-Rupters account for 3 failures, affecting 30 commercial customers.

- Average number of customers affected by 1 failure is: 30/3 = 10 (commercial customers)
- Average CMI for 1 failure is: 10 (customers) x 4 (hours) x 60 = 2,400 CMI
- Projected CMI for 3 failures is: 2,400 x 3 = 7,200 CMI

The CMI saving for the next six years is shown below:

Table 22:CMI savings from mini-rupter replacement program

Year	2015	2016	2017	2018	2019	2020
CMI Saving	7,200	7,200	7,200	7,200	3,600	0

8.12 Ice-Storm Hardening Program

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, at its peak, over 92,000 customers in PowerStream's service territory, predominantly in Aurora, Markham, Richmond Hill and Vaughan.

This project is in response to the recommendations from the Ice 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.

The ice storm 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.

The ice-Storm Hardening Program will commence in 2016 and the CMI savings are expected to be observed starting 2017. Planning has estimated the CMI savings based on discussions with Lines and Operations as follows:

Table 23: CMI savings from Ice-Storm Hardening Program

Year	2015	2016	2017	2018	2019	2020
CMI Saving	0	0	188,761	173,350	98,231	0

8.13 Rear Lot Supply Remediation Program

PowerStream has a number of pockets of customers supplied by rear lot (backyard) construction. In general, the majority of these areas are older neighbourhoods, and the electrical distribution components are old. The oldest location is 59 years old (installed in 1955). As a result, the electrical distribution components are aging and the assets are deteriorating. The rear lot supply system poses some reliability, operations, health and safety, and customer service issues.

There are approx. 4,625 customers supplied by rear lot systems at 49 rear lot locations throughout PowerStream service territory. The average installation year of all rear lot supply is 1967 (45 years old).

The main driver for this project is system reliability and customer service. This project is part of PowerStream's long-term rear lot supply remediation program. Project is carried out to change the supply configuration of existing rear lot supply and also to replace end-of-life components to maintain system reliability and customer service. Safety issues will also be addressed by the project. On a prioritized basis, each year PowerStream will review and select suitable rear lot locations for implementation.

Based on outage data and feedback from Operations the following CMI savings were estimated for the next six years:

Table 24:CMI savings from Rear Lot Remediation Program

Year	2015	2016	2017	2018	2019	2020
CMI Saving	200,000	200,000	200,000	200,000	100,000	0

8.14 Other Initiatives

The following are other initiatives that are believed to a have a positive impact on CMI however no savings have been attributed to the program as it is very difficult to quantify the realized CMI savings.

Asset Condition Assessment (ACA) Program (Station and Distribution Assets)

An effective ACA process will assist PowerStream to make the right decisions on the short term and long term plans for various distribution and station assets. The following enhancement is planned for the existing ACA models:

- Review and update existing models with accurate conditions observed through Inspection & Maintenance programs. (CMI savings are not estimated at this time.)

It is recommended that PowerStream Planning:

- Continue development of the ACA program to accurately assess the condition and the risk of failure of various distribution asset classes and tie the inspection and maintenance results to the ACA condition assessment.
- Continue to refine the station asset condition assessment program and ensure that the current condition of the assets are accurately captured in the model.

Contingency Plan, Spare Equipment & Materials

Contingency Plans are required to deal with any asset related event that affects the proper functioning of the distribution system. Contingency planning will deal with potential high impact low probability (HILP) events that can have major repercussions on the distribution system and our customers. All other events that occur regularly, have low impact, and have established processes to deal with, are not part of this Contingency Plant. The HILP events considered here are shown in Table 25.

Asset Class	Contingency Event	Contingency Plan
TS Power Transformers	Transformer failure requiring off-site servicing	1. Spare Transformer 2. Storage location for spare 3. Individual plans to move spare to affected TS 4. Individual connection plans for each TS configuration
TS Switchgear Cell(s)	Cell or multi-cell failure	1. Spares – Critical parts list 2. Contact plan for manufacturer repair support 3. Spare cell 4. Feeder emergency loading capability
230kV switches	Switch failure – non-repairable	1. Spare switch(s)/parts 2. Storage location for spare(s) 3. Individual mounting plan(s) for each TS structure
TS Feeder cables	Failure of one or more underground cables	1. Spare cable reel
TS Capacitor banks	Failure of significant portion of capacitor bank	1. Spare Capacitor cans 2. Contact plan for manufacturer repair support
TS Reactor failure	Failure of reactor	1. Spare reactor
Station RTU	Failure of RTU leading to loss of station control	1. Standby staff to man station 2. Contact plan for manufacturer repair support
Station Protective Devices	Device failure leading to full/partial loss of station	1. Spare – Critical Parts list
Poles	Loss of high number of pole structures through high impact event (severe weather, etc.)	1. Stock poles 2. Supplier stock 3. Neighbouring LDC stock

Table 25: Contingency Plans

In all cases if available contingency measures prove insufficient, rotating load shedding may be required to ensure equipment is not loaded beyond approved tolerances. Sufficient spare equipment and materials are essential for PowerStream to manage power outages.

Cost and CMI saving are not estimated at this time.

It is recommended that PowerStream take the following steps:

- Procurement, Operations, Lines and Planning review, as required, emergency stock levels to ensure that adequate stock is on hand to deal with the various component failure/replacement rates.

Trouble Crew Coverage

In 2010, it was proposed that Trouble Crew coverage be extended to 24 hours per day, 7 days per week. It was projected this initiative will have a significant impact on power restoration duration, and therefore improve reliability. System Control was tasked with the preparation of the report on 24x7 coverage. System control has submitted an initial report " Business case- 24/7 Trouble Crew" and recommended the days- week end option.

The report proposes the following CMI savings for the days- weekend option.

Period	Scenario	Average Number of Customers during Outages	Estimated Response (Outage) Savings (mins)	Number of Outages	CMI Savings	Apply to 50% of outages	Divided by # customers= Minutes of Interruption saved (from annual total)
Sat/Sun Days	#1	420	15	400	2,520,000	1,260,000	3.8
	#2	420	30	400	5,040,000	2,520,000	7.6
	#3	420	45	400	7,560,000	3,780,000	11.5
Weeknights	#1	420	15	246	1,549,800	774,900	2.3
	#2	420	30	246	3,099,600	1,549,800	4.7
	#3	420	45	246	4,649,400	2,324,700	7.0
Weekend Nights	#1	420	15	118	743,400	371,700	1.1
	#2	420	30	118	1,486,800	743,400	2.3
	#3	420	45	118	2,230,200	1,115,100	3.4

Table-26: CMI Savings Projections for Days- Weekend Option

Best (Scenario 1) – 21.9 minutes
Average (Scenario 2) – 14.6 minutes
Least (Scenario 3)- 7.2 minutes

Due to resource limitations and other considerations the project was never implemented.

A new target implementation date would be required to predict CMI savings.

9. Reliability Centres of Focus

In 2014, a reliability initiative was introduced to study the Reliability history of PowerStream's Key Account customers in an effort to identify areas which were under performing and in need of improvement. This activity was labelled as the' Reliability Centres of Focus'.

a. Zones

Several Centres were identified as starting focal points based on known trouble areas and feedback from customers:

- Commerce Valley (E&W)
- Beaver Creek (E&W)
- Hwy 7/ Hwy 27
- Cochrane Area
- Remainder of Markham
- Barrie South end (West side of 400)
- Barrie North end (Georgian Drive where college/hospital are located)
- Warden & 14th (Warden Industrial)

b. Evaluation Method and Criteria

Using the 2014 Key Account customer list as identified by the Manager, Key Accounts, reliability performance is evaluated over the past two years based on the CEMI and CELID reliability metrics. CEMI and CELID are defined as follows:

- CEMI-X is customers experiencing multiple interruptions; the number of customers who experienced X interruptions or greater

- CELID-X is customers experiencing long interruption durations; CELID-8 is the number of customers who experienced outages greater than or equal to 8 hours

PowerStream's SAIFI and SAIDI performance for the past two years is listed below:

	SAIFI	SAIDI
2013	1.309	1.153
2012	1.529	1.041
Average	**1.419**	**1.097**

Table 27: System SAIFI/SAIDI for 2012 and 2013, excluding LOS &MED

It is expected that Key Account customers should receive at a minimum, the system average performance for SAIDI and SAIFI. Therefore, the CEMI and CELID evaluation criteria for Key Account customers will be based on the average SAIFI and SAIDI performance experienced over the past two years and will be as follows:

- CEMI-1.4

- CELID-1.1

c. Prioritization and Remediation

Key Account Customers tend to be large industrial buildings that are engaged in manufacturing, and because these manufacturing processes are highly dependent on uninterrupted power, their primary concern in regards to reliability is any disruption to service. Therefore, Key Customers are more vocal about the number of outages they experience rather than the duration of an average outage. Based on this feedback, the primary metric for prioritizing focus areas shall be CEMI.

Industrial customers are also very sensitive to voltage sag and momentary outages however, at this early stage in the activity; we will focus on reducing their number of overall outages. On a case by case basis, PowerStream will review system settings and may propose capital projects to eliminate voltage sags and momentary outages.

Focus areas along with their outage data and CEMI/ CELID performance are listed below. The table is listed in order of most significant CEMI results:

	Focus Area	Key Customer Count	Key Customer Outages	Key Customer Outages/year	# of Customers exceeding CEMI-1.5	# of Customers Exceeding CELID-1.1	Annual CMI Contribution
		(Key Customers only)	(Cum. 2012 to 2014)	(Avg. 2012 to 2014)	(2012/2013 Avg SAIFI = **1.419**)	(2012/2013 Avg SAIDI = **1.097**)	(Avg. 2012 to 2014)
1	Warden & 14th (Warden Industrial)	14	32	11	9	6	1,656
2	Hwy 7/ Hwy 27	16	16	6	6	14	2,498
3	Markham	7	32	11	3	3	1,203
4	Concord	14	27	10	2	4	753
5	Cochrane Area	1	10	4	1	1	163
6	Barrie - West side 400 by TD&BMO	5	4	1	0	0	57
7	Georgian Drive by College&Hospital	2	3	1	0	0	73
8	Commerce Valley (E&W)	4	3	1	0	0	2

Table 28: CEMI/ CELID performance

Based on Table 28, it can be seen that the following areas exceed the system average SAIFI of 1.419 and need to be prioritized for improvement:

i. Warden & 14th (Warden Industrial)
ii. Hwy 7/ Hwy 27
iii. Markham (Remainder of Markham)
iv. Concord

Specific outage cause codes are broken down for each area below:

Outage Code/ Area	Warden & 14th	Markham	Concord	Hwy 7/ Hwy 27	Cochrane	Barrie - West 400	Commerce valley	Georgian Drive	Grand Total
AE - Contamination	1			1					2
AE - Fire				1				1	2
AE - Salt			4	1					5
AW - Rain								1	1
AW - Snow	1			2					3
AW - Thunder Storm	1		1						2
AW - Wind		2			1				3
DE - Arrestor	2	1							3
DE - Elbow		1	1						2
DE - Insulator		1				1		1	3
DE - Line Hardware			3	1					4
DE - Other				1					1
DE - Primary Cable	1						1		2
DE - Splice	9	7			3				19
DE - Switch	1	2	1						4
DE - Switch - LIS/Recloser		1				1			2
DE - Switch - Manual LIS			1						1
DE - Switching Unit	3		2	2					7
DE - Termination	1	1	1	1	1				5
DE - Underground Transformer					1				1
FI - Animals	2	6	3						11
FI - Birds			2			1			3
FI - Vehicles	1	6	3	3		1			14
HE - Other			1						1
LT - Lightning	1		2	1	1		1		6
SO - Scheduled Customer Outage	1								1
UK - Unknown	7	4	2	2	3		1		19
Grand Total	**32**	**32**	**27**	**16**	**10**	**4**	**3**	**3**	**127**

Table 29: Outage cause code breakdown

The top 3 cause codes for each priority area and the recommended remediation are listed below:

i. Warden & 14th (Warden Industrial)

Cause	Outages	Recommended Remediation	Resp.	Timeline
Splice	9	Continue existing injection and splice replacement program	SP	2015
Unknown	7	-Review feeder protections -Confirm adequate animal protection -Investigate additional need for Fault Indicators	Stations Lines SP	2015-Q1 2015-Q2 2015
Switching Unit	3	Continue existing Minirupter program	SP	2015

ii. Hwy 7/ Hwy 27

Cause	Outages	Recommended Remediation	Resp.	Timeline
Vehicles	3	Review outage data for locational trends. Suggest bollards where applicable.	SP	2015
Switching Unit	2	Analyze and prioritize switchgear replacements.	SP	2015
Snow	2	Review data for root causes	SP	2015

iii. Markham (Remainder of Markham)

Cause	Outages	Recommended Remediation	Resp.	Timeline
Splice	7	Continue existing injection and splice replacement program Investigate if additional cable testing is warranted for this area.	SP SP	2015 2015-Q1
Animals	6	Confirm adequate animal protection	Lines	2015-Q2
Vehicles	6	Review outage data for locational trends	SP	2015

iv. Concord

Cause	Outages	Recommended Remediation	Resp.	Timeline
Salt	4	Investigate if any remaining Insulators still need to be upgraded to the new K-Line type.	SP	2015
Line Hardware	3	Review details of line hardware failures	SP	2015-Q1
Animals	3	Confirm adequate animal protection	Lines	2015-Q2

It is recommended that the Reliability Centres of Focus list be updated annually by the Reliability Committee to identify areas which are currently under performing and in need of improvement.

10. Recommendations

1. It is recommended to use the following Five year Reliability projection for 2015 to 2019, utilizing a SAIDI threshold value that is bound by an upper limit:

Year	2015	2016	2017	2018	2019	2020
SAIDI Upper Limit (Minutes)	(84.10)	(82.87)	(82.67)	(82.64)	(81.07)	(81.07)
SAIDI target (Minutes)	69.26	68.02	64.69	61.54	59.97	59.97

Table 30: Five year Reliability Targets

2. The Reliability Committee approve the 5 Year Reliability Work Plan shown in Appendix A and Implementation Responsibilities shown in Appendix B.

3. The Reliability Committee take the key role of overseeing the implementation of the reliability work plan, which will continue to be a standing agenda item in the Reliability Committee meetings.

4. The business units referred to under each work program continue to work on implementing or refining the respective work program.

5. The reliability work plan should be reviewed annually, and adjustments (planned vs. actual, activity changes) will be made as required.

6. Continually investigate new and improved methodologies to predict future SAIDI.

7. The Reliability Committee review the Reliability Centers of Focus list annually to update the target areas and capture the area's most in need of improvement.

11. Appendix A – 5 year Reliability Work Plan

Program	Program Description	Responsibility	Program Type	2015 362,122 Customers				2016 369,822 Customers				2017 377,522 Customers				2018 385,222 Customers				2019 392,922 Customers				2020 400,622 Customers				Six Years Acc Cost (2014 Dollar)	Six Years Acc CMI Savings	Six Years Acc SAIDI Savings
				Cost ($)	CMI Saving	SAIDI Saving (Minutes) 362,122 Cust	Cost per CMI ($)	Cost ($)	CMI Saving	SAIDI Saving (Minutes) 369,822 Cust	Cost per CMI ($)	Cost ($)	CMI Saving	SAIDI Saving (Minutes) 377,522 Cust	Cost per CMI ($)	Cost ($)	CMI Saving	SAIDI Saving (Minutes) 382,000 Cust	Cost per CMI ($)	Cost ($)	CMI Saving	SAIDI Saving (Minutes) 392,922 Cust	Cost per CMI ($)	Cost ($)	CMI Saving	SAIDI Saving (Minutes) 392,922 Cust	Cost per CMI ($)			
1	Worst Performing Feeders (WPF)	Lines	OM&A	250,000	220,000	0.61	1.14	250,000	200,000	0.54	$1.25	250,000	180,000	0.48	1.39	250,000	150,000	0.39	1.67	250,000	50,000	0.13	5.00	250,000	0	0.00	2.27	1,500,000	800,000	2.14
2	Automatic Fault Restoration	SP&S, Ops, Station Sustainment	OM&A	400,000	50,000	0.14	8.00	400,000	50,000	0.14	$8.00	400,000	50,000	0.13	8.00	400,000	50,000	0.13	8.00	400,000	25,000	0.06	16.00	400,000	0	0.00	16.00	2,400,000	225,000	0.60
3	Inspection and Maintenance	Lines, Station Sustainment	OM&A	3,000,000	139,125	0.38	21.56	3,000,000	139,125	0.38	$21.56	3,000,000	139,125	0.37	21.56	3,000,000	139,125	0.36	21.56	3,000,000	69,563	0.18	43.13	3,000,000	0	0.00	19.39	18,000,000	626,063	1.67
4	Wood Pole Replacement	SP&S	Capital	4,643,377	27,312	0.08	170.01	4,757,432	27,312	0.07	$174.19	5,163,139	27,312	0.07	189.04	5,280,548	27,312	0.07	193.34	5,399,708	13,656	0.03	395.41	5,399,708	0	0.00	395.41	30,643,912	122,904	0.33
5	Distribution Automation Switch/Recloser Installation	SP&S	Capital	1,850,276	91,847	0.25	20.15	1,530,249	74,304	0.20	$20.59	2,080,457	122,866	0.33	16.93	2,283,805	122,866	0.32	18.59	2,354,895	122,866	0.31	38.33	2,354,895	122,866	0.31	38.33	12,454,577	657,615	1.72
6	Underground Cable Replacement and Rejuvenation	SP&S	Capital	15,738,066	188,800	0.52	83.71	16,237,719	188,800	0.51	$86.37	17,251,397	188,800	0.50	91.76	17,779,521	188,800	0.49	94.57	18,322,521	94,400	0.24	116.58	18,322,521	0	0.00	66.93	103,651,744	849,600	2.26
7	Distribution Switchgear Replacement	SP&S	Capital	2,000,437	81,348	0.22	24.59	2,063,837	81,564	0.22	$25.30	2,462,129	52,853	0.14	46.58	2,533,373	53,931	0.14	46.97	2,606,624	39,292	0.10	66.34	2,606,624	0	0.00	52.11	14,273,025	308,988	0.83
8	Submersible Transformer & Vault and Pad Mount Transformer Replacement	SP&S, Lines	Capital	1,534,405	32,931	0.09	46.59	1,137,763	23,665	0.06	$48.08	521,766	7,800	0.02	66.89	536,122	7,800	0.02	68.73	550,844	3,900	0.01	141.24	550,844	0	0.00	141.24	4,831,744	76,096	0.21
9	Fault Indicator Program	Lines	OM&A	270,000	31,500	0.09	8.57	270,000	31,500	0.09	$8.57	270,000	31,500	0.08	8.57	270,000	31,500	0.08	8.57	270,000	15,750	0.04	17.14	270,000	0	0.00	17.14	1,620,000	141,750	0.38
10	44kV Insulators Replacement Program	SP&S	Capital	66,000	50,000	0.14	1.32	68,000	50,000	0.14	$1.36	69,000	50,000	0.13	1.13	71,000	50,000	0.13	1.16	71,000	50,000	0.13	1.62	71,000	50,000	0.13	1.62	416,000	300,000	0.79
11	Mini-Rupter Switch Replacement Program	SP&S	Capital	577,736	7,200	0.02	80.24	592,267	7,200	0.02	$82.26	607,090	7,200	0.02	84.32	622,214	7,200	0.02	86.42	637,649	3,600	0.01	177.12	637,649	0	0.00	177.12	3,674,605	32,400	0.09
12	Ice Storm Hardening	SP&S, Ops, Station Sustainment	OM&A	0	0	0.00	0.00	6,675,344	0	0.00	$0.00	6,872,001	188,761	0.50	36.41	7,074,617	173,350	0.45	40.81	7,283,370	98,231	0.25	74.15	7,283,370	0	0.00	38.59	35,188,702	460,342	1.20
13	Rear Lot Supply Remediation	SP&S	Capital	3,348,998	200,000	0.55	16.74	3,429,673	200,000	0.54	$17.15	3,549,751	200,000	0.53	17.75	3,595,217	200,000	0.52	9.25	3,680,170	100,000	0.25	18.97	3,680,170	0	0.00	18.97	21,283,979	900,000	2.40
		Total Program		33,679,295	1,120,062	3.09		40,412,284	1,073,471	2.90		42,496,731	1,246,217	3.30		43,696,416	1,201,884	3.12		44,826,781	686,258	1.75		44,826,781	172,866	0.44		249,938,288	5,500,758	14.60

12. Appendix B – Implementation Responsibilities

	Program Description	Responsibility	Date
1	**Worst Performing Feeders (WPF)** • Assign resources to carry out the required maintenance work	SP, Lines	Annual
2	**Automatic Fault Restoration** • Report on the benefits of the pilot completed in 2013 • Continue to propagate AFR schemes on 27.6 kV feeders	Station Design	Annual
3	**Inspection & Maintenance Program** • Ensure the existing tree trimming program adequately addresses actual vegetation growth • Emphasize feeder patrols to identify potential vegetation problems to aid in proactively prioritizing tree trimming work. • Continue the implement the inspection and maintenance work program and activities	Lines, Stations Sustainment	Annual
4	**Wood Pole Replacement** • Continue the inspection and annually refine the ACA program and manage the annual pole replacement program.	SP	Annual
5	**Distribution Automation Switch/Recloser Installation** • Annual installation of 17 automated switches in 2015 and 2016, and 23 from 2017 onwards.	SP	Annual
6	**Underground Cable Replacement and Rejuvenation** • Continue to inject and replace 107 km of cable each year.	SP	Annual
7	**Distribution Switchgear Replacement** • Continue the annual switchgear replacement program each year	SP	Annual
8	**Submersible Transformer & Vault Replacement/Retrofit** • Proceed with the proposed replacement under the asset replacement program.	SP, Lines	Annual
9	**Fault Indicator Program** • Proceed with the annual installation program	Operations	Annual
10	**44kV Insulators Replacement Program** • Proceed with the annual installation program	SP, Lines	Starting 2015
11	**Mini-Rupter Switch Replacement Program** • Proceed with the annual installation program	Lines	Annual
12	**Ice-Storm Hardening** • Implement system hardening work program on various components of the distribution system to ensure the distribution system can withstand ice storm better, as recommended by the "Hardening the Distribution System Against Severe Storms" Report	Asset Management	Starting 2017
13	**Rear Lot Supply Remediation** • Keep rear lot until end of life and then replace with one of the following options: o Replace rear lot with rear lot with improved design o Replace rear lot with front lot Overhead o Hybrid – Replace rear lot primary and transformer with front lot underground, keep secondary at rear lot o Replace rear lot with front lot underground	Lines	Starting 2015

	Program Description	Responsibility	Date
14	**Other Initiatives:** **Trouble Crew Coverage on 24/7 Basis, Improve Trouble Response Times, Process & Procedure** • Operations to lead the implementation of the project. • Report to the Reliability Committee on the outcomes and recommendations of the Outage Performance Group. • Continue to implement process that result in reducing outage response times	SP	Not Known
	Asset Condition Assessment Program (Station and Distribution Assets) • Continue to refine the asset condition assessment program and ensure that the condition data is updated with the current data from the inspection and maintenance programs for the Station as well as Distribution Assets.	SP	Annual
	Contingency, Spare Equipment and Materials Ensure adequate spare equipment are available.	SP, Supply chain	Q4 2015

13. Appendix C – Reliability Metrics

PowerStream is using the industry-accepted metrics to monitor and report the system reliability. The Reliability metrics are described below.

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. "Sustained interruption" means an interruption of one minute or more.

SAIDI is defined as the total customer-hours of sustained interruptions normalized per customer served, and is expressed as follows:

$$\text{SAIDI} = \frac{\text{Total Customer-Hours of Sustained Interruptions}}{\text{Total Number of Customers Served}}$$

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.

SAIFI is defined as the number of sustained interruptions normalized per customer served, and is expressed as follows:

$$\text{SAIFI} = \frac{\text{Total Customer Sustained Interruptions}}{\text{Total Number of Customers Served}}$$

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.

CAIDI is defined as the total customer-hours of sustained interruptions normalized per customer sustained interruption, and is expressed as follows:

$$\text{CAIDI} = \frac{\text{Total Customer-Hours of Sustained Interruptions}}{\text{Total Customer Sustained Interruptions}}$$

CELID-X is customers experiencing longest interruption durations; CELID-8 is the number of customers who experienced outages exceeding 8 hours

CEMI-X is customers experiencing multiple interruptions; the number of customers who experienced X interruptions or greater

IOR – Index of Reliability

IOR is an indicator of system reliability that expresses the per unit annual customer-hours that service is available. This is another way of expressing SAIDI. All planned and unplanned sustained interruptions are used to calculate this index.

$$\text{IOR} = \frac{\text{8,760 hours/year - SAIDI}}{\text{8,760 hours/year}}$$

When SAIDI = 0 (i.e. no interruption in the year), IOR = 1 (i.e. the system is available at all time).

Example:

In order to achieve an IOR = 0.99999 (Five 9's), PowerStream must achieve a SAIDI = 5.3 minutes, as calculated below:
IOR = (8760 – SAIDI) / 8760
Therefore:
SAIDI = 8760 (1 – IOR)
SAIDI = 8760 (1 – 0.99999) = 8760 x 0.00001 = 0.0876 hours
SAIDI = 0.0876 hours x 60 minutes/hour = 5.3 minutes

MAIFI – Momentary Average Interruption Frequency Index

MAIFI is an indicator that expresses the average number of momentary interruptions each customer experiences in a year. All planned and unplanned momentary interruptions are used to calculate this index.
"Momentary interruption" means an interruption of less than one minute.

MAIFI is defined as the number of momentary interruptions normalized per customer served, and is expressed as follows:

$$\text{MAIFI} = \frac{\text{Total Number of Momentary Customer Interruptions}}{\text{Total Number of Customers Served}}$$

FAIDI – Feeder Average Interruption Duration Index

FAIDI is an indicator of feeder 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.

FAIDI is defined as the total customer-hours of sustained interruptions on the feeder normalized per customer served on the feeder, and is expressed as follows:

$$\text{FAIDI} = \frac{\text{Total Customer-Hours of Sustained Interruptions on the Feeder}}{\text{Total Number of Customers Served on the Feeder}}$$

FAIFI – Feeder Average Interruption Frequency Index

FAIFI is an indicator of feeder reliability that expresses the average number of sustained interruptions that each customer experiences in a year. All planned and unplanned sustained interruptions should be used to calculate this index.

FAIFI is defined as the number of sustained interruptions on the feeder normalized per customer served on the feeder, and is expressed as follows:

$$\text{FAIFI} = \frac{\text{Total Customer Sustained Interruptions on the Feeder}}{\text{Total Number of Customers Served on the Feeder}}$$

FESI-x – Feeder Experiencing Sustained Interruption x times or more during a 12-month rolling period. This can be adopted to highlight Feeders that experience multiple sustained outages in a year.

FESI-x is an indicator of feeder reliability that expresses how many feeders (out of the total feeder population in the system) experience x outages or more over the past 12 months.

FESI-x is described below, via an example.

Example:
FESI-8 : Feeder that has 8 or more sustained interruptions during the past 12 months.
Say by December 31, 2013, feeder JOHF5 has accumulated a total of 9 sustained interruptions during 2013 (i.e. in the past 12 months). Because 9 is greater than the threshold 8, feeder JOHF5 is classified as one of FESI-8 group.

PowerStream can set a target such as follows:
In any one year, there will be less than 10% of the total number of feeders will fall into the FESI-8 group. Another interpretation of the above is: how many feeders have 8 or more sustained interruptions in the past 12 months?

The above 8 metrics will be compiled and reported according to the 4 categories:

All Events: data is inclusive of all outage cause codes.

Excluding Loss of Supply (LOS): outages that resulted because of Hydro One's feeder or transmission outage are excluded from the calculation.

- Excluding Loss of Supply (LOS) and Major Event Days (MED):

Outages that resulted because of a loss of supply from Hydro One's system or Major Event Days are excluded from the calculation.