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Rate Plan

This Exhibit sets out PowerStream's proposal for the Custom IR plan and how this aligns with the Board's objectives in its *Renewed Regulatory Framework for Electricity* ("RRFE").

PowerStream is proposing a five year Custom IR plan term, covering the 2016 to 2020 rate years, where the rates are determined in the following manner:

- The revenue requirement for each year of the five year IR term is determined based on the forecasted rate base and costs;
- Inflation and productivity savings are incorporated in the capital and operating costs forecasts that underpin the revenue requirement calculations;
- Customer counts and billing determinants are forecast for each year; and
- The Board's cost allocation methodology is applied for each year to ensure that the revenue requirement allocated to each customer class maintains the revenue to cost ratios within the Board approved ranges.

This Schedule consists of the following sections:

1. Rate Framework
2. Proposed Annual Adjustments
3. Re-opening or Termination of Rate Plan

1. Rate Framework

As discussed in the RRFE, a Custom IR plan requires:

a) Minimum five year term;
b) A forecast of a distributor's revenue requirement and sales volumes including inflation and productivity;
c) Detailed infrastructure investment plans for the IR term, i.e. a Distribution System Plan prepared in accordance with Chapter 5 of the Filing Requirements;
d) Annual reporting on capital spending;
e) Benchmarking to assess the reasonableness of the distributor forecasts; and
f) Expected inflation and productivity gains built into the rate adjustment over the term.

These requirements are discussed below along with references to the supporting details.

a) PowerStream's Custom IR plan covers a five year term, with proposed rates for each of the years 2016 through 2020. Rates for 2017 to 2020 inclusive are subject to annual adjustments as noted below in Section 2.

b) PowerStream has provided detailed revenue requirement and sales forecasts for the 2015 Bridge Year and the 2016 through 2020 Test Years.

The revenue requirement forecast is based on PowerStream's capital and operating budgets for the years 2015 to 2020. Details of the Revenue Requirement calculations can be found at Exhibit E, Tab1.

Details regarding the rate base amounts can be found in Exhibit G, Tab 1.

PowerStream has prepared load forecasts and developed sales volume forecasts for the 2015 Bridge Year and the 2016 through 2020 Test Years. Details of these forecasts can be found at Exhibit H, Tab 1.

Details regarding OM&A costs, including depreciation expense and taxes can be found at Exhibit J.

Details regarding Revenue Offsets can be found in Exhibit I.

c) Detailed infrastructure investment plans for the IR term:

PowerStream has prepared five year capital investment plans in the past but only optimized and prepared detailed capital budgets for two year periods. In preparation for this Custom IR application, PowerStream implemented an industry leading optimization tool, Copperleaf C55, which allows it to rank and prioritize capital spending over a six year period.

PowerStream's Distribution System Plan ("DSP") for 2015 to 2020 is summarized at Exhibit G, Tab 2.

d) Annual reporting on capital spending;

Subject to further direction from the Board, PowerStream proposes to report its actual capital spending in the same manner as in Exhibit G, Tab 2, Table 3. It is proposed that this be filed as an addendum to the annual RRR filing.

e) Benchmarking of forecasts:

Benchmarking details can be found at Exhibit F, Tab 2.

f) Productivity analysis:

Details regarding the estimated productivity savings reflected in the amounts underpinning this application can be found at Exhibit F, Tab 1.

2. Proposed Annual Adjustments

PowerStream proposes an annual updating of the revenue requirement and resulting rates for 2017 through 2020 through a draft rate order process.

PowerStream is proposing annual adjustments for recurring events that are likely to occur but which cannot be reliably forecast. These items are:

a) Changes in working capital arising from changes in third party pass through costs, i.e. cost of power;
b) Changes in inflation rates;
c) Changes in tax rates;
d) Changes in the cost of capital;
e) Changes in third party pass through costs; and
f) Disposition of deferral and variance account balances.

These adjustments are mechanical in nature and result in a recalculation of the revenue requirement and rates with changes limited to the proposed adjustments. The proposed adjustments are discussed further below.

a) The cost of power makes up the bulk of the working capital allowance portion of rate base. PowerStream has no control over the cost of power. Many factors can affect the cost of power which makes it difficult to forecast reliably. This is evident in the significant changes in the Long Term Energy Plan (“LTEP”) forecasts in recent years.

It is proposed that the cost of power portion of the working capital allowance be updated based on the most current information as part of the annual draft rate order process.

b) As discussed above, inflation and productivity have been built into PowerStream’s forecasted costs underpinning rates, so no automatic annual adjustment is proposed.

Inflation is a factor that is beyond PowerStream’s control and one that is difficult to predict reliably. The Board established an inflation factor of 1.6% for the price cap index used to set 2015 rates. PowerStream notes the inflation rate of 1.6% is at historically low levels.

There is the potential for an unexpected significant increase in inflation during the IR term that could materially impact PowerStream’s cost forecasts. To ensure that PowerStream can manage within the rates during the term, it is proposed that there be an annual adjustment if inflation exceeds a threshold level.

PowerStream proposes a 200 basis points threshold test for the rate year based on a comparison of the Board’s inflation rate, used in the IR Price Cap Index formula, and the forecast inflation rate underpinning PowerStream’s forecast. It is proposed that this adjustment would apply only to the operating costs portion of the revenue requirement.

For example: if for 2017 PowerStream’s forecast inflation rate is 2.0% and the Board determines an inflation factor of 4.0% or less for 2017 IRM filings then there would be no adjustment. However if the Board establishes an inflation factor greater than 4.0% for 2017 IRM filings then there would be an adjustment to PowerStream’s 2017 revenue requirement in preparing the 2017 draft rate order.

c) PowerStream proposes a limited adjustment to the PILS portion of revenue requirement to reflect changes in tax rates as well as changes in regulatory taxable income arising from the other annual adjustments, i.e. an updating of the tax model calculation as filed to reflect the new regulatory net income and resulting taxes at the then current rates.

d) The Board's deemed interest rates and allowed ROE could change substantially over the IR plan period resulting in significantly higher or lower weighted average cost of capital amounts. Failure to adjust the revenue requirement to reflect the current economic conditions could result in an over or under stated revenue requirement.

PowerStream proposes an annual cost of capital adjustment when preparing the draft rate orders for each of the years 2017 to 2020.

e) PowerStream proposes to update rates annually to reflect changes in third party pass-through costs to minimize future adjustments to customers. This would include the updating of Retail Transmission Service rates based on the most current wholesale transmission rates using the Board's methodology.

f) PowerStream proposes to request disposition and rate riders in accordance with the July 31, 2009 *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative* ("EDDVAR"). PowerStream may also request disposition of certain other deferral and variance accounts where the amounts are significant and the circumstances are appropriate for disposition similar to the Board's current direction on disposing of LRAM variance amounts during IR.

3. Re-opening or termination of rate plan

Due to the essential nature of electricity distribution, the maintenance of a reliable and stable distribution system is part of the OEB mandate and key to meeting customers' needs.

The Board has developed a number of ways to deal with unexpected events to ensure the maintenance of a financial viable electricity industry while protecting the interests of consumers.

As indicated in the RRFE, the Board's existing off-ramp of ±300 basis points will apply to Custom IR applications.

For specific significant unexpected costs, the Board allows distributors to apply for deferral accounts that may be approved for later cost recovery through rates.

PowerStream proposes that some unexpected or unpredictable events might be best addressed through a re-opening of the Custom IR rate plan and in other cases may require termination of the Custom IR rate plan.

As the nature and extent of these events is unknown, it is difficult to determine whether a re-opening and adjustment of the existing Custom IR rate plan would be the best approach. In some cases the changes may be so pervasive and extensive that a new rate plan would be required. This would be determined if and when such events occur.

It is proposed that in the case of such an event, PowerStream be permitted to file either an update to its Custom IR plan or a new rate plan at its discretion. This filing would be subject to the Board's review and approval and it would be up to PowerStream to make its case for the changes sought.

PowerStream would endeavour where feasible to address such events within the existing rate plan by re-opening and adjusting the current Custom IR rate plan. These adjustments would be beyond the scope of the annual adjustments proposed above and would require a more extensive review by the Board.

PowerStream provides the following examples of events that could have a material impact to the operations of the utility, which are outside Management's control and may require re-opening or termination of the rate plan:

- Changes to income tax rates and laws beyond simple rate changes;
- Changes to Board policies on distributor rate design such as those outlined in the *Draft Report on Rate Design for Electricity Distributors* dated March 31, 2014 (EB-2012-0410,"Revenue Decoupling") or the *Development of a Standby Rate Policy for Load Displacement Generation* (EB-2013-0004);
- Changes to the Board's requirements such as those outlined in *Draft Report of the Board, Electricity and Natural Gas Distributors' Residential Customer Billing Practices and Performance dated September 18, 2014 (EB-2014-0198);*

- Development of an Ongoing, Ratepayer Funded, Electricity Bill Assistance Program Board File No.: EB-2014-0227 - in a letter dated April 23, 2014, the Minister of Energy asked the Ontario Energy Board to develop options for the implementation of an ongoing, ratepayer-funded, bill assistance program for low-income electricity customers. The Minister has referred to this program as the ‘Ontario Electricity Support Program’ (“OESP”).

- Items that would meet the OEB’s Z-Factor criteria as defined in Chapter 3 of the Board’s Filing Requirements for Transmission and Distribution Applications;

- Changes to the Board’s policy on cost allocation such as changes that may result from the *Review of the Board’s Cost Allocation Policy for Unmetered Loads* (EB-2012-0383);

- Changes to the IESO Market Rules or OEB Codes that materially impact costs or revenues;

- Accounting framework changes that significantly impact the recording of expenses and revenues;

- Ministerial Directives or other changes in governmental requirements that materially affect operations, costs and/or revenues such as new directives regarding conservation and demand management or changes in environmental laws.

This list of examples is meant to be informative and not exhaustive.

Specific Proposals

1. PowerStream proposes rates effective January 1, 2016 and interim rates effective January 1 for each of the years 2017 to 2020 inclusive subject to annual adjustments as specified in Exhibit A, Tab 1. It is proposed that PowerStream will file the necessary information regarding the annual adjustments and updated rates in a draft rate order for approval of final rates for each of the years 2017 to 2020.

2. PowerStream proposes a 2016 Base Revenue Requirement of $191.4 million. If the 2016 Base Revenue Requirement and the other changes proposed are approved, the total electricity bill of a residential customer using 800 kWh/month and of a General Service < 50 kW customer using 2,000 kWh per month in the PowerStream rate zone will be increased by $5.58 (4.2 percent) and $12.81 (3.8 percent) per month, respectively.

3. PowerStream proposes a 2017 Base Revenue Requirement of $210.0 million, a 2018 Base Revenue Requirement of $220.7 million, a 2019 Base Revenue Requirement of $231.2 million and a 2020 Base Revenue Requirement of $240.9 million, each subject to annual adjustments.

   The base revenue requirement for 2017 to 2020 respectively would be updated based on the following annual adjustments: changes in working capital resulting from changes in the pass through costs of power; changes in inflation (subject to a threshold test); changes in tax rates; and changes in the cost of capital.

4. PowerStream proposes to update rates annually for pass-through costs for low voltage and transmission charges.

5. PowerStream proposes the addition of greater than 50 kV assets with net book values totaling $26,332,000 to rate base, and that the Board make a determination that these assets will be deemed distribution assetsPowerStream proposes disposition of deferral and variance account balances as at December

31, 2014 as detailed in , together with accrued interest up to December 31, 2015 based on the proposed January 1, 2016 effective date for the rate riders

6. PowerStream proposes disposition of deferral and variance account balances in 2017 through 2020 consistent with Board policy and on the same basis as other utilities filing IRM applications.

7. PowerStream proposes continuation of the deferral account to track changes in the accrued liability for post-retirement employee benefits resulting from actuarial revaluations.

8. PowerStream is requesting a deferral account to capture the remaining net book value of meters removed from service as a result of the requirement that all General Service Greater than 50 kW demand customers to have a time-of-use meter by August 2020.

9. PowerStream pays low voltage ("LV") charges to Hydro One Networks Inc. ("Hydro One") for use of certain Hydro One distribution assets. The difference between Hydro One's LV charges to PowerStream (recorded in Account 4750) and the LV amounts billed to PowerStream's customers (recorded in Account 4075) is recorded in Account 1550 – LV Variance Account, in accordance with Appendix B of a Board directive dated June 13, 2006. In this Application, PowerStream is seeking: (i) to clear Account 1550 to December 31, 2014; and (ii) to recover in 2016 rates, a forecast LV amount of $2,731,456 through an updated LV charge.

10. PowerStream requests continuation of a charge to customers to recover the cost of the Meter Data Management and Repository ("MDM/R") system as proposed by the Independent Electricity System Operator ("IESO") and as determined by the Board. PowerStream has not included these costs in this Application

11. PowerStream requests new Retail Transmission Service ("RTS") rates to reflect currently approved Hydro One's sub-transmission ("ST") rates and the most recent Board-approved Uniform Transmission Rates. As noted above,

PowerStream proposes that its RTS rates be subject to adjustments over the Custom IR period to reflect changes in the Board-approved ST rates and Uniform Transmission Rates.

Bill Impacts and Proposed Rates

Changes in Revenue Requirement and Drivers

Table 1 summarizes the change in revenue requirement over the custom IR plan period along with the major drivers.

Table 1: Changes in Revenue Requirement and Drivers ($ millions)

	2016	% change	2017	% change	2018	% change	2019	% change	2020	% change
Revenue Requirement	$191.50		$210.00		$220.70		$231.30		$240.90	
Revenue at "current" rates	$162.40		$191.50		$210.00		$220.70		$231.30	
Increase in revenue required	$29.00	17.90%	$18.60	9.70%	$10.70	5.10%	$10.60	4.80%	$9.60	4.20%
Drivers:										
IRM Lag	$20.10	69.40%	$ -	0.00%	$ -	0.00%	$ -	0.00%	$ -	0.00%
Extraordinary items	$5.40	18.40%	$10.10	54.30%	$2.00	19.10%	$0.80	7.70%	$0.80	8.10%
Business as usual	$3.50	12.10%	$8.50	45.70%	$8.60	80.90%	$9.80	92.30%	$8.80	91.90%
Total	$29.00	100.00%	$18.60	100.00%	$10.70	100.00%	$10.60	100.00%	$9.60	100.00%

The most significant increase in revenue requirement is in 2016, the first year of rebasing. PowerStream previously rebased in 2013. The main driver is the Incentive Regulation Mechanism Lag ("IRM Lag"). IRM lag represents the increase in 2016 revenue requirement to reflect the increase in rate base from the capital investments in 2014 and 2015 as well as an increase in the level of operating costs to the 2015 levels. This excludes the impact of the extraordinary items discussed in the next paragraph.

The extraordinary items are the second largest driver of increases in 2016 and the largest in 2017. The extraordinary items consist of:

- the replacement of PowerStream's thirty year old customer billing system with a new Oracle Customer Care and Billing System which goes into service in the second quarter of 2015;
- System hardening: capital and Operating, Maintenance & Administration ("OM&A") expenditures to make PowerStream's distribution system more resistant to outages from storms; and
- A new Vaughan Transformer Station going into service in the spring of 2017 to provide needed capacity (no impact in 2016).

"Business as usual" consists of capital additions and increases in OM&A expenditures in the rebasing year excluding the extraordinary items discussed above.

Table 2 summarizes the increase in revenue requirement during the Custom IR plan term due to capital and OM&A. As can be seen from the table, capital accounts for 70%-75% of the change in the revenue requirement.

Table 2: Changes in Revenue Requirement- Capital and OM&A ($ millions)

	2016	% change	2017	% change	2018	% change	2019	% change	2020	% change
Revenue Requirement	$191.50		$210.00		$220.70		$231.30		$240.90	
Revenue at "current" rates	$162.40		$191.50		$210.00		$220.70		$231.30	
Increase in revenue required	$29.00	17.90%	$18.60	9.70%	$10.70	5.10%	$10.60	4.80%	$9.60	4.20%
Drivers:										
Capital	$20.46	70.55%	$14.10	75.82%	$7.88	73.67%	$7.37	69.57%	$6.94	72.33%
OM&A	$8.54	29.45%	$4.50	24.18%	$2.82	26.33%	$3.23	30.43%	$2.66	27.67%
Total	$29.00	100.00%	$18.60	100.00%	$10.70	100.00%	$10.60	100.00%	$9.60	100.00%

Bill Impacts

In addition to changes in the revenue requirement, bill impacts are also affected by other changes, such as changes in rate riders arising from disposition of deferral and variance account balances, in low voltage rates, in retail transmission service rates and changes in billing loss factors.

The actual bill impacts differ by rate class. Bill impacts for typical customers have been calculated using the proposed rates which include revised Low Voltage ("LV") charges, the proposed regulatory assets recovery rate riders, the Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") rate rider and the Account 1575 rate rider, and revised Retail Transmission Service Rates ("RTSRs").

For bill impact calculation purposes, the commodity prices and regulatory charges are assumed to be constant. For customers on Time-of-Use (TOU), bill impacts have been calculated using the commodity prices effective November 1, 2014: 7.7¢/kWh – Off-Peak, 11.4¢/kWh - Mid-Peak, and 14¢/kWh - On-Peak.

For customers on the Regulated Price Plan (RPP), bill impacts have been calculated using the commodity prices effective November 1, 2014: 8.8¢/kWh – for the consumption below the threshold; and 10.3¢/kWh – for the consumption above the threshold.

The threshold for the Residential customers on RPP has been annualized at 800 kWh/month. The threshold for non-Residential customers on RPP is 750 kWh/month.

The currently approved 2015 Tariff of Rates and Charges contains 2014 LRAM rate riders specific to the former Barrie rate zone. As a result, there are two sets of bill impacts – one for the former York Region rate zone and another for the former Barrie rate zone.

A completed Appendix 2-W is provided illustrating the bill impacts in accordance with Chapter 2 of the Board's Filing Requirements in electronic Appendix B-2. Summaries of the total and distribution impacts for each rate class, for each service region, are provided in Tables 3 through 6 below. They exclude HST and the Ontario Clean Energy benefit ("OCEB").

Table 3: Summary of Monthly Bill Impacts for a Typical Customer – Total Bill (York Region)

Customer Class	Billing Determinant	Consumption per Customer (kWh)	Load per Customer (kW)	Total bill 2016	2017	2018	2019	2020
Residential	kWh	800		4.0%	2.3%	1.2%	0.6%	1.1%
GS<50 kW	kWh	2,000		3.8%	1.7%	1.1%	0.7%	0.9%
GS>50 kW	kW	80,000	250	3.5%	1.2%	(0.3%)	0.7%	0.6%
Large Use	kW	2,800,000	7,350	2.3%	1.0%	0.6%	0.6%	0.5%
Unmetered Scattered Load	kWh	150		5.6%	3.0%	1.2%	1.2%	1.0%
Sentinel Lights	kW	180		7.6%	4.1%	0.5%	1.7%	1.4%
Street Lighting	kW	280		5.5%	4.6%	3.2%	1.7%	1.6%
Average				4.6%	2.5%	1.0%	1.0%	1.0%

Table 4: Summary of Monthly Bill Impacts for a Typical Customer – Distribution Portion (York Region)

Customer Class	Billing Determinant	Consumption per Customer (kWh)	Load per Customer (kW)	Distribution Component 2016	2017	2018	2019	2020
Residential	kWh	800		17.3%	8.6%	3.9%	1.8%	3.4%
GS<50 kW	kWh	2,000		17.4%	6.8%	3.5%	2.4%	3.1%
GS>50 kW	kW	80,000	250	30.7%	7.4%	(3.2%)	3.6%	2.9%
Large Use	kW	2,800,000	7,350	29.4%	9.1%	4.0%	3.9%	3.1%
Unmetered Scattered Load	kWh	150		15.9%	7.8%	3.1%	3.1%	2.3%
Sentinel Lights	kW	180		21.6%	10.2%	0.9%	3.8%	3.0%
Street Lighting	kW	280		21.0%	13.5%	4.8%	5.3%	4.8%
Average				21.9%	9.1%	2.4%	3.4%	3.2%

Table 5: Summary of Monthly Bill Impacts for a Typical Customer – Total Bill (Barrie Zone)

Customer Class	Billing Determinant	Consumption per Customer (kWh)	Load per Customer (kW)	Total bill 2016	2017	2018	2019	2020
Residential	kWh	800		3.9%	2.3%	1.2%	0.6%	1.1%
GS<50 kW	kWh	2,000		3.5%	1.7%	1.1%	0.7%	0.9%
GS>50 kW	kW	80,000	250	3.5%	1.2%	(0.3%)	0.7%	0.6%
Large Use	kW	2,800,000	7,350	2.3%	1.0%	0.6%	0.6%	0.5%
Unmetered Scattered Load	kWh	150		5.6%	3.0%	1.2%	1.2%	1.0%
Sentinel Lights	kW	180						
Street Lighting	kW	280		5.5%	4.6%	3.2%	1.7%	1.6%
Average				4.0%	2.3%	1.1%	0.9%	1.0%

Table 6: Summary of Monthly Bill Impacts for a Typical Customer – Distribution Portion (Barrie Zone)

Customer Class	Billing Determinant	Consumption per Customer (kWh)	Load per Customer (kW)	Distribution Component 2016	2017	2018	2019	2020
Residential	kWh	800		16.6%	8.6%	3.9%	1.8%	3.4%
GS<50 kW	kWh	2,000		15.9%	6.8%	3.5%	2.4%	3.1%
GS>50 kW	kW	80,000	250	30.4%	7.4%	(3.2%)	3.6%	2.9%
Large Use	kW	2,800,000	7,350	29.4%	9.1%	4.0%	3.9%	3.1%
Unmetered Scattered Load	kWh	150		15.9%	7.8%	3.1%	3.1%	2.3%
Sentinel Lights	kW	180						
Street Lighting	kW	280		21.0%	13.5%	4.8%	5.3%	4.8%
Average				21.5%	8.9%	2.7%	3.3%	3.3%

Tariff of Rates and Charges

PowerStream's current rates, effective January 1, 2015, were approved by the Board in its Decision dated December 4, 2014 on PowerStream's 2015 IRM rate application (EB-2014-0108). PowerStream's existing rate schedule is provided as supplementary information in electronic Appendix B-1-1.

PowerStream's proposed 2016 Tariffs of Rates and Charges are provided as supplementary information in electronic Appendix B-1-2. Tables 7 to 10 below provide a summary of the Current and Proposed distribution rates and other rates for 2016-2020. Rates for 2017 to 2020 are subject to annual adjustments as discussed in Exhibit A.

Table 7: Current and Proposed Distribution Rates

Customer Class	Billing Determinant	Current 2015 Rates		Proposed Rates 2016		2017		2018		2019		2020	
		Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable
Residential	*kWh*	12.67	0.0140	14.58	0.0170	15.70	0.0188	16.19	0.0200	16.66	0.0212	17.04	0.0223
GS<50 kW	*kWh*	26.08	0.0139	30.01	0.0167	32.55	0.0182	33.10	0.0194	33.20	0.0207	33.37	0.0219
GS>50 kW	*kW*	138.48	3.3278	138.48	4.0108	138.48	4.4248	138.48	4.6509	138.48	4.8735	138.48	5.0712
Large Use	*kW*	5,966.29	1.4159	5,966.29	2.1455	5,966.29	2.4901	5,966.29	2.6930	5,966.29	2.8778	5,966.29	3.0387
Unmetered Scattered	*kWh*	7.01	0.0159	8.07	0.0192	8.65	0.0214	8.87	0.0227	9.03	0.0242	9.12	0.0256
Sentinel Lights	*kW*	3.41	8.0172	3.92	9.7021	4.33	10.4450	4.56	10.8193	4.77	11.2191	4.97	11.5304
Street Lighting	*kW*	1.26	6.6546	1.45	8.0925	1.56	9.0580	1.61	9.7775	1.66	10.3887	1.70	10.9884

Table 8: Current and Proposed Low Voltage Rates

Customer Class	Billing Determinant	Current 2015	Proposed 2016	2017	2018	2019	2020
Residential	*kWh*	$0.0003	$0.0006	$0.0006	$0.0007	$0.0007	$0.0007
GS<50 kW	*kWh*	$0.0003	$0.0005	$0.0005	$0.0006	$0.0006	$0.0006
GS>50 kW	*kW*	$0.1189	$0.1989	$0.2092	$0.2192	$0.2299	$0.2299
Large Use	*kW*	$0.1437	$0.2040	$0.2146	$0.2249	$0.2358	$0.2358
Unmetered Scattered Load	*kWh*	$0.0003	$0.0006	$0.0006	$0.0006	$0.0007	$0.0007
Sentinel Lights	*kW*	$0.1031	$0.1464	$0.1539	$0.1613	$0.1692	$0.1692
Street Lighting	*kW*	$0.0917	$0.1612	$0.1695	$0.1777	$0.1863	$0.1864

Table 9: Proposed Rate Riders

Customer Class	Billing Determinant	DVA Dispostion	Global Adjustment Dispostion	LRAMVA (2013 Balance)	Stranded Meter Asets	Account 1575
		Recovery Period 2 YEARS	Recovery Period 2 YEARS	Recovery Period 1 YEAR	Recovery Period 1 YEAR	Recovery Period 1 YEAR
Residential	*kWh*	$0.0002	$0.0011	($0.0001)	$0.0001	($0.0005)
GS<50 kW	*kWh*	$0.0002	$0.0011	$0.0001	$0.0002	($0.0003)
GS>50 kW	*kW*	$0.0347	$0.4175	($0.0126)		($0.0564)
Large Use	*kW*	$0.0169		($0.0353)		($0.0311)
Unmetered Scattered	*kWh*	$0.0002	$0.0011	($0.0002)		($0.0005)
Sentinel Lights	*kW*	$0.0397	$0.4323	($0.1662)		($0.2470)
Street Lighting	*kW*	($0.1920)	$0.3987	($0.1296)		($0.2306)

Table 10: Current and Proposed RTS Rates

Customer Class	Billing Determinant	Current 2015 Rates		Proposed Rates 2016		2017		2018		2019		2020	
		TN	TC	TN	TC	TN	TC	TN	TC	TN	TC	TN	TC
Residential	*kWh*	$ 0.0080	$ 0.0035	$ 0.0080	$ 0.0037	$ 0.0081	$ 0.0038	$ 0.0083	$ 0.0038	$ 0.0084	$ 0.0039	$ 0.0086	$ 0.0040
General Service < 50 kW	*kWh*	$ 0.0072	$ 0.0030	$ 0.0072	$ 0.0032	$ 0.0073	$ 0.0032	$ 0.0075	$ 0.0033	$ 0.0076	$ 0.0034	$ 0.0077	$ 0.0035
General Service > 50 kW	*kW*	$ 2.9192	$ 1.1726	$ 2.8960	$ 1.2343	$ 2.9367	$ 1.2538	$ 2.9823	$ 1.2758	$ 3.0321	$ 1.2998	$ 3.0802	$ 1.3234
General Service > 50 kW Interval	*kW*	$ 3.0601	$ 1.2687	$ 3.0358	$ 1.3354	$ 3.0784	$ 1.3566	$ 3.1263	$ 1.3803	$ 3.1785	$ 1.4064	$ 3.2289	$ 1.4319
Large Use	*kW*	$ 3.4638	$ 1.2027	$ 3.4798	$ 1.2820	$ 3.5558	$ 1.3123	$ 3.6338	$ 1.3437	$ 3.7114	$ 1.3753	$ 3.7928	$ 1.4086
Unmetered Scattered Load	*kWh*	$ 0.0072	$ 0.0034	$ 0.0070	$ 0.0035	$ 0.0069	$ 0.0035	$ 0.0068	$ 0.0034	$ 0.0067	$ 0.0034	$ 0.0067	$ 0.0034
Sentinel Lighting	*kW*	$ 2.2561	$ 0.8629	$ 2.2538	$ 0.9146	$ 2.2870	$ 0.9297	$ 2.3200	$ 0.9450	$ 2.3520	$ 0.9600	$ 2.3857	$ 0.9760
Street Lighting	*kW*	$ 2.2203	$ 0.9503	$ 2.5104	$ 1.1400	$ 2.9365	$ 1.3359	$ 3.5555	$ 1.6206	$ 3.6409	$ 1.6631	$ 3.7471	$ 1.7154

BUSINESS PLANNING AND BUDGETING PROCESS AND ECONOMIC ASSUMPTIONS

Business Planning and Budgeting Process

PowerStream has a detailed annual planning process which involves all the business groups in the organization. The planning process begins by reviewing and confirming corporate strategy and objectives. This in turn sets the parameters for the development of a six-year plan. The business planning process begins in late March and results in a six year Budget/Outlook delivered to PowerStream's Board of Directors for approval in December. Once the Budget/Outlook is approved, this document serves as the baseline for PowerStream's operating and capital spending activities.

To enhance the Business Plan and Budget review process, a Budget Working Group was created in 2013. Its mandate is to review and prioritize Operating, Maintenance & Administration ("OM&A") spending and capital requirements. A budget is presented to the Executive Management Committee for review, which after any changes then goes to PowerStream's Board of Directors for approval in December.

The Corporate Finance Department coordinates and manages the business planning and budgeting process. Targets are set for operating and capital expenditures based on a "top down" approach considering corporate strategy and objectives, business needs and financial impact. Corporate Finance communicates these targets so the business units can develop detailed budgets based on a "bottom up" approach. Gaps between targets and detailed budget build amounts are reviewed and addressed by the Budget Working Group in order to balance the objectives of rate mitigation, with prudent spending to meet customer needs.

In May, Corporate Finance "kicks off" the annual business planning and budgeting process. Targets and economic budget assumptions are communicated to senior leaders. Further work is done by the Corporate Finance to communicate with Managers of individual business units in order to explain specific budget targets and the overall process and schedule. The budget process focuses on identifying required work program expenditures consistent with corporate strategy and objectives. This work also involves developing work program costs and supporting information such as headcount, labour costs, and other expenses.

The capital budget is developed in parallel with the OM&A budget and the detailed process is led by the Asset Investment Planning Department. A 10 year capital plan is developed early in the year based on high level assumptions of potential project activity and program work. As part of the top down approach a capital expenditure target is communicated by Corporate Finance to the Asset Investment Planning. This target is the starting point for the process to facilitate and arrive at an appropriate capital portfolio for the budget period that balances the need to invest in plant and the level of spending that can be supported by the organization. Business units that have major capital requirements assemble their detailed plans during the June-August period, and those plans are later summarized into a Distribution System Plan (the "DS Plan") (see Exhibit G). The capital budgeting process includes setting value and priority to the individual projects in order to evaluate the best capital portfolio expenditure mix.

PowerStream utilizes project optimization software and a multi-disciplinary review that helps determine the value and risks associated with a portfolio of projects. The DS Plan describes the capital planning process in detail and provides key supporting documents.

Economic Assumptions

The following are the economic assumptions used in the Custom IR rate plan:

- Labour increase based on anticipated cost of living increases
- Depreciation based on half year rule for first year of service
- Long term debt interest at 4.5%, short term interest at 2 to 3%
- Debt issuance and equity injections based on financing plan

Accounting and Regulatory Standards

PowerStream adopted International Financial Reporting Standards ("IFRS") as of January 1, 2012 with restatement of the previous year, January 1 to December 31, 2011.

PowerStream filed its 2013 Cost of Service application under Modified IFRS. As part of that process, an amount of $9,571,000 was set up in account 1575, IFRS-CGAAP Transitional PP&E Amounts. This and other matters related to regulatory accounts are discussed in Exhibit N, Deferral and Variance Accounts.

REVENUE REQUIREMENT CALCULATIONS

Table 1 summarizes the calculation of Base Revenue Requirement for the years 2015 to 2020; revenue at current approved 2015 rates; and the resulting revenue deficiency.

Table 1: Revenue Requirement and Revenue Sufficiency (Deficiency)

	2015	2016	2017	2018	2019	2020
Rate Base	$977,718,949	$1,073,615,242	$1,153,674,695	$1,238,500,808	$1,312,461,667	$1,384,079,504
Cost of Capital	5.85%	6.02%	6.08%	6.10%	6.10%	6.10%
Return on Rate Base	57,193,566	64,667,180	70,181,135	75,496,552	80,005,059	84,370,740
OM&A Expenses	92,557,500	96,216,191	98,112,314	99,919,944	102,194,621	104,193,445
Amortization Expense	41,677,590	46,903,102	50,840,767	53,526,966	56,385,592	59,523,663
PILs	(4,652,035)	(3,748,694)	3,587,891	4,560,308	5,600,264	5,849,838
Service Revenue Requirement	$186,776,621	$204,037,779	$222,722,107	$233,503,769	$244,185,537	$253,937,686
LESS: Revenue Offsets	12,487,117	12,590,603	12,718,312	12,816,681	12,938,953	13,069,086
Base Revenue Requirement	$174,289,504	$191,447,176	$210,003,795	$220,687,088	$231,246,583	$240,868,600
Revenue at Current Rates	161,153,031	162,444,354	163,344,950	164,308,195	165,283,011	166,318,900
Revenue Defficinecy	($13,136,473)	($29,002,822)	($46,658,845)	($56,378,893)	($65,963,572)	($74,549,701)

The calculation of the revenue deficiency does not include the recovery of Regulatory Assets (Exhibit N) and Low Voltage Charges (Exhibit M, Tab 3). Additionally, in accordance with the Board's Filing Requirements, costs and revenues related to the Cost of Power are segregated from the calculation of the revenue sufficiency/deficiency.

PowerStream has provided detailed calculations supporting its 2016 - 2020 revenue deficiencies in the Board’s Revenue Requirement Work Form (“RRWF”), which is provided as supplementary information in electronic Appendix E-1-1.

PRODUCTIVITY

Guidance and Expectations

At page 3 of the *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (“RRFE”), issued October 18, 2012, the Board discusses its rate-setting policy and methods and states:

> *”These rate-setting methods will provide choices suitable for distributors with varying capital requirements, while ensuring continued productivity improvement.”*

On page 12, the Board says:

> *“To ensure that the benefits from greater efficiency are appropriately shared throughout the rate-setting term between the distributor/shareholder and the distributor’s customers, the expected benefits will be taken into account in establishing the rate adjustment mechanisms applicable to each rate method through the X factor.”*

To understand the Board’s expectations regarding productivity, PowerStream has considered the Board’s methodology for incorporating productivity into the Incentive Regulation rate setting framework.

For the 4^{th} Generation IR and Annual IR Index, there is an implicit productivity factor built into the price cap IR formula of inflation less productivity, “IPI-X”. The RRFE explains the productivity part of the formula as follows:

> *The productivity component of the X-factor is intended to be the external benchmark which all distributors are expected to achieve. It should be derived from objective, data-based analysis that is transparent and replicable. Productivity factors are typically measured using estimates of the long-run trend in TFP growth for the regulated industry.*
>
> *The stretch factor component of the X-factor is intended to reflect the incremental productivity gains that distributors are expected to achieve under IR and is a common feature of IR plans. These expected productivity gains can vary by distributor and depend on the efficiency of a given distributor at the outset of the IR plan. Stretch factors are generally lower for distributors that are relatively more efficient.*
>
> *The Board has concluded that X-factors for individual distributors under 4th Generation IR will continue to consist of an empirically derived industry productivity trend*

> *(productivity factor) and stretch factor, but will be based on Ontario Total Factor Productivity (TFP) trends.*[1]

The total productivity and stretch factors referred to by the Board in the above quote are discussed below.

Total Factor Productivity

The long-run Ontario electricity distribution industry total factor productivity (TFP) to be used in rate setting was updated by the Board in the *Report of the Board, Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, issued November 21, 2013 (EB-2010-0379) ("Rate Setting Report"). The resulting TFP estimate was based on an econometric analysis prepared for the Board by Pacific Economics Group (PEG) and informed by other expert evidence presented during the stakeholder consultations.

In the Rate Setting Report, the Board set the productivity factor to 0, saying:

> *The Board has determined that the appropriate value for the productivity factor (Industry TFP) for Price Cap IR is zero. The Board believes that setting the productivity factor at zero reflects a reasonable balance of the estimated productivity trend in the sector over the last 10 years and a value that is reasonable to project into the future as an on-going external industry benchmark which all distributors should be expected to achieve.*[2]

Stretch Factor

The stretch factor is assigned based on a benchmarking exercise that compares a distributor's actual total costs (capital and OM&A) to the predicted cost based on an econometric model developed by PEG for the Board. The stretch factor is assigned based on a three year average of the percentage variance of a distributor's actual costs from predicted costs.

If a distributor's actual costs are below the costs predicted by the PEG model, then the distributor is deemed to be relatively more productive and a smaller stretch factor is assigned. If a distributor's actual costs are above the predicted costs then the distributor is deemed to have greater opportunities for productivity gains and a higher stretch factor is assigned.

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[1] Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach (RRFE) page 17

[2] Report of the Board, Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors, November 21, 2013, page 17 [emphasis per Board report]

The stretch factors for the price cap IR for 2014 and 2015 are set based on 2010 to 2012 and 2011 to 2013 costs respectively. These 3 year averages show PowerStream's actual costs below predicted costs but within 10%. This has resulted in PowerStream being assigned a stretch factor of 0.3% in both years. Benchmarking of PowerStream's costs using Board's benchmarking methodology for setting of stretch factors is discussed further in Exhibit F, Tab 2.

The above review of the Board's price cap IR approach to productivity has been used to help inform PowerStream regarding the Board's expectations for productivity in Custom IR rate setting and to interpret the following statement from the RRFE:

> *The Board is satisfied that the Custom IR process will be sufficiently rigorous that an assessment of the adequacy of past and future productivity levels can be made and the results of that assessment can be incorporated into the distributor's future rates.*[3]

Based on the Board's approach under price cap IR, PowerStream concludes that the Board's expectation would be for PowerStream to demonstrate annual productivity savings of 0.3% or greater.

Based on PowerStream's 2013 Board Approved Base Revenue Requirement of $154.2 million, the expected productivity saving for 2014 is approximately $0.5 million. By 2020 the expected productivity savings grow to $3.2 million as illustrated in Table 1 directly below.

Table 1: Expected Productivity Savings ($ Millions)

Productivity Savings Expected	2014	2015	2016	2017	2018	2019	2020	Total
Added in 2014	$ 0.46	$ 0.46	$ 0.46	$ 0.46	$ 0.46	$ 0.46	$ 0.46	$ 3.24
Added in 2015		$ 0.46	$ 0.46	$ 0.46	$ 0.46	$ 0.46	$ 0.46	$ 2.78
Added in 2016			$ 0.46	$ 0.46	$ 0.46	$ 0.46	$ 0.46	$ 2.31
Added in 2017				$ 0.46	$ 0.46	$ 0.46	$ 0.46	$ 1.85
Added in 2018					$ 0.46	$ 0.46	$ 0.46	$ 1.39
Added in 2019						$ 0.46	$ 0.46	$ 0.93
Added in 2020							$ 0.46	$ 0.46
Total	$ 0.46	$ 0.93	$ 1.39	$ 1.85	$ 2.31	$ 2.78	$ 3.24	$ 12.95
Based on:								
2013 Board Approved Revenue Requirement	$154.2	X Factor	0.30%	Annual savings requirement			$ 0.46	

[3] RRFE page 74

Expected vs. Estimated Productivity Savings

PowerStream has estimated its Productivity Savings as shown in Table 2 below.

Table 2: Estimated Productivity Savings ($ Millions)

	2014	2015	2016	2017	2018	2019	2020	Total
Capital		$3.8	$4.1	$4.5	$4.7	$5.0	$5.0	$27.1
OM&A	$2.5	($0.8)	($1.0)	$0.3	$1.2	$2.0	$3.0	$7.1
Total	**$2.5**	**$3.0**	**$3.1**	**$4.8**	**$5.9**	**$7.0**	**$8.0**	**$34.2**

Details in support of Capital and OM&A savings estimates are discussed later in this exhibit.

Table 3 directly below compares the Board's expected productivity savings with PowerStream's estimated productivity savings.

Table 3: Expected vs. Estimated Productivity Savings ($ Millions)

	2014	2015	2016	2017	2018	2019	2020	Total
OEB Expected Productivity Savings	$ 0.5	$ 0.9	$ 1.4	$ 1.9	$ 2.3	$ 2.8	$ 3.2	$ 13.0
Estimated Productivity Savings	$ 2.5	$ 3.0	$ 3.1	$ 4.8	$ 5.9	$ 7.0	$ 8.0	$ 34.3
Over (under) achieved	$ 2.0	$ 2.1	$ 1.7	$ 2.9	$ 3.6	$ 4.2	$ 4.8	$ 21.3

The results indicate that PowerStream's capital and OM&A amounts underpinning its revenue requirement proposals reflect productivity savings in excess of the Board's expectation under the X factor. For each of the years 2014-2020, estimated productivity savings exceed the Board's expected savings. For the entire period, the additional productivity savings over Board expectations total $21.3 million.

Operating Costs – Estimated Productivity Savings

PowerStream has used a top-down analysis of its operating costs (OM&A) to estimate the magnitude of productivity savings reflected in its forecasted OM&A costs. This has been done by a comparison of "Status Quo" OM&A to Forecasted OM&A.

Status Quo OM&A is an estimate of what OM&A would have been if the productivity initiatives had not been undertaken. When PowerStream staff are preparing their capital and operating budgets, they are basing these on the information and processes expected to be in place for the budget period. They are not preparing two budgets, one based on the “old” way of doing things and another based on the current budgeting assumptions. This is why the Status Quo analysis is necessary.

Table 4 below compares the Status Quo OM&A and the Forecasted OM&A underpinning the rate application.

Table 4: Estimated Productivity Savings from OM&A ($ thousands)

				Custom IR Term				
"Status Quo” OM&A	2013 BA	2014	2015	2016	2017	2018	2019	2020
Prior year OM&A starting point	$ 83,319	$ 83,319	$ 87,911	$ 91,795	$ 95,192	$ 98,369	$ 101,081	$ 104,220
Inflation adjustment-(Table 5)		$ 1,416	$ 1,407	$ 2,019	$ 2,094	$ 2,164	$ 2,224	$ 2,293
Customer growth adjustment (Table 5)		$ 182	$ 172	$ 178	$ 187	$ 191	$ 197	$ 205
Net incremental new costs (Table6)		$ 2,994	$ 2,305	$ 1,200	$ 895	$ 356	$ 719	$ 484
“Status Quo” OM&A	$ 83,319	$ 87,911	$ 91,795	$ 95,192	$ 98,369	$ 101,081	$ 104,220	$ 107,202
Historical and Forecasted OM&A in Application	$ 81,192	$ 85,454	$ 92,558	$ 96,216	$ 98,112	$ 99,920	$ 102,195	$ 104,193
Variance/Productivity savings		$2,457	($763)	($1,024)	$257	$1,161	$2,025	$3,009

“Status Quo” OM&A is determined by taking the most recent 2013 Board Approved OM&A and adjusting for significant cost drivers affecting OM&A costs such as inflationary wage and price increases, growth and other identified cost drivers.

Forecasted OM&A costs are those contained in the rate filing and are derived from PowerStream’s budgeting process where budgeted costs are forecasted at a detailed level within each business unit.

To arrive at the Status Quo costs, the previous Board Approved costs are adjusted for the following: Changes in OM&A costs due to inflation and customer growth (Table 5) and changes in net incremental new costs from changing requirements (Table 6).

Table 5: OM&A Adjustment Factors for Inflation and Customer Growth

Adjustment Factors	2014	2015	2016	2017	2018	2019	2020
Inflation	1.70%	1.60%	2.20%	2.20%	2.20%	2.20%	2.20%
Customer Growth adjustment factor:							
Customer Growth (A)	1.91%	1.71%	1.69%	1.72%	1.70%	1.70%	1.72%
Customer Growth effect on OM&A (B)	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%
Customer Growth adjustment (A*B)	0.22%	0.20%	0.19%	0.20%	0.19%	0.19%	0.20%

Table 6: Net Incremental New Costs for Changing Requirements ($ thousands)

			Custom IR Term					
Net incremental new costs	2014	2015	2016	2017	2018	2019	2020	2016-2020 Total
New CIS incremental costs	$1,349	$1,310	($122)	($158)	($182)	$1	$1	($460)
Vegetation management	$299	$300	$614	$526	$531	$536	$542	$2,749
Compliance	$262	$185	$132	$18	$18	$18	$19	$205
Risk Management	$330	$757	$518	$485	($36)	$138	($103)	$1,002
Customer expectation	$754	($248)	$58	$25	$25	$25	$25	$158
Total	$2,994	$2,305	$1,200	$895	$356	$719	$484	$3,654

The net incremental cost table above ties to the OM&A cost drivers in Appendix 2-JB in Exhibit J tab 1, except it does not include the compensation, growth or asset management cost drivers as these are captured in the inflation and customer growth adjustment factors above.

Capital – Estimated Productivity Savings

PowerStream plans to rehabilitate 140 kilometres of end-of-life or beyond underground cable in 2015 and each year during the 2016 to 2020 IR plan term.

PowerStream has managed to achieve significant savings in the costs of rehabilitating underground cable through the use of cable injection instead of replacement. Injection costs less than 10% of the cost of replacement. Injected cable has an estimated useful life of 20 years or 40% compared to 50 years for replacement cable. Taking into account the shorter life, this represents a cost of 40% for injected cable versus replacement cable.

Based on PowerStream's experience with cable injection, it has been determined that the amount of cable replacement for 2015 to 2020 can be reduced by 22 kilometers per year as this cable can now be injected rather than replaced. This translates into the savings summarized in Table 7 below.

Table 7: Additional Productivity Savings from Capital ($ Millions)

	2015	2016	2017	2018	2019	2020
Replacement cost savings	$ 10.3	$ 11.0	$ 12.0	$ 12.6	$ 13.3	$ 13.5
Injection Cost	$ 0.9	$ 0.8	$ 0.8	$ 0.8	$ 0.9	$ 0.9
Net Savings	$ 9.4	$ 10.2	$ 11.2	$ 11.7	$ 12.4	$ 12.6
Adjust for 40% life	$ 3.8	$ 4.1	$ 4.5	$ 4.7	$ 5.0	$ 5.0

These additional productivity gains related to a recent change in the cable injection program are described under the heading Continuous Productivity Improvement, directly below.

Continuous Productivity Improvement

PowerStream applies a broad and holistic approach to improvement. This balanced approach is multidimensional as it realizes that overall improvement can only be sustained by considering and initiating change that yields a mix of benefits. For greatest value, a combination of hard and soft improvements is required. PowerStream's stakeholders who include customers, rate payers and shareholders desire an organization that continues to improve its operations. Below are some of the many initiatives that PowerStream has undertaken to drive productivity improvements.

Customer Information System (CIS)

In its 2013 Cost of Service Application, PowerStream provided information with regard to initiating a new CIS Project. This project is scheduled to go live in the second quarter of 2015. The implementation of the new CIS replaces a 30 year old legacy system which does not meet current and expected customer needs and operational demands. In modernizing the CIS architecture, Customer Service is updating the backbone information system for future requirements.

The benefits of modernization are significant including the movement to a cross functional pooling of staff resources versus sequential and silo work assignment and scheduling, the availability of Wikipedia type information for shared use, real time workload balancing, optimization of capacity, the setting and electronic tracking of Key Performance Indicators, enhanced cycle time with the elimination of low value activity and process gaps and improved customer service and experience with an enhanced self-serve option.

Critical to realizing the full value of the new CIS is business processes that mirror system functionality. Workload balancing achieved through pooling is anticipated to increase capacity in the Customer Service area. This additional capacity has been incorporated into this rate application, the outcome of which can be demonstrated by the ability of Customer Service to continue to provide more value to more customers without increasing headcount.

Work Force Management (WFM)

Operations and Construction is planning to initiate Work Force Management in 2015 which will be phased over 4 years. The implementation of Work Force Management (WFM)/Mobile Dispatch will improve capacity through automated end to end planning and scheduling which integrates all departments along the project lifecycle (i.e. Engineering → Materials → Metering → Lines). The various benefits which will be realized include:

- Increased value added work time through decreased travel time and movement between jobs through enhanced route planning
- Decreased administration time through the simplification of document and information flow
- Increased schedule adherence by meeting planned job start dates
- Introduction of additional key metrics to track performance

The anticipated increased capacity upon full implementation of WFM has been incorporated into the rate application. The anticipated capacity increase will allow Operations and Construction to advance and/or do more planned and unplanned work, as well as build and maintain an increasing infrastructure with little or no increase in work hours.

Cable Injection

PowerStream uses two rehabilitation options to rehabilitate cable segments that are aged and are in deteriorated condition. The options are cable replacement and cable injection. PowerStream's initial cable injection program (pre 2015) excluded the older cable population (31 years and older). In 2014, in an effort to find methods of improving reliability while working within a constrained budget, PowerStream consulted with cable injection service providers and other utilities to obtain broader information. PowerStream also completed additional research by determining the effectiveness of cable injection on older cables and deteriorated cables which previously would have been replacement candidates. This work, combined with the past success of PowerStream's cable injection program, led PowerStream to make the decision to expand the cable age group for cable injection.

Beginning in 2015, PowerStream will be injecting cables in the range of 31 to 39 years and thus deferring the high cost of cable replacement, for this new range of cables, by 20 years. This new approach allows PowerStream to rehabilitate more cable segments with the same amount of capital funding. As well, the new approach is more expedient as it makes it possible to address potential reliability problems faster. PowerStream is one of the few utilities in Canada that have fully embraced a new and innovative way to rehabilitate cable segments that are aged and in deteriorated condition. This new program demonstrates PowerStream's success in developing innovative solutions to improve reliability while working within a constrained budget.

In House Cable Testing

PowerStream is one of the few (if not only) electricity utilities in Canada to have its own in-house Cable Testing Program. This program ensures replacement decisions are made in the most cost effective and efficient manner. Operating cost savings occur because it is less costly for PowerStream to do its own in-house testing than it would be to have external contractors do cable testing for PowerStream.

Pole Reinforcement Program

PowerStream has a significant Pole Replacement Program due to the quantity of wood poles in service (approx. 40,000). In 2014, PowerStream completed an engineering evaluation and pilot project using pole reinforcement technology to reinforce poles rather than replacing poles. Based on the successful completion of the pilot, PowerStream has embraced pole reinforcement as a new and innovative way to reduce capital costs associated with wood pole replacements. It should be noted that PowerStream is one of the first Local Distribution Companies in Ontario to embrace Pole Reinforcement Technology.

PI Enterprise software to manage real-time data and events

PI Enterprise software, introduced to PowerStream, provides notification capability for certain Transformer conditions as well as Circuit Breaker status. This new software allowed PowerStream to migrate from time based maintenance to a more proactive maintenance model based on condition and risk. Notification capability acquired with the implementation included equipment alarms, peak loads, oil temperatures, fire alarms, etc. PowerStream's new proactive based maintenance model, enabled by the new software notification capability, has already resulted in PowerStream successfully avoiding future costs on several occasions, one of which resulted in PowerStream avoiding the two million dollar expenditure to replace a transformer.

Non-Quantifiable Benefits

PowerStream's initiatives often have several purposes, such as improved customer service, better operational information and decision making. These initiatives provide benefits that are of direct or indirect value to customers but may not provide any productivity savings. The operational improvements may result in other savings.

An example is the purchase and use of PI Enterprise software to monitor transformer stations and municipal substations. This operational improvement has already provided timely warning to avert a capital replacement cost of $2 million and avoid customer outages. PowerStream was able to remedy the situation with a repair costing approximately $100,000.

BENCHMARKING

There can be a range of benchmarking techniques to provide an indication of the reasonableness of a distributor's costs.

Traditionally, it has been common for electricity distributors to assess their costs by employing internal benchmarking measures and by keeping a watch on industry standards. This continues to be the case for PowerStream. For example section 5.2.3, Performance Measurement for Continuous Improvement, in the Distribution System Plan provides information on the measures that PowerStream uses to monitor quality and drive continuous improvement in its distribution system planning and implementation work. These internal measures focus on reliability, safety and asset management and are aimed at making PowerStream's processes more effective and efficient.

In the context of industry standards, PowerStream has paid close attention to the Board's Scorecard since its introduction and strives to ensure that it meets the standards set by the Board.

Prior to the implementation of the RRFE, a standard for cost comparison used by the Board was peer-to-peer benchmarking, based on the Board's Annual Year Book. Subsequent to the implementation of the RRFE, a new approach has been introduced by the Board. The Board determined that the Pacific Economic Group ("PEG") econometric model ("the PEG model") will be used for benchmarking distributor cost performance and for informing the Board's annual assignment of stretch factors to distributors. While the PEG model is meant to replace the peer-to-peer method, it has been PowerStream's observation that parties to rates proceedings continue to be interested in the peer-to-peer benchmarking approach, perhaps because there has not yet been a full transition to the PEG model method alone. Therefore, to be of assistance, PowerStream discusses below both methods pertaining to its relative performance.

Econometric Benchmarking (PEG Model)

The Board determined that the PEG model would be used for benchmarking distributor cost performance and for informing the Board's annual assignment of stretch factors to distributors.

According to that methodology, model parameters are estimated using Ontario LDC data from 2002-2012. Inserting the observed values of distributor's variables into this estimated function, to obtain the predicted value of a distributor's costs based on the parameters derived from applying the economic model to all of the other Ontario LDCs' costs. The percentage difference between a distributor's observed costs and these predicted costs reflects the efficiency (or inefficiency) of a distributor relative to other Ontario Local Distribution Companies (LDCs), and this is the Board's measure of cost performance. LDCs with larger differences between actual and predicted costs are considered to be better or worse cost performers and therefore assigned, respectively, lower or higher stretch factors.

Given reasonable expectations about future values of output, input prices, and business conditions, the PEG model is used to forecast future values of predicted costs.

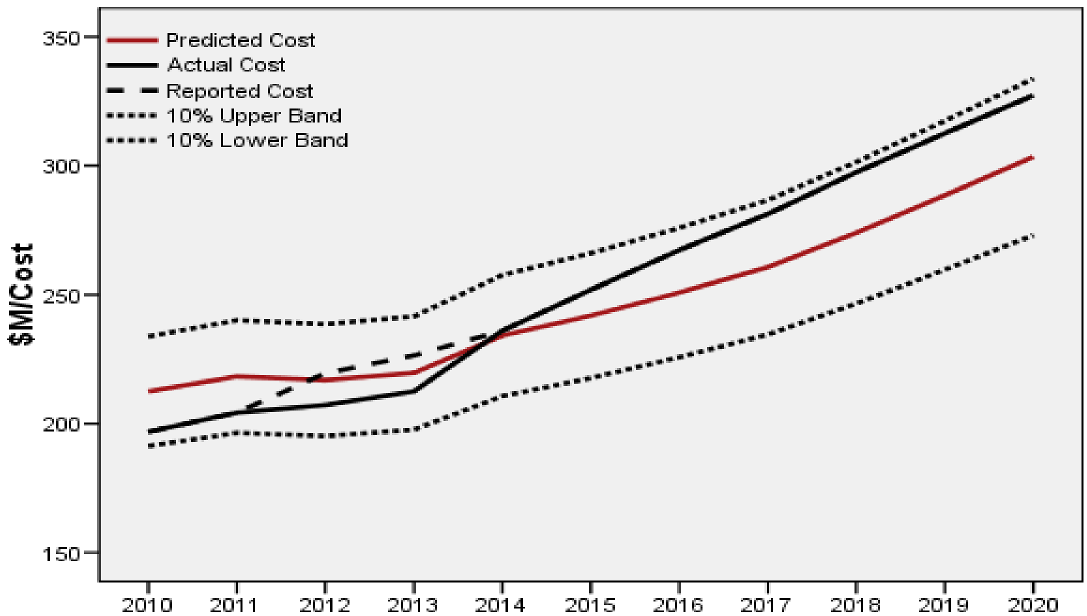
PowerStream has used the PEG model to derive future values of predicted costs and compare them to actual and forecasted costs using the PEG's definitions of Capital and OM&A costs. The results are shown in Table 1 below.

Table 1: Predicted vs. Actual (and Forecasted) Costs ($000)

Year	Predcited Total Costs	Actual Total Costs	Actual OM&A	Actual Capital
2010	$212,561	$196,831	$51,332	$145,499
2011	218,280	204,310	54,882	149,428
2012	216,915	207,288	58,480	148,808
2013	219,646	212,560	60,250	152,309
2014	234,155	236,035	65,541	170,494
2015	241,911	251,926	69,674	182,253
2016	250,838	267,255	70,309	196,946
2017	260,667	281,330	72,465	208,866
2018	274,017	297,427	75,437	221,990
2019	288,558	312,578	77,734	234,844
2020	303,387	327,274	79,734	247,539

PowerStream's forecasted costs remain within ±10% of Predicted Costs. This coincides with the Board's criteria for Stretch factor Group 3, where PowerStream currently resides. This is illustrated in Figure 1 below.

Figure 1: Time Series of Predicted vs. Actual Forecasted Costs



However, there are a number of factors that must be considered before drawing hard conclusions regarding the above graph.

The predicted cost model is designed to compare a utility's costs to the predicted costs for a "typical" utility. This is done by taking the historical data for the other Ontario electricity distributors (in this case excluding PowerStream) and using regression analysis to create a formula to estimate the predicted costs (capital and operating costs).

PowerStream is experiencing different operating conditions than typical in the industry. To the extent that these differences are or will be experienced by other Ontario LDCs, this may not be fully reflected in the historical data used to calculate Predicted and Actual Costs. As a result, the PEG model will not accurately reflect these cost pressures, as there is no business condition variable included in the model to account for them. These differences include:

- Substantial increases in the capital costs related to sustainment of assets; replacement of capital stock and distribution infrastructure, some of which was financed by contributed capital and therefore never attracted a depreciation charge;
- Extraordinary expenditures like a new transformer station; and
- A new Customer Information System, which requires substantial initial investments.

There are significant net incremental new costs in 2014 and 2015 related primarily to the new customer billing and information system ("CIS"), system hardening to better withstand storms and increased costs to meet customer expectations and compliance requirements. (See Exhibit J, Tab 1 for more information on the OM&A cost drivers. See Exhibit G, Tab 1 and the Distribution System Plan for more details on the capital costs related to the new CIS and system hardening).

The need for increased capital spending on sustainment causes the capital portion of Actual (and forecasted) cost to continue to rise faster than predicted costs until 2018-2019. At this point the Actual costs and predicted costs are increasing at the same rate.

It is important to distinguish between the accuracy with which the PEG model can be used to benchmark the costs of an LDC operating under usual circumstances, and the accuracy with which it can be used to assess the costs of an LDC facing unusual business conditions. In particular, the estimates generated from the PEG model should be interpreted as the predicted costs of a typical (i.e., average) distributor facing similar output demands, input prices, and business conditions as the LDC under examination. As stated in the Board's RRFE, a Custom IR method will: be most appropriate for distributors with significantly large multi-year or highly variable investment commitments with relatively certain timing and level of associated expenditures; this rate-setting method is intended to be customized to fit the specific applicant's circumstances; this flexibility is to accommodate differences in the operations of distributors, some of which have capital programs that are expected to be significant and include ‘lumpy’ investments and others of which have capital needs that are expected to be comparatively stable over a prolonged period of time.

Peer-to-Peer Benchmarking

Costs

Data sources such as the Board’s 2013 Year Book of Electricity Distributors allow comparisons to other utilities.

One must be aware that differences do exist between utility conditions that may affect their costs. For example, PowerStream owns many of the transformer stations that supply its service territory in the York Region area. These over 50,000 volt (>50kV) assets are deemed to be distribution assets and are included in its distribution costs and rates. Other utilities which do not own >50KV assets would not have these costs, and other things being equal their distribution rates would be expected to be lower. In PowerStream’s case, PowerStream’s retail transmission service rates for network connection are reduced since there are no wholesale transmission charges for connection and transformation service in respect of the PowerStream-owned transformer stations.

There are many factors that may affect the cost of distributing electricity. Some examples are density (urban, suburban or rural), types of customers, service territory terrain, growth and age of existing plant. To the extent that there are differences in utility characteristics, it is reasonable to expect that costs will differ. This makes the selection of comparable peers challenging and somewhat subjective.

Comparison to peers also relies on historical actual data. As forecast data is only available for PowerStream and not the other utilities, it is not possible to compare the forecasted future amounts.

Despite the limitations of peer-to-peer comparison, it provides some indication of the reasonableness of the actual historical amounts that are a reference point for explaining and justifying the forecasted amounts. For this purpose, PowerStream has provided below OM&A Cost per Customer and Rates comparisons.

OM&A Cost per Customer

Table 2 below summarizes PowerStream's OM&A per customer as per the Ontario Energy Board 2013 Yearbook of Electricity Distributors issued August 14, 2014.

Table 2: OM&A per Customer Comparison based on 2013 Yearbook

	OM&A Per Customer	PowerStream Rank/%
PowerStream Inc.	$ 234.24	13
Average	$ 316.39	74.0%
Median	$ 276.62	84.7%

Table 2 shows that PowerStream's OM&A cost per customer is the 13th lowest and is 74.0% of the average and 84.7% of the median OM&A cost per customer for the 73 Ontario LDCs in the 2013 Yearbook.

Rates

PowerStream compares its rates annually with other Southern Ontario utilities of similar size and/or geographic proximity to PowerStream's service territory. PowerStream's goal is to have rates that are in the lowest quartile.

This is a total bill comparison to take into account the fact that the PowerStream distribution rates contain transformer station costs and the offsetting effect on transmission rates. The following figures contain the results of this comparison using current Board-Approved 2014 rates for Residential, General Service under 50 kW and General Service greater than 50 kW demand customers based on the customary "typical" customer consumption and load.

Figure 2: 2014 Typical Residential Customer Bill Comparison

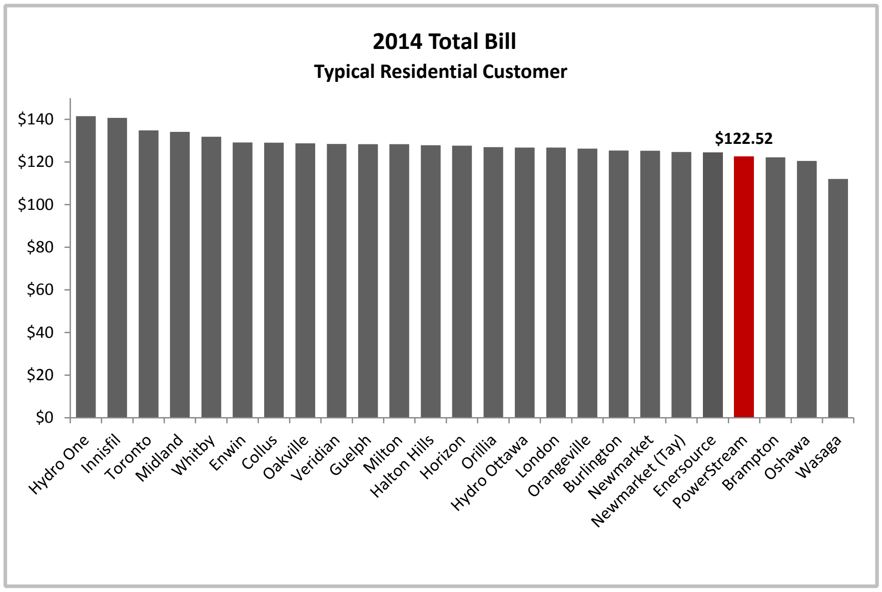
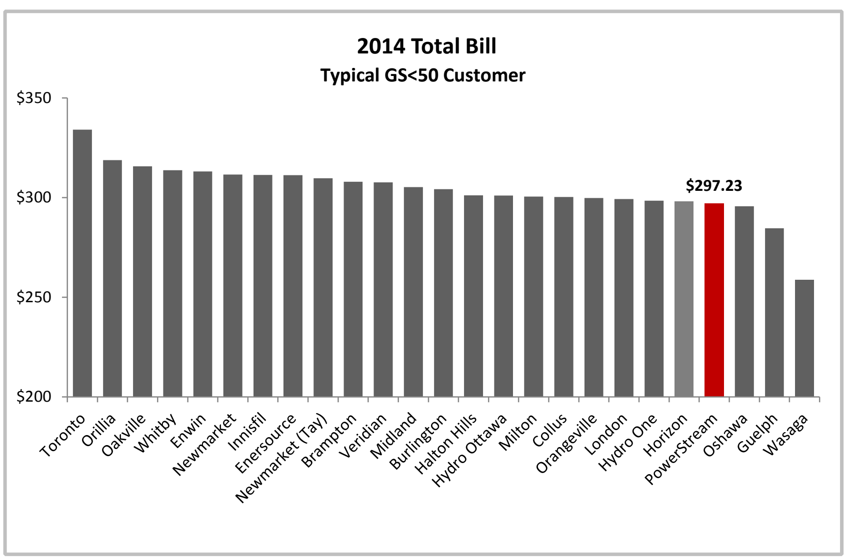
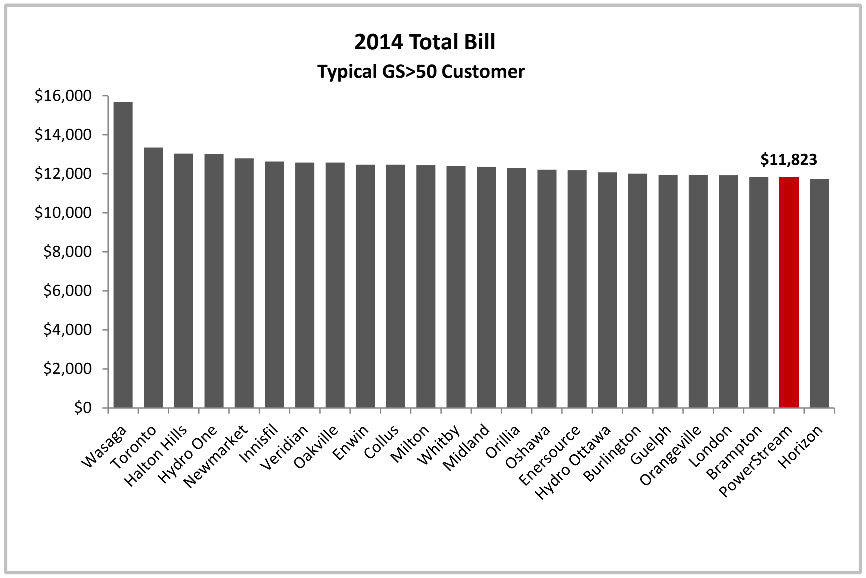


Figure 3: Typical GS<50kW Customer Bill Comparison



1 **Figure 4: Typical GS>50kW Customer Bill Comparison**



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Customer Engagement

PowerStream’s general customer engagement activities as well as customer engagement activities specific to the development of the Distribution System Plan are set out in detail in section 5.4.2 of that plan which can be found in the Supplemental Information as electronic document G-2-1 – Distribution System Plan.

Rate Base Summary

Table 1 below summarizes PowerStream's rate base from 2012 to 2020.

Table 1: Rate Base 2012 to 2020 ($ Millions)

Rate Base	Actual 2012	Actual 2013	Actual 2014	Bridge Year 2015	Test Year 2016	Test Year 2017	Test Year 2018	Test Year 2019	Test Year 2020
Opening PP&E NBV	$ 660.0	$ 686.1	$ 733.9	$ 788.4	$ 884.1	$ 951.3	$ 1,041.6	$ 1,108.1	$ 1,182.3
Closing PP&E NBV	$ 686.1	$ 733.9	$ 788.4	$ 884.1	$ 951.3	$ 1,041.6	$ 1,108.1	$ 1,182.3	$ 1,245.9
PPE Average NBV	$ 673.1	$ 710.0	$ 761.1	$ 836.2	$ 917.7	$ 996.5	$ 1,074.9	$ 1,145.2	$ 1,214.1
Working Capital Allowance	$ 114.6	$ 124.9	$ 131.4	$ 141.5	$ 155.9	$ 157.2	$ 163.6	$ 167.2	$ 170.0
Rate Base	$ 787.7	$ 834.9	$ 892.5	$ 977.7	$ 1,073.6	$ 1,153.7	$ 1,238.5	$ 1,312.4	$ 1,384.1

The Property Plant and Equipment (PP&E) Net Book Value (NBV) amounts are net of contributed capital and accumulated depreciation.

Table 2 below provides a rate base comparison between the 2013 Board Approved and the 2020 test year.

Table 2: Rate Base Comparison – 2013 Board Approved vs. 2020 ($ Millions)

Rate Base	2013 Board Approved	Test Year 2020	Change 2013 Bd Approved to 2020	% Change 2013 Board Approved to 2020	% Annual Change 2013 Board Approved to 2020
PPE Average NBV	$ 719.3	$ 1,214.1	$ 494.9	69%	8%
Working Capital Allowance	$ 121.9	$ 170.0	$ 48.1	39%	5%
Unadjusted Rate Base	$ 841.2	$ 1,384.1	$ 543.0	65%	7%
PP&E Transitional Amount	$ (9.6)	$ -	$ 9.6	-100%	-100%
GEA deferral adjustment	$ 0.5	$ -	$ (0.5)	-100%	-100%
Adjusted Rate Base	$ 832.1	$ 1,384.1	$ 552.1	66%	8%

Note: annual % Change is compounded

Details of the change in "PP&E Average NBV" can be found in Exhibit G, Tab 2, Table 1, "In-Service Additions".

Details of the change in "Working Capital Allowance" can be found in Exhibit G, Tab 3.

The details of the changes in the "PP&E Transitional Amount" are as follows. In 2012 PowerStream adopted International Financial Reporting Standards (IFRS) for financial reporting purposes. The adoption of IFRS required the restatement of 2011 balances under IFRS. In PowerStream's 2013 Cost of Service proceeding PowerStream received Board approval to record a PP&E Transitional amount of $9,571,000 in account 1575. This amount was deducted from rate base and it was amortized over four years with $2,392,750 being deducted from the 2013 Test Year depreciation expense. In this application PowerStream proposes to dispose of the remaining credit balance of $2,392,750 in account 1575 at December 31, 2015 as part of the deferral and variance accounts rather than as an adjustment to rate base and depreciation expense.

The details of the changes in the "GEA deferral adjustment" are as follows. In its 2013 Cost of Service application, PowerStream had applied for disposition of Green Energy Act (GEA) capital deferral amounts and these amounts were added to rate base. In this application the GEA capital amounts are included in the in-service additions rather than deferral accounts as directed in the Board's filing guidelines.

Distribution System Plan Summary

On March 28, 2013, the Ontario Energy Board ("OEB") issued Chapter 5 of the Board's Filing Requirements for Electricity Transmission and Distribution Applications, entitled *Consolidated Distribution System Plan Filing Requirements (the "Chapter 5 Requirements").* PowerStream has compiled its consolidated Distribution System Plan ("DS Plan") in accordance with the Chapter 5 Filing Requirements. The complete DS Plan is available as supplementary information in electronic Appendix - *Exhibit G, Tab 2, Chapter 5 Consolidated Distribution System Plan*.

PowerStream's DS Plan reflects PowerStream's integrated approach to planning, prioritizing and managing assets and includes regional planning, local stakeholder consultations, renewable generation connections and smart grid considerations. PowerStream has completed the DS Plan with a focus on customer preferences and operational effectiveness while achieving optimal value for capital spending.

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

- System Access (mandated for customer connections and service obligations);
- System Renewal (replacing or refurbishing to extend service life);
- System Service (ensure operational objectives are met); and
- General Plant (for assets not part of the electrical distribution system).

PowerStream's Capital Expenditure Plan includes a total of 71 Material Investments. PowerStream's 2014 Materiality Threshold is calculated to be $771,000 based on 0.5% of PowerStream's 2013 distribution revenue of $154M allocated as:

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

The summary totals of investments within the four requisite OEB categories for historical expenditures, 2011-2015 and the rate proposal 2016-2020 in the DS Plan are provided in Table

2 and Table 3 respectively. Table 1 compares the total capital spending for two periods: 2011 to 2015 and 2016 to 2020.

Table 1: Annual Capital Spending – Comparison of 2011-2015 to 2016-2020 ($000)

	2011 to 2015 Total	2016 to 2020 Total		
CATEGORY	**TOTAL**	**TOTAL**	**$ Change**	**% Change**
System Access	108,711	146,855	38,144	35%
System Renewal	132,946	257,643	124,698	94%
System Service	116,987	150,299	33,312	28%
General Plant	101,030	86,202	- 14,829	-15%
Total	**459,674**	**641,000**	**181,325**	**39%**

System Access spending has increased due to growth and road authority work. System Renewal spending has increased due to the implementation of a comprehensive asset management process. System Service spending has grown due to system needs for capacity delivery. General Plant spending has decreased as larger expenditures related to CIS will be completed in 2015.

Table 2: Annual Capital Spending – Rate Plan by OEB Category ($000)

CATEGORY	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Plan	TOTAL
System Access	21,007	19,888	17,030	26,641	24,145	108,711
System Renewal	11,527	16,974	22,254	39,802	42,388	132,946
System Service	22,885	13,770	34,780	18,229	27,322	116,987
General Plant	7,877	24,200	19,593	24,816	24,545	101,030
Total	**63,297**	**74,832**	**93,657**	**109,488**	**118,400**	**459,674**

Table 3: Annual Capital Spending – Rate Plan by OEB Category ($000)

CATEGORY	2016 Plan	2017 Plan	2018 Plan	2019 Plan	2020 Plan	TOTAL
System Access	28,232	28,470	29,561	28,726	31,867	146,855
System Renewal	48,715	51,500	52,052	52,971	52,406	257,643
System Service	38,322	32,072	29,920	26,963	23,022	150,299
General Plant	17,631	19,558	13,967	16,840	18,206	86,202
Total	**132,900**	**131,600**	**125,500**	**125,500**	**125,500**	**641,000**

All asset information used for Asset Condition Assessment and reliability analysis in the DS Plan is as of December 31, 2014.

Significant contributors to the increases seen in Table 1 are noted below by category.

System Access

<u>Road Authority</u>

Road Authority projects involve the relocation of PowerStream's distribution system assets to allow road relocation and road reconstruction projects at the request of the Regions of York, Simcoe County, the Ministry of Transportation or the local municipalities. Road Authority projects are customer initiated and PowerStream is obligated under the Distribution System Code and its Conditions of Service to perform these projects and incur its share of related expenditures. PowerStream adheres to the *Public Service Works on Highways Act* and associated regulations governing the recovery of costs related to road reconstruction work by collecting contributed capital for 50% of labour and labour saving devices.

The Road Authority projects within York Region are most notably driven by:

- areas identified within the provincial Places to Grow framework; and
- the construction of the VIVA transit way along Highway 7.

The investments included in the DS Plan for Road Authority projects are $39 million for 2016-2020.

System Service

<u>Vaughan TS#4</u>

Coordinated regional planning within the four regions in which PowerStream participates resulted in the need for PowerStream to construct a new transformer station (with associated feeder integration) within this DS Plan timeframe. Spending on the station will take place between 2015 and 2017, and spending on feeder integration will take place between 2016 and 2019.

Vaughan Transformer Station #4 (“VTS#4”) will provide 170 MVA of new capacity through twelve new 27.6kV feeders that will be integrated into the distribution system. VTS#4 will service future load growth in the Vaughan area. In addition, VTS#4 will off-load some existing feeders in Vaughan which in turn will provide feeder capacity to the Richmond Hill service territory as soon as VTS#4 is ready for service

PowerStream’s in service date for VTS#4 is the spring of 2017. This will provide additional capacity prior to the summer peak demand. The Class EA process for siting the station is complete.

The investments included in the DS Plan for Vaughan TS#4 total $42 million.

System Renewal

<u>Asset Remediation</u>

PowerStream makes assessments on whether an aged asset is suited for refurbishment or replacement based on criteria that are pertinent to a given asset class. PowerStream has several asset remediation programs for maintaining distribution system and general plant integrity.

The remediation programs for maintaining distribution system assets are:

- Pole remediation (replacement or reinforcement) – 400 poles/year;
- Cable remediation (replacement and injection) – 130km per year;
- Switchgear Replacement – 31-36 units per year;
- Mini-Rupter Switch Replacement – 15 per year ;
- Automated Switch replacement – 5 per year;
- Submersible Transformer replacement – complete in 2015; and
- Distribution Transformer replacement – 60 per year;

PowerStream’s system renewal program for the distribution system has been designed to:

- Hold system failures, and consequently, reliability, at a constant level (no degradation);
- Strike a balance between affordable spending and tolerable risk; and
- Result in the levelling of capital reactive spending (emergency replacements).

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

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

There is an expectation that the projects and programs will lead to a modest improvement in reliability to customers as the controllable portion of the System Average Interruption Duration Index ("SAIDI") will decrease as the capital projects/programs and the appropriate Operations & Maintenance spending practices are implemented.

The investments included in the DS Plan for the remediation programs stated above are $148 million for 2016-2020.

Storm Hardening and Rear Lot Conversion

There are investments included in the DS Plan for Storm Hardening and Rear Lot Conversion, as a result of recommendations from the review of the 2013 ice storm, in a total amount of $37.5 million for 2016-2020.

General Plant

Customer Information System

In 2015, PowerStream will begin using a new Oracle-based Customer Information System ("CIS") to replace the existing T&W Info-Systems Ltd. CIS system ("T&W") that dates back to the 1970s. In November of 2011, PowerStream's Board of Directors approved a purchase agreement for the Oracle Customer Care and Billing CIS ("CC&B") solution. In February of 2012 PowerStream purchased Oracle's CIS Custom Components for the Ontario Market ("CCOM").

Implementing a new CIS is essential given the age of the existing system and the resulting risk of failure of this critical system.

The CIS is a critical and comprehensive business system for PowerStream. The CIS provides the full meter-to-cash applications required to meet one of the core business mandates of providing account management, billing, collections, payments, and meter management/meter reading functionality for over 370,000 electricity customers within PowerStream's service territory. It also is a hub system providing inbound and outbound information to approximately twenty other interface systems both internal and external to PowerStream.

The major cost components of the new CIS system are the system hardware and software, internal resources, consulting and legal costs and the cost for integration of the CIS with PowerStream's existing processes and systems.

The investments included for the CIS Replacement project are $19.9 million for 2016-2020.

In-Service Additions

The change in the year-end net book value ("NBV") of Property, Plant & Equipment ("PP&E") from 2012 to 2020 is summarized in Table 1 below.

Table 1: PP&E NBV Change 2011 to 2020 ($ Millions)

	Actual December 31,2011	Forecast December 31,2020	Change	% change	Average Annual % Change
Gross Cost	$937.5	$2,154.8	$1,217.3	130%	14%
Contributed Capital	($244.7)	($457.1)	($212.4)	87%	10%
PP&E Net Cost	$692.8	$1,697.7	$1,004.9	145%	16%
Accumulative Depreciation	($32.3)	($451.8)	($419.5)	1299%	144%
PP&E Net Book Value	$660.5	$1,245.9	$585.4	89%	10%

Notes:
Annual percent change is on a compounded basis.
Gross cost is the in-service fixed asset additions with non-distribution assets removed and renewable generation connection rate protection funded assets removed.

Table 2 below summarizes the in-service additions consisting of the Capital Expenditures, described in the Distribution System Plan ("DSP"), Exhibit G, Tab 2, plus an adjustment for opening and closing Work in Progress ("WIP").

Table 2: In- Service Additions ($ Millions)

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Opening Work in Progress	$23.5	$37.9	$47.6	$59.9	$38.4	$54.0	$41.3	$43.4	$34.8
Capital expenditures per DSP	$74.8	$93.7	$108.2	$118.4	$132.9	$131.6	$125.5	$125.5	$125.5
Closing Work in Progress	$37.9	$47.6	$59.9	$38.4	$54.0	$41.3	$43.4	$34.8	$33.6
In- service additions	$60.4	$84.0	$95.9	$139.9	$117.3	$144.3	$123.4	$134.1	$126.7

Table 3 below is a summary of the opening and closing net fixed assets and rate base net fixed assets.

Table 3: Rate Base Net Fixed Assets ($ Millions)

					TEST YEARS				
	2012	2013	2014	2015	2016	2017	2018	2019	2020
Opening Balance Cost - Jan 1	$692.8	$753.5	$835.9	$927.8	$1,065.5	$1,180.1	$1,321.7	$1,442.4	$1,573.8
In- service PP&E Additions	$60.4	$84.0	$95.9	$139.9	$117.3	$144.3	$123.4	$134.1	$126.7
Retirements	$0.3	($1.6)	($4.0)	($2.2)	($2.7)	($2.7)	($2.7)	($2.7)	($2.7)
Closing Balance Cost - Dec 31	$753.5	$835.9	$927.8	$1,065.5	$1,180.1	$1,321.7	$1,442.4	$1,573.8	$1,697.8
Opening Net Fixed Assets	$660.1	$686.1	$733.9	$788.3	$884.1	$951.3	$1,041.6	$1,108.1	$1,182.3
Closing Net Fixed Assets	$686.1	$733.9	$788.3	$884.1	$951.3	$1,041.6	$1,108.1	$1,182.3	$1,245.9
Rate Base Net Fixed Assets	$672.9	$710.0	$761.1	$836.2	$917.7	$996.5	$1,074.9	$1,145.2	$1,214.1

The detailed PP&E continuity schedule is provided as supplemental information in electronic Appendix G-2a-1.

ICM True-up and Addition of ICM Assets to Rate Base

In its 2014 Incentive Regulation Mechanism ("IRM") rate application (EB-2013-0166), PowerStream received approval for additional capital funding through an Incremental Capital Module ("ICM"). PowerStream has included the actual capital additions into rate base and calculated a true-up of the rate riders received. This is discussed in the following sections:

1. Details of ICM Approval
2. Actual vs. Approved Amounts
3. True-up Process

1. Details of ICM Approval:

The terms of the approved settlement agreement ("Settlement") in EB-2013-0166 included an eligible incremental capital amount of $11,326,840 and incremental revenue requirement of $834,037. Under the terms of the Settlement, PowerStream agreed to a "true-up" process at the next Cost of Service or Custom IR application: "This will take into account actual spending, in-service dates, and prudence. This is anticipated to be similar to the Board's policy and practice on Smart Meter cost recovery."[1]

The eligible incremental capital amount of $11,326,840, and the associated revenue requirement of $834,037, represented a ratio of 33.43% of five ICM eligible projects totalling $33,886,187.

The ratio of 33.43% was used to reduce the eligible capital project amounts to match the eligible incremental capital amount. Correspondingly, this ratio was applied to reduce the amortization and CCA amounts from the individual Incremental Capital Project Summary models, one for each project, that were entered into the Incremental Capital Workform. This is summarized in Table 1 below.

[1] EB-2013-0166 Decision and Rate Order, February 20, 2014, Appendix A, Settlement Agreement, Page 8, available at:
http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/426105/view/

Table 1: Derivation of ICM Workform Amounts

Per Incremental Capital Project Summary Workforms:				
#	Project Description	Incremental Capital CAPEX	Amortization Expense	CCA
ICP 1	Underground Cable Rehabilitation	$20,183,168	$451,251	$1,614,653
ICP 2	Pole Replacements	4,775,873	109,181	382,070
ICP 3	Station Replacements	1,062,733	38,140	85,019
ICP 4	Switchgear and Transformer Replacement	3,931,290	90,092	314,503
ICP 5	System Capacity Relief	3,933,123	90,911	314,650
	Total	$33,886,187	$779,575	$2,710,895
INPUT TO INCREMENTAL CAPITAL WORKFORM FOR 2014 FILERS:				
#	Project Description	Incremental Capital CAPEX	Amortization Expense	CCA
ICP 1	Underground Cable Rehabilitation	$6,746,451	$150,836	$539,716
ICP 2	Pole Replacements	$1,596,389	$36,495	$127,711
ICP 3	Station Replacements	$355,230	$12,749	$28,418
ICP 4	Switchgear and Transformer Replacement	$1,314,078	$30,114	$105,126
ICP 5	System Capacity Relief	$1,314,691	$30,388	$105,175
	Total	$11,326,840	$260,582	$906,147
	Ratio	33.43%	33.43%	33.43%

The amounts shown above in the bottom section of Table 1 were entered into the Incremental Capital Workform for 2014 Filers resulting in the incremental revenue requirement of $834,037 used to calculate the Incremental Capital rate riders.

2. Actual vs. Approved Amounts:

PowerStream has tracked the actual spending on these projects and when the assets went into service. The approved and actual amounts are summarized in Table 2 below:

Table 2: Actual Incremental Capital Spending and In-Service

#	Project Description	Approved CAPEX	Actual CAPEX	Variance
ICP 1	Underground Cable Rehabilitation	$20,183,168	$20,989,023	($805,855)
ICP 2	System Renewal - Pole Replacements	4,775,873	$4,948,885	($173,012)
ICP 3	System Renewal - Station Replacements	1,062,733	$966,717	$96,016
ICP 4	System Renewal - Switchgear and Transformer Replacement	3,931,290	$3,910,185	$21,105
ICP 5	System Capacity Relief	3,933,123	$1,958,990	$1,974,133
	Total	$33,886,187	$32,773,799	$1,112,388

As shown in Table 2, PowerStream has carried out the incremental capital work substantially as budgeted and approved in the 2014 IRM rate application. Actual spending was lower than approved spending by $1.1 million or 3.3%. This is mainly due to the deferral of a large job in ICP 5 System Capacity Relief category.

Actual spending on underground cable rehabilitation was $805,855 or 4% higher than budgeted. PowerStream was able to accomplish the planned rehabilitation by doing more cable injection and slightly less replacement. PowerStream has had good experience with cable injection and has found ways to use it in more situations to reduce costs while being able to address more cable. PowerStream remediated 139 km of cable compared to 119 km of cable that was planned.

Actual spending on pole replacement was higher than budget by $173,000 or 3.6%. PowerStream introduced a new method of pole remediation – pole reinforcement. PowerStream was successful in reinforcing 14 poles that would have been slated for replacement. This method costs approximately 20-25% of the cost of replacement. Because of this, PowerStream was able to remediate 451 poles compared to 400 Poles as planned with a small increase in spending over budget.

Actual spending on station replacements was slightly lower than budget by $96,000 or 9.0% due to a lower than estimated cost for the replacement of the Markham TS#1 circuit breaker.

Actual spending on switchgear and transformer replacement was lower than budget by $21,000 or 0.5% due to a lower than estimated cost for this project.

Actual spending on system capacity relief was lower than budget by $1,974,000 or 50.1% due to the deferral of a pole line project near the Buttonville Airport, in Richmond Hill. Due to planned closing of the airport, PowerStream determined that it is best to wait until the airport is closed. At that time the requirements will be different and this can be done at lower cost.

3. True-up Process:

PowerStream has calculated the actual revenue requirement and the true-up amount when compared to the incremental capital funding rate riders collected from customers. Table 3 below summarizes the results.

Table 3: ICM True-Up Summary

	2014	2015	Total
Revenue Requirement	$ 1,079,600	$ 1,079,600	$ 2,159,200
Interest on deferred amortization expense	$ 2,543	$ 7,629	$ 10,172
Subtotal A	$ 1,082,143	$ 1,087,229	$ 2,169,372
Less:			
ICM Funding adders	$ 927,500	$ 928,000	$ 1,855,500
Interest on ICM Funding adders	$ 5,000	$ 19,887	$ 24,887
Subtotal B	$ 932,500	$ 947,887	$ 1,880,387
ICM True-up Amount (A-B)	$ 149,643	$ 139,342	$ 288,985

Note: ICM rate adders for 2015 are forecast

PowerStream proposes to collect the ICM true-up amount of $288,985 over a period of one year from January 1, 2016 to December 31, 2016. This amount has been included in the Deferral and Variance Account balances for disposition in Exhibit N, Tab 1.

The ICM True-up model is available as Supplemental information electronic document G-2b-1, ICM True-up model.

WORKING CAPITAL ALLOWANCE

In accordance with the Board's most recent Chapter 2 Filing Requirements for Distribution Rate Applications, dated July 18, 2014, at section 2.5.1.3, PowerStream continues to apply the 13% working capital allowance (WCA) factor to the sum of the Cost of Power and Controllable OM&A Expenses. The 13% WCA factor is applied throughout the five test years in this application. Table 1 below shows the changes in working capital allowance from 2013 to 2020.

Table 1: Working Capital Allowance from 2013 to 2020

	Board Approved	Historic Actual			Bridge Year	TEST YEAR 1	TEST YEAR 2	TEST YEAR 3	TEST YEAR 4	TEST YEAR 5
	2013	2012	2013	2014	2015	2016	2017	2018	2019	2020
	$ 000	*$ 000*	*$ 000*	*$ 000*	*$ 000*	*$ 000*	*$ 000*	*$ 000*	*$ 000*	*$ 000*
Cost of Power	857,780	799,483	880,223	925,280	995,940	1,103,218	1,111,266	1,158,754	1,184,080	1,203,134
OM&A Controllable Expenses	80,000	82,793	80,849	85,454	92,558	96,216	98,112	99,920	102,195	104,193
TOTAL FOR WORKING CAPITAL CALCULATION	937,780	882,276	961,072	1,010,734	1,088,498	1,199,434	1,209,378	1,258,674	1,286,274	1,307,328
Working Capital Allowance, %	*13.0%*	*13.0%*	*13.0%*	*13.0%*	*13.0%*	*13.0%*	*13.0%*	*13.0%*	*13.0%*	*13.0%*
Working Capital Allowance, $	**$121,911**	**$114,696**	**$124,939**	**$131,395**	**$141,505**	**$155,926**	**$157,219**	**$163,628**	**$167,216**	**$169,953**

See Exhibit G, Tab 4 for details regarding the cost of power. See Exhibit J for details regarding OM&A expenses.

COST OF POWER FORECAST

Introduction

PowerStream's cost of power serves as one of the inputs in calculating the Working Capital Allowance that is included in rate base.

The cost of power consists of the following components:

- Commodity Cost
- IESO related charges
- Hydro One related charges

The forecasts for the 2016 - 2020 Test Years were derived by applying the appropriate unit cost of power, IESO related charges and Hydro One charges to the forecasted energy sales (kWh) and demand (kW).

Commodity Cost

The commodity costs for the 2016 - 2020 Test Years were calculated by multiplying the forecasted Monthly kWh Purchases to the forecasted Commodity Price for the Test Years and split between RPP and Non-RPP customers.

- Monthly kWh Forecast
  - The forecasted Monthly kWh Purchases is derived by multiplying the forecasted monthly sales to the proposed Line Loss Adjustment Factor. The proposed Line Loss Adjustment Factor is discussed in Exhibit M, Tab 4.
  - The Forecasted Monthly kWh Purchase is split between RPP and Non-RPP customers based on the actual consumption data in 2014.

- Commodity Price Forecast
  - For the 2016 - 2020 Test Years, given the challenges and risks in predicting future commodity prices, PowerStream has decided to use the commodity price forecasted by the OPA and provided in its Cost of Electricity Service – 2013 Long Term Energy Plan (Module 4) published in January 2014. The OPA's long term commodity price forecast takes into account impact from a multitude of variables, including among others, natural gas prices, input fuel cost for nuclear facilities, load forecast, supply mix, and CDM activities.
  - Table 1 provides All-In Electricity Rates in real 2012 dollars which includes both the HOEP and the Global Adjustment. All-In Electricity Rates in nominal dollars are then derived by applying an annual compounded inflation rate of 2% to the real 2012 dollar. All-In Electricity Rates in nominal dollars are used as the forecasted Non-RPP rates.

Table 1: All-In Electricity Rates 2016-2020 $/kWh

	2016	2017	2018	2019	2020
All-In Electricity Rate in Real $ 2012	0.0980	0.0970	0.1000	0.1010	0.1010
All-In Electricity Rate in Nominal $	0.1061	0.1071	0.1126	0.1160	0.1183

  - The forecasted RPP rates are derived by applying a historical average ratio (between RPP rate to Non-RPP rate) to the forecasted Non-RPP rates. The ratio of the RPP to Non-RPP rate was calculated using the rates from the semi-annual Regulated Price Plan (RPP) Price Reports issued by the Board over the period from May 2009 to November 2014.

IESO Related Charges

- ***Transmission Network*** demand forecast is derived by applying a historical average ratio to the total energy purchase forecast for 2016 - 2020. This historical average ratio is calculated between the total system demand in kW and the total energy purchase in kWh over the period from 2012 to 2014. The forecasted transmission network rates for 2016 – 2020 are based on the 3 year average growth ratio from 2012 to 2014.

- ***Transmission Connection*** incudes Transmission Line Connection and Transmission Transformation Connection. The average ratios in the last 3 years (2012 – 2014) were calculated between Transmission Line Connection demand and total system demand, and between Transmission Transformation Connection demand and system demand. These historic ratios were then applied to the forecasted total system demand to obtain the Transmission Line Connection and Transmission Transformation Connection demand projections. The forecasted transmission connection rates are based on the 3 year average growth ratio from 2012 to 2014.

- ***Wholesale Market Service (‘WMS”) and Rural or Remote Electricity Rate Protection (“RRRP”)*** for the 2016 - 2020 Test Years, were determined by using the most recent WMS and RRRP rate approved by the Board:

    - The WMS rate of $ 0.0044/kWh and RRRP rate of $0.0013/kWh in the rate order (EB-2014-0347) was applied to the Test Years.

- ***Smart Metering Entity Charge (SME)*** is effective from May 1, 2013 to October 31, 2018, at the rate of $0.788 per month for each Residential and General Service < 50 kW customer (EB-2012-0100). Smart Metering Entity Charge amounts were forecasted by applying the $0.788/kWh charge to forecasted customer counts (in year-end format) for Residential and General Service < 50 kW respectively, from 2016 to October 2018.

Hydro One Related Charges

- ***Transmission Network*** demand forecast is derived by applying a historical average ratio to the total energy purchase forecast for the Test Years. This historical average ratio is calculated between the total system demand in kW and the total energy purchase in kWh over the period from 2011 to 2013.

- ***Transmission Connection*** is comprised of Transmission Line Connection and Transmission Transformation Connection. The average ratios in the last 3 years (2011 – 2013) were calculated between Transmission Line Connection demand and system demand, and between Transmission Transformation Connection demand and system demand. These historic ratios were then applied to the forecasted system demand to obtain Transmission Line Connection and Transmission Line Transformation Connection projections.

- ***Hydro One Sub-Transmission ("ST")*** class rates are applied to the relevant transmission quantities noted above to obtain the Hydro One Transmission component of cost of power. The ST rates used for the Test Years were based on Hydro One proposed rates in its 2015-2019 Custom IR Application (Exhibit G1, Tab6, Schedule 1) filed with the Board on May 30, 2014.

- ***Low Voltage ("LV")*** demand forecast is derived by applying a historical average ratio to the forecasted system demand for the Test Years. This historical average ratio is calculated between the LV demand and system demand over the period from 2011 to 2013. The forecasted LV rate reflected Hydro One's 2015 - 2019 Custom IR Application filed with the Board on May 30, 2014.

Overall Cost of Power

The cost of power forecast by account and full month-by-month development of the cost of power is provided as supplementary information in electronic Appendix G-4-1.

2016 Update

PowerStream proposes that the commodity and Global Adjustment rates for RPP and non-RPP customers be updated to reflect the most current parameters in the RPP Price Reports and Ontario Wholesale Electricity Market Price Forecast, which are to be issued by the Board in the fall of 2015.

Annual Adjustments

PowerStream proposes that the Cost of Power forecast for the 2017 - 2020 Test Years be adjusted annually to reflect the most updated rates comprised of:

- Energy and Global Adjustment rates for RPP and non-RPP customers per the semi-annual RPP Price Reports and Ontario Wholesale Electricity Market Price Forecast issued by the Board;
- Uniform Transmission Rates per the IESO and Hydro One Networks Inc.;
- IESO Rates – WMS, RRRP, SME; and
- Hydro One Low Voltage rate.

LOAD FORECAST

Introduction

In its 2013 Cost of Service Application (EB-2012-0161), PowerStream forecasted sales using a "top-down" approach. This entailed forecasting total monthly system purchases and then allocating purchases to rate classes. The forecast was derived using a linear regression model where system purchases were defined as a function of weather conditions, measured in cooling-degree-days ("CDD") and heating-degree-days ("HDD"), and Ontario GDP as a proxy for service area customer growth and economic activity. Resulting forecasted system purchases, after adjusting for total losses, were then allocated to each rate class based on the class' historical share of total sales.

Striving for continuous improvement, PowerStream has since developed and is now proposing a new forecasting approach to load, customers and connections for this Application. The new approach, developed in MetrixND, forecasts class-specific sales based on multifactor regression models. Monthly rate class sales models incorporate economic drivers (and for residential an energy efficiency measure) that are most relevant to the specific customer class. Modeling sales at the rate class level allows PowerStream to account for differences in sales trends across customer classes and capture what truly drives sales growth (or decline) in the individual rate classes. The new approach results in an enhanced billing determinant forecast which leads to improved accuracy of rate setting for each rate class.

MetrixND, supported by Itron Inc., is widely used by utilities and energy companies primarily in the United States and Canada, and has been accepted by the Board in previous distribution rate applications.

Forecasting Methodology

The forecast is based on monthly rate class sales. Separate monthly models are estimated for each rate class, including Residential, General Service < 50 kW, General Service > 50 kW, Sentinel Lighting and Street Lighting. Models are estimated with monthly sales data over the period from January 2008 to December 2014, providing 84 monthly observations. Model variables include a primary economic driver, an energy intensity trend variable in the Residential model, HDD, CDD, and binary variables to account for non-weather related load variation and large data point outliers.

The estimated models are statistically strong. The primary economic drivers in the Residential, General Service < 50 kW and General Service > 50kW are all statistically significant at the 95% level of confidence. The model Adjusted R-Squared, measuring how well the model explains historical sales variation (with 1.0 being perfect), varies from 0.84 in the General Service > 50 kW sales model to 0.91 in the Residential sales model.

Large Use and Unmetered Scatter Load were forecasted outside the regression model. The load forecast for these two rate classes were developed based on historical averages. The forecasting methodology for these two classes is provided as supplementary information in electronic Appendix H-1-3.

Forecast Drivers

Economic Variables

The economic drivers are based on the Conference Board of Canada's December 2014 economic forecast for the Toronto Census Metropolitan Areas ("CMA"). The data set includes historical and forecasted economic data for Toronto CMA; PowerStream's service territory falls within the Toronto CMA. As part of the model estimation process, PowerStream evaluated a number of different economic variables in Toronto CMA including population, household income, employment, total and manufacturing GDP. The final economic drivers are those that best explained historical sales variation as measured by the regression model statistics. For the purpose of modeling and comparing forecast drivers, the economic variables were indexed to January 2008. The Economic Data set is provided as supplementary information in electronic Appendix H-1-1.

The Residential sales model also includes an energy intensity estimate to capture the downward trend in customer usage. Since 2010, while customers have been increasing at an approximately 2.0% annual rate, sales have averaged just about 1.0% annual growth; average use has been declining by 1.0% per year. While past Conservation & Demand Management ("CDM") has contributed to the declining usage, customer usage has been trending down well before any significant CDM activity. Declining customer usage has largely been driven by energy efficiency improvements that are the result of naturally occurring replacement of less efficient appliances, new appliance and lighting efficiency standards, and improving housing shell efficiency.

To capture improving energy efficiency, the Residential forecast model includes an energy intensity variable ("EI"), measured in kWh per household. The historical and forecasted intensity index was developed by Itron based primarily on the OPA's recent long-term energy forecast *(OPA Long-Term Energy Plan 2013).* The EI projection reflects OPA historical and forecasted end-use saturation and projected improvements in end-use efficiency before CDM adjustments. Lighting intensity and thermal shell improvement factors are based on the Energy Information Agency ("EIA") 2014 Annual Energy Outlook. Itron felt the OPA lighting intensity decline was too strong and the OPA did not have an available thermal shell index. Electronic Appendix H-1-2 provides detailed schedules of the constructed EI variable.

Residential: the Residential load forecast regression model is best explained by combining population, per capita income and energy intensity.

- Population: Change in population in Toronto and the GTA has a direct impact on PowerStream's customer base. The annual population growth for Toronto CMA averaged 1.7%; PowerStream customer growth has been tracking this trend.

- Per Capita Income: Personal per capital income captures customers' response to changing economic conditions. Increase in per capita income translates into higher electricity consumption.

- Energy Intensity: The energy intensity variable reflects changes in end-use saturation, and end-use stock and thermal shell efficiency improvements. End-use intensities are calculated by combing end-use saturation, end-use efficiency indices, and thermal shell efficiency indices (for heating and cooling). Household energy intensity has been declining as end-use efficiency has been improving faster than end-use saturation growth.

General Service < 50 kW: General Service < 50 kW sales are strongly correlated with GDP. The GDP model coefficient is statistically significant at the 95% level of confidence with an implied elasticity of 0.24 - a 1.0% change in GDP will result in a 0.24% change in sales.

General Service > 50 kW: the General Service > 50 kW is most strongly correlated with Manufacturing GDP. The General Service > 50 kW model was evaluated using both GDP and Manufacturing GDP. The model statistics are significantly stronger with Manufacturing GDP. The Manufacturing GDP variable is statistically significant at the 95% level of confidence with an estimated elasticity of 0.30; this implies a 1.0% change in Manufacturing GDP will result in a 0.30% change in sales.

Weather Variables

Month to month sales variation is largely related to changes in heating and cooling load requirements. This variation is captured with monthly heating-degree days ("HDD") and cooling-degree days ("CDD"). HDD and CDD are often referred to as spline variables as HDD only take on a positive value when temperatures are below a base temperature, and CDD only take on a positive value when temperatures are above a base temperature. Based on its analysis of daily purchases and average daily temperatures, PowerStream found that cooling-related demand began when temperatures exceeded 18 degrees and heating-related demand began when temperatures fell below 10 degrees.

For each day (d), CDD is calculated as:

- *CDD_d = (average temperature$_d$ – 18), if average daily temperature is above 18 degrees*
- *CDD_d = 0, if temperature is 18 degrees or below*

The monthly CDD are calculated by summing the daily CDD for that month.

For each day (d), HDD is calculated as:

- *HDD_d = (10 – average temperature), if average daily temperature is below 10 degrees.*
- *HDD_d = 0, if temperature is 10 degrees or above*

The monthly HDD are calculated by summing the daily HDD for that month.

The forecast is based on normal HDD and CDD. Normal monthly HDD and CDD are calculated by averaging the historical monthly HDD and CDD over a ten-year period. Normal HDD and CDD are based on weather data over the period from 2005 to 2014. Actual and normal degree-days are derived from historical temperature data for Toronto Lester B. Pearson International Airport. The data was obtained from Environment Canada's website.

Other Model Variables

The class-specific regression models also include the following variables:

- Number of days: The number of days in the month is statistically significant in the General Service < 50 kW and General Service > 50 kW models. The Days variable acts like a regression model constant; the more days in a month, the greater the sales.

- Hours of Light: Daily hours of light for the years from 2008 through to the 2020 Test year were used as input variable to forecast Street Lighting sales. The daily hours of light were calculated based on the sunrise and sunset times derived from relevant geographic co-ordinates for PowerStream service area. The calculated daily hours of light were verified by the model provided by National Oceanic & Atmospheric Administration.

- Monthly Binaries: Monthly binary variables are used to account for monthly sales variation that cannot be explained by weather alone. For example, the binary variable "Nov" is 1 when it is November and 0 in all other months; the variable "Nov" is used in the Residential sales model.

- Observation-specific binaries: Binaries for specific months are used to account for large outliers. Month-specific binaries minimize the weight these outliers have on the forecast and primary model derivers. The variable "Jan08", for example, is 1 in January 2008, and is 0 in all other months. Jan08 is used in the Residential sales forecast model.

CDM Adjustments

As the forecast models are estimated with actual sales data, the forecast models capture the impact of all past CDM program activity including measure persistency. The forecast is only adjusted for future CDM activity beginning in January 2015. Expected savings from future CDM programs are subtracted from the baseline forecasts derived from the estimated regression models. The CDM adjustments to load forecast are discussed in Exhibit H, Tab2.

Weather Normalization

PowerStream performed an analysis by comparing the average monthly HDD and CDD between 2005 to 2014 and 1995 to 2004. The result is showing an average monthly decline in HDD which would suggest that the weather during colder months is becoming warmer. The result also shows that the average monthly CDD is rising which would suggest that the weather during warmer months is getting warmer.

PowerStream believes that the 10-year average HDD and CDD are reasonable estimates of expected near-term weather conditions. PowerStream proposes that “normal” weather conditions are defined using the most current ten year-period, 2005-2014. This approach has been approved by the Board in the recent distribution rate applications submitted by other LDCs.

Forecast Results

PowerStream developed regression models, using the input variables and methodology described earlier, to forecast future loads for each of the customer classes including Residential, General Service < 50 kW, General Service> 50 kW, Sentinel Lighting and Street Lighting, over the Bridge and Test Years.

To assess the robustness of the regression models and the accuracy of the results, key model statistics such as Adjusted R-Square, Mean Absolute Percentage Error (MAPE), Durbin-Watson Statistic, T-Statistic and P-Value are discussed in details for each of the class-specific regression model as supplementary information in electronic Appendix H-1-3.

Table 1 summarizes the weather normalized historical and forecast sales before and after the CDM adjustments.

Table 1: Weather Normalized Historical and Forecast Result (GWh)

Years	Weather Normalized Actual/Forecast before CDM Adjustment	% Change	CDM Adjustment	Weather Normalized Actual/Forecast after CDM Adjustment	% Change
2008	8,552			8,552	
2009	8,205	-4.05%	-	8,205	-4.05%
2010	8,225	0.23%	-	8,225	0.23%
2011	8,339	1.39%	-	8,339	1.39%
2012	8,476	1.65%	-	8,476	1.65%
2013	8,507	0.36%	-	8,507	0.36%
2014	8,498	-0.09%	-	8,498	-0.09%
Average 2010 -2014		**-0.09%**			
2015 Bridge Year	8,519	0.24%	26.04	8,493	-0.06%
2016 Test Year	8,594	0.87%	84.68	8,509	0.19%
2017 Test Year	8,643	0.58%	157.71	8,486	-0.28%
2018 Test Year	8,711	0.78%	248.13	8,463	-0.27%
2019 Test Year	8,791	0.92%	356.24	8,435	-0.33%
2020 Test Year	8,876	0.97%	464.53	8,412	-0.27%
Average 2015 - 2020		**0.73%**			**-0.17%**

The Conference Board forecasts moderate economic growth for the Toronto CMA over the next five years. Economic projections coupled with end-use efficiency improvements in the residential sector results in 0.73% annual sales growth through 2020. Economic-driven sales growth is largely offset by expected savings from future CDM activities.

CDM ADJUSTMENT TO LOAD FORECAST

On November 13, 2014, PowerStream became the first distribution company to sign on to the Ministry of Energy's Conservation First framework for 2015 – 2020. Under the new six-year framework, announced early in 2014 by Bob Chiarelli, Minister of Energy, Ontario's distribution companies are responsible for achieving a combined target of 7,000 gigawatt-hours ("GWh") of energy savings by 2020. This represents approximately a 5% reduction in provincial electricity consumption compared to current levels.

Based on the multi-year conservation agreement signed on November 13, 2014, PowerStream's new conservation target is to achieve a 535 GWh reduction for its service territory by 2020 – equivalent to taking more than 61,000 homes off the grid for one year.

On December 18, 2014, PowerStream submitted its 2015 -2020 CDM Plan ("the Plan") to the OPA in advance of the May 1, 2015 deadline that all distribution companies in Ontario must adhere to for submitting their plans to the OPA. The Plan outlines how PowerStream will achieve the new conservation target of 535 GWh over 2015 to 2020.

The Plan includes a comprehensive mix of conservation programs to be made available to various types of customers including residential, commercial and industrial customers. Many of the province wide CDM programs designed and funded by the OPA under the 2011-2014 framework will continue to be available to LDCs under the 2015-2020 framework. PowerStream anticipates that these existing provincial programs, along with some planned enhancements, will continue to contribute the majority of savings within the program portfolio. The Plan also calls for new and innovative local programs to supplement the provincial programs. PowerStream must obtain approval from the IESO for any local program (through a separate business case submission and review process) prior to introducing a new program to the marketplace.

The annual CDM savings forecast over 2015 – 2020 was developed at a program level based on inputs from several sources including: CDM achievable potential study conducted by the OPA, PowerStream's historical CDM results, market research, input from third party consultants and CDM management staff. The key steps in developing the CDM savings forecast were as follows:

Step 1 – Provincial Programs. Savings were forecasted by estimating the annual participation levels (e.g. number of projects or participants) for each continuing Provincial Program and multiplying the participation forecast by the average savings per project achieved in the program historically.

Step 2 – Anticipated Enhancements to Provincial Programs. Energy savings for anticipated enhancements to the Provincial Programs during the 2015-2020 timeframe were developed based on a review of similar program design elements in other jurisdictions. Based on steps 1 and 2, PowerStream estimates that Provincial Programs (including planned enhancements) will contribute energy savings amounting to approximately 64% of its six-year CDM target.

Step 3 – New Programs. In its CDM Plan submission to IESO, PowerStream identified five concepts for new CDM programs. The detailed program design and business cases for these programs are yet to be developed and approved by the IESO. For the purposes of its CDM Plan, PowerStream made a high level estimate of potential energy savings based on a review of similar programs in other jurisdictions. The delivery costs for the programs were then estimated by multiplying the forecasted energy savings by the 'budget rates' (i.e. $310/MWh for residential programs; $240/MWh for non-residential programs) used by the IESO in allocating PowerStream its overall CDM delivery budget of $140.7 Million.

Step 4 – Shortfall. Based on all planned CDM programs (current provincial programs, planned enhancements to provincial programs, and new programs), PowerStream estimates achieving about 75% of its 2020 CDM target. In its CDM Plan, PowerStream has identified 131 GWh (25% of target) as a current shortfall. PowerStream plans to achieve 100% of its IESO-allocated target and will continue to explore and develop new program ideas for addressing this shortfall.

The forecasted savings derived from the 2015-2020 programs are incremental to the existing projects installed during the 2011–2014 frameworks. Energy savings from 2011-2014 programs that persist into 2015 and beyond will not count toward PowerStream's 2020 CDM Target of 535 GWh.

As a part of the Chapter 2 Filing Requirements, Appendix 2-I is provided as supplementary Information in electronic Appendix H-2-1. It provides the annual CDM savings for the current CDM framework from 2011 to 2014, including the OPA's verified results up to 2013 and forecasted savings for 2014. The impacts of 2011- 2014 CDM programs were already implicitly reflected and embedded in the actual sales data that are the basis for the regression load forecast. Any incremental CDM savings from the new six year (2015-2020) of CDM programs are manually subtracted from the regression load forecasting results.

It is recognized that the CDM projects installed in a year are not in effect for the full year, although persistence of prior years' projects will be. Therefore, the actual impact on the load forecast for the first year of a project should not be the full annualized amount. PowerStream adopted a "half-year" rule on the load impact resultant from the CDM projects implemented in a particular year. For example, for projects installed in 2015, only 50% of the expected annual savings are assumed to impact the 2015 load forecast based on the "half-year" rule. Table 2 provides the expected cumulative CDM savings for each year under the "half-year" rule.

Table 2: Cumulative CDM Savings in kWh (Half-Year Rule)

6 Year (2015-2020) kWh Target:							
535,400,000							
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
2015 CDM Programs	1.95%						1.95%
2016 CDM Programs		2.44%					2.44%
2017 CDM Programs			3.28%				3.28%
2018 CDM Programs				5.07%			5.07%
2019 CDM Programs					5.19%		5.19%
2020 CDM Programs						5.31%	5.31%
Total in Year	**1.95%**	**2.44%**	**3.28%**	**5.07%**	**5.19%**	**5.31%**	**23.23%**
kWh							
2015 CDM Programs	26,039,043	52,078,087	52,078,087	52,078,087	51,351,325	51,351,325	284,975,955
2016 CDM Programs		32,602,676	61,770,326	61,770,326	61,770,326	61,043,564	278,957,217
2017 CDM Programs			43,861,543	66,489,632	66,489,632	66,489,632	243,330,440
2018 CDM Programs				67,792,152	107,183,019	107,183,019	282,158,191
2019 CDM Programs				-	69,449,813	107,495,108	176,944,921
2020 CDM Programs				-	-	70,968,675	70,968,675
Total in Year	**26,039,043**	**84,680,763**	**157,709,956**	**248,130,197**	**356,244,116**	**464,531,325**	**1,337,335,399**

These amounts were manually subtracted from the class – specific load forecasting results as incremental CDM savings.

With respect to future Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA"), the CDM adjustment applied in the 2015 – 2020 load forecast will be the basis for the LRAMVA and the LRAMVA balance will reflect the difference between estimated and actual CDM savings on a net basis.

CUSTOMER FORECAST

Under PowerStream's new forecasting approach, customer counts and connections forecasts are based on rate class-specific regression models. The monthly models relate the number of customers to factors strongly correlated with historical customer growth. The models are estimated using MetrixND. Detailed model statistics are provided as supplementary information in electronic Appendix H-3-1.

Residential customer counts are forecasted using a simple regression model that correlates customer counts to Toronto CMA population as published by the Conference Board of Canada. The correlation coefficient between Residential customer counts and Toronto CMA population is 0.99 with 1.0 being perfectly correlated.

General Service > 50 kW customer counts are strongly correlated with population. The correlation coefficient between General Service > 50 kW customer counts and population is 0.9 with 1.0 being perfectly correlated.

General Service < 50 kW customer counts are strongly correlated with Residential customer counts. The correlation coefficient is 0.98. The General Service < 50 kW customer forecast model relates General Service < 50 kW customers to Residential customers; the Residential customer forecast is then used to drive the General Service < 50 kW commercial customer forecast. The model coefficient is statistically significant at the 95% level of confidence with an estimated elasticity of 0.55 - a 1.0% change in Residential customer counts results in a 0.55% change in General Service < 50 kW customer counts.

Street Lighting connections are forecasted using a simple regression model that correlates street lighting unit to the number of residential customers. Unmetered Scattered Load and Sentinel Lighting customer forecasts are generated using a simple linear trend model. PowerStream does not expect to add any additional Large Use customers. Large Use customers are held constant throughout the 2015 Bridge to 2020 Test Year.

The class–specific customer/connection forecast models track historical customer counts well. Table 3 compares actual and predicted customer counts and connections for 2011 to 2014.

Table 3: Historical Actual vs. Predicted Customer Counts/Connections

	Customer Counts			Connections		
Year	**Actual**	**Predicted**	**Var %**	**Actual**	**Predicted**	**Var %**
2011	335,935	335,809	-0.04%	80,969	81,080	0.14%
2012	343,344	343,361	0.00%	82,520	82,666	0.18%
2013	349,797	349,422	-0.11%	84,418	84,455	0.04%
2014	356,461	356,633	0.05%	85,990	85,867	-0.14%

Estimated rate class customer forecast models are statistically strong and generate predicted estimates that are extremely close to actual customer counts. Given rate-class customer model performance, PowerStream is confident and hence submits that the class-specific customer and connection regression models are robust and appropriate tools for forecasting future customer counts and connections.

Customer growth has been highly correlated with population growth. PowerStream has been experiencing a steady customer growth rate averaging 2% over the 2008 – 2014 periods. The 2015 – 2020 growth rates average 1.7% per year. This is consistent with the Conference Board population forecast. Table 4 and 5 illustrate the growth rates over the historical and forecast periods.

Table 4: Historic Customer Counts and Growth Rate (2008 – 2014)

	2008	2009	2010	2011	2012	2013	2014
Customer Counts	314,357	320,869	328,589	335,935	343,344	349,797	356,461
Growth Rates		2.07%	2.41%	2.24%	2.21%	1.88%	1.91%

Table 5: Forecast Customer Counts and Growth Rate (2015 – 2020)

	2015	2016	2017	2018	2019	2020
Customer Counts	362,543	368,663	374,990	381,372	387,845	394,508
Growth Rates	1.71%	1.69%	1.72%	1.70%	1.70%	1.72%

Rate class actual (2010 to 2014) and forecasted customer counts (2015 to 2020) are provided as supplementary information in electronic Appendix H-3-2.

Billing Determinants

Using the results from the new forecasting approach to load, customers and connections, Tables 6 and 7 provide summaries of billing determinants based on forecasted load and customers/connections by rate class respectively.

Table 6: Billing Determinants - Forecasted Load by Rate Class

Rate Class	Unit	2015	2016	2017	2018	2019	2020
Residential	kWh	2,749,691,613	2,750,618,680	2,739,228,627	2,734,798,535	2,726,183,581	2,713,502,642
			0.03%	-0.41%	-0.16%	-0.32%	-0.47%
General Service < 50 kW	kWh	1,041,113,015	1,040,222,617	1,034,670,636	1,029,394,734	1,023,938,194	1,020,971,574
			-0.09%	-0.53%	-0.51%	-0.53%	-0.29%
Unmetered Scattered Load	kWh	13,806,616	14,169,725	14,542,385	14,924,845	15,317,364	15,720,206
			2.63%	2.63%	2.63%	2.63%	2.63%
General Service > 50 kW	kW	12,151,190	12,212,781	12,214,760	12,199,953	12,164,212	12,146,171
			0.51%	0.02%	-0.12%	-0.29%	-0.15%
Large Use	kW	151,945	150,807	149,679	148,561	147,454	146,357
			-0.75%	-0.75%	-0.75%	-0.75%	-0.74%
Street Lighting	kW	168,060	148,205	128,504	107,648	106,567	105,032
			-11.81%	-13.29%	-16.23%	-1.00%	-1.44%
Sentinel Lighting	kW	977	975	975	975	975	975
			-0.19%	-0.05%	-0.01%	-0.01%	0.00%

Table 7: Billing Determinants – Customers and connections

Rate Class	Unit	2015	2016	2017	2018	2019	2020
Residential	Customer Counts	322,324	327,907	333,673	339,480	345,362	351,406
General Service < 50 kW	Customer Counts	32,228	32,594	32,973	33,354	33,739	34,134
Unmetered Scattered Load	Customer Counts	2,943	3,006	3,077	3,160	3,255	3,363
General Service > 50 kW	Customer Counts	4,896	5,005	5,116	5,227	5,339	5,453
Large Use	Customer Counts	2	2	2	2	2	2
Street Lighting	Customer Connections	87,377	88,953	90,575	92,207	93,857	95,547
Sentinel Lighting	Customer Connections	209	207	207	207	207	207
Total	Customer Counts	362,393	368,514	374,841	381,223	387,696	394,358
			1.69%	1.72%	1.70%	1.70%	1.72%
Total	Customer Connections	87,586	89,160	90,782	92,414	94,064	95,754
			1.80%	1.82%	1.80%	1.79%	1.80%

The detailed variance analysis on weather normalized actual and forecasted load, customers and connections (Appendix 2-IA to the Board's Filling Requirements) is provided as supplementary information in electronic Appendix H-4-1.

OTHER OPERATING REVENUE

Other operating revenue is defined as sources of utility revenue other than Distribution Revenue. For the purposes of this presentation PowerStream categorizes other operating revenue into four main categories: Specific Service Charges; Late Payment Charges; Other Distribution Revenues; and Other Income or Deductions. PowerStream's accounting practices are consistent with OEB accounting guidelines and have not changed since the last cost of service application. For the purposes of this presentation, Table 1 summarizes other operating revenue amounts for each of the above categories. This is followed by some additional information for each of these categories.

Table 1: Other Operating Revenue

Other Operating Revenues ($)	2013 Board-Approved*	2013 Actuals	2014 Actuals	Bridge Year³	TEST YEAR 1	TEST YEAR 2	TEST YEAR 3	TEST YEAR 4	TEST YEAR 5
				2015	2016	2017	2018	2019	2020
Specific Service Charges	3,385,000	3,463,771	3,478,694	3,488,043	3,471,316	3,474,784	3,475,039	3,474,966	3,476,285
Late Payment Charges	2,500,000	1,923,553	2,182,713	2,022,227	2,038,288	2,076,532	2,045,682	2,053,501	2,058,572
Other Distribution Revenues	2,032,000	1,947,598	1,966,180	1,977,232	2,001,095	2,025,296	2,047,023	2,070,949	2,095,056
Other Income or Deductions	4,868,598	6,206,278	6,416,221	4,999,616	5,079,905	5,141,699	5,248,937	5,339,537	5,439,173
Total	**12,785,598**	**13,541,200**	**14,043,807**	**12,487,117**	**12,590,603**	**12,718,312**	**12,816,681**	**12,938,953**	**13,069,086**

* OEB 2013 Approved Budget is $ 9,844,598. Difference of $ 2,941,000 relates to Joint Services Revenue included in Other Operating Revenue.

Appendix A is a depiction of the Board's Appendix 2-H in Chapter 2 of the filing requirements for Price Cap filers, titled "Other Operating Revenue". Below is some additional information on the figures above.

Specific Service Charges

Specific Service Charges are Board-approved fixed rate charges. The current list of service charges with the applicable rates is listed in Appendix B. PowerStream is not proposing to alter the list or change the charges during the term of the Custom IR. The year over year changes in the forecast period are based on historical trends.

Late Payment Charges

The current late payment charge is at a rate of 1.5% per month (19.56% annually) on overdue accounts. This rate has not changed since PowerStream's last cost of service application and no change is proposed for the term of the Custom IR. The forecasted year to year changes are driven by historical trends.

Other Distribution Revenue

The main components of other distribution revenue are Standard Supply Service Administration charges, Retail Services Revenue and Rent from Electric Property.

Standard Supply Service Administration charges relates to an administrative charge of $0.25 per customer per month. This rate has not changed since the last cost of service application and no change is proposed for the term of the Custom IR. The forecasted year to year changes are driven by the forecasted change in number of customers.

Retail Services Revenue charges relate to billing services that PowerStream provides to its retailers. There have been no changes to the rates charged since the last cost of service application and no change is proposed for the term of the custom IR. The year to year changes are driven by the number of customers.

Rent from Electric Property relates to fees that PowerStream charges third parties to install apparatus onto poles. The fee is the Board's standard rate of $22.35/pole/year. There have been no changes to the rates charged since the last cost of service application and no change is proposed for the term of the Custom IR. The forecasted year to year changes are driven by historical trends.

Other Income or Deductions

This category cosists primarily of Joint Services Revenue and Miscellaneous Non-Operating Income.

Joint Services Revenue is included as a revenue item; the inclusion of joint service revenue is not consistent with the approach taken in PowerStream's 2013 cost of service application. In 2013 only the margin earned on the joint services provided was included in other income; going forward PowerStream is including all of the joint service revenue in other operating revenue and all joint service costs in OM&A. Forecasted year over year changes are driven by the rates specified in the joint service agreements and an estimated annual price escalation of 3% from 2016 onwards as stated in the joint service agreements. See also Supplemental Information electronic document I-1-1, Appendix 2-N, Shared Services and Corporate Cost Allocation.

Miscellaneous non-operating income relates to income earned on insurance claims caused by accidents that damage PowerStream's assets (e.g. poles). Forecasted year over year changes are based on historical trends.

The $1,571,000 decrease in other income or deductions in the 2015 Bridge Year compared to 2014 relates to a payout of a $600,000 surplus in health and dental benefits which was the direct result of changing carriers. In 2014 there was also a one time insurance claim received for $767,000 as a result of an assessment conducted in relation to the loss of assets. As a result of this assessment there was also a write down of fixed assets which resulted in a derecognition loss which was recorded in depreciation expense. Both of these items were extraordinary and the forecast going forward was normalized for the 2014 events.

Table 2 – Other Operating Revenue (Appendix 2-H)

USoA #	Description	2013 Board-Approved*	2013 Actuals	2014 Actuals	Bridge Year[3]	TEST YEAR 1	TEST YEAR 2	TEST YEAR 3	TEST YEAR 4	TEST YEAR 5
					2015	2016	2017	2018	2019	2020
	Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Special Service Charges										
4235	Service	**3,385,000**	**3,463,771**	**3,478,694**	**3,488,043**	**3,471,316**	**3,474,784**	**3,475,039**	**3,474,966**	**3,476,285**
Late Payment Charges										
4225	Payment	**2,500,000**	**1,923,553**	**2,182,713**	**2,022,227**	**2,038,288**	**2,076,532**	**2,045,682**	**2,053,501**	**2,058,572**
Other Distribution										
4078	Administra	932,400	968,592	996,403	1,014,425	1,032,693	1,051,477	1,070,630	1,089,911	1,109,662
4082	Services	399,600	234,984	212,405	216,247	220,141	224,145	228,228	232,339	236,549
4210	Electric	700,000	744,022	757,373	746,560	748,260	749,673	748,165	748,699	748,846
4245	nt & Other Assistanc	-	1,887,586	-	-	-	-	-	-	-
4245	nt & Other Assistanc e Directly Credited to	-	(1,887,586)	-	-	-	-	-	-	-
Sub total		**2,032,000**	**1,947,598**	**1,966,180**	**1,977,232**	**2,001,095**	**2,025,296**	**2,047,023**	**2,070,949**	**2,095,056**
Other Income or Deductions										
4324	Purpose Charge	-	(449)	-	-	-	-	-	-	-
4355	Dispositio n of Utility and Other	-	75,771	46,182	-	-	-	-	-	-
4362	Retirement of Utility and Other	-	(1,462,182)	(2,078,248)	(1,500,000)	(1,300,000)	(1,300,000)	(1,300,000)	(1,300,000)	(1,300,000)
4375	from Non Rate-Regulated	32,993,598	23,653,392	27,719,176	3,641,949	3,759,090	3,850,269	3,925,633	4,027,688	4,130,311
4380	from Non Rate-Regulated	(28,500,000)	(19,955,141)	(24,140,021)	-	-	-	-	-	-
4385	Regulated Utility	-	5,677	4,909	-	-	-	-	-	-
4390	ous Non-Operating	1,020,000	2,233,238	2,673,172	1,115,667	1,078,814	1,049,431	1,081,304	1,069,850	1,066,861
4405	Dividend Income	125,000	338,792	239,331	260,000	260,000	260,000	260,000	260,000	260,000
4420	Profit or Loss of	-	313,794	307,982	300,000	300,000	300,000	300,000	300,000	300,000
4324	Special Purpose Charge	-	449	-	-	-	-	-	-	-
4355	Gain on Dispositio n of Utility	-	(75,771)	(46,182)	-	-	-	-	-	-
4362	Loss from Retirement of Utility	-	1,462,182	2,078,248	1,500,000	1,300,000	1,300,000	1,300,000	1,300,000	1,300,000
4375	Revenues from Non Rate-	(29,270,000)	(20,019,143)	(24,215,458)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)
4380	Expenses from Non Rate-	28,500,000	19,955,141	24,140,021	-	-	-	-	-	-
4385	Non Rate-Regulated Utility	-	(5,677)	(4,909)	-	-	-	-	-	-
4420	Share of Profit or Loss of	-	(313,794)	(307,982)	(300,000)	(300,000)	(300,000)	(300,000)	(300,000)	(300,000)
Sub total		**4,868,598**	**6,206,278**	**6,416,221**	**4,999,616**	**5,079,905**	**5,141,699**	**5,248,937**	**5,339,537**	**5,439,173**
TOTAL		**12,785,598**	**13,541,200**	**14,043,807**	**12,487,117**	**12,590,603**	**12,718,312**	**12,816,681**	**12,938,953**	**13,069,086**

* OEB 2013 Approved Budget is $ 9,844,598. Difference of $ 2,941,000 relates to Joint Services Revenue included in Other Operating Revenue.

NOTES:

1 - For Revenue Offsets calculation, the amount in account 4245 are not included in Other Operating Revenues .

2 - For Revenue Offsets calculation, the amount in account 4105, 4110, 4230, 4305, 4324, 4355, 4362, 4375, 4380, 4385 & 4420 are not included in Other Income or Deductions .

3 - The amounts in account 4405 are net of interest on Regulatory Assets and interest on Customer Deposits

Table 3: Current List of Service Charges with Applicable rates

Customer Administration

Arrears certificate	$	15.00
Statement of Account	$	15.00
Duplicate Invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income Tax Letter	$	15.00
Account History	$	15.00
Returned cheque (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late Payment – per month	%	1.50
Late Payment – per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect at meter - during regular hours (for non-payment)	$	65.00
Disconnect/Reconnect at meter - after regular hours (for non-payment)	$	185.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Specific Charge for Access to the Power Poles - $/pole/year	$	22.35
Temporary Service – Install & remove – overhead – no transformer	$	500.00

OPERATIONS, MAINTENANCE AND ADMINISTRATION ("OM&A") EXPENSES

PowerStream has a detailed planning process for OM&A expenses which involves collaboration among all business units in the organization. The budget planning starts with a top down approach where budget targets are reviewed by the Budget Working Group and reviewed and approved by the Executive Management Committee and Board of Directors. A bottom up approach follows whereby the Corporate Finance team works with the business units to build a detailed OM&A budget for each year of the Custom IR term which includes future operational and business needs over the five year period. Please refer to Exhibit C for more information on Budget Assumptions.

PowerStream has attached summaries of OM&A expenses using the following OEB Chapter 2 Appendices, in the supplemental electronic information.

- J-1-1: Appendix 2-JA, Summary of Recoverable OM&A Expenses
- J-1-2: Appendix 2-JB, Recoverable OM&A Cost Driver Table
- J-1-3: Appendix 2-JC, OM&A Programs Table
- J-1-4: Appendix 2-L, Recoverable OM&A Cost per Customer and per FTE
- J-1-5: Appendix 2-M, Regulatory Cost Schedule
- J-1-6: Appendix 2-N, Shared Services

There have been no changes to the pricing methodology for the shared service agreements since PowerStream's 2013 Cost of Service filing.

Net incremental new costs from changing requirements

PowerStream has presented the cost drivers for net incremental new costs resulting from changing requirements in Table 1, below. This table highlights extraordinary events which have occurred that have increased OM&A expenses.

Table 1: Net Incremental New Costs for Changing Requirements and Extraordinary items

Total OM&A ($000's)	2013 Actual	2014 Actual	2015 Bridge Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year	2020 Test Year	2013 Actuals to 2015 Bridge Year	2016 to 2020 Test Years
Opening Balance *	**82,941**	**80,849**	**85,454**	**92,558**	**96,216**	**98,112**	**99,920**	**102,195**	**82,941**	**92,558**
-										
Compensation	(204)	538	2,508	1,136	267	745	787	901	2,842	3,837
Asset Management	(922)	1,949	579	472	578	364	416	369	1,605	2,199
Risk Management	(109)	330	757	518	485	(36)	138	(103)	978	1,002
Growth	(73)	59	144	369	140	232	87	106	131	935
Customer Expectation	95	754	(248)	58	25	25	25	25	602	158
Compliance	(361)	262	185	132	18	18	18	19	86	205
Other	(2,390)	929	1,464	482	15	110	265	139	4	1,011
Closing Balance-Business as usual	**78,977**	**85,670**	**90,844**	**95,724**	**97,745**	**99,571**	**101,657**	**103,650**	**89,188**	**101,904**
Year over year ($)		**6,693**	**5,173**	**4,881**	**2,021**	**1,826**	**2,086**	**1,993**	**Note 1**	**Note 2**
Year over year (%)		**8.5%**	**6.0%**	**5.4%**	**2.1%**	**1.9%**	**2.1%**	**2.0%**		
Extra-ordinary items										
Vegetation Management	1,872	(1,565)	403	614	526	531	536	542	710	2,749
CIS Implementation	-	1,349	1,310	(122)	(158)	(182)	1	1	2,659	(460)
Closing Balance-Business with Extra-ordinary items	**80,849**	**85,454**	**92,558**	**96,216**	**98,112**	**99,920**	**102,195**	**104,193**	**92,558**	**104,193**
Year over year ($)		**4,605**	**7,104**	**3,659**	**1,896**	**1,808**	**2,275**	**1,999**		
Year over year (%)		**5.7%**	**8.3%**	**4.0%**	**2.0%**	**1.8%**	**2.3%**	**2.0%**		

* The opening balance for the 2013 actual is 2013 OEB approved amount of $80,000,000 plus the inclusion of the joint services expenses of $2,941,000 that were not included in the 2013 OEB approved OM&A. In 2013 the net of joint services revenues and expenses were reported as Revenue Offsets. In this application the expenses are reported in OM&A and the full revenue in Revenue Offsets. Accordingly the 2013 Approved revenue offsets have also increased by $2,941,000.

Note 1: The change from 2013 to 2015 is 2% per year.

Note 2: The change from 2016 to 2020 is 1.6% per year.

Background information on the extraordinary incremental costs is set out below:

New Customer Information System ("CIS")

A new CIS was implemented in 2015 by CGI Inc. CGI was also chosen to provide the maintenance on the new CIS based on the results of due diligence process including a pricing proposal; discussions with other out of province utilities who had used CGI for maintenance; and discussions with other LDCs.

There are $2,000,000 in incremental costs related to the maintenance agreement to support the new CIS and $1,392,000 in training costs. The maintenance costs are initially higher than the cost to support and maintain the former T&W Billing System however there is some reduction in cost over the term of the Custom IR plan.

Vegetation Management

In December 2013 there was a major ice storm that damaged a number of trees and increased OM&A expenses in 2013 by $1,809,000. As a result of the ice storm PowerStream changed its vegetation management policies for rear yards and heavily treed front yards from a 5 year tree trimming cycle to a 2 year cycle. Further, rural areas now have a 4 year tree trimming cycle where previously they were not part of the tree trimming cycle.

In addition to the change in policy after the ice storm, PowerStream changed its annual tree trimming cycle from 5 years to 3 years for urban areas in December 2012.

With the implementation of these changes, incremental costs for vegetation management have correspondingly been higher.

Below is some background information on other incremental costs:

Compliance

The evolution in a number of regulatory requirements, including the implementation of the smart grid that PowerStream is required to implement, has resulted in higher incremental costs, primarily prior to the term of the Custom IR plan.

Risk Management

Risk Management activities impact work management (pre-hiring/apprentices, new headcount) and associated costs. Trending information cannot be provided for such incremental costs as it can be in other cost categories, because year to year changes are program-specific.

Customer Expectations

The increases relate to the expanded focus on customer expectations following the Board's RRFE Report, including surveys and activities associated with the development of the Distribution System Plan. There were significant incremental costs in 2014 and 2015 but the incremental costs post 2015 are in fact negative.

Compensation

The increases in compensation relate to cost of living wage adjustments for union and management and merit and step increases. Cost of living adjustment is based on the Collective Bargaining Agreement. The cost of living adjustment under the Collective Agreement was 2.5% for 2013 and 2.75% for 2014-2015.

Growth

By the end of 2020, PowerStream expects its total customer base to have grown to 394,508, an increase of 14% from 2013, resulting in higher incremental costs.

Asset Management

Asset Management activities impact maintenance programs (Inspections, patrol testing, switchgear and insulator cleaning, accidents and vandalism and poles and hardware). Trending information cannot be provided for such incremental costs as it can be in other cost categories, because year to year changes are program-specific.

COMPENSATION

Establishing headcount and wages is a part of PowerStream's business planning process. As such there is a thorough review and approval process for both new positions and compensation. The starting assumption is that current staffing levels are sufficient and any increases are to be justified. Senior management are required to justify the need for all new staff positions to the Executive Management Team ("EMT"). The EMT recommends changes to the Audit and Finance Committee of the Board of Directors, and to the full Board of Directors, as part of the overall budget. PowerStream is planning an increase in Full Time Equivalent from the 2013 Board approved level of 551 to 563 in 2020, an increase of 12 FTEs.

PowerStream offers employee benefits including medical and dental coverage, long term disability and life insurance, various forms of leaves and a company-sponsored defined retirement plan (OMERS). Benefits also include the company cost of Canada Pension Plan contributions, Employment Insurance, Employer Health Tax and Workers Safety Insurance premiums. Benefits are a negotiated item for unionized staff and changes to the plan may only be achieved through the collective bargaining process. PowerStream undertook a market review and request for proposals for a Benefit Service Advisor and for Employee Health Care & Dental benefits. The specifications were sent out to all of the major carriers within the insurance marketplace that could provide a benefit program with a greater return on investment with the same benefit structure. PowerStream appointed a new carrier with lower administrative costs which were built into this application.

PowerStream engaged in collective bargaining with the Power Workers Union ("PWU") in 2013. The unionized workforce at PowerStream is represented by the PWU, Local 1000 and consists of "outside workers" and administrative and clerical staff, commonly referred to as "inside workers". Both inside and outside workers are covered under a single Collective Agreement. The annual inflation adjustment under the Collective Agreement was 2.5% for 2013 and 2.75% for 2014-2015. The next round of bargaining will cover the period April 1, 2016 to March 31, 2019. Average Yearly Incentive Pay is commonly referred to at PowerStream as the Performance Incentive Program ("PIP"). Senior Management and all permanent Non-union employees are eligible to participate. The program has not changed since the last rate application.

Below is the Board's Appendix 2-K, Employee Costs.

Appendix 2-K
Employee Costs

	2012 Actual	2013 Board Approved	2013 Actual	2014 Actual	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
Number of Employees (FTEs including Part-Time)[1]										
Management (including executive)	103.56	110.20	104.41	105.36	112.50	117.50	117.00	117.75	118.75	118.75
Non-Management (union and non-union)	415.38	440.45	428.69	438.73	454.95	449.37	444.87	445.12	446.12	444.12
Total	**518.94**	**550.65**	**533.10**	**544.09**	**567.45**	**566.87**	**561.87**	**562.87**	**564.87**	**562.87**
Total Salary and Wages including ovetime and incentive pay										
Management (including executive)	$ 15,021,009	$ 15,708,582	$ 15,573,563	$ 16,390,784	$ 17,510,000	$ 18,529,018	$ 18,926,555	$ 19,440,591	$ 19,961,461	$ 20,443,074
Non-Management (union and non-union)	$ 33,667,780	$ 35,452,576	$ 35,578,299	$ 38,088,707	$ 37,376,380	$ 38,281,748	$ 39,533,577	$ 40,637,238	$ 41,692,675	$ 42,499,243
Total	**$ 48,688,789**	**$ 51,161,159**	**$ 51,151,862**	**$ 54,479,491**	**$ 54,886,381**	**$ 56,810,766**	**$ 58,460,132**	**$ 60,077,830**	**$ 61,654,136**	**$ 62,942,317**
Total Benefits (Current + Accrued)										
Management (including executive)	$ 3,961,929	$ 3,790,641	$ 4,322,335	$ 4,536,113	$ 4,485,371	$ 4,727,768	$ 4,797,718	$ 4,916,002	$ 5,059,781	$ 5,182,854
Non-Management (union and non-union)	$ 8,894,205	$ 11,701,493	$ 9,604,147	$ 9,739,250	$ 10,958,897	$ 11,318,056	$ 11,786,367	$ 12,036,423	$ 12,299,700	$ 12,556,006
Total	**$ 12,856,134**	**$ 15,492,134**	**$ 13,926,483**	**$ 14,275,363**	**$ 15,444,267**	**$ 16,045,824**	**$ 16,584,084**	**$ 16,952,425**	**$ 17,359,481**	**$ 17,738,859**
Total Compensation (Salary, Wages, & Benefits)										
Management (including executive)	$ 18,982,938	$ 19,499,223	$ 19,895,898	$ 20,926,897	$ 21,995,371	$ 23,256,785	$ 23,724,272	$ 24,356,593	$ 25,021,241	$ 25,625,928
Non-Management (union and non-union)	$ 42,561,986	$ 47,154,069	$ 45,182,446	$ 47,827,957	$ 48,335,277	$ 49,599,804	$ 51,319,944	$ 52,673,662	$ 53,992,375	$ 55,055,249
Total	**$ 61,544,923**	**$ 66,653,293**	**$ 65,078,344**	**$ 68,754,854**	**$ 70,330,648**	**$ 72,856,589**	**$ 75,044,216**	**$ 77,030,255**	**$ 79,013,616**	**$ 80,681,176**

DEPRECIATION AND AMORTIZATION

PowerStream amortizes its Property, Plant and Equipment ("PP&E") in accordance with International Financial Accounting Standards ("IFRS").

The PP&E assets are amortized on a straight-line basis. The half-year rule is applied to the 2015 Bridge Year and to the years 2016 to 2020. Specifically, one-half of the annual amortization amount is applied in the first year. The historical actual depreciation, for the years 2012 to 2014, reflects amortization calculated on a monthly basis once the assets are in service.

Table 1 below provides a summary of the total depreciation for the historical years 2012 to 2014, Bridge Year 2015 and Test Years 2016 to 2020.

Table 1: Depreciation Summary - For the period 2012 to 2020 ($ Thousands)

Detail Asset Class	2012 Actual	2013 Actual	2014 Actual	2015 Bridge Year Forecast	2016 Test Year Forecast	2017 Test Year Forecast	2018 Test Year Forecast	2019 Test Year Forecast	2020 Test Year Forecast
Distribution Assets	$32,351	$34,038	$36,725	$39,317	$42,139	$45,311	$48,755	$52,279	$55,893
General Plant Assets	$8,427	$8,974	$9,972	$12,534	$15,977	$17,549	$17,664	$17,981	$18,216
Other Capital Assets	$733	$731	$731	$731	$733	$731	$731	$731	$733
Subtotal	$41,511	$43,743	$47,428	$52,581	$58,849	$63,590	$67,150	$70,990	$74,842
Contributed Capital Amortization	($8,199)	($8,873)	($9,413)	($9,958)	($10,620)	($11,322)	($12,073)	($12,831)	($13,522)
Depreciation	$33,313	$34,870	$38,015	$42,623	$48,229	$52,268	$55,076	$58,159	$61,320
Less RGCRP	($50)	($73)	($105)	($119)	($110)	($108)	($106)	($105)	($104)
Allocated to OM &A	($1,766)	($1,954)	($2,107)	($2,207)	($2,406)	($2,512)	($2,637)	($2,864)	($2,888)
TOTAL DEPRECIATION	$31,497	$32,843	$35,803	$40,297	$45,713	$49,648	$52,333	$55,190	$58,328
DEPRECIATION METHODOLOGY	Monthly in-service	Monthly in-service	Monthly in-service	Half year	Half year	Half year	Half year	Half year	Half year

RGCRP – Renewable Generation Connection Rate Protection represents depreciation expense reimbursed Ont. Reg. 330/09.

For 2012 to 2020 PowerStream used the same amortization rates, approved by the Board, as in its 2013 Cost of Service distribution rate application (EB-2012-0161).

Since the 2013 COS rate application, PowerStream has added the following two new PP&E sub-accounts: First, Underground Cable Injection was established in 2014 to recognize PowerStream’s decision to utilize cost saving engineering technology to extend the life of existing underground conductor by injecting special compounds. The useful life of this new class of asset is 20 years. Second, Customer Information System software (“CIS”) was established in 2014 to recognize the unique useful life specific to PowerStream’s new customer care and billing system that will be in service in 2015. Deprecation on the new CIS will begin in 2015.

Depreciation and amortization schedules by asset account for each of the years 2012 to 2020 are provided as supplementary information in electronic Appendix G-2a-1.

Service life comparison with the Kinectrics report, ”Asset Amortization Study for the Ontario Energy Board”, issued April 28,2010 is provided as supplementary information in electronic Appendix J-3-1.

Regulatory Costs

PowerStream has prepared and provided OEB Chapter 2 Appendix 2-M Regulatory Costs in the supplemental information as electronic document “J-4-1: 2-M Regulatory Costs”.

Costs related to this application are included in the amounts for 2014 and 2015.

PowerStream is not requesting any adjustment to the Custom IR plan Test Years for the cost of this application.

Taxes

PowerStream has calculated taxes on its target net income based on the Board's allowed return on equity for each of the years 2016 to 2020. PowerStream has used the Board's tax model modified to handle multiple test years. The model is available as Supplemental information electronic document J-5-1, Income Taxes/PILs Workform.

The results are summarized in Table 1 below together with comparative information for 2013 Board Approved and the 2015 Bridge Year.

Table 1: Summary of Taxes

Description	2013 Board Approved	2015 Bridge Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year	2020 Test Year
Target net income	$29,722	$34,924	$39,939	$42,917	$46,072	$48,824	$51,488
Adjustments	($22,732)	($43,633)	($46,103)	($28,694)	($29,113)	($28,939)	($30,870)
Regulatory Taxable Income	$6,990	($8,709)	($6,165)	$14,223	$16,960	$19,885	$20,618
Combined Federal & Ontario rate	25.99%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Taxes	$1,817	($2,308)	($1,634)	$3,769	$4,494	$5,269	$5,464
Less ITCs	($473)	($606)	($606)	($606)	($606)	($606)	($606)
Less Ontario Tax Credits	($244)	($506)	($516)	($526)	($537)	($548)	($559)
Net Taxes	$1,099	($3,419)	($2,755)	$2,637	$3,352	$4,116	$4,300
Gross-up factor (1/(-tax rate)	1.3512	1.3605	1.3605	1.3605	1.3605	1.3605	1.3605
Taxes recoverable from rates	$1,486	($4,652)	($3,749)	$3,588	$4,560	$5,600	$5,850

PowerStream has calculated a tax benefit of the Regulatory Taxable Loss for 2016 of $4.65 million and included this in the calculation of revenue requirement.

As discussed in Exhibit A, Tab 1, Rate Plan, PowerStream proposes to adjust the taxes recoverable amount annually to reflect changes in legislated tax rates.

COST OF CAPITAL

Capital Structure

In calculating the cost of capital for each of the years in the Custom IR Plan, PowerStream has used the Board's current deemed capital structure of 56% long-term debt, 4% short-term debt, and 40% equity. The attached Board Appendix 2-OA depicts PowerStream's capital structure for 2013-2020 years.

Cost of Equity

For the purposes of this rate application, PowerStream used a Return on Equity ("ROE") of 9.30%, as per the Board's letter of November 20, 2014 (which set cost of capital parameters for applications for 2015 distribution rates), for each of the 2016-2020 test years. This value is a "placeholder" as PowerStream proposes that this parameter be updated for setting 2016 rates as per the Board's current practice when data for 2016 becomes available. PowerStream further proposes that for the 2017-2020 years this parameter be subject to annual adjustments based on the Board's annual update for the corresponding rate year. This proposed method is the same as that approved by the Board in the Horizon Utilities Custom IR proceeding.

Cost of Short-Term Debt

For the purposes of this rate application, for the 2016 test year PowerStream used a deemed short-term rate of 2.16% as per the Board's letter of November 20, 2014. This value is a "placeholder" as PowerStream proposes that it be updated for setting 2016 rates as per the Board's current practice when data for 2016 becomes available. A 3% rate for short-term rate is used for the 2017-2020 test years. Once again, this value is a "placeholder" as PowerStream further proposes that for the 2017-2020 years this parameter be subject to annual adjustments based on the Board's annual update to this parameter for the corresponding rate year. This proposed method is the same as that approved by the Board in the Horizon Utilities Custom IR proceeding.

Cost of Long-Term Debt

As an appendix to this exhibit, PowerStream is providing the Board's Appendix 2-OB to the Chapter 2 Filing Requirements for Price Cap filers titled "Debt Instruments", for each year from 2013 to 2020. Notable changes since the last rates application to this point are:

- On July 30, 2012, PowerStream issued 3.958% unsecured debentures Series A for $200,000,000, due July 30, 2042.
- On November 21, 2014, PowerStream issued 3.239% unsecured debentures Series B for $150,000,000, due November 21, 2024.

Going forward, to ensure that PowerStream has adequate funding available and to maintain the prescribed debt to equity ratio, PowerStream anticipates further long-term borrowing in 2016-2018. The exact timing of the borrowings would be affected by various factors, such as timing of capital expenditures, as well as the financial market conditions. PowerStream's 2016-2020 forecast assumes new financings for each year starting in 2016, all at the rate of 4.5%. However, PowerStream proposes that the long-term rate used to determine distribution rates will be subject to adjustment annually, based on the OEB methodology and the deemed long-term rates effective at the time of the update, and the actual cost of the issued debt. This approach is consistent with what the Board approved recently in Horizon Utilities' Custom IR proceeding.

In PowerStream's last cost of service proceeding, the Board approved a long-term debt cost of 4.15%, calculated as the weighted average of the rates for the shareholders' promissory notes, existing bank loans and newly issued bonds.

Similarly, in this application, the long-term debt rate for each year from 2016 to 2020 is computed as the weighted average of rates for all existing and forecasted components of long-term debt, and depicted in Appendix 2-OB.

Overall Cost of Capital

PowerStream's forecasted cost of Capital is shown in the table below:

	Actual	Bridge	Test years				
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Long-term debt	3.91%	3.91%	3.96%	4.01%	4.03%	4.03%	4.03%
Short-term debt	2.11%	2.16%	2.16%	3.00%	3.00%	3.00%	3.00%
Equity	8.93%	8.93%	9.30%	9.30%	9.30%	9.30%	9.30%
WACC	**5.85%**	**5.85%**	**6.02%**	**6.08%**	**6.10%**	**6.10%**	**6.10%**

COST ALLOCATION

PowerStream has followed the guidance in the *"Report of the Board: Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219) dated March 31, 2011"* and has prepared a Cost Allocation Study ("CAS") for each of the five test years using the Board's v 3.2 Cost Allocation Model ("Board 3.2 CA Model")

PowerStream engaged the services of Elenchus Research Associates Inc. to assist with updating of load profiles for the Test Years' load forecasts and to review the 2016-2020 cost allocation models.

The Board 3.2 CA Models have been used to determine the proportion of PowerStream's total revenue requirement that is recoverable from each rate class in each year.

Input sheets I-6, I-8, Output O-1 and O-2, as well a live Excel versions of the 2016 – 2020 CA models have been provided as supplementary information in electronic Appendix L-1-1.

The Status Quo class revenue-to-cost ratios as determined in the cost allocation models are shown in Table 1 below.

Table 1: Revenue-to-Cost Ratios (Status Quo)

	"STATUS QUO"						
	2013 BA	2016	2017	2018	2019	2020	Policy Allowed Range
Residential	102.1%	102.4%	103.7%	104.7%	105.5%	106.2%	85 - 115
GS Less Than 50 kW	98.0%	99.9%	100.7%	100.9%	101.1%	101.1%	80 - 120
GS 50 to 4,999 kW	98.0%	96.6%	94.3%	92.7%	91.4%	90.4%	80 - 120
Large Use	85.0%	71.4%	68.6%	67.1%	66.1%	65.3%	85 - 115
Unmetered Scattered Load	102.4%	91.3%	94.8%	96.3%	97.2%	98.0%	80 - 120
Sentinel Lighting	95.0%	84.7%	83.6%	83.5%	83.2%	83.2%	80 - 120
Street Lighting	89.7%	88.1%	85.1%	82.4%	81.7%	81.0%	70 - 120

A revenue allocation adjustment was required for the Large Use customer class, to increase the revenues and bring the revenue-to-cost ratios within the Policy Allowed Range. PowerStream proposes that the revenue-to-cost ratio be increased to the bottom of the Policy Allowed Range. The resulting additional revenue from the Large Use class in 2016-2020 is in a range of $62,000

- $119,000. Since the Residential customer class has the highest revenue-to-cost ratio, the additional revenue has been credited to this customer to move its revenue-to-cost ratio closer to 1.00. Table 2 below provides the proposed Revenue-to-Cost ratios.

Table 2: Appendix 2P (D) – Proposed Revenue-to-Cost Ratios

Class	Proposed Revenue-to-Cost Ratios					Policy Allowed Range
	2016	2017	2018	2019	2020	
	%	%	%	%	%	%
Residential	102.4	103.6	104.6	105.4	106.1	85 - 115
GS < 50 kW	99.9	100.7	100.9	101.1	101.1	80 - 120
GS > 50 kW	96.6	94.3	92.7	91.4	90.4	80 - 120
Large User	85.0	85.0	85.0	85.0	85.0	85 - 115
Street Lighting	88.1	85.1	82.4	81.7	81.0	70 - 120
Sentinel Lighting	84.7	83.6	83.5	83.2	83.2	80 - 120
Unmetered Scattered Load (USL)	91.3	94.8	96.3	97.2	98.0	80 - 120

Tables 3 through 7 provide details on the revenue allocation to rate classes for 2016 through 2020.

Table 3: Appendix 2P (B) – Allocated Class Revenues - 2016

Classes (same as previous table)	Column 7B Load Forecast (LF) X current approved rates	Column 7C LF X current approved rates X (1 + d)	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 88,037,077	$ 103,755,221	$ 103,692,721	$ 7,532,107
GS < 50 kW	$ 24,606,848	$ 29,000,156	$ 29,000,156	$ 1,864,195
GS > 50 kW	$ 46,721,959	$ 55,063,700	$ 55,063,700	$ 2,909,448
Large User	$ 266,234	$ 313,768	$ 376,268	$ 14,404
Street Lighting	$ 2,320,226	$ 2,734,479	$ 2,734,479	$ 209,630
Sentinel Lighting	$ 16,350	$ 19,269	$ 19,269	$ 1,591
Unmetered Scattered Load (USL)	$ 475,661	$ 560,585	$ 560,585	$ 59,228
Total	$ 162,444,354	$ 191,447,177	$ 191,447,177	$ 12,590,603

Table 4: Appendix 2P (B) – Allocated Class Revenues - 2017

Classes (same as previous table)	Column 7B Load Forecast (LF) X current approved rates	Column 7C LF X current approved rates X (1 + d)	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 88,807,634	$ 114,175,187	$ 114,090,187	$ 7,595,559
GS < 50 kW	$ 24,646,566	$ 31,686,762	$ 31,686,762	$ 1,862,152
GS > 50 kW	$ 46,908,541	$ 60,307,783	$ 60,307,783	$ 2,975,170
Large User	$ 265,314	$ 341,100	$ 426,100	$ 14,929
Street Lighting	$ 2,213,358	$ 2,845,595	$ 2,845,595	$ 209,776
Sentinel Lighting	$ 16,286	$ 20,938	$ 20,938	$ 1,589
Unmetered Scattered Load (USL)	$ 487,250	$ 626,431	$ 626,431	$ 59,137
Total	$ 163,344,950	$ 210,003,796	$ 210,003,796	$ 12,718,312

Table 5: Appendix 2P (B) – Allocated Class Revenues - 2018

Classes (same as previous table)	Column 7B Load Forecast (LF) X current approved rates	Column 7C LF X current approved rates X (1 + d)	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 89,692,812	$ 120,469,009	$ 120,370,009	$ 7,643,712
GS < 50 kW	$ 24,692,287	$ 33,164,925	$ 33,164,925	$ 1,868,229
GS > 50 kW	$ 47,043,329	$ 63,185,256	$ 63,185,256	$ 3,017,741
Large User	$ 264,402	$ 355,126	$ 454,126	$ 15,260
Street Lighting	$ 2,099,230	$ 2,819,537	$ 2,819,537	$ 210,024
Sentinel Lighting	$ 16,285	$ 21,872	$ 21,872	$ 1,593
Unmetered Scattered Load (USL)	$ 499,851	$ 671,364	$ 671,364	$ 60,122
Total	$ 164,308,195	$ 220,687,089	$ 220,687,089	$ 12,816,681

Table 6: Appendix 2P (B) – Allocated Class Revenues - 2019

Classes (same as previous table)	Column 7B Load Forecast (LF) X current approved rates	Column 7C LF X current approved rates X (1 + d)	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 90,524,165	$ 126,651,879	$ 126,541,479	$ 7,708,534
GS < 50 kW	$ 24,736,122	$ 34,608,177	$ 34,608,177	$ 1,876,626
GS > 50 kW	$ 47,112,553	$ 65,914,923	$ 65,914,923	$ 3,061,612
Large User	$ 263,499	$ 368,660	$ 479,060	$ 15,513
Street Lighting	$ 2,116,796	$ 2,961,598	$ 2,961,598	$ 213,691
Sentinel Lighting	$ 16,284	$ 22,783	$ 22,783	$ 1,594
Unmetered Scattered Load (USL)	$ 513,592	$ 718,564	$ 718,564	$ 61,383
Total	$ 165,283,011	$ 231,246,584	$ 231,246,584	$ 12,938,953

Table 7: Appendix 2P (B) – Allocated Class Revenues - 2020

Classes (same as previous table)	Column 7B Load Forecast (LF) X current approved rates	Column 7C LF X current approved rates X (1 + d)	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 91,320,209	$ 132,252,985	$ 132,133,185	$ 7,777,654
GS < 50 kW	$ 24,817,227	$ 35,941,140	$ 35,941,140	$ 1,888,327
GS > 50 kW	$ 47,242,131	$ 68,417,637	$ 68,417,637	$ 3,105,538
Large User	$ 262,603	$ 380,311	$ 500,111	$ 15,733
Street Lighting	$ 2,131,874	$ 3,087,451	$ 3,087,451	$ 217,367
Sentinel Lighting	$ 16,284	$ 23,583	$ 23,583	$ 1,594
Unmetered Scattered Load (USL)	$ 528,571	$ 765,494	$ 765,494	$ 62,873
Total	$ 166,318,900	$ 240,868,600	$ 240,868,600	$ 13,069,086

Revenue Allocation and Fixed Variable Split

PowerStream's proposed distribution rates are set to recover the base revenue requirement for each of the test years 2016 to 2020 as presented in Exhibit E, Tab 1 and reflect the proposed revenue to cost ratios presented in Exhibit L, Tab 1. Rate Schedules are provided as supplementary information in electronic Appendix B-1-2.

The current fixed/variable split in distribution revenue was approved in PowerStream's 2013 Cost of Service application (EB-2012-0161). Table 1 below provides the 2013 Board-approved split between fixed and variable distribution revenue

Table 1: 2013 Board-Approved Fixed/Variable Split

	2013 Board Approved	
Customer Class	Variable	Fixed
Residential	44.9%	55.1%
GS<50 kW	59.8%	40.2%
GS>50 kW	83.1%	16.9%
Large Use	51.3%	48.7%
Unmetered Scattered Load	46.5%	53.5%
Sentinel Lights	67.0%	33.0%
Street Lighting	48.4%	51.6%
	58.3%	41.7%

Table 2 below identifies the proposed 2016-2020 Fixed/Variable Split.

Table 2: 2016-2020 Proposed Fixed/Variable Split

	2016		2017		2018		2019		2020	
Customer Class	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed
Residential	45.0%	55.0%	45.2%	54.8%	45.4%	54.6%	45.6%	54.4%	45.7%	54.3%
GS<50 kW	59.7%	40.3%	59.6%	40.4%	60.3%	39.7%	61.4%	38.6%	62.2%	37.8%
GS>50 kW	85.1%	14.9%	86.1%	13.9%	86.4%	13.6%	86.7%	13.3%	86.9%	13.1%
Large Use	61.9%	38.1%	66.4%	33.6%	68.5%	31.5%	70.1%	29.9%	71.4%	28.6%
Unmetered Scattered Load	48.6%	51.4%	49.6%	50.4%	50.5%	49.5%	51.6%	48.4%	52.6%	47.4%
Sentinel Lights	49.1%	50.9%	48.6%	51.4%	48.2%	51.8%	48.0%	52.0%	47.6%	52.4%
Street Lighting	43.9%	56.1%	40.9%	59.1%	37.3%	62.7%	37.4%	62.6%	37.4%	62.6%
	58.8%	41.2%	59.1%	40.9%	59.3%	40.7%	59.6%	40.4%	59.8%	40.2%

In setting the proposed fixed/variable splits PowerStream has used the monthly fixed service charge ("MSC") ceiling calculated in the OEB Cost Allocation Study ("CAS") models in determining the proposed MSC for each rate class as discussed directly below.

For each year, where the current 2015 MSC is at or above the ceiling, the proposed MSC has been capped at the 2015 MSC. Otherwise, the proposed MSC has been determined as the lower of the calculated MSC (calculated at the current fixed-variable revenue split) and the ceiling.

Once the MSC for each class is determined, the fixed distribution revenue from the MSC is calculated and subtracted from the total class revenue allocation. The remainder is the variable distribution revenue for the class. This variable distribution revenue value is then used to determine the variable charge.

Tables 3 to 7 below compare in each year the 2015 Current MSC and the calculated MSC at the current approved fixed/ variable split to the MSC values in the cost allocation study models and shows the proposed MSC. The highlighted numbers are the higher of current 2015 rates and the CAS ceiling.

Table 3: PowerStream Monthly Fixed Service Charges ($) – 2016

Customer Class	2016 CAS Floor	2016 CAS Ceiling	2015 Charge	2016 Calculated	2016 Proposed
Residential	$4.68	$16.71	$12.67	$14.58	$14.58
GS<50 kW	$14.98	$33.30	$26.08	$30.01	$30.01
GS>50 kW	$51.24	$123.91	$138.48	$159.36	$138.48
Large Use	$345.22	$675.83	$5,966.29	$6,865.73	$5,966.29
Unmetered Scattered Load	$4.30	$14.78	$7.01	$8.07	$8.07
Sentinel Lights	$0.81	$7.03	$3.41	$3.92	$3.92
Street Lighting	$0.62	$6.78	$1.26	$1.45	$1.45

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Table 4: PowerStream Monthly Fixed Service Charges ($) – 2017

Customer Class	2017 CAS Floor	2017 CAS Ceiling	2015 Charge	2017 Calculated	2017 Proposed
Residential	$4.63	$17.21	$12.67	$15.70	$15.70
GS<50 kW	$14.73	$33.28	$26.08	$32.55	$32.55
GS>50 kW	$50.41	$122.00	$138.48	$171.05	$138.48
Large Use	$382.69	$735.25	$5,966.29	$7,531.22	$5,966.29
Unmetered Scattered Load	$4.06	$14.97	$7.01	$8.65	$8.65
Sentinel Lights	$0.79	$7.60	$3.41	$4.33	$4.33
Street Lighting	$0.62	$7.39	$1.26	$1.56	$1.56

Table 5: PowerStream Monthly Fixed Service Charges ($) – 2018

Customer Class	2018 CAS Floor	2018 CAS Ceiling	2015 Charge	2018 Calculated	2018 Proposed
Residential	$4.60	$17.27	$12.67	$16.19	$16.19
GS<50 kW	$14.63	$33.10	$26.08	$33.81	$33.10
GS>50 kW	$50.22	$120.65	$138.48	$175.96	$138.48
Large Use	$379.67	$736.05	$5,966.29	$7,914.34	$5,966.29
Unmetered Scattered Load	$4.01	$15.11	$7.01	$8.87	$8.87
Sentinel Lights	$0.79	$7.83	$3.41	$4.56	$4.56
Street Lighting	$0.62	$9.63	$1.26	$1.61	$1.61

Table 6: PowerStream Monthly Fixed Service Charges ($) – 2019

Customer Class	2019 CAS Floor	2019 CAS Ceiling	2015 Charge	2019 Calculated	2019 Proposed
Residential	$4.60	$17.41	$12.67	$16.66	$16.66
GS<50 kW	$14.66	$33.20	$26.08	$35.02	$33.20
GS>50 kW	$50.36	$120.72	$138.48	$180.56	$138.48
Large Use	$379.41	$761.84	$5,966.29	$8,293.03	$5,966.29
Unmetered Scattered Load	$4.02	$15.33	$7.01	$9.03	$9.03
Sentinel Lights	$0.79	$8.03	$3.41	$4.77	$4.77
Street Lighting	$0.62	$10.00	$1.26	$1.66	$1.66

Table 7: PowerStream Monthly Fixed Service Charges ($) – 2020

Customer Class	2020 CAS Floor	2020 CAS Ceiling	2015 Charge	2020 Calculated	2020 Proposed
Residential	$4.64	$17.54	$12.67	$17.04	$17.04
GS<50 kW	$14.80	$33.37	$26.08	$36.06	$33.37
GS>50 kW	$50.93	$120.98	$138.48	$184.16	$138.48
Large Use	$383.83	$785.73	$5,966.29	$8,638.10	$5,966.29
Unmetered Scattered Load	$4.02	$15.47	$7.01	$9.12	$9.12
Sentinel Lights	$0.79	$8.19	$3.41	$4.97	$4.97
Street Lighting	$0.62	$10.30	$1.26	$1.70	$1.70

The numbers in the tables exclude Transformer Ownership Allowance. The cost of the transformer allowance was excluded from the Cost Allocation Study. In rate design the amount of transformer ownership allowance has been allocated only to the classes that receive it.

PowerStream has maintained the current transformer ownership allowance of $0.60 per kW, pending the results of further cost allocation refinements by the OEB.

PowerStream notes that the OEB is currently undergoing a process to review rate design for the Residential and small General Service classes (EB-2012-0410). PowerStream has not incorporated any of the rate designs as outlined in the Draft Report of the Board at this time. However, should the OEB issue direction to LDCs related to this consultation, PowerStream is prepared to incorporate changes as applicable.

REVENUE VALIDATION

Board Appendix 2-V has been prepared to reconcile PowerStream's rates and revenue by Rate Class to the Base Revenue Requirement for each of the 2016 through 2020 Test Years. This information is presented below in Tables 1 to 5. The small variances are the result of a difference in the methodology of calculating the average numbers of customers, connections, and devices. Appendix 2-V utilizes the averages of the customer, connections, and device count as of January 1 and December 31, whereas the PowerStream Rate Model uses the summation of the monthly average customers divided by 12 to determine an average for the year.

Table 1: Appendix 2-V Revenue Reconciliation 2016

Rate Class	Customers/ Connections	Number of Customers/Connections			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric						
								kWh	kW					
Residential	Customers	323,639	327,907	325,773	2,750,618,680		$ 14.58	$ 0.0170		$ 103,757,737	$ 103,692,721		$ 103,692,721	-$ 65,016
GS < 50 kW	Customers	32,258	32,594	32,426	1,040,222,607		$ 30.01	$ 0.0167		$ 29,048,969	$ 29,000,156		$ 29,000,156	-$ 48,812
GS > 50 to 4,999 kW	Customers	4,902	5,005	4,954	4,574,077,591	12,212,781	$ 138.48		$ 4.0108	$ 57,214,642	$ 55,063,700	$ 2,150,523	$ 57,214,222	-$ 420
Large Use	Customers	2	2	2	76,536,992	150,807	$ 5,966.29		$ 2.1455	$ 466,747	$ 376,268	$ 90,484	$ 466,752	$ 5
Streetlighting	Connections	87,506	88,953	88,230	53,007,707	148,205	$ 1.45		$ 8.0925	$ 2,734,542	$ 2,734,479		$ 2,734,479	-$ 63
Sentinel Lighting	Connections	209	207	208	378,080	975	$ 3.92		$ 9.7021	$ 19,246	$ 19,269		$ 19,269	$ 23
Unmetered Scattered Load	Customers	2,948	3,006	2,977	14,169,725		$ 8.07	$ 0.0192		$ 560,351	$ 560,585		$ 560,585	$ 234
Total										$ 193,802,233	$ 191,447,177	$ 2,241,007	$ 193,688,184	-$ 114,050

Table 2: Appendix 2-V Revenue Reconciliation 2017

Rate Class	Customers/ Connections	Number of Customers/Connections			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric						
								kWh	kW					
Residential	Customers	330,096	333,673	331,885	2,739,228,627		$ 15.70	$ 0.0188		$ 114,024,546	$ 114,090,187		$ 114,090,187	$ 65,641
GS < 50 kW	Customers	32,626	32,973	32,800	1,034,670,626		$ 32.55	$ 0.0182		$ 31,642,490	$ 31,686,762		$ 31,686,762	$ 44,271
GS > 50 to 4,999 kW	Customers	5,007	5,116	5,062	4,574,818,701	12,214,760	$ 138.48		$ 4.4248	$ 62,459,004	$ 60,307,783	$ 2,150,871	$ 62,458,654	-$ 350
Large Use	Customers	2	2	2	75,964,677	149,679	$ 5,966.29		$ 2.4901	$ 515,907	$ 426,100	$ 89,807	$ 515,907	$ 1
Streetlighting	Connections	89,087	90,575	89,831	45,961,281	128,504	$ 1.56		$ 9.0580	$ 2,845,623	$ 2,845,595		$ 2,845,595	-$ 28
Sentinel Lighting	Connections	207	207	207	377,900	975	$ 4.33		$ 10.4450	$ 20,938	$ 20,938		$ 20,938	$ 0
Unmetered Scattered Load	Customers	3,011	3,077	3,044	14,542,385		$ 8.65	$ 0.0214		$ 627,174	$ 626,431		$ 626,431	-$ 743
Total										$ 212,135,682	$ 210,003,796	$ 2,240,678	$ 212,244,474	$ 108,792

Table 3: Appendix 2-V Revenue Reconciliation 2018

Rate Class	Customers/ Connections	Number of Customers/Connections: Start of Test Year	End of Test Year	Average	Test Year Consumption: kWh	kW	Proposed Rates: Monthly Service Charge	Volumetric: kWh	Volumetric: kW	Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
Residential	Customers	336,730	339,480	338,105	2,734,798,535		$ 16.19	$ 0.0200		$ 120,383,053	$ 120,370,009		$ 120,370,009	-$ 13,044
GS < 50 kW	Customers	33,004	33,354	33,179	1,029,394,754		$ 33.10	$ 0.0194		$ 33,148,178	$ 33,164,925		$ 33,164,925	$ 16,746
GS > 50 to 4,999 kW	Customers	5,115	5,227	5,171	4,569,273,124	12,199,953	$ 138.48		$ 4.6509	$ 65,333,905	$ 63,185,256	$ 2,148,264	$ 65,333,520	-$ 385
Large Use	Customers	2	2	2	75,397,535	148,561	$ 5,966.29		$ 2.6930	$ 543,267	$ 454,126	$ 89,137	$ 543,263	-$ 4
Streetlighting	Connections	90,712	92,207	91,460	38,502,066	107,648	$ 1.61		$ 9.7775	$ 2,819,530	$ 2,819,537		$ 2,819,537	$ 6
Sentinel Lighting	Connections	207	207	207	377,840	975	$ 4.56		$ 10.8193	$ 21,872	$ 21,872		$ 21,872	-$ 0
Unmetered Scattered Load	Customers	3,084	3,160	3,122	14,924,845		$ 8.87	$ 0.0227		$ 671,100	$ 671,364		$ 671,364	$ 264
Total										$ 222,920,906	$ 220,687,089	$ 2,237,401	$ 222,924,489	$ 3,583

Table 4: Appendix 2-V Revenue Reconciliation 2019

Customers/ Connections	Number of Customers/Connections: Start of Test Year	End of Test Year	Average	Test Year Consumption: kWh	kW	Proposed Rates: Monthly Service Charge	Volumetric: kWh	Volumetric: kW	Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
Customers	343,395	345,362	344,378	2,726,183,601		$ 16.66	$ 0.0212		$ 126,643,223	$ 126,541,479		$ 126,541,479	-$ 101,744
Customers	33,385	33,739	33,562	1,023,938,204		$ 33.20	$ 0.0207		$ 34,567,462	$ 34,608,177		$ 34,608,177	$ 40,715
Customers	5,222	5,339	5,280	4,555,886,909	12,164,212	$ 138.48		$ 4.8735	$ 68,056,607	$ 65,914,923	$ 2,141,970	$ 68,056,893	$ 286
Customers	2	2	2	74,835,513	147,454	$ 5,966.29		$ 2.8778	$ 567,534	$ 479,060	$ 88,472	$ 567,532	-$ 2
Connections	92,344	93,857	93,101	38,115,123	106,567	$ 1.66		$ 10.3887	$ 2,961,650	$ 2,961,598		$ 2,961,598	-$ 52
Connections	207	207	207	377,820	975	$ 4.77		$ 11.2191	$ 22,783	$ 22,783		$ 22,783	$ 0
Customers	3,167	3,255	3,211	15,317,364		$ 9.03	$ 0.0242		$ 718,624	$ 718,564		$ 718,564	-$ 60
									$ 233,537,884	$ 231,246,584	$ 2,230,443	$ 233,477,026	-$ 60,858

Table 5: Appendix 2-V Revenue Reconciliation 2020

Rate Class	Customers/ Connections	Number of Customers/Connections: Start of Test Year	End of Test Year	Average	Test Year Consumption: kWh	kW	Proposed Rates: Monthly Service Charge	Volumetric: kWh	Volumetric: kW	Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
Residential	Customers	350,149	351,406	350,778	2,713,502,642		$ 17.04	$ 0.0223		$ 132,238,109	$ 132,133,185		$ 132,133,185	-$ 104,924
GS < 50 kW	Customers	33,772	34,134	33,953	1,020,971,584		$ 33.37	$ 0.0219		$ 35,953,646	$ 35,941,140		$ 35,941,140	-$ 12,506
GS > 50 to 4,999 kW	Customers	5,332	5,453	5,393	4,549,129,870	12,146,171	$ 138.48		$ 5.0712	$ 70,556,974	$ 68,417,637	$ 2,138,793	$ 70,556,430	-$ 544
Large Use	Customers	2	2	2	74,278,555	146,357	$ 5,966.29		$ 3.0387	$ 587,925	$ 500,111	$ 87,814	$ 587,925	$ 0
Streetlighting	Connections	93,997	95,547	94,772	37,566,265	105,032	$ 1.70		$ 10.9884	$ 3,087,483	$ 3,087,451		$ 3,087,451	-$ 32
Sentinel Lighting	Connections	207	207	207	377,820	975	$ 4.97		$ 11.5304	$ 23,583	$ 23,583		$ 23,583	$ 0
Unmetered Scattered Load	Customers	3,263	3,363	3,313	15,720,206		$ 9.12	$ 0.0256		$ 765,012	$ 765,494		$ 765,494	$ 482
Total										$ 243,212,732	$ 240,868,600	$ 2,226,607	$ 243,095,208	-$ 117,525

TRANSMISSION RATES

Retail transmission service rates ("RTSRs") are charges that a distributor applies to customers to recover the costs associated with the payment by the distributor of wholesale transmission line connection, transformation connection and network charges.

On June 28, 2012, the Board issued a Revision 4.0 to the *Electricity Distribution Retail Transmission Service Rates Guideline* (G-2008-0001, referred to here as the "Guideline"). The revised Guideline provided instructions on the evidence to be submitted, and the methodology to be used to adjust RTSRs by the distributors, in order to reflect changes in the Ontario Uniform Transmission Rates ("UTRs"). The Board's guidance has been followed in calculating the proposed RTSRs.

2016-2020 Proposed RTSRs

PowerStream applied the following methodology in the proposed 2016-2020 transmission rate design:

1. For each rate class, revenue at current rates is calculated by multiplying the 2015 Board approved RTSRs to the 2015 forecasted billing determinants adjusted by the proposed line losses factor for each rate class. Table 1 summarizes PowerStream's 2015 RTSRs per the OEB's final Rate Order (EB-2014-0108), issued on December 4, 2014 and effective on January 1, 2015.

Table 1: 2015 Retail Transmission Service Rates (EB-2014-0108)

Rate Class	Network Service Rate	Line and Transformation Connection Service Rate
Residential	0.0080	0.0035
General Service < 50 kW	0.0072	0.0030
General Service > 50 kW	2.9192	1.1726
General Service > 50 kW Interval	3.0601	1.2687
Large Use	3.4638	1.2027
Unmetered Scattered Load	0.0072	0.0034
Sentinel Lighting	2.2561	0.8629
Street Lighting	2.2203	0.9503

2. These revenue amounts are then added to derive the total revenue for all customer classes. The revenue amount in each rate class is divided by this total revenue amount to derive the percentage for each class which is used to allocate forecasted wholesale transmission costs of 2016-2020 Test Years. The forecasted wholesale transmission costs are part of the Cost of Power Forecast provided in Exhibit G, Tab 4.

3. The forecasted wholesale transmission costs for each rate class are then divided by the corresponding forecasted billing determinants for 2016-2020 Test Years to arrive at the RTSRs. The resulting RTSRs are provided in Table 2 and Table 3 below.

PowerStream is proposing to update the RTSRs for 2016-2020 on an annual basis so that the Board Approved UTRs for each year can be incorporated into the RTSR rate design.

Table 2: Proposed RTSR - Network Service Rate 2016-2020

Network Service Rate					
Rate Class	**2016**	**2017**	**2018**	**2019**	**2020**
Residential	0.0080	0.0081	0.0083	0.0084	0.0086
General Service < 50 kW	0.0072	0.0073	0.0075	0.0076	0.0077
General Service > 50 kW	2.8960	2.9367	2.9823	3.0321	3.0802
General Service > 50 kW Interval	3.0358	3.0784	3.1263	3.1785	3.2289
Large Use	3.4798	3.5558	3.6338	3.7114	3.7928
Unmetered Scattered Load	0.0070	0.0069	0.0068	0.0067	0.0067
Sentinel Lighting	2.2538	2.2870	2.3200	2.3520	2.3857
Street Lighting	2.5104	2.9365	3.5555	3.6409	3.7471

Table 3: Proposed RTSR - Line and Transformation Connection Service Rate 2016-2020

Line and Transformation Connection Service Rate					
Rate Class	**2016**	**2017**	**2018**	**2019**	**2020**
Residential	0.0037	0.0038	0.0038	0.0039	0.0040
General Service < 50 kW	0.0032	0.0032	0.0033	0.0034	0.0035
General Service > 50 kW	1.2343	1.2538	1.2758	1.2998	1.3234
General Service > 50 kW Interval	1.3354	1.3566	1.3803	1.4064	1.4319
Large Use	1.2820	1.3123	1.3437	1.3753	1.4086
Unmetered Scattered Load	0.0035	0.0035	0.0034	0.0034	0.0034
Sentinel Lighting	0.9146	0.9297	0.9450	0.9600	0.9760
Street Lighting	1.1400	1.3359	1.6206	1.6631	1.7154

The detailed calculations for PowerStream's RTSRs for each class are provided as supplementary Information in electronic Appendix M-3-1.

LOW VOLTAGE ("LV") CHARGES

LV charges are excluded from PowerStream's Base Revenue Requirement. PowerStream treats Hydro One's LV charges as a "pass-through," as prescribed by Article 220 of the Board's Accounting Procedures Handbook (the "APH").

PowerStream is supplied from Hydro One's sub-transmission/distribution facilities that are connected to the Hydro One transmission system. PowerStream is considered by Hydro One as a Sub-Transmission ("ST") customer, because PowerStream has some embedded supply points; that is, PowerStream receives supply via Hydro One distribution assets.

PowerStream's proposed 2016 LV charges are based on the 2016 forecast of LV costs of $4,654,991. See Exhibit G, Tab 4 for more details on forecasted LV costs.

The LV forecast for 2016 has been allocated to the customer classes based on the methodology previously approved in PowerStream's 2013 Rate Model, which is based on the OEB's 2006 EDR Model. The LV costs are allocated based on the transmission connection amounts. The calculation is presented in Table 1 below.

Table 1: LV Charge Allocation to Rate Classes

		PowerStream							PowerStream			2016
		2015 Transmission Connection Rate		Loss Factor	Basis for Allocation (based on 2015 Approved Rates)				Basis for Allocation			Allocated LV charges
		$ per kwh / kw			kwh	kw	$		$		%	$
Residential	$/kWh	$	0.0035	1.0345	2,750,618,680	0	$9,627,165	$	9,627,165		35.1%	$1,633,190
GS<50	$/kWh	$	0.0030	1.0345	1,040,222,607	0	$3,120,668	$	3,120,668		11.4%	$529,402
GS>50	$/kW	$	1.1726	1.0345	4,574,077,591	12,212,781	$14,320,707	$	14,320,707		52.2%	$2,429,421
Large Use	$/kW	$	1.2027		76,536,992	150,807	$181,375	$	181,375		0.7%	$30,769
USL	$/kWh	$	0.0034	1.0345	14,169,725	0	$48,177	$	48,177		0.2%	$8,173
Sentinel Lighting	$/kW	$	0.8629	1.0345	378,080	975	$842	$	842		0.0%	$143
Street Lighting	$/kW	$	0.9503	1.0345	53,007,707	148,205	$140,839	$	140,839		0.5%	$23,893
Total					8,509,011,382	12,512,768	$27,439,773	$	27,439,773		100.0%	**$4,654,991**
									Total to be allocated		**$**	**4,654,991**

The calculation of PowerStream's proposed LV rates for each customer class is presented in Table 2, below.

Table 2: LV Rates Calculation

		2016				LV Wheeling Rates	
		LV charge allocated, $	kwh	kw		$/kwh	$/kw
Residential	*$/kWh*	$ 1,633,190	2,750,618,680	-		0.0006	
GS<50	*$/kWh*	$ 529,402	1,040,222,607	-		0.0005	
GS>50	*$/kW*	$ 2,429,421	4,574,077,591	12,212,781			0.1989
Time of use	*0*	$ -	-	-			
Large Use	*$/kW*	$ 30,769	76,536,992	150,807			0.2040
USL	*$/kWh*	$ 8,173	14,169,725	-		0.0006	
Sentinel Lighting	*$/kW*	$ 143	378,080	975			0.1464
Street Lighting	*$/kW*	$ 23,893	53,007,707	148,205			0.1612
Total		**$ 4,654,991**	**8,509,011,382**	**12,512,768**			

PowerStream has allocated the forecasted LV costs for 2017 through 2020 on the same basis. It then used the forecasted billing determinants for each year to calculate the LV rate. Table 3 below provides the summary of LV rates by year.

Table 3: Low Voltage Rates by Year

Customer Class	*Billing Determinant*	Current 2015	Proposed 2016	2017	2018	2019	2020
Forecasted LV Charges			$ 4,654,991	$ 4,882,065	$ 5,103,784	$ 5,334,655	$ 5,320,773
Residential	*kWh*	$0.0003	$0.0006	$0.0006	$0.0007	$0.0007	$0.0007
GS<50 kW	*kWh*	$0.0003	$0.0005	$0.0005	$0.0006	$0.0006	$0.0006
GS>50 kW	*kW*	$0.1189	$0.1989	$0.2092	$0.2192	$0.2299	$0.2299
Large Use	*kW*	$0.1437	$0.2040	$0.2146	$0.2249	$0.2358	$0.2358
Unmetered Scattered Load	*kWh*	$0.0003	$0.0006	$0.0006	$0.0006	$0.0007	$0.0007
Sentinel Lights	*kW*	$0.1031	$0.1464	$0.1539	$0.1613	$0.1692	$0.1692
Street Lighting	*kW*	$0.0917	$0.1612	$0.1695	$0.1777	$0.1863	$0.1864

LOSS ADJUSTMENT FACTORS

Overview

PowerStream's proposed loss factors are well below the Board's threshold of 5% cited in section 2.11.9 of the Filing Requirements.

Note that several different "total loss factors" are derived to be used as the loss adjustment factor for billing in different situations as described in the following section.

LOSS ADJUSTMENT FACTOR CALCULATIONS

PowerStream has calculated the billing loss adjustment factors pertaining to secondary-metered customers with demand less than 5,000 kW in accordance with the Filing Requirements, using Appendix 2-R. PowerStream's proposed loss adjustment factors are based on the average of the three most recent complete years from 2011 to 2013.

PowerStream receives most of its electricity through IESO-controlled delivery points. PowerStream proposes to use the current Board approved Supply Facility Loss Factor ("SFLF") of 1.0045. The SFLF is intended to account for losses that occur from the point that power is taken from the transmission grid to the point where it enters PowerStream's distribution lines. Losses occur mainly from the transformation of the power from the transmission grid voltage to the distribution system voltage.

The Distribution Loss Factor ("DLF") represents losses in the Distributor's system as calculated using the Board's Appendix 2-R. PowerStream calculated an average DLF of 1.0323 over the last three years.

There are several different loss factors depending on whether or not the customer is a Large Use customer (with average monthly peak demand over 5,000 kW) and how the customer is metered.

The Total Loss Factor ("TLF") to be used as the billing loss factor adjustment is calculated as the SFLF multiplied by DLF. The same SFLF of 1.0045 is used for all customers.

Appendix 2-R

	PS Harmonized Losses in Distributor's System	2013	2012	2011	3-yr Average 2011-2013
A_1	"Wholesale" kWh delivered to distributor (higher value)	Not available	Not available	Not available	
A_2	"Wholesale" kWh delivered to distributor (lower value)	8,700,104,584	8,737,318,975	8,658,416,020	**8,698,613,193**
B	Portion of "Wholesale" kWh delivered to distributor for Large Use Customer(s)	62,258,329	26,670,727	27,116,405	**38,681,820**
C	Net "Wholesale" kWh delivered to distributor (A_2)-(B)	8,637,846,255	8,710,648,248	8,631,299,615	**8,659,931,372**
D	"Retail" kWh delivered by distributor	8,421,546,061	8,467,722,619	8,394,821,657	**8,428,030,113**
E	Portion of "Retail" kWh delivered by distributor for Large Use Customer(s)	62,258,329	26,670,727	27,116,405	**38,681,820**
F	Net "Retail" kWh delivered by distributor (D)-(E)	8,359,287,732	8,441,051,892	8,367,705,252	**8,389,348,292**
G	Loss Factor in distributor's system [(C)/(F)]	1.0333	1.0319	1.0315	**1.0323**
	Losses Upstream of Distributor's System				
H	Supply Facility Loss Factor	1.0045	1.0045	1.0045	**1.0045**
	Total Losses				
I	Total Loss Factor [(G)x(H)]	1.0380	1.0366	1.0361	**1.0369**

PowerStream proposes to use the current Board-approved loss adjustment factor for primary metered Large Use (>5000 kW demand) customers of 1.0045, which represents the SFLF. For secondary metered Large Use (>5000 kW demand) customers, PowerStream proposes to use the current Board-approved loss adjustment factor of 1.0145, which represents the SFLF and the secondary metered distribution loss factor of 1.0100 described in the next paragraph.

PowerStream proposes to use the current Board approved secondary metered loss factor of 1.0100. This secondary metered loss factor is a default value representing the losses that occur in the line transformer where the voltage is stepped down from the distribution voltage (typically 27.6kV) to the customer's service voltage (typically 600V for commercial and 120/240V for residential). Table 1 shows the DLF for each type of customer and resulting TLF when the SFLF of 1.0045 is applied.

Table1: PowerStream Loss Adjustment Factors – Detailed Calculation

Biling Loss Factors	**2013 Approved**	**Proposed 2016 -2020 Test Years**
Total Loss Factor - Primary Metered Customer < 5,000 kW	**1.0243**	**1.0266**
Total Loss Factor - Secondary Metered Customer < 5,000 kW	**1.0345**	**1.0369**
Total Loss Factor - Primary Metered Customer > 5,000 kW	**1.0045**	**1.0045**
Total Loss Factor - Secondary Metered Customer > 5,000 kW	**1.0145**	**1.0145**
Supply Facilities Loss Factor	**1.0045**	**1.0045**
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	**1.0197**	**1.0220**
Distribution Loss Factor - Secondary Metered Customer < 5,000 kW	**1.0299**	**1.0323**
Distribution Loss Factor - Primary Metered Customer > 5,000 kW	**1.0000**	**1.0000**
Distribution Loss Factor - Secondary Metered Customer > 5,000 kW	**1.0100**	**1.0100**

DEFERRAL AND VARIANCE ACCOUNTS

In this application, PowerStream is seeking disposition of deferral and variance account ("DVA") balances as at December 31, 2014 plus accrued interest up to December 31, 2015, totalling a net amount of $10,860,100 to be recovered from customers.

Table 1 below provides a summary of the accounts and amounts requested for disposition. Positive amounts denote recovery from customers (debit), negative amounts denote payable to customers (credit). For more details see Supplemental Information electronic document N-1-1, DVA Continuity Schedule, and Supplemental Information electronic document N-1-2, Reconciliation of DVA disposition amounts to the December 31, 2014 RRR filing balances.

Table 1: Summary of DVA Amounts for Disposition ($ thousands)

Description	Amount
Group 1 and 2 excluding certain accounts[1]	$2,556.6
Account 1589 Global Adjustment	$10,422.1
Account 1575 IFRS PP&E Amount	($2,392.7)
Account 1568 LRAMVA	($504.3)
Account 1555 Stranded Meters residual	$599.1
Total for disposition	$10,680.8
Notes:	
1. Excluding accounts, 1555, 1568, 1575 and 1589	

The Group 1 and 2 total for disposition is net of the following adjustments:

- Account 1508 sub-account OPEB Deferral Account in the amount of $2,062,300 credit has been excluded from the amount for disposition. Per the Board-approved accounting order (EB-2012-0161), this amount, if disposed, is to be amortized over the average employee remaining service years. This would result in a fairly small amount. PowerStream proposes to defer recovery and leave this amount to absorb any further actuarial revaluation.

- Account 1508 sub-account CGAAP-CWIP Differential Deferral Account in the amount of $2,759,700 debit has been excluded from the amount for disposition. This balance is already being recovered through approved rate riders which run to December 31, 2015.

- Account 1508 sub-account Incremental Capital Module (ICM) amounts have been excluded from the amount for disposition and replaced with the ICM true-up amount. Details supporting the ICM true-up amount can be found in Exhibit G, Tab 2b, ICM True-up.

- Green Energy deferral accounts for capital, account 1531 Renewable Generation Enabling Investments deferral and account 1534 Smart Grid capital deferral have been removed as these amounts are added to fixed assets and included in rate base. Account 1536 Smart Grid funding adder has been adjusted to reflect the true-up amount - see Exhibit N, Tab 2, Smart Grid Funding Adder True-up.

Tables 2 to 6 below summarize the allocation of the amounts for disposition to the rate classes and the associated rate riders.

The calculation of the rate riders reflect the period of disposition. For all accounts other than Group 1 and 2 and account 1589 Global Adjustment, the proposed disposition period is one year, which is consistent with the Board’s guideline. For Group 1 and 2 and account 1589 Global Adjustment, the proposed disposition period is two years to reduce the rate impact for customers.

Table 2: Group 1 and 2 Allocation and Rate Riders

Rate Class	Units	Quantity	Allocated Amount	Rate Rider
RESIDENTIAL	kWh	2,750,618,680	$ 1,322,563	$0.0002
GENERAL SERVICE LESS THAN 50 KW	kWh	1,040,222,607	$ 433,407	$0.0002
GENERAL SERVICE 50 TO 4,999 KW	kW	12,212,781	$ 846,675	$0.0347
LARGE USER	kW	150,807	$ 5,085	$0.0169
UNMETERED SCATTERED LOAD	kWh	14,169,725	$ 5,756	$0.0002
SENTINEL LIGHTING	kW	975	$ 77	$0.0395
STREET LIGHTING	kW	148,205	-$ 56,920	($0.1920)
Total			$ 2,556,643	

Table 3: Global Adjustment Allocation and Rate Riders

Rate Class	Units	Quantity	Allocated Amount	Rate Rider
RESIDENTIAL	kWh	159,139,043	$ 354,807	$0.0011
GENERAL SERVICE LESS THAN 50 KW	kWh	170,983,976	$ 381,215	$0.0011
GENERAL SERVICE 50 TO 4,999 KW	kW	11,434,409	$ 9,548,116	$0.4175
LARGE USER	kW	-	$ -	
UNMETERED SCATTERED LOAD	kWh	274,430	$ 612	$0.0011
SENTINEL LIGHTING	kW	119	$ 103	$0.4323
STREET LIGHTING	kW	172,101	$ 137,238	$0.3987
Total			$ 10,422,091	

Table 4: IFRS PP&E Account 1575 Allocation and Rate Riders

Rate Class	Units	Quantity	Allocated Amount	Rate Rider
RESIDENTIAL	kWh	2,750,618,680	($1,295,981)	($0.0005)
GENERAL SERVICE LESS THAN 50 KW	kWh	1,040,222,607	($362,450)	($0.0003)
GENERAL SERVICE 50 TO 4,999 KW	kW	12,212,781	($688,198)	($0.0564)
LARGE USER	kW	150,807	($4,695)	($0.0311)
UNMETERED SCATTERED LOAD	kWh	14,169,725	($7,006)	($0.0005)
SENTINEL LIGHTING	kW	975	($241)	($0.2472)
STREET LIGHTING	kW	148,205	($34,176)	($0.2306)
Total			($2,392,747)	

Table 5: Account 1568 LRAMVA Allocation and Rate Riders

Rate Class	Units	Quantity	Allocated Amount	Rate Rider
RESIDENTIAL	kWh	2,750,618,680	($377,952)	($0.0001)
GENERAL SERVICE LESS THAN 50 KW	kWh	1,040,222,607	$55,770	$0.0001
GENERAL SERVICE 50 TO 4,999 KW	kW	12,212,781	($154,035)	($0.0126)
LARGE USER	kW	150,807	($5,320)	($0.0353)
UNMETERED SCATTERED LOAD	kWh	14,169,725	($3,344)	($0.0002)
SENTINEL LIGHTING	kW	975	($162)	($0.1662)
STREET LIGHTING	kW	148,205	($19,214)	($0.1296)
Total			($504,257)	

Table 6: Stranded Meter Residual Allocation and Rate Riders

Rate Class	Units	Quantity	Allocated Amount	Rate Rider
RESIDENTIAL	kWh	2,750,618,680	$407,018	$0.0001
GENERAL SERVICE LESS THAN 50 KW	kWh	1,040,222,607	$192,093	$0.0002
GENERAL SERVICE 50 TO 4,999 KW	kW	12,212,781		$0.0000
LARGE USER	kW	150,807		$0.0000
UNMETERED SCATTERED LOAD	kWh	14,169,725		$0.0000
SENTINEL LIGHTING	kW	975		$0.0000
STREET LIGHTING	kW	148,205		$0.0000
Total			$599,111	

SMART GRID FUNDING ADDER TRUE-UP

In its 2014 Incentive Regulation Mechanism application (EB-2013-0166), PowerStream received approval for a Smart Grid funding adder that would provide for the collection of $840,791 over a 10-month period, March 1, 2014 to December 31, 2014.

In this Custom IR proposal, PowerStream has calculated the revenue requirement on its actual and forecasted in-service smart grid capital to December 31, 2015 and compared this to the smart grid funding adders collected plus interest thereon. The Smart Grid True-up model has been provided in the Supplemental Information as electronic document N-2-1 – Smart Grid Funding Adder True-up model. The results are summarized in Table 1 below (taken from the model).

Table 1: Summary of Smart Grid Funding Adder True-up

	2014		2015	Total
Deferred and forecasted SG Revenue Requirement (from Sheet 5)	$76,918		$286,946	$363,864
SG Funding Adder Revenues (from Sheet 4)	$872,000		$0	$872,000
SG Funding Adder Interest (from Sheet 4)	$4,807		$12,818	$17,625
Net Deferred Revenue Requirement	($799,889)	$0	$274,128	($525,761)

The net credit of $525,761 to be returned to customers has been included in the deferral and variance account balances for disposition. See Exhibit N, Tab 1 for more details.

DEFERRAL AND VARIANCE ACCOUNT (“DVA”) TREATMENT

PowerStream currently has several deferral accounts related to the transition to IFRS that were approved in its 2013 Cost of Service application (“2013 COS”):

- Account 1508 Subaccount – Post Retirement Employee Benefits (“PREB”)
- Account 1508 Subaccount – CGAAP CWIP Differential (“CWIP”)
- Account 1575 IFRS-CGAAP Transitional PP&E Amounts (“PP&E Amount”)

PowerStream does not propose to dispose of the PREB account at this time. This is meant to track amounts resulting from actuarial revaluations and allow them to be recognized over a longer period than is the case under IFRS, i.e. the average remaining service life of the employees. The magnitude of the amount is small when converted to an annual amount on the service life basis.

There are approved rate rides for recovery of the CWIP amount that are in effect until December 31, 2016. Accordingly this balance has been excluded from the amounts for disposition in Exhibit N, Tab 1.

The PP&E amount was deducted from rate base in the 2013 COS; in order to amortize that amount over four years, ¼ of the PP&E amount was deducted from depreciation expense in calculating the 2013 Test Year revenue requirement. In this application, PowerStream has not made any adjustment to rate base or revenue requirement for the remaining balance at December 31, 2015 of $2,392,750 credit (refund to customers). This amount has been included in the DVA amounts for disposition in Exhibit N, Tab 1.

PowerStream requests a new deferral account to capture the net book value of meters removed from service to comply with the Board’s May 21, 2014 Distribution System Code (“DSC”) amendment requiring all General Service over 50 kW customers to have meters capable of recording time-of-use electricity consumption.