October 1, 2012

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
26th Floor, Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli

Re: PowerStream Inc. (Licence ED-2004-0420)
2013 Electricity Distribution Rates Application EB-2012-0161

The Technical Conference held on September 24, 2012 at the Board's offices resulted in PowerStream having a number of undertakings. The responses to these undertakings are attached. These responses have been sent by e-mail to the parties and have been filed on RESS.

We trust that this is satisfactory, but if further information is needed, please do not hesitate to contact the undersigned.

Yours truly,

Original signed by

Colin Macdonald
Vice President, Rates and Regulatory Affairs

PowerStream Inc.

Responses to Undertakings of:

September 24, 2012 Technical Conference

Table of Contents

UNDERTAKING NO. JT1.1: TO UPDATE THE LOAD FORECAST MODEL IN A SIMILAR WAY AS VECC TCQ No. 55b), USING 37 RATHER THAN 12 MILLION KILOWATT HOURS. (PAGE 10)

Response:

PowerStream has updated the load forecast model using 37.27 million kWh which was the 2011 CDM savings per the OPA-Contracted Province-Wide CDM Programs Final 2011 Results. The resulting load forecast is 5,976,950 kWhs higher than PowerStream's pre-filed evidence, which represents a 0.068% increase in the total load forecast for 2013. This increase in load represents an approximate $62,000 increase in the 2013 revenue at the current rates. Please refer to the tables below.

Table JT1.1-1: CDM Savings Breakdown by Component

Year	OPA Programs	3rd Tranche	2011-2014 Targets 2011 Annualized Verified	Total Revised Annual	2011-2014 Targets Original Evidence	2011-2014 Targets VECC TCQ 55b)
2005	0	3,130,723	0	3,130,723	0	0
2006	23,745,838	24,080,564	0	47,826,403	0	0
2007	37,320,287	33,881,792	0	71,202,078	0	0
2008	74,910,984	33,568,782	0	108,479,766	0	0
2009	118,966,981	0	0	118,966,981	0	0
2010	125,158,173	0	0	125,158,173	0	0
2011	114,674,894	0	37,270,000	151,944,894	14,637,000	12,183,372
2012	*112,573,489*	*0*	*63,374,000*	175,947,489	*63,374,000*	*63,374,000*
2013	*112,089,533*	*0*	*141,438,000*	253,527,533	*141,438,000*	*141,438,000*
2014	*108,636,708*	*0*	*187,851,000*	296,487,708	*187,851,000*	*187,851,000*
			429,933,000		**407,300,000**	**404,846,372**

Table JT1.1-2: Re-estimated Load Forecast Model

Dependent Variable: Monthly Energy Purchases grossed up by CDM
Form: Multiple Regression
Sample: 01/2002 - 12/2011
Included observations: 120
Degree of Freedom for Error: 110

Variable	Coefficient	t-Statistics	Sig.
(Constant)	547,885,816	126.89	0.00%
Real GDP	33,629,118	27.43	0.00%
CDD18	1,059,523	42.13	0.00%
HDD10	191,322	26.07	0.00%
Feb	(48,394,312)	(11.95)	0.00%
Apr	(21,335,891)	(5.53)	0.00%
Adjusted R-squared	96.4%	**MAD**	8,308,090
Standard Error of regression	11,030,970	**MAPE**	1.2%
F-test	357.7	**Durbin-Watson statistics**	1.9

Table JT1.1-3: 2012-2013 CDM Reduction to Re-estimated Load Forecast

Year	Actual Gross	CDM Reduction	Actuals	WN Actual Gross	WN Actual Net	Growth, %
2002	7,866,379,970	0	7,866,379,970	7,773,586,010	7,773,586,010	
2003	7,916,829,430	0	7,916,829,430	7,938,644,200	7,938,644,200	2.1%
2004	8,134,619,560	0	8,134,619,560	8,255,258,020	8,255,258,020	4.0%
2005	8,613,124,000	3,130,723	8,609,993,277	8,445,458,410	8,442,327,687	2.3%
2006	8,554,533,740	47,826,403	8,506,707,337	8,607,722,940	8,559,896,537	1.4%
2007	8,781,190,980	71,202,078	8,709,988,902	8,685,827,150	8,614,625,072	0.6%
2008	8,672,944,380	108,479,766	8,564,464,614	8,781,872,660	8,673,392,894	0.7%
2009	8,406,357,790	118,966,981	8,287,390,809	8,612,192,150	8,493,225,169	-2.1%
2010	8,773,591,030	125,158,173	8,648,432,857	8,735,830,630	8,610,672,457	1.4%
2011	8,849,252,550	151,944,894	8,697,307,656	8,786,337,060	8,634,392,166	0.3%
2012 Bridge		**175,947,489**		**8,895,431,000**	**8,719,483,511**	**1.0%**
2013 Test		**253,527,533**		**8,995,400,120**	**8,741,872,587**	**0.3%**

2012 Bridge - as per original evidence	**8,714,187,901**	**0.8%**
2013 Test - as per original evidence	**8,735,895,637**	**0.2%**

UNDERTAKING NO. JT1.2: TO PERFORM AN ANALYSIS SIMILAR TO THAT FOR VECC 55a) SHOWING THE ACTUAL IMPACT IN 2011 OF THOSE PROGRAMS, BASED ON THE ESTIMATED START DATES FOR EACH OF THE SUB PROGRAMS AND PRORATED FOR 37 MILLION KILOWATT HOURS. (PAGE 12)

Response:

PowerStream has provided the prorated savings for the 2011 OPA programs in the table below. The re-estimated load forecast based on the pro-rated savings results in an approximate $51,000 increase in 2013 revenue at current rates as compared to the pre-filed evidence.

Table JT1.2: CDM Initiatives Prorated by Month (2011 Verified results)

Month	Appliance Retirement	Appliance Exchange	HVAC	Coupon Booklet	Bi-Annual Retailer Event	Retailer-Coop	Residential Demand Response	ERII	DIL	HPNC	DR3	ERIP 2010 Carryover	HPNC 2010 Carryover	MEER 2010 Carryover	DCIP 2010 Carryover	Total 2011
Jan	0	0	0	0	0	0	270	0	0	0	0	795,002	90,241	16,211	44,420	**946,144**
Feb	0	0	0	0	0	0	270	0	0	0	0	795,002	90,241	16,211	44,420	**946,144**
Mar	96,746	0	432,674	107,929	0	0	270	893,888	441,357	5,822	0	795,002	90,241	16,211	44,420	**2,924,560**
Apr	96,746	0	432,674	107,929	0	0	270	893,888	441,357	5,822	0	795,002	90,241	16,211	44,420	**2,924,560**
May	96,746	1,580	432,674	107,929	162,570	195	270	893,888	441,357	5,822	0	795,002	90,241	16,211	44,420	**3,088,905**
Jun	96,746	1,580	432,674	107,929	162,570	195	270	893,888	441,357	5,822	16,927	795,002	90,241	16,211	44,420	**3,105,832**
Jul	96,746	1,580	432,674	107,929	162,570	195	270	893,888	441,357	5,822	16,927	795,002	90,241	16,211	44,420	**3,105,832**
Aug	96,746	1,580	432,674	107,929	162,570	195	270	893,888	441,357	5,822	16,927	795,002	90,241	16,211	44,420	**3,105,832**
Sep	96,746	1,580	432,674	107,929	162,570	195	270	893,888	441,357	5,822	16,927	795,002	90,241	16,211	44,420	**3,105,832**
Oct	96,746	1,580	432,674	107,929	162,570	195	270	893,888	441,357	5,822	16,927	795,002	90,241	16,211	44,420	**3,105,832**
Nov	96,746	1,580	432,674	107,929	162,570	195	270	893,888	441,357	5,822	16,927	795,002	90,241	16,211	44,420	**3,105,832**
Dec	96,746	1,580	432,674	107,929	162,570	195	270	893,888	441,357	5,822	16,927	795,002	90,241	16,211	44,420	**3,105,832**
Total 2011 YTD	**967,455**	**12,641**	**4,326,741**	**1,079,294**	**1,300,559**	**1,557**	**3,239**	**8,938,878**	**4,413,565**	**58,223**	**118,491**	**9,540,024**	**1,082,896**	**194,534**	**533,038**	**32,571,136**
Annualized Savings	1,160,946	18,962	5,192,089	1,295,153	1,950,839	2,335	3,239	10,726,654	5,296,278	69,868	203,127	9,540,024	1,082,896	194,534	533,038	**37,269,983**
															Variance	**(4,698,846)**

UNDERTAKING NO. JT1.3: TO EXPLAIN DISCREPANCY IN DEPRECIATION IN RESPONSE TO BOARD STAFF INTERROGATORY NO. 5-2, APPENDIX 2-CD (PAGE 16)

Response:

Table Jt1.3-1 below shows how the depreciation expense on the Revenue Requirement Work Form (RRWF) was determined. Appendix 2-CD does not include the $1,400,000 in derecognition expense that is grouped with depreciation as per the *Report of the Board: Implementing IFRS in an Incentive Rate Mechanism Environment (EB-2008-0408).* PowerStream has also requested disposition of Green Energy Act capital deferral accounts as at December 31, 2011. Depreciation on these fixed assets in the amount of $45,463 has also been included.

Table JT1.3-1: Reconciliation of Depreciation Expense per RRWF to Appendix 2-CD

	August 31, 2012 Update	**Notes**
Depreciation per RRWF	$ 36,607,422	1
Depreciation per Appendix 2-CD	$ 35,161,316	2
Derecognition expense	$ 1,400,000	
Depreciation on GEA capital	$ 45,463	
Rounding	$ 643	
Total Depreciation expense	$ 36,607,422	

NOTES:

1. RRWF = Revenue Requirement Work Form, Depreciation per page 2, Data Input
2. Net of PP&E amount amortization of $596,714

UNDERTAKING NO. JT1.4: TO PERFORM OR PROVIDE A VERSION OF APPENDIX 2-EA USING THE FIXED ASSET AMOUNTS FROM APPENDIX 2-B. (PAGE 19)

Response:

Please see Attachment JT1.4 for the Appendix 2-EA using the fixed asset amounts from Appendix 2-B, as requested in this undertaking.

This is not a revision to PowerStream's application and PowerStream submits that the Appendix 2-EA filed in its August 31, 2012 update is the correct application of Board guidance on this matter.

PowerStream notes that the Appendix 2-EA in this undertaking effectively excludes the burden on work in progress that would have been capitalized under Canadian GAAP and results in a material out of period cost due to the adoption of IFRS that is not in current rates. PowerStream submits that this scenario is inconsistent with the Board's stated policy.

UNDERTAKING NO. JT1.5: TO UPDATE THE RESPONSE TO CCC INTERROGATORY NO. 7 TO REFLECT THE DEPRECIATION AMOUNT OF 1.883 MILLION (PAGE 21)

Response:

PowerStream has included a full year of depreciation for 2013 additions; this has increased depreciation expense by $1,883,000 as compared to the amount determined using the half-year rule. For details, please refer to Exhibit D1, Tab 4, Schedule 1.

If this proposal is not approved by the Board, the 2013 revenue requirement will be decreased by this amount and the corresponding decrease in PILs. The resulting revenue requirement decrease is $2,527,000.

UNDERTAKING NO. JT1.6: TO RECONCILE NUMBERS IN RATE BASE SCHEDULES. (PAGE 24)

Response:

Table JT1.6-1 below reconciles the amounts in the Appendix 2-B Fixed Asset Continuity Schedules to the amounts included in the rate base calculation in the Revenue Requirement Work Form. There is a small difference of about one thousand dollars due to rounding to thousands of dollars in the fixed asset continuity schedule.

Table JT1.6-1: Reconciliation of Fixed Asset Amounts with RRWF Rate Base ($000)

Per Appendix 2-B Fixed Assets:	
Appendix 2-B Dec. 31, 2012 MIFRS	$ 698,664
Appendix 2-B Dec. 31, 2013 MIFRS	$ 743,872
Average for NBV of FA 2013	$ 721,268
Less PP&E Adjustment	$ (2,387)
Add GEA capital amounts	$ 463
Average Net Fixed Assets for rate base	**$ 719,344**
RRWF (page 3 Rate Base & Working Capital):	
Gross Fixed Assets (average)	$ 805,988
Accumulated Depreciation (average)	$ (86,643)
Average Net Fixed Assets for rate base	**$ 719,345**
Allowance for Working Capital	$ 122,697
Total Rate Base	$ 842,042

PowerStream has attached a sheet showing the calculation of the Rate Base and Service Revenue Requirement for the August 31, 2012 update (Attachment JT1.6). This shows the adjustments related to the account 1575 PP&E amount, adjustments made regarding the requested disposition of capital amounts in green energy deferral accounts and the inclusion of derecognition expense in depreciation expense. This should assist in tying in amounts on the Revenue Requirement Work Form to the chapter 2 Appendices for fixed assets and depreciation expense.

UNDERTAKING NO. JT1.7: TO RECONCILE DEPRECIATION AMORTIZATION NUMBER IN THE RRWF. (PAGE 25)

Response:

Please see the responses to Undertakings JT1.3 and JT1.6.

UNDERTAKING NO. JT1.8: TO CONFIRM THAT DATA IN EXHIBIT KT1.1, TABLE PREPARED BY BOARD STAFF, IS CORRECT; OR TO SUBMIT TABLE IF NECESSARY.

Response:

PowerStream notes a revision to the actual interest expense to remove duplication is required as discussed below. PowerStream has also provided additional information regarding several important factors that need to be considered in determining the interest true-up:

- Removal of interest expense on Regulatory Assets & Liabilities (RAL)
- Financing of the purchase of Richmond Hill Hydro
- Changes in the actual rate base compared to the 1999 rate base upon which the deemed interest expense is calculated.

PowerStream notes that in Exhibit KT1.1, the table showing "Actual Interest from AFS (Audited Financial Statements)" needs to be updated to remove the 50% of Richmond Hill Hydro (RHH) interest expense included in both Markham Hydro and Hydro Vaughan interest expense for 2002 to 2004 inclusive. The financial statement amounts shown are from the consolidated financial statements and include 50% of RHH's interest expense, due to the proportionate consolidation to reflect the 50% interest each had in RHH, acquired December 27, 2001. Table JT1.8-1 below reflects the actual interest expense after removing the double counted RHH interest expense for those years.

Table JT1.8-1: Actual Interest Expense per Audited Financial Statements

Actual Interest Expense from Audited Financials	**2001**	**2002**	**2003**	**2004**	**2005**
Aurora	$ -	$ 1,154,200	$ 923,360	$ 923,360	$ 770,942
Markham	$ 1,833,000	$ 4,904,197	$ 5,624,632	$ 2,237,812	$ -
Richmond Hill	$ 1,401,595	$ 2,285,607	$ 3,392,737	$ 1,328,377	
Hydro Vaughan	$ 3,187,323	$ 5,626,197	$ 6,810,065	$ 2,767,812	$ -
PowerStream	$ -	$ -	$ -	$ 11,680,000	$ 19,305,000
Total	**$ 6,421,918**	**$ 13,970,200**	**$ 16,750,794**	**$ 18,937,360**	**$ 20,075,942**
Markham	$ 1,833,000	$ 6,047,000	$ 7,321,000	$ 2,902,000	
less 50% of Richmond Hill	**$** -	$ 1,142,804	$ 1,696,369	$ 664,189	
Markham only	**$ 1,833,000**	**$ 4,904,197**	**$ 5,624,632**	**$ 2,237,812**	**$ -**
Vaughan	$ 3,187,323	$ 6,769,000	$ 6,810,065	**$ 3,432,000**	
less 50% of Richmond Hill	**$** -	$ 1,142,804		$ 664,189	
Vaughan only	**$ 3,187,323**	**$ 5,626,197**	**$ 6,810,065**	**$ 2,767,812**	**$ -**

In calculating the actual interest expense for purposes of the interest true-up in Table JT1.8-2, PowerStream has excluded the portion of interest expense related to Regulatory Assets & Liabilities (RAL). Regulatory assets and liabilities and the related interest costs were not factored into the deemed interest amount and accordingly should be excluded from the actual interest amount compared to the deemed interest. Additionally these are costs that are outside PowerStream's control. PowerStream was able to determine the amount of RAL interest expense included in the total interest expense for 2004 and 2005. PowerStream was unable to identify this for earlier periods so no adjustments are proposed for those years.

PowerStream submits that the purchase of RHH requires further adjustments to interest expense in determining the interest true-up amount. As shown in Exhibit KT1.1 there is $33.0 million in goodwill resulting from the purchase price premium paid for RHH in excess of the book value of its assets. This goodwill and the cost of financing this purchase price premium is not factored into rates and not paid for by rate payers. Accordingly the cost of financing this goodwill should be removed from the actual interest expense for purposes of the interest true-up. The cost of financing this goodwill is $2,128,000 per year for 2002 to 2005 inclusive.

Table JT1.8-2 shows the adjusted actual interest expense and compares this to the deemed interest expense.

Table JT1.8-2: Adjusted Interest Expense and Deemed Interest Comparison

	2001	2002	2003	2004	2005
Actual Interest Expense per Audited Financials	$ 6,421,918	$ 13,970,200	$ 16,750,794	$ 18,937,360	$ 20,075,942
less interest expense on regulatory assets & liabilities				$ (1,332,449)	$ (3,589,657)
Revised interest expense subtotal	$ 6,421,918	$ 13,970,200	$ 16,750,794	$ 17,604,911	$ 16,486,285
Less interest on Goodwill		$ (2,127,726)	$ (2,127,726)	$ (2,127,726)	$ (2,127,726)
Revised interest expense total	$ 6,421,918	$ 11,842,474	$ 14,623,068	$ 15,477,185	$ 14,358,559
Deemed interest	$ 17,106,682	$ 17,106,682	$ 17,106,682	$ 17,106,682	$ 17,106,682
Potential excess interest for true-up	$ -	$ -	$ -	$ -	$ -

As can be seen in the Table JT1.8-2 above, once the interest expense on Regulatory Assets & Liabilities is removed, only 2004 has any potential excess interest (i.e. $498,229, $17,604,911 less $17,106,682). In all other years the actual interest expense is below deemed.

PowerStream has also made a comparison of actual 2005 rate base and deemed interest thereon to the 1999 rate base and deemed interest, which is the basis of the deemed interest used in the interest true-up calculation. This is summarized in Table JT1.8-3 below.

Table JT1.8-3: Comparison of 2005 Actual Rate Base and Deemed Interest

	Rate base	Deemed interest
2005 Actual	$ 458,569,396	$ 17,588,286
1999 basis for rates	$ 446,012,794	$ 17,106,682
Increase (decrease)	$ 12,556,602	$ 481,605

Powerstream notes that the increase in actual rate base and the increase in deemed interest thereon accounts for most of the potential excess interest of $498,229 in 2004. Adjusting for the cost of financing the goodwill eliminates any remaining potential excess interest.

The followng two tables provide the supporting details for the amounts in the summary table JT1.8-3.

Table JT1.8-4:1999 Rate Base And Deemed Interest Used For Rates

1999 Rate Base and Deemed Interest	Aurora	Markham	Richmond Hill	Vaughan	Total /Weighted Average
Rate Base	$ 28,804,790	132,012,571	104,354,290	180,841,143	$ 446,012,794
Debt ratio	50.00%	55.00%	55.00%	55.00%	54.68%
Deemed Debt	$ 14,402,395	$ 72,606,914	$ 57,394,860	$ 99,462,629	$ 243,866,797
Deemed interest rate	7.25%	7.00%	7.00%	7.00%	7.01%
Deemed Interest	$ 1,044,174	$ 5,082,484	$ 4,017,640	$ 6,962,384	$ 17,106,682

Table JT1.8-5: 2005 Actual Rate Base and Deemed Interest

2005 Actual Rate Base and Deemed Interest	**Total**
Opening Net Fixed Assets	$ 371,366,031
Closing Net Fixed Assets	$ 376,773,000
Average Net Fixed Assets	$ 374,069,516
Working Capital:	
Cost of Power	$ 520,411,291
Operating costs	$ 42,921,245
Total Working Capital	$ 563,332,536
Working capital allowance	$ 84,499,880
Rate Base	$ 458,569,396
Debt ratio	54.68%
Deemed Debt	$ 250,732,381
Deemed interest rate	7.01%
Deemed Interest	$ 17,588,286

UNDERTAKING NO. JT1.9: TO PROVIDE COMPARISON OF THE BILL IMPACTS IN THE APPLICATION AS FILED AND BILL IMPACTS IN THE UPDATE. (Page 33)

Response:

The table below provides the requested comparison of the bill impacts for Residential and GS< 50 kW classes:

Table JT1.9-1 Comparison of Changes in Total Monthly Bill (Revised Aug. 31, 2012 vs. Pre-filed)

	Original		Revised Aug. 31st		Change from the original			
	South	Barrie	South	Barrie	South	Barrie	South	Barrie
					$	$	%	%
Residential	$ 2.80	$ (5.13)	$ 2.83	$ (5.09)	$ 0.03	$ 0.04	1.1%	-0.8%
GS<50	$ 1.69	$ (6.20)	$ 1.95	$ (5.93)	$ 0.26	$ 0.27	15.4%	-4.4%

The impact of an overall 0.18% increase in revenue requirement has differing impacts for the Residential and GS<50 kW classes. As shown in Table JT1.9-2, for the Residential class, only the fixed rate increases as a result of the increase in revenue requirement, the change is the variable rate rounded to the same amount. In contrast, for GS<50 kW class, both fixed and variable rates are slightly higher.

Consequently, the $0.0001 increase in the variable distribution rate, multiplied by 2,000 kWh consumption for typical GS<50 kW customer, results in $0.20 increase in the monthly bill (before taxes). Therefore, the final bill impact for GS<50 class is relatively higher than for residential customers.

Table JT1.9-2 Comparison of Proposed Rates

	PowerStream South		PowerStream Barrie		Proposed Harmonized Rates			
	Current		Current		Original		Revised Aug. 31st	
	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed
Residential	$ 0.0135	$ 13.41	$ 0.0137	$ 17.12	$ 0.0151	$ 13.77	$ 0.0151	$ 13.80
GS<50	$ 0.0116	$ 33.02	$ 0.0164	$ 20.84	$ 0.0148	$ 28.11	$ 0.0149	$ 28.17

Note: For the purpose of this table, the existing fixed rates include Smart meters rate riders, and the proposed fixed rates include the GEA rate rider.

UNDERTAKING NO. JT1.10: TO REFILE RESPONSE TO SEC INTERROGATORY NO. 2 (PAGE 34)

Response:

Taking a full year depreciation on additions added $1,833,000 in depreciation expense compared to using a half year on additions. The revenue requirement impact is $2,479,000, as shown below in table JT1.10.

Table JT1.10: Revenue Requirement Impact of Full Year Depreciation ($000)

Rate Base Impacts			
Reduced NBV	$	(1,883)	
Less averaging effect	$	942	
net impact on rate base	**$**	**(942)**	
Revenue Requirement (RR) Impacts			
Rate base impact on RR	$	(61)	
Depreciation increase	$	1,883	
PILs grossed up (26.5%)	$	657	
Total RR impact	**$**	**2,479**	
PILS calculation			
Changes to taxable income			
Rate base impact on RR	$	(61)	
Depreciation increase	$	1,883	
Net change in taxable income	$	1,822	
PILs thereon	$	483	26.50%
PILS grossed up	$	657	73.50%

This response has been updated to reflect the revised amount of depreciation expense and to correct the PILs calculation.

The revenue requirement amount above varies slightly from the amount of $2,527,000 shown in the response to undertaking JT1.5, although both are approximately $2.5 million. The above calculation was performed at a high level as shown. The result in JT1.5 was obtained in a more detailed approach by making the change in the rate and PILS models.

UNDERTAKING NO. JT1.11: TO RESPOND TO AMPCO TECHNICAL CONFERENCE QUESTIONS FILED AS EXHIBIT NO. KT1.2 (PAGE 37)

Cost Allocation

Issue 7.1 Is PowerStream's proposed cost allocation methodology for 2013 appropriate?

Reference: AMPCO Interrogatory # 1

Questions

1. Part (b) - **"**PowerStream does not track assets and costs by customer class. Most of PowerStream's assets are used by most or all customer classes."

    i) Please confirm the assets used by PowerStream's original Large User compared to the assets used by the class when an additional Large User is added to the class.

    ii) Is PowerStream's original Large User aware of the change in assets allocated to the Large User class in 2013?

    Part (c) - Table 1-1 shows Assets and Cost Allocated to the Large Use Class in 2009 and 2013. Please reproduce the table assuming the size of the rate class has not changed in 2013 and there is the same single large user in both 2009 and 2013.

Response:

1)

Part (b)

In its response to this undertaking, PowerStream has reproduced Table AMPCO #1-1 below for ease of reference.

Table AMPCO #1-1: Assets and Costs Allocated to the Large Use Class

	2009 Cost Allocation	2013 Cost allocation	Change
Costs Allocated:			
Distribution Costs (di)	$ 5,530	$ 68,959	$ 63,429
Customer Related Costs (cu)	$ 616	$ 2,891	$ 2,275
General and Administration (ad)	$ 5,860	$ 65,534	$ 59,675
Depreciation and Amortization (dep)	$ 11,148	$ 81,174	$ 70,026
PILs (INPUT)	$ 3,784	$ 6,350	$ 2,566
Interest	$ 9,376	$ 62,128	$ 52,753
Total Expenses	$ 36,312	$ 287,036	$ 250,724
Direct Allocation	$ 9,281	$ 10,240	$ 959
Total Costs for Large Use	**$ 45,593**	**$ 297,276**	**$ 251,683**
Assets Allocated:			
Distribution Plant - Gross	$ 351,374	$ 2,331,181	$ 1,979,807
General Plant - Gross	$ 43,290	$ 277,600	$ 234,310
Accumulated Depreciation	$ (104,066)	$ (198,961)	$ (94,896)
Capital Contribution	$ (52,511)	$ (565,419)	$ (512,908)
Total Net Assets allocated	$ 238,088	$ 1,844,400	$ 1,606,312
Directly Allocated Net Fixed Assets	$ 100,089	$ 79,414	$ (20,675)
Total Net Assets for Large Use	**$ 338,177**	**$ 1,923,814**	**$ 1,585,637**

i) PowerStream submits that the allocation in the 2009 Cost Allocation model, which is for the single Large Use customer at that time, reasonably approximates what would be allocated to that Large Use customer in the 2013 Cost Allocation model, if it were the only Large Use customer in 2013.

ii) PowerStream has discussed the changes in the Large Use class and resulting rate impact from the 2013 cost of service rate filing with the original large Use customer. This customer did not raise any objection or make any requests of PowerStream in this regard.

At the time of the proposed change to 2010 Large Use rates, PowerStream discussed the nature of the cost allocation with the original Large Use customer. It was explained how the addition of another Large Use customer that uses most of PowerStream’s distribution system results in an allocation of more assets and costs and a significant increase in rates to this class.

Part (c): PowerStream does not have a separate load profile for the original Large Use customer so it cannot rerun the cost allocation for 2013 based on a single Large Use customer. As stated above in part (b) (i), PowerStream submits that the 2009 Cost Allocation results are a reasonable approximation to what would be allocated to the original Large Use customer in 2013.

UNDERTAKING NO. JT1.12: TO PROVIDE SUPPORTING DOCUMENT TO SHOW THAT 7.5 TO 8 PERCENT IS an APPROPRIATE RANGE ACCORDING TO CONSULTANT. (PAGE 54)

Response:

Please refer to Attachment JT1.12.

UNDERTAKING NO. JT1.13: TO PROVIDE SPREADSHEET WITH 7.8 PERCENT CALCULATION. (PAGE 54)

Response:

Please refer to Attachment JT1.13 which shows the derivation of the 7.8% implicit rate of return on the lease for the Addiscott Road Markham operations centre.

The implicit rate of return has been calculated as the rate which equates the net present value (NPV) of the lease payments to the fair market value at the inception of the lease and the return of original investment at the end of the lease.

UNDERTAKING NO. JT1.14: TO PRODUCE A PRINTOUT FROM ASSET MANAGEMENT SYSTEM SHOWING WHEN ASSETS IN RATE BASE WILL REACH END OF USEFUL LIFE, TO 2023 (PAGE 58)

Response:

Please see Attachment JT1.14.

UNDERTAKING NO. JT1.15: FOR ENERGY PROBE TABLE 5A AND THE 5-YEAR CAPITAL WORK PLAN IN APPENDIX B, to IDENTIFY AND EXPLAIN THE MAJOR DIFFERENCES. (page 60)

Response:

Attachment JT1-15 describes the major differences between the Five Year Capital Plan(s) filed in interrogatory responses to CCC #9 (issue 2.3), Appendix B, and EP #5a.

The reader should be cautioned in their comparison of Five Year Capital Plan to Table EP #5a. The Five Year Capital Plan was based on CGAAP while the 2012 & 2013 COS numbers are based on MIFRS.

There were three occasions where change occurred from the time the Five Year Capital Plan was developed early in the year and the final capital costs that were put forward for the 2013 rate application. These occasions for change are part of the PowerStream business process and were as follows:

- The first occasion for change occurred when the business units put together their project details and budgets as part of the capital budget build. This occurred 4 to 6 months after the Five Year Plans were completed. Normally, there are numerous changes at this stage, both in project costs, and additional projects that are not listed in the Five Year Plan that are put forward. Changes occur due to new available information in loadings, new available information from outside agencies or customers, learning from current year's execution, more detailed cost estimates than used in the Five Year Plan or new ideas that are put forward. In 2012 the projects totaled approximately $97 million and for 2013 the projects totaled approximately $96 million (both years based on MIFRS costing).
- The second occasion for change occurred through the optimization of the portfolio against both value and risk. Through the optimization process approximately $22 million of the budget request was delayed to future years.
- The third occasion for change came when material changes were identified prior to the COS application being filed. These were identified to the PowerStream Board in April.

UNDERTAKING NO. JT1.16: to RECONCILE 3.9 MILLION DIFFERENCE BETWEEN EXHIBIT No. J1, TAB 4, SCHEDULE 4.1, APPENDIX D, PAGE 2 AND INTERROGATORY NO. 53 (Page 67)

Response:

The total MIFRS impact of $12.4M includes annual MIFRS impacts for 2011 - 2013. It includes the burden impact as well as the removal of joint services revenue and associated costs.

As explained in JT1.17, under CGAAP the joint services revenue less markup was netted against OM&A so the net impact on OM&A was zero.

Under MIFRS, revenues and expenses are not allowed to be netted. To comply with this requirement, in 2011, the joint service revenue of $3.9M was removed from the OM&A and reported as Other Revenue – Non-Utility Operation. In order not to overstate revenue requirement, correspondingly the associated joint services costs of $3.6M were also removed from the OM&A, as shown on page 2, Exhibit J1, Tab 4, Schedule 4.1, Appendix D, as those are non-rate recoverable costs. Please see the table below for reconciliation.

Table JT1.16: Impact of IFRS

In $ Millions								
		2011 MIFRS		**2012 Bridge**		**2013 Test**		**Total**
Burdens	$	11.50					$	11.50
Remove Shared Services Revenue	$	3.90					$	3.90
Remove Shared Services Costs* (See Note Below)	$	(3.60)	$	0.73	$	(0.085)	$	(2.96)
	$	11.80	$	0.73	$	(0.085)	$	12.44
***Note: Shared Service Costs Year-Over-year Comparison ($000)**								
Shared Services Costs	$	3,568	$	(2,843)	$	(2,928)		
(Page 2, Appendix D, Exhibit J1, Tab4, Schedule 4.1)								
Year-over-year changes			$	725	$	(85)		

In summary, both the joint services revenue of $3.9M and the associated costs of $2.96M were removed for the calculation of the revenue requirement.

The difference of approximately $0.9M, although classified as part of the MIFRS impact, is primarily related to the increase in OM&A as a result of PowerStream no longer providing Barrie water services, as explained in PowerStream's response to CCC IR #48.

UNDERTAKING NO. JT1.17: to EXPLAIN WHY THE 3.9 MILLION IS NOT SHOWN AS AN OM&A REDUCTION AND PROVIDE REAL STARTING POINTS FOR 2009 POWERSTREAM AND BARRIE ACTUALS. (page 69)

Response:

Under CGAAP, the joint services revenue less markup was recorded as a credit to the total OM&A costs. This credit (revenue) was netted against the joint services costs and embedded in (but not separately identified from) the total OM&A costs, therefore, the net effect on OM&A was zero.

The 2009 Board approved PowerStream South budget of $43.2M excluded joint services revenue and costs. Similarly, Barrie 2009 actual of $9.8M also excluded joint services revenues and costs. Accordingly, the starting point for cost driver analysis does not need to be restated.

Under MIFRS starting in 2011 the joint services revenue was recorded as Other Revenue – Non Utility Distribution. To ensure that the revenue requirement is not overstated, the corresponding joint services costs were identified separately and removed out of the total recoverable OM&A costs, as shown in Undertaking No. JT1.16.

UNDERTAKING NO. JT1.18: to PROVIDE A BREAKDOWN OF THREE COMPONENTS, BEING SOLAR, CDM AND RELATED, INTO REVENUES AND EXPENSES FOR THE TEST YEAR. (page 70)

Response:

Table JT1.18 provides the breakdown of "Other Revenues and Expenses" as included in PowerStream's Financial Statements in accounts 4375 and 4380.

Table JT1.18 Breakdown of Non-Utility Revenues and Expenses

			Test Year
			2013 MIFRS
4375	**Revenues from Non-Utility Operations**		
		Joint services	(3,201,000)
		Water penalty	(510,000)
		CDM	(28,500,000)
		Fibre Revenue	
		PowerStream Solar	(10,700,000)
		Total including Solar	(42,911,000)
		Less PS Solar (company 950)	10,700,000
		Total	**(32,211,000)**

			Test Year
			2013 MIFRS
4380	**Expenses of Non-Utility Operations**		
		Joint services	-
		CDM	28,500,000
		PowerStream Solar	7,300,000
		Total including Solar	35,800,000
		Less PS Solar (company 950)	(7,300,000)
		Total	**28,500,000**

Please note that the amounts shown in the detailed schedule of Appendix 2-C do not include PowerStream Solar. In PowerStream's accounting system, the PowerStream Solar transactions are fully segregated and recorded under a separate "company code". For rate application purposes, the amounts under the Solar "company code" have not been uploaded to the model.

As shown in table JT1.18, in the 2013 test year, there is about $ 3.7 million of non-utility revenues, other than CDM and Solar from joint services and water penalties.

Under CGAAP, the cost of Joint Services used to be recorded in OM&A accounts and then credited to the same OM&A accounts, with a corresponding debit to account 4380, so the net effect on OM&A was zero. Under MIFRS, it is no longer allowed to net revenues and expenses for the financial reporting purposes. Therefore, there is no credit to OM&A accounts and no debit to account 4380. Consequently, the costs of providing joint services are not shown in account 4380 for 2012-2013. To ensure that the revenue requirement is not overstated by this amount, the corresponding costs were removed from the OM&A as a one-line adjustment, $2.8 million for 2012 and $2.9 million in 2013. Those credits can be seen in the Appendix 2-F as filed.

UNDERTAKING NO. JT1.19: to IDENTIFY DOCUMENTS RELATING TO FUTURE SAVINGS FROM MERGER. (Page 72)

Response:

See Attachment JT1.19 for the relevant documents filed during the Barrie MAADs proceeding.

UNDERTAKING NO. JT1.20: to EXPLAIN HOW THE BARRIE AND POWERSTREAM SALARY SCHEDULES WERE MERGED AND WHY (Page 79)

Response:

An independent consultant was retained to review the compensation structure for management employees. The consultant conducted salary surveys of comparable companies, in terms of size both within and outside the utility sector. The consultant rated positions through their defined process which resulted in points for each position. As the consultant felt it was more relevant to the new merged entity size, the previous PowerStream salary grid was used as a starting point and modified based on the information provided from the consultant.

UNDERTAKING NO. JT1.21: to EXPLAIN CHANGES IN REVENUE, EXPENSE, AND INCOME LEVELS IN 2013 PRELIMINARY BUDGET. (Page 82)

Response:

Summary – Proposed 2013 Budget Presented At Various Time Frames

Prelim Summarized Statement of Operations				
	A	B	C	D
	Sept 21	Sept 21	Dec 14	COS
	Page 3	Page 8	Page 9	Filed
(in Millions of Dollars)	2013	2013	2013	2013
Cost of Power	789.9	761.2	822.8	857.8
Distribution Revenue	175.7	179.2	170.7	169.8
Other Revenue	7.7	10.4	11.3	9.1
OM&A	79.7	88.0	89.0	86.0
Depreciation Expense	40.7	40.6	34.7	36.6
Interest Expense	25.8	25.8	25.0	23.1
EBT	37.3	35.2	33.2	33.2
Provision for Income Taxes	5.1	2.9	0.7	2.5
Net Income	**32.2**	**32.3**	**32.5**	**30.7**
Deemed ROE - Apprvd Ratebase	9.4%	9.4%	9.4%	9.12%
Deemed ROE - Realtime Ratebase	9.7%	9.4%	9.4%	9.12%
Net Capital Expenditure	61.0	99.9	94.7	114.3
Statutory Tax Rate	25.5%	25.5%	25.5%	25.5%
Rate Base - Approved	856	856	862	842.0
Rate Base - Real Time	835	857	862	842.0

Note:

A – 5 Year Financial Outlook completed in 2010 presented September 21, 2011

B – Preliminary 2012 Budget and 5 Year Financial Outlook presented September 21, 2011

C – Preliminary 2012 Budget and 5 Year Financial Outlook presented in December 2011

D – COS filed with the OEB in August 2012

Comparison – A vs. B: September 21'11 Page 3 and Page 4

(in Millions of Dollars)	A Sept 21 Page 3 2013	B Sept 21 Page 8 2013	Variance	Explaination
Distribution Revenue	175.7	179.2	3.5	Revenue requirement higher due to higher OM&A
Other Revenue	7.7	10.4	2.7	Joint Service Revenue of $3.2M was being moved from OM&A to "Other Revenue"; plus other updates in the rest of the categories of the Other Revenue
OM&A	79.7	88.0	8.3	Joint Service offset moved to "Other Revenue"; plus increased OM&A costs of approximately $4.5M identified through the detailed bottom-up build budget process. For detailed increases, please see Exhibit J1/Tab1/ Schedule 1.1, Appendix F- EOC Update dated September 7, 2011, Page 12 - 15.
Depreciation Expense	40.7	40.6	-0.1	More updated information available through the budget bottom-up build process.
Interest Expense	25.8	25.8	0.0	
EBT	37.3	35.2	-2.1	
Provision for Income Taxes	5.1	2.9	-2.2	Higher capital expenditure resulted in higher CCA claim, and in return, lower taxes.
Net Income	**32.2**	**32.3**	**0.1**	
Deemed ROE - Apprvd Ratebase	9.4%	9.4%		
Deemed ROE - Realtime Ratebase	9.6%	9.4%		
Net Capital Expenditure	61.0	99.0		
Statutory Tax Rate	25.5%	25.5%		
Rate Base - Approved	856	856		
Rate Base - Real Time	835	857		

Comparison – B vs. C: September 21'11 vs. December'11

(in Millions of Dollars)	B Sept 21 Page 8 2013	C Dec 14 Page 9 2013	Variance	Explaination
Distribution Revenue	179.2	170.7	-8.5	Revenue requirement lower due to lower depreciation
Other Revenue	10.4	11.3	0.9	Further adjustment per MIFRS: removed "Loss on derecognition" from Other Revenue to Depreciation by $1.4M; Removed "Work Order Gain & Loss - Industry Commercial & Institution" from Other Revenue to Contributed Capital by ($0.5M).
OM&A	88.0	89.0	1.0	Increase due to burden absorption, inventory slow moving provision, etc.
Depreciation Expense	40.6	34.7	-5.9	Mainly due to extended useful life of fixed assets of ($7M); and derecognition of $1.4M .
Interest Expense	25.8	25.0	-0.8	Less borrowing due to less capex spending; and lower interest rate used in regulatory liabilities and customer deposit.
EBT	35.2	33.2	-2.0	Less taxable income of ($2M); $5.9M less depreciation being added back to taxiable income
Provision for Income Taxes	2.9	0.7	-2.2	
Net Income	**32.3**	**32.5**	**0.2**	
Deemed ROE - Apprvd Ratebase	9.4%	9.4%		
Deemed ROE - Realtime Ratebase	9.4%	9.4%		
Net Capital Expenditure	99.0	94.7		
Statutory Tax Rate	25.5%	25.5%		
Rate Base - Approved	856	862		
Rate Base - Real Time	857	862		

Comparison – C vs. D: December 14'11 vs. COS Filed

(in Millions of Dollars)	C Dec 14 Page 9 2013	D COS Filed 2013	Variance	Explaination
Distribution Revenue	170.7	169.8	-0.9	Revenue requirement lower due to lower ROE
Other Revenue	11.3	9.1	-2.2	Per the rates filing requirement: Joint Service revenue of $3.6M was removed for revenue requirement purpose. "SSS Admin Charges" and "Retail Services Revenue" of $1.4M was added.
OM&A	89.0	86.0	-3.0	Removed sponsorship & donation of ($0.4M); removed Joint Services Costs of ($2.93M); and added OMERS costs of $0.3M.
Depreciation Expense	34.7	36.6	1.9	Full year depreciation of 2013 capital additon was included in the filed depreciation.
Interest Expense	25.0	23.1	-1.9	deemed interest expense vs. bottom build
EBT	33.2	33.2	0.0	
Provision for Income Taxes	0.7	2.5	1.8	CIS in-services in 2014 rather than 2013, resulting in lower CCA claim in 2013 as filed.
Net Income	**32.5**	**30.7**	**-1.8**	
Deemed ROE - Apprvd Ratebase	9.4%	9.12%		
Deemed ROE - Realtime Ratebase	9.4%	9.12%		
Net Capital Expenditure	94.7	114.3		
Statutory Tax Rate	25.5%	25.5%		
Rate Base - Approved	862	842.0		
Rate Base - Real Time	862	842.0		

UNDERTAKING NO. JT1.22: TO PROVIDE A COMPARISON OF JUNE 2011, ACTUALS TO BUDGET, FOR O&M AND ADMINISTRATION CATEGORIES (PAGE 89)

Response:

Please see the table below for 2011 June YTD comparison between budget and actual.

($ 000)

	June YTD 2011 Actual	June YTD 2011 Budget	June YTD 2011 Variance
Operation & Maintenance (O&M)	**9,937**	**10,330**	**393**
Administration Expenses	**17,380**	**21,734**	**4,354**
OM&A Expenses	**27,317**	**32,064**	**4,747**

Powerstream notes that the actual OM&A expense for the 2011 year was 98% of budget. In 2011 PowerStream budgeted most amounts in total for the year and the monthly budget was determined as 1/12th of the annual amount. As a result the budget and actual for six months are not truly comparable if the nature of the expenses is other than incurred evenly throughout the year.

UNDERTAKING NO. JT1.23: TO EXPLAIN INCREASE IN COMPUTER MAINENTANCE COSTS BETWEEN 2009 AND 2010 (PAGE 93)

Response:

In our response to Interrogatory CCC #36 Information/Communications Systems section, the 2009 budget for the Barrie IS cost center was missed. Please see table below for the complete IS budget from 2009 to 2013.

OM&A Budget - IS	2009	2010	2011	2012	2013
Labour	1,089,151	1,286,842	1,804,892	2,308,804	2,697,639
Contract/Consulting	800,000	52,000	184,000	230,000	287,600
Computer	1,374,000	1,827,929	2,227,650	2,684,850	2,866,515
Supplies & Equipment	110,500	105,000	120,000	113,600	127,308
Telephone	980,000	1,162,000	925,000	826,560	855,532
Training	75,500	53,000	80,004	132,610	117,251
Other	37,850	86,250	112,196	339,956	353,434
TOTAL EXPENSES	4,467,001	4,573,021	5,453,742	6,636,380	7,305,279

The increase in computer maintenance between 2009 and 2010 was primarily attributable to the following:

Outage Management System Application	$57,000	$57,000
Additional Software Maintenance in Barrie	$220,000	
GL Company reporting package- Maintenance for new software	$32,000	
Biztalk Data Transfer Support - Maintenance for new software	$40,000	
ERP One - New Support contract in 2010 for JDE system	$17,000	
vmWare – application to virtualize servers	$9,000	
	$318,000	$318,000
Audio Video Maintenance Contract	$50,000	
Barracuda – spam filter updates	$5,000	
AS400 Maintenance – JDE hardware maintenance	$10,000	
	$65,000	$65,000
		$440,000

UNDERTAKING NO. JT1.24: to advise HOW MUCH OF THE INCREASE IN MIFRS IS DUE TO RATE INCREASES VS ADDED REAL ESTATE (Page 96)

Response:

The overall property tax increase from 2009 to 2013 is $847,580. Please see table below for a breakdown of the increase.

Description	Increase/Decrease
MIFRS Impact	296,636
New Real Estate_ Addiscott	430,000
New TS#4 Station	35,000
Exit Rutherford Facility	(153,659)
Tax increase (Properties & Stations)	170,000
Other	69,602
Total	**847,580**

UNDERTAKING NO. JT1.25: to PROVIDE JUNE 2011 IFRS ESTIMATE (Page 97)

Response:

The 5 million dollar increase in administrative and general expenses (Energy Probe IR#28) between the June 2011 YTD actual CGAAP and the 2012 YTD actual MIFRS are as follows:

Reasons	In Millions		Explanation
MIFRS Impact	$	3.4	Costs that are no longer burdened in 2012, but were part of the burden pool costs in 2011
IS Software Maintenance	$	0.6	Including Oracle license fee, Interactive Voice System enhancements and CIS system support
Building Maintenance	$	0.3	Related to general repairs and property maintenance and increased security services
Staff Increase	$	0.3	Staff increase in HR, IS and Finance areas
Consulting/Legal	$	0.4	Related to tax consulting, actuarial valuation and general legal services
Total	**$**	**5.0**	

UNDERTAKING NO. JT1.26: to CONFIRM IF A FORMAL RFP WAS ISSUED FOR INSURANCE COSTS AND COVERAGE (PAGE 103)

Response:

We have not issued a formal RFP for insurance. However, senior management conducts an annual review of the insurance policy, premiums and deductible levels, to ensure that our costs are reasonable.

UNDERTAKING NO. JT1.27: TO QUANTIFY HOW MUCH THE CHARGE TO POWERSTREAM SOLAR WOULD BE DIFFERENT IF IT WAS AN AFFILIATE RATHER THAN A BUSINESS UNIT (Page 104)

Response:

As discussed in PowerStream's response to Board Staff IR #35, if PowerStream's Solar was an affiliate, the price of the services provided would be subject to ARC. To determine the exact price, PowerStream would need to verify whether there is a market for the services provided and determine the market price for those services.

For the purpose of this analysis it was assumed the market price for all services provided to PowerStream Solar, would approximate PowerStream's cost of providing the services plus a mark-up identical to the one that is currently used in the determination of prices for services provided to shareholders. On this basis the existing price would be higher by about $30,000.

UNDERTAKING NO. JT1.28: TO PROVIDE AN EXPLANATION OF THE DIFFERENCE IN THE COSTING METHOD, AND WHAT IT MEANS – HOW IT WAS DONE BEFORE, HOW IT'S DONE AFTER, AND WHY CHANGES WERE MADE (Page 106)

Response:

The current Joint Services Agreement (JSA) between PowerStream and the Town of Markham covers the years 2011 to 2013. The previous JSA was for 2008 to 2010. The key reasons for the pricing decrease of $289,328 ($1,426,190 less $1,136,862) for water and sewer meter reading and billing are shown in Table JT1.28, below:

Table JT1.28: Changes in Markham Water and Sewer Pricing

Factor	*Amount*
Increased Meter Reading costs directly attributable to Markham	$63,000
Increased Postage costs directly attributable to Markham	$40,000
Increased water customer base due to 2009 merger, 26% reduction in allocation of directly attributable costs to Markham	(S283,000)
Increased water customer base due to 2009 merger, reduction in allocation of shared overhead costs to Markham Other	$(96,000) ($13,328)
Total CHANGE	$289,328

UNDERTAKING NO. JT1.29: to PROVIDE BREAKDOWN IN "OTHER" CATEGORY OF FLEET SERVICES BUDGET, AND REASONS FOR INCREASE FROM 2009 TO 2013. (Page 114)

Response:

Please see below for a breakdown of “Other” category of the Fleet Services Budget:

OM&A - Fleet - Other	2009	2010	2011	2012	2013
Meals	1,500	1,000	1,000	1,000	1,000
Memberships	1,000	700	700	700	700
Vehicle Leases	0	0	0	175,000	175,000
Supplies & Equipment	6,500	6,500	6,000	6,000	6,000
Telephone	0	0	0	8,400	8,400
Training	10,500	9,500	9,500	10,000	10,000
Total	**19,500**	**17,700**	**17,200**	**201,100**	**201,100**

The increase from 2009 to 2013 is primarily driven by the treatment of vehicle leases under MIFRS. Prior to the implementation of MIFRS, the vehicle leases were treated as burden pool costs and recovered through the applied burdens. Under MIFRS, the vehicle leases are no longer allowed to be capitalized and are treated as direct OM&A costs.

Appendix 2-EA - revised only for purposed of responding to Undertaking JT1.4
IFRS-CGAAP Transitional PP&E Amounts
2012 Adopters of IFRS for Financial Reporting Purposes

For applicants that adopt IFRS on January 1, 2012 for financial reporting purposes

Note: this sheet should be filled out if the applicant adopts IFRS for its financial reporting purpose as of January 1, 2012.

	2009 Rebasing Year	2010	2011	2012	2013 Rebasing Year	2014	2015	2016
Reporting Basis	CGAAP	IRM	IRM	IRM	MIFRS	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast			
			$	$				
PP&E Values under CGAAP								
Opening net PP&E - Note 1			613,158,000	651,911,000				
Additions			83,771,000	86,106,000				
Depreciation (amounts should be negative)			(45,018,000)	(48,924,000)				
Closing net PP&E (1)			651,911,000	689,093,000				
PP&E Values under MIFRS (Starts from 2011, the transition year)								
Opening net PP&E - Note 1			613,158,000	659,803,000				
Additions			81,202,000	72,347,000				
Depreciation (amounts should be negative)			(34,557,000)	(33,486,000)				
Closing net PP&E (2)			659,803,000	698,664,000				
Difference in Closing net PP&E, CGAAP vs. MIFRS (Shown as adjustment to rate base on rebasing)			(7,892,000)	(9,571,000)				
Account 1575 - IFRS-CGAAP Transitional PP&E Amounts								
Opening balance			-	(7,892,000)	(9,571,000)	(7,178,250)	(4,785,500)	(2,392,750)
Amounts added in the year			(7,892,000)	(1,679,000)				
Sub-total			(7,892,000)	(9,571,000)	(9,571,000)	(7,178,250)	(4,785,500)	(2,392,750)
Amount of amortization, included in depreciation expense - Note 2					2,392,750	2,392,750	2,392,750	2,392,750
Closing balance in deferral account			(7,892,000)	(9,571,000)	(7,178,250)	(4,785,500)	(2,392,750)	-

Effect on Revenue Requirement

Amortization of deferred balance as above - Note 2	(2,392,750)	**WACC**		
Return on Rate Base Associated with deferred PP&E balance at WACC - Note 3	-	**Disposition Period - Note 4**	4	Years
Amount included in Revenue Requirement on rebasing	(2,392,750)			

Notes:

1 For an applicant that adopts IFRS on January 1, 2012, the PP&E values as of January 1, 2011 under both CGAAP and MIFRS should be the same.

2 Amortization of the deferred balance in Account 1575 will start from the rebasing year.
Assume the utility requests for a certain disposition period, the amortization that should be included in the depreciation expense is calculated as:
the opening balance of Account 1575 / the approved disposition period

3 Return on rate base associated with deferred balance is calculated as:
the deferred account opening balance as of 2013 rebasing year x WACC
* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.

4 Consistent with the 4 year normal rate cycle, the model is using a 4 year amortization period as a default selection to "clear" the PP&E deferral account through a one-time adjustment to ratebase to capture and remove the impact of the accounting policy changes as caused by the transition from CGAAP to MIFRS.

PowerStream 2013 COS EDR EB-2012-0161
2013 EDR Model - Clarification for Undertaking JT1.6

RATE BASE	PS North	PS South	PowerStream Combined					
	Board Approved	Board Approved	Historic Actual				Bridge Year	Test Year
	2008	2009	2009	2010	2011	2011 MIFRS	2012	2013
Net Fixed Assets	**130,388,048**	**457,086,663**	**537,272,316**	**576,322,124**	**632,532,791**	**636,479,430**	**679,233,596**	**721,269,093**
Working Capital Allowance								
Cost of Power and Distribution Expenses	**129,770,174**	**464,850,049**	**681,396,445**	**748,156,142**	**813,544,070**	**825,342,700**	**900,687,757**	**943,820,807**
Working Capital Allowance	19,465,526	69,727,507	102,209,467	112,223,421	122,031,610	123,801,405	117,089,408	122,696,705
RATE BASE	**149,853,574**	**526,814,171**	**639,481,783**	**688,545,545**	**754,564,401**	**760,280,835**	**796,323,004**	**843,965,798**
Adjust rate base for PP&E deferral account								(2,386,855)
Adjust rate base for GEA deferral account								462,834
ADJUSTED RATE BASE	**149,853,574**	**526,814,171**	**639,481,783**	**688,545,545**	**754,564,401**	**760,280,835**	**796,323,004**	**842,041,777**

Notes:
1. The Rate Base is adjusted for the full amount in Account 1575. This amount is amortized voer four years and is a shown as a reduction in depreciation expense.
2. The adjustment for disposition of green energy capital deferral amounts was not included in the Appendix 2-B, as these amounts were determiend later in the process.

REVENUE REQUIREMENT	Board Approved	Board Approved	Historic Actual				Bridge Year	Test Year
	2008	2009	2009	2010	2011	2011 MIFRS	2012	2013
								$
Rate Base	149,853,574	526,814,171	639,481,783	688,545,545	754,564,401	760,280,835	796,323,004	843,965,798
Adjust rate base for PP&E deferral account								(2,386,855)
Adjust rate base for GEA deferral account								462,834
Adjusted Rate Base								**842,041,777**
x Cost of Capital	7.30%	6.56%	6.65%	7.39%	7.30%	7.30%	6.36%	6.39%
Return on Ratebase	**10,941,592**	**34,543,472**	**42,536,502**	**50,873,094**	**55,053,671**	**55,470,747**	**50,681,932**	**53,822,666**
Operations, Maintenance and Administration	10,047,532	43,216,300	59,677,127	56,837,729	62,086,731	73,885,361	81,595,680	86,041,101
Depreciation and Amortization	10,150,089	36,242,684	41,855,013	45,970,569	45,756,070	33,947,147	32,435,629	35,758,672
Distribution Expenses	**20,197,621**	**79,458,984**	**101,532,141**	**102,808,298**	**107,842,801**	**107,832,508**	**114,031,308**	**121,799,773**
Depreciation Adjustment for PP&E Deferral amortiz 4 years								(596,714)
Depreciation Adjustment: Derecgnition Expense								1,400,000
Depreciation Adjustment for GEA Deferral amortization								45,463
Distribution Expenses with Depreciation adjusted	**20,197,621**	**79,458,984**	**101,532,141**	**102,808,298**	**107,842,801**	**107,832,508**	**114,031,308**	**122,648,523**
Revenue Requirement Before Income Taxes	**31,139,213**	**114,002,455**	**144,068,643**	**153,681,392**	**162,896,472**	**163,303,255**	**164,713,240**	**176,471,189**
Income Taxes	2,890,210	**7,128,578**	**9,932,216**	**10,806,922**	**6,214,659**	**88,174**	**1,794,063**	**2,461,463**
SERVICE REVENUE REQUIREMENT	**34,029,423**	**121,131,033**	**154,000,859**	**164,488,314**	**169,111,131**	**163,391,429**	**166,507,303**	**178,932,651**

Cresa Toronto
LNR Corporation, Brokerage
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The Tenant's Advantage
cresa.com

September 27, 2012

Mr. Michael Matthews
Senior Vice President, Operations & Construction
PowerStream Inc.
161 Cityview Blvd.
Vaughan, Ontario
L4H 0A9

Dear Mike:

Re: PowerStream South Operations Centre
80 Addiscott Court, Markham

In reference to the leasing transaction for PowerStream's South Operations Centre at 80 Addiscott Court, Markham, negotiated in 2008, capitalization rates utilized in determining the rental rates were based on market transactions at the time for specialized facilities and typical private or institutional landlords taking into account the financial covenant of the tenant, estimated to be in the range of 7.5% to 8% per annum.

The foregoing is based on our professional opinion and experience as a qualified Real Estate Broker, licensed in the Province of Ontario.

Yours truly

Dean Newman, Principal
Broker of Record

Partners in Global Real Estate

Operations Centre Lease

interest rate -annual	7.8%
interest rate - monthly	0.65%
Net Present value of lease payments including purchase option:	$ 30,441,458

DETAILED CALCULATION:

Month	Annual payment	monthly payment	NPV
0	2,286,011	190,501	190,501
1	2,286,011	190,501	189,269
2	2,286,011	190,501	188,045
3	2,286,011	190,501	186,829
4	2,286,011	190,501	185,621
5	2,286,011	190,501	184,421
6	2,286,011	190,501	183,228
7	2,286,011	190,501	182,044
8	2,286,011	190,501	180,866
9	2,286,011	190,501	179,697
10	2,286,011	190,501	178,535
11	2,286,011	190,501	177,381
12	2,286,011	190,501	176,234
13	2,286,011	190,501	175,094
14	2,286,011	190,501	173,962
15	2,286,011	190,501	172,837
16	2,286,011	190,501	171,719
17	2,286,011	190,501	170,609
18	2,286,011	190,501	169,506
19	2,286,011	190,501	168,410
20	2,286,011	190,501	167,321
21	2,286,011	190,501	166,239
22	2,286,011	190,501	165,164
23	2,286,011	190,501	164,096
24	2,286,011	190,501	163,035
25	2,286,011	190,501	161,980
26	2,286,011	190,501	160,933
27	2,286,011	190,501	159,892
28	2,286,011	190,501	158,859
29	2,286,011	190,501	157,831
30	2,286,011	190,501	156,811
31	2,286,011	190,501	155,797
32	2,286,011	190,501	154,789
33	2,286,011	190,501	153,788
34	2,286,011	190,501	152,794
35	2,286,011	190,501	151,806
36	2,286,011	190,501	150,824
37	2,286,011	190,501	149,849
38	2,286,011	190,501	148,880
39	2,286,011	190,501	147,917
40	2,286,011	190,501	146,961
41	2,286,011	190,501	146,011
42	2,286,011	190,501	145,067
43	2,286,011	190,501	144,129
44	2,286,011	190,501	143,197
45	2,286,011	190,501	142,271
46	2,286,011	190,501	141,351
47	2,286,011	190,501	140,437
48	2,286,011	190,501	139,529
49	2,286,011	190,501	138,626
50	2,286,011	190,501	137,730
51	2,286,011	190,501	136,839
52	2,286,011	190,501	135,954
53	2,286,011	190,501	135,075
54	2,286,011	190,501	134,202

Month	Annual payment	monthly payment	NPV
55	2,286,011	190,501	133,334
56	2,286,011	190,501	132,472
57	2,286,011	190,501	131,615
58	2,286,011	190,501	130,764
59	2,286,011	190,501	129,919
60	2,286,011	190,501	129,079
61	2,286,011	190,501	128,244
62	2,286,011	190,501	127,415
63	2,286,011	190,501	126,591
64	2,286,011	190,501	125,772
65	2,286,011	190,501	124,959
66	2,286,011	190,501	124,151
67	2,286,011	190,501	123,348
68	2,286,011	190,501	122,551
69	2,286,011	190,501	121,758
70	2,286,011	190,501	120,971
71	2,286,011	190,501	120,189
72	2,286,011	190,501	119,411
73	2,286,011	190,501	118,639
74	2,286,011	190,501	117,872
75	2,286,011	190,501	117,110
76	2,286,011	190,501	116,353
77	2,286,011	190,501	115,600
78	2,286,011	190,501	114,853
79	2,286,011	190,501	114,110
80	2,286,011	190,501	113,372
81	2,286,011	190,501	112,639
82	2,286,011	190,501	111,911
83	2,286,011	190,501	111,187
84	2,286,011	190,501	110,468
85	2,286,011	190,501	109,754
86	2,286,011	190,501	109,044
87	2,286,011	190,501	108,339
88	2,286,011	190,501	107,639
89	2,286,011	190,501	106,943
90	2,286,011	190,501	106,251
91	2,286,011	190,501	105,564
92	2,286,011	190,501	104,881
93	2,286,011	190,501	104,203
94	2,286,011	190,501	103,529
95	2,286,011	190,501	102,860
96	2,286,011	190,501	102,195
97	2,286,011	190,501	101,534
98	2,286,011	190,501	100,878
99	2,286,011	190,501	100,225
100	2,286,011	190,501	99,577
101	2,286,011	190,501	98,933
102	2,286,011	190,501	98,294
103	2,286,011	190,501	97,658
104	2,286,011	190,501	97,026
105	2,286,011	190,501	96,399
106	2,286,011	190,501	95,776
107	2,286,011	190,501	95,156
108	2,286,011	190,501	94,541
109	2,286,011	190,501	93,930
110	2,286,011	190,501	93,322
111	2,286,011	190,501	92,719
112	2,286,011	190,501	92,119
113	2,286,011	190,501	91,524
114	2,286,011	190,501	90,932
115	2,286,011	190,501	90,344
116	2,286,011	190,501	89,760
117	2,286,011	190,501	89,179
118	2,286,011	190,501	88,603
119	2,286,011	190,501	88,030

Month	Annual payment	monthly payment	NPV
120	2,457,011	204,751	94,003
121	2,457,011	204,751	93,395
122	2,457,011	204,751	92,791
123	2,457,011	204,751	92,191
124	2,457,011	204,751	91,595
125	2,457,011	204,751	91,003
126	2,457,011	204,751	90,414
127	2,457,011	204,751	89,830
128	2,457,011	204,751	89,249
129	2,457,011	204,751	88,672
130	2,457,011	204,751	88,098
131	2,457,011	204,751	87,529
132	2,457,011	204,751	86,963
133	2,457,011	204,751	86,400
134	2,457,011	204,751	85,842
135	2,457,011	204,751	85,286
136	2,457,011	204,751	84,735
137	2,457,011	204,751	84,187
138	2,457,011	204,751	83,643
139	2,457,011	204,751	83,102
140	2,457,011	204,751	82,565
141	2,457,011	204,751	82,031
142	2,457,011	204,751	81,500
143	2,457,011	204,751	80,973
144	2,457,011	204,751	80,450
145	2,457,011	204,751	79,929
146	2,457,011	204,751	79,413
147	2,457,011	204,751	78,899
148	2,457,011	204,751	78,389
149	2,457,011	204,751	77,882
150	2,457,011	204,751	77,378
151	2,457,011	204,751	76,878
152	2,457,011	204,751	76,381
153	2,457,011	204,751	75,887
154	2,457,011	204,751	75,396
155	2,457,011	204,751	74,909
156	2,457,011	204,751	74,424
157	2,457,011	204,751	73,943
158	2,457,011	204,751	73,465
159	2,457,011	204,751	72,990
160	2,457,011	204,751	72,518
161	2,457,011	204,751	72,049
162	2,457,011	204,751	71,583
163	2,457,011	204,751	71,120
164	2,457,011	204,751	70,660
165	2,457,011	204,751	70,204
166	2,457,011	204,751	69,750
167	2,457,011	204,751	69,299
168	2,457,011	204,751	68,850
169	2,457,011	204,751	68,405
170	2,457,011	204,751	67,963
171	2,457,011	204,751	67,523
172	2,457,011	204,751	67,087
173	2,457,011	204,751	66,653
174	2,457,011	204,751	66,222
175	2,457,011	204,751	65,794
176	2,457,011	204,751	65,368
177	2,457,011	204,751	64,946
178	2,457,011	204,751	64,526
179	2,457,011	204,751	64,109
180	2,457,011	204,751	63,694
181	2,457,011	204,751	63,282
182	2,457,011	204,751	62,873
183	2,457,011	204,751	62,466
184	2,457,011	204,751	62,062

Month	Annual payment	monthly payment	NPV
185	2,457,011	204,751	61,661
186	2,457,011	204,751	61,262
187	2,457,011	204,751	60,866
188	2,457,011	204,751	60,473
189	2,457,011	204,751	60,082
190	2,457,011	204,751	59,693
191	2,457,011	204,751	59,307
192	2,457,011	204,751	58,924
193	2,457,011	204,751	58,543
194	2,457,011	204,751	58,164
195	2,457,011	204,751	57,788
196	2,457,011	204,751	57,414
197	2,457,011	204,751	57,043
198	2,457,011	204,751	56,674
199	2,457,011	204,751	56,308
200	2,457,011	204,751	55,944
201	2,457,011	204,751	55,582
202	2,457,011	204,751	55,223
203	2,457,011	204,751	54,865
204	2,457,011	204,751	54,511
205	2,457,011	204,751	54,158
206	2,457,011	204,751	53,808
207	2,457,011	204,751	53,460
208	2,457,011	204,751	53,114
209	2,457,011	204,751	52,771
210	2,457,011	204,751	52,430
211	2,457,011	204,751	52,091
212	2,457,011	204,751	51,754
213	2,457,011	204,751	51,419
214	2,457,011	204,751	51,087
215	2,457,011	204,751	50,756
216	2,457,011	204,751	50,428
217	2,457,011	204,751	50,102
218	2,457,011	204,751	49,778
219	2,457,011	204,751	49,456
220	2,457,011	204,751	49,136
221	2,457,011	204,751	48,819
222	2,457,011	204,751	48,503
223	2,457,011	204,751	48,189
224	2,457,011	204,751	47,878
225	2,457,011	204,751	47,568
226	2,457,011	204,751	47,261
227	2,457,011	204,751	46,955
228	2,457,011	204,751	46,651
229	2,457,011	204,751	46,350
230	2,457,011	204,751	46,050
231	2,457,011	204,751	45,752
232	2,457,011	204,751	45,456
233	2,457,011	204,751	45,162
234	2,457,011	204,751	44,870
235	2,457,011	204,751	44,580
236	2,457,011	204,751	44,292
237	2,457,011	204,751	44,006
238	2,457,011	204,751	43,721
239	2,457,011	204,751	43,438
240	2,621,011	218,418	46,038
241	2,621,011	218,418	45,740
242	2,621,011	218,418	45,445
243	2,621,011	218,418	45,151
244	2,621,011	218,418	44,859
245	2,621,011	218,418	44,569
246	2,621,011	218,418	44,281
247	2,621,011	218,418	43,994
248	2,621,011	218,418	43,710
249	2,621,011	218,418	43,427

Month	Annual payment	monthly payment	NPV
250	2,621,011	218,418	43,146
251	2,621,011	218,418	42,867
252	2,621,011	218,418	42,590
253	2,621,011	218,418	42,315
254	2,621,011	218,418	42,041
255	2,621,011	218,418	41,769
256	2,621,011	218,418	41,499
257	2,621,011	218,418	41,231
258	2,621,011	218,418	40,964
259	2,621,011	218,418	40,699
260	2,621,011	218,418	40,436
261	2,621,011	218,418	40,175
262	2,621,011	218,418	39,915
263	2,621,011	218,418	39,657
264	2,621,011	218,418	39,400
265	2,621,011	218,418	39,146
266	2,621,011	218,418	38,892
267	2,621,011	218,418	38,641
268	2,621,011	218,418	38,391
269	2,621,011	218,418	38,143
270	2,621,011	218,418	37,896
271	2,621,011	218,418	37,651
272	2,621,011	218,418	37,408
273	2,621,011	218,418	37,166
274	2,621,011	218,418	36,926
275	2,621,011	218,418	36,687
276	2,621,011	218,418	36,450
277	2,621,011	218,418	36,214
278	2,621,011	218,418	35,980
279	2,621,011	218,418	35,747
280	2,621,011	218,418	35,516
281	2,621,011	218,418	35,286
282	2,621,011	218,418	35,058
283	2,621,011	218,418	34,831
284	2,621,011	218,418	34,606
285	2,621,011	218,418	34,382
286	2,621,011	218,418	34,160
287	2,621,011	218,418	33,939
288	2,621,011	218,418	33,720
289	2,621,011	218,418	33,502
290	2,621,011	218,418	33,285
291	2,621,011	218,418	33,070
292	2,621,011	218,418	32,856
293	2,621,011	218,418	32,644
294	2,621,011	218,418	32,432
295	2,621,011	218,418	32,223
296	2,621,011	218,418	32,014
297	2,621,011	218,418	31,807
298	2,621,011	218,418	31,602
299	2,621,011	218,418	31,397
300	Purchase Option	30,441,000	4,347,568
TOTAL		90,976,275	30,441,458

Undertaking JT1.14: Cost of Assets Becoming Fully Depreciated 2011-2023 ($ thousands)

GL	Description	2011 MIFRS	2012 MIFRS	2013 MIFRS	2014 MIFRS	2015 MIFRS	2016 MIFRS	2017 MIFRS	2018 MIFRS	2019 MIFRS	2020 MIFRS	2021 MIFRS	2022 MIFRS	2023 MIFRS
1606	Organizational Cost	-	-	-	-	-	-	-	-	-	-	-	-	-
1805	Land	-	-	-	-	-	-	-	-	-	-	-	-	-
1806	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-
1808	Building Structure	-	-	-	-	-	-	-	-	-	-	-	-	-
1810	Major Spare Parts	-	-	-	-	-	-	-	-	-	-	-	-	-
1815	Transformer Stations - other	1,476	936	445	805	-	-	-	-	-	-	-	-	-
1816	Power Transformer - other	-	-	-	-	-	-	-	-	-	-	-	-	-
1817	Tap Changer	-	-	-	-	-	731	1,873	26	6	2	16	25	32
1818	Winding	-	-	-	-	-	-	-	-	-	-	-	-	-
1819	Support Steel Structure	-	-	-	-	-	-	-	-	-	-	-	-	-
1821	Grounding System	-	-	-	-	-	-	-	-	-	-	-	-	-
1822	Protection and Control System TS	-	-	-	-	1	8	12	16	8	322	434	447	34
1823	SwitchGear and Relays	-	-	-	-	-	594	-	778	1,444	-	1,315	3,371	46
1824	Capacitor Banks	-	-	-	-	-	132	-	173	321	-	292	749	10
1820	Distribution Stations	3,979	105	129	300	-	-	-	-	-	-	-	-	-
1826	Power Transformer	-	-	-	-	-	-	-	-	-	-	-	-	417
1827	Protection and Control System	-	-	-	-	24	590	22	388	67	2,547	719	372	990
1828	SwitchGear and Relays	-	-	-	-	74	33	169	31	206	244	6	23	8
1830	Poles, Towers & Fixtures	-	-	-	-	-	-	-	-	-	-	-	-	-
1835	O/H Cond.& Devices	-	-	-	-	-	-	-	-	-	-	-	-	-
1840	U/G Conduit	-	-	-	-	1,023	548	245	196	84	284	263	663	695
1845	U/G Cond & Devices	-	-	-	844	3,444	3,363	4,472	4,792	3,347	4,288	5,230	2,184	2,465
1849	O/H Transformers	-	-	-	-	-	-	-	-	-	-	-	252	344
1850	U/G transformers	324	1,197	1,770	1,764	3,070	-	7,605	6,323	6,224	5,890	4,295	4,005	4,684
1855	O/H Services	5,438	-	-	-	-	-	-	-	-	-	-	-	-
1856	U/G Services	2,189	2,989	3,296	2,823	-	-	-	-	-	-	-	-	-
1860	Meters	-	245	-	-	-	-	-	-	-	-	-	-	-
1861	Interval Meters	-	-	-	-	-	-	438	-	-	-	-	949	2,257
1862	Smart meters	-	-	-	-	62	1,797	-	-	-	13,234	-	9,777	6,153
1908	Building - Other	-	-	-	-	-	-	-	-	-	727	-	-	-
1912	Building - Structure	-	-	-	-	-	-	-	-	-	-	-	-	-
1913	Building - Windows	-	-	-	-	-	-	-	-	-	-	-	-	-
1914	Barrie Hydro building- Structural	-	-	-	-	-	-	-	-	-	-	-	-	-
1916	Barrie Hydro building- Other	-	-	-	-	-	-	-	-	-	-	-	-	-
1910	Leashold Improvements	-	-	-	-	-	-	-	-	-	-	-	-	-
1911	LH Improvements- JOC/Cochrane	-	-	-	-	-	-	-	-	-	-	-	-	-
1915	Office Furniture & Equip	61	106	22	13	111	2	35	3,418	283	-	-	-	-
1920	Computer hardware	1,712	1,559	1,751	1,601	-	-	-	-	-	-	-	-	-
1921	Desktops/Laptops	-	-	-	-	8	23	14	14	-	-	-	-	-
1922	Servers (including servers and SAN)	-	-	-	-	620	18	15	38	32	32	-	-	-
1923	MFP's (including all printers)	-	-	-	-	58	2	1	3	3	3	-	-	-
1924	Switches/Routers	-	-	-	-	359	264	2	12	16	-	14	14	-
1611	Computer Software Application	-	2,403	2,526	2,988	333	223	335	264	-	213	-	-	-
1926	Computer Software Operations	-	-	-	-	-	-	-	-	-	-	-	-	-
1930	Light Vehicles - 1930	-	45	1,132	1,247	1,447	1,639	1,985	266	2,565	2,533	984	1,366	-
1931	Heavy Vehicles - 1931	-	-	-	-	7	1	-	-	-	-	-	458	-
1932	Trailers	-	-	-	-	-	-	-	-	-	-	-	-	-
1935	Stores Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
1940	Tools, Shop & Garage	293	210	556	179	327	243	493	260	507	415	10	38	-
1955	Communication Equipment	284	35	24	735	558	228	31	6	12	-	46	51	-
1956	Wireless Communication Devices	-	-	-	-	-	-	-	-	-	-	-	-	-
1961	Process Re-Engineering	-	-	-	-	-	-	-	-	-	-	-	-	-
1980	aka communication equipment	3,517	684	587	908	254	329	140	319	178	187	188	103	252
1981	RTU	-	-	-	-	952	1,221	515	1,194	667	699	703	386	944
1982	Display Wall	-	-	-	-	67	67	37	90	38	46	0	8	-
1985	Sentinel Light	-	-	-	-	-	-	-	-	-	-	-	-	-
2005	Property Under Capital Lease	-	-	-	-	-	-	-	-	-	-	-	-	-
2075	Non-Util. Prop. Owned	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	**19,274**	**10,514**	**12,238**	**14,207**	**12,798**	**12,055**	**18,440**	**18,609**	**16,008**	**31,665**	**14,514**	**25,239**	**19,332**

Undertaking JT1.15 - Comparison 5 Year Capital Plan to Table EP #5a

PROJECT DESCRIPTION	2012 - 5 Year Capital Plan	2013- 5 Year Capital Plan	2012 - COS Rate Case	2013 - COS Rate Case	2012 - Difference COS to Capital Plan	2013 - Difference COS to Capital Plan	Reason for Differences 2012	Reason for Differences 2013
Sustainment Capital								
Replacement Program	$7,830,000	$8,682,000	$6,967,807	$7,979,035	-$862,193	-$702,965	Decrease due to MIFRS	Decrease due to MIFRS
Sustainment Driven Lines Projects	$11,295,000	$23,792,000	$9,919,810	$23,238,712	-$1,375,190	-$553,288	Decrease due to MIFRS; Only half of distribution automation approved; Penetanguishene 44 kV Feeder tie delayed to 2013; Varden Cable Rehab delayed to 2013; Increase due to new project John St. Riser; Increase due to revised estimates on projects;	Decrease due to MIFRS; Only half of distribution automation approved; Increase due to Pentanguished 44 kV feeder tie moved from 2012;
Emergency / Restoration	$9,790,000	$10,251,000	$9,100,468	$9,527,350	-$689,532	-$723,650	Decrease due to MIFRS	Decrease due to MIFRS
Transformer / Municipal Stations	$7,536,000	$7,694,000	$1,123,370	$2,673,187	-$6,412,630	-$5,020,813	Decrease due to MIFRS; Amber MS Feeder conversion delayed to future; Automatic Feeder Restoration at VTS1 delayed to 2013; Feeder Protection at Markham TS# delayed to future; Tottenham substation protection upgrade delayed to future; Oil containment systems delayed to 2013; and several small projects delayed	Decrease due to MIFRS; Refurbishment of Aurora MS delayed to future; Conversion of Concord MS delayed to future; Amber MS feeder conversion delayed to future & several smaller projects delayed to future; Increase due to Automatic Feeder Restoration at VTS and Oil containment systems moved from 2012;
Emerging Sustainment Capital	$1,300,000	$1,300,000	$2,824,959	$2,847,386	$1,524,959	$1,547,386	Decrease due to MIFRS; Increase for emerging underground cable repairs	Decrease due to MIFRS; Increase for emerging underground cable repairs
Total Sustainment Capital	$37,751,000	$51,719,000	$29,936,414	$46,265,670	-$7,814,586	-$5,453,330		
Development Capital								
Subdivision / Services	$10,300,000	$9,880,000	$9,469,121	$11,672,797	-$830,879	$1,792,797	Decrease due to MIFRS	Decrease due to MIFRS; Increase due to impact of removal of upstream not appropriately considered in 5 year plan
Road Authority Projects	$4,200,000	$11,970,000	$6,298,918	$13,044,233	$2,098,918	$1,074,233	Decrease due to MIFRS; Increase due to increase in expected activity	Decrease due to MIFRS; Increase due to inclusion of funds for undergrounding with no cost sharing
Additional Capacity (Transformer / Municipal Stations)	$3,106,000	$6,448,000	$727,500	$5,983,906	-$2,378,500	-$464,094	Decrease due to MIFRS; Decrease due to Sandringham construction delayed to 2013,	Decrease due to MIFRS; Decrease due to Harvie Rd delayed to 2014; Increased due to Sandringham moved from 2012
Growth Driven Lines Projects	$7,458,000	$14,518,000	$4,024,577	$6,544,575	-$3,433,423	-$7,973,425	Decrease due to MIFRS; Decrease due to delay of extension of 27.6 kV Circuits on 14th Avenue to future; Decrease to splitting Pole Line on Dufferin St. across 2012 & 2013; Decrease to delay of pole line on Middletown Rd in Bradford to future	Decrease due to MIFRS; Decrease due to Double Cct Ressor Rd delayed to future; Decrease due to 27.6 kV circuits on 14th Avenue delayed to future; Decrease due to 27.6 kV pole line on 16th Avenue delayed to future;
Emerging Development Capital	$340,000	$201,000	$540,569	$435,371	$200,569	$234,371	Decrease due to MIFRS; Increase based on historical	Decrease due to MIFRS, then increase based on historical
Distributed Generation Connections	$840,000	$35,000	$0	$0	-$840,000	-$35,000	Decrease due to projects should have been covered under deferral accounts	Not significant
Total Development Capital	$26,244,000	$43,052,000	$21,060,685	$37,680,882	-$5,183,315	-$5,371,118		
Operations Capital								
Metering	$2,092,000	$2,092,000	$2,582,260	$2,619,518	$490,260	$527,518	Decrease due to MIFRS; Increase due to Buttonville TS Meter	Decrease due to MIFRS; Increase due to Buttonville TS meter
Fleet	$3,000,000	$3,000,000	$2,037,200	$2,932,600	-$962,800	-$67,400	Decrease due to one large truck deferred to 2013 and purchase of small vehicles cut in half	Increase due to 2012 large truck deferred to 2013; Off setting decrease in purchase of small vehicles cut in half
Tools	$698,000	$550,000	$712,810	$596,576	$14,810	$46,576	Not significant	Not significant
Buildings	$643,000	$21,000	$864,930	$221,372	$221,930	$200,372	New projects identified at budget time that were approved	New projects identified at budget time that were approved.
Information / Communication Systems	$6,199,000	$5,083,000	$5,729,493	$6,756,999	-$469,507	$1,673,999	Decrease due Designer for Layouts deferred to future and a number of small projects delayed to 2013	Increase due 2012 delayed projects moved to 2013 and increase of small projects identified at budget time that were approved. A number of small projects requested at budget time were delayed.
Purchase of spare equipment	$230,000	$130,000	$66,000	$127,654	-$164,000	-$2,346	Purchase of 44 kv switch delayed to future	Not significant
Emerging Operations Capital	$500,000	$500,000	$686,770	$120,120	$186,770	-$379,880	Increase due to known potential impacts	Decrease due to change in how emerging P&C/Substation projects handled
Interest Capitalization	$1,000,000	$1,000,000	$330,000	$1,317,372	-$670,000	$317,372	Decrease due to MIFRS	Increase due to increased costs for CIS and better methodolgy for forecasting
Total Operations Capital	$14,362,000	$12,376,000	$13,009,463	$14,692,211	-$1,352,537	$2,316,211		
Total Capital Expenditure (Without Special Projects)	$78,357,000	$107,147,000	$64,006,562	$98,638,763	-$14,350,438	-$8,508,237		
Capital Special Projects								
New CIS (Removed from Information/ Communications Systems)	$7,610,000	$7,060,000	$12,693,417	$15,640,000	$5,083,417	$8,580,000	Increase in Costs for CIS compared to that estimated in original IT strategy plan	Increase in Costs for CIS compared to that estimated in original IT strategy plan
Total Capital Special Projects	$7,610,000	$7,060,000	$12,693,417	$15,640,000	$5,083,417	$8,580,000		
Total Capital Expenditure	$85,967,000	$114,207,000	$76,699,979	$114,278,763	-$9,267,021	$71,763		
Capital Deferral Accounts								
Smart Meters	$0	$0	$0	$0	$0	$0	No Change	No Change
Smart Grid	$1,250,000	$650,000	$1,250,000	$650,000	$0	$0	No Change	No Change
Customer - Renewable Generation	$0	$0	$756,361	$77,250	$756,361	$77,250	Increase due to projects being covered in 5 Year plan under Distributed Generation Connections	Not significant
Total Capital Deferral	$1,250,000	$650,000	$2,006,361	$727,250	$756,361	$77,250		

Merge Co B|S

PowerStream - Barrie Hydro Consolidated Pro Forma Financial Statements

Balance Sheet ($ millions)

	2009F	2010F
Current Assets		
Cash	53.2	46.1
Accounts Receivable	62.3	64.7
Unbilled Revenue	89.4	92.8
Inventory	8.9	9.2
Prepaid Expenses	1.6	1.7
Total Current Assets	215.5	214.5
Fixed Assets (Net of Acc. Depr)	651.0	695.6
Goodwill	42.6	42.6
Other Long Term Assets		
Restricted Cash (Customer Deposits)	16.4	16.6
Deferred Financing Charges	1.9	1.3
Other Intangibles	0.0	0.0
Other Assets	6.8	6.9
Total Other Long Term Assets	25.1	24.8
TOTAL ASSETS	934.2	977.5
Current Liabilities		
Accounts Payable / Accrued Liabilities	122.5	127.1
Income Taxes Payable	2.0	2.0
Due to Related Parties	8.1	8.4
Liability for Subdivision Development	5.4	5.6
Total Current Liabilities	137.9	143.1
Long-Term Liabilities		
Note Payable - Markham & Vaughan	162.5	162.5
Note Payable - City of Barrie	20.0	20.0
Debenture Debt - EDFIN	125.0	125.0
New Long Term Debt	127.2	162.1
Total Long-Term Liabilities	434.7	469.6
Other Liabilities		
Regulatory Liabilities	41.1	26.5
Customer Deposits	16.4	16.6
Employee Future Benefits	10.5	11.2
Liability for Subdivision Developments	8.0	6.0
Other Liabilities	0.0	0.0
Total Other Liabilities	75.9	60.3
TOTAL LIABILITIES	648.5	673.0
Shareholder's Equity		
Common	225.3	225.3
Retained Earnings	60.4	79.2
Total Equity	285.7	304.5
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	934.2	977.5

MergeCo Cash F

EB-2012-0161
PowerStream Inc.
Attachment JT1.19
Page 2 of 9
Filed: October 1, 2012

PowerStream - Barrie Hydro Consolidated Pro Forma Financial Statements

Cash Flow Statement ($ millions)

	2009F	2010F
OPERATING ACTIVITIES		
Net Income from Continuing Operations	24.7	31.1
Non-Cash Items:		
Depreciation of Capital Assets	44.9	48.8
Amortization of Debt Issue Costs	0.6	0.6
Gains/Loss on Disposal	0.0	0.0
Employee Future Benefits	0.5	0.6
Funds from Operations	70.7	81.2
Regulatory Asset/Liability (Decrease)	7.5	(14.6)
Change in Working Capital	(0.8)	(0.9)
Cash Flows From Operations	77.4	65.7
FINANCING ACTIVITIES		
Decrease in Liability for Subdivision Development	(2.0)	(2.0)
Increase (decrease) in New Debt	21.3	34.9
Change in Long-Term Customers Deposits, Net of Cash	0.0	0.0
Change in Other Liabilities	0.0	0.0
Change in Other Assets	0.0	0.0
Adjustment to Working Capital Deficiency	0.0	0.0
Special Dividend	0.0	0.0
Standard Dividend	(13.1)	(12.4)
Cash Flows From Financing	6.2	20.5
INVESTING ACTIVITIES		
Fixed Asset Additions, Net of Capital Contributions	(109.6)	(93.4)
Change in Other Assets	0.1	0.1
Cash Flows from Investing	(109.5)	(93.3)
NET CHANGE IN CASH FOR THE YEAR	-26.0	-7.2
CASH BEGINNING OF THE YEAR	79.2	53.2
CASH END OF THE YEAR	53.2	46.1

MergeCo I/S

PowerStream - Barrie Hydro Consolidated Pro Forma Financial Statements

Income Statement ($ millions)

	2009F	2010F
REVENUE		
Cost of Power	649.2	670.1
Distribution	151.3	161.9
Fibre	0.0	0.0
Miscellaneous Revenue	12.2	11.7
TOTAL REVENUE	812.7	843.6
Less: Cost of Power	649.2	670.1
NET REVENUE	163.5	173.6
COSTS		
Operation, Maintenance, Administration	58.8	53.7
EBITDA	104.6	119.8
Depreciation and Amortization	44.9	48.8
EBIT	59.8	71.0
Interest Expense	24.1	26.4
EBT before Extraordinary Items	35.7	44.6
EBT	35.7	44.6
Tax Rate	33.0%	32.0%
Provision for Income taxes	11.8	14.3
Less taxes paid in previous years (regulatory assets)	0.8	0.8
NET INCOME	24.7	31.1

Statement of Retained Earnings

		2009F	2010F
Opening Retained Earnings		48.8	60.4
Add:	Net Income	24.7	31.1
Deduct:	Allowance for (Excess) / Deficient Working Capital		
	Standard Dividend	(13.1)	(12.4)
	Special Dividend	0.0	0.0
Closing Retained Earnings		60.4	79.2

BARRIE BIS

Stand Alone Model for Merger- Barrie Hydro

BALANCE SHEET ($ Millions)	2009F	2010F
Current Assets		
Cash	3.5	2.2
Accounts Receivable	12.0	12.4
Unbilled Revenue	17.2	17.8
Inventory	1.7	1.8
Prepaid Expenses	0.3	0.3
Total Current Assets	34.7	34.5
Fixed Assets (Net of Acc. Dep.)	149.1	157.4
Goodwill	9.6	9.6
Other Long Term Assets		
Restricted Cash (Customer Deposits)	3.1	3.2
Deferred Financing Charge	0.0	0.0
Other Intangibles	0.0	0.0
Other Assets	0.5	0.4
Total Other Long Term Assets	3.6	3.6
Total Assets	197.0	205.1
Current Liabilities		
Accounts Payable / Accrued Liabilities	23.5	24.4
Income Taxes Payable	0.4	0.4
Due to Related Parties	1.6	1.6
Liability for Subdivision Development	1.0	1.1
Total Current Liabilities	26.5	27.5
Long-Term liabilities		
Note Payable - Shareholder	20.0	20.0
Debenture Debt - EDFIN	25.0	25.0
New Long-Term Debt	50.5	59.2
Total Long Term Liabilities	95.5	104.2
Other Liabilities		
Regulatory Liabilities	5.2	2.6
Customer Deposits	3.1	3.2
Employee Future Benefits	2.6	2.7
Liability for Subdivision Deposits	8.0	6.0
Other Liabilities	0.0	0.0
Total Other Liabilities	18.9	14.5
Total Liabilities	140.9	146.1
Shareholder's Equity		
Common	61.5	61.5
Retained Earnings	(5.6)	(2.6)
Total Equity	55.9	58.9
Total Liabilities & Equity	196.9	205.1

BARRIE CASH F.

Stand Alone Model for Merger- Barrie Hydro

CASH FLOW STATEMENT ($ Millions)	2009F	2010F
Operating Activities:		
Net Income From Continuing Operations	7.0	6.5
Non-Cash Items:		
Depreciation of Capital Assets	10.1	11.1
Amortization of Debt Issue Costs	0.0	0.0
Gains/Loss on Disposal	0.0	0.0
Employee Future Benefits	0.0	0.0
Funds From Operations	17.1	17.6
Regulatory Asset/Liability (Decrease)	0.1	(2.6)
Change in Working Capital	(0.2)	(0.2)
Cash Flow From Operations	17.1	14.8
Financing Activities:		
Decrease in Liability for Subdivisions Development (Long-T	(2.0)	(2.0)
Increase (Decrease) in New Debt	6.1	8.7
Change in Long-Term Customers Deposits, Net of Cash	0.0	0.0
Change in Other Liabilities	0.0	0.0
Dividend - Lump Sum Recapitalization	0.0	0.0
Dividends - Standard	(3.2)	(3.5)
Cash Flow from Financing	0.9	3.2
Investing Activities:		
Fixed Asset Additions, Net of Capital Contributions	(29.3)	(19.4)
Change in Other Assets	0.1	0.1
Cash Flow from Investing	(29.2)	(19.3)
Net Change in Cash for the Year	(11.2)	(1.3)
Cash, Beginning of Year	14.7	3.5
Cash, End of Year	3.5	2.2

BARRIE I/S

Stand Alone Model for Merger- Barrie Hydro

INCOME STATEMENT ($ Millions)	2009F	2010F
Revenue		
Cost of Power	119.0	123.1
Distribution	33.1	34.9
Miscellaneous Revenue	4.1	3.9
Total Revenue	156.2	161.9
Less: Cost of Power	119.0	123.1
Net Revenue	37.2	38.7
Costs		
Operation & Maintenance & Administration	12.7	13.4
EBITDA	24.5	25.4
Depreciation and Amortization	10.1	11.1
EBIT	14.4	14.2
Interest expense	5.1	5.9
EBT before Extraordinary Items	9.3	8.4
EBT	9.3	8.4
Tax Rate	33.00%	32.00%
Provision for income taxes	3.1	2.7
Less Taxes paid in previous years (regulatory assets)	0.8	0.8
Net Income	7.0	6.5
Earnings available for common before customer sharing	7.0	6.5
Customer sharing for over / under earnings	0.0	0.0
Net Income after customer sharing	7.0	6.5

RETAINED EARNINGS STATEMENT ($ Millions)	2009F	2010F
Opening Retained Earnings	(9.4)	(5.6)
Add: Net Income	7.0	6.5
Deduct:		
Customer sharing for over / under earnings	0.0	0.0
Deduct: Standard Dividend	(3.2)	(3.5)
Allowance for Excess Opening Working Capital	0.0	0.0
Deduct: Lump Sum Dividend	0.0	0.0
Closing Retained Earnings	(5.6)	(2.6)

POWERSTREAM 012
(CORRECTED)

PowerStream
(C$millions unless otherwise noted)

BALANCE SHEET ($ Millions)	2009F	2010F
Current Assets		
Cash	48.1	38.6
Accounts Receivable	50.4	52.3
Unbilled Revenue	72.2	75.0
Inventory	7.2	7.5
Prepaid Expenses	1.3	1.4
Total Current Assets	179.2	174.7
Fixed Assets (Net of Acc. Dep.)	506.4	543.4
Goodwill	33.0	33.0
Other Long Term Assets		
Restricted Cash (Customer Deposits)	13.2	13.5
Deferred Financing Charges	1.9	1.3
Other Intangibles	0.0	0.0
Other Assets	6.5	6.5
Total Other Long Term Assets	21.6	21.3
Total Assets	740.2	772.3
Current Liabilities		
Accounts Payable / Accrued Liabilities	98.9	102.7
Income Taxes Payable	1.6	1.6
Due to Related Parties	6.6	6.8
Liability for Subdivision Development	4.3	4.5
Total Current Liabilities	111.4	115.7
Long-Term Liabilities		
Note Payable - Shareholder	162.5	162.5
Debenture Debt - EDFIN	100.0	100.0
New Long-Term Debt	78.0	105.7
Total Long Term Liabilities	340.5	368.2
Other Liabilities		
Regulatory Liabilities	35.9	23.9
Customer Deposits	13.2	13.5
Employee Future Benefits	7.9	8.5
Other Liabilities	0.0	0.0
Total Other Liabilities	57.0	45.9
Total Liabilities	508.9	529.7
Shareholders' Equity		
Common	163.8	163.8
Retained Earnings	67.5	78.8
Total Equity	231.3	242.5
Total Liabilities & Equity	740.2	772.3

POWERSTREAM CF
(CORRECTED)

PowerStream
(C$millions unless otherwise noted)

CASH FLOW STATEMENT ($ Millions)	2009F	2010F
Operating Activities:		
Net Income From Continuing Operations	19.2	20.8
Non-Cash Items:		
Depreciation of Capital Assets	34.9	38.1
Amortization of Debt Issue Costs	0.6	0.6
Gains/Loss on Disposal	0.0	0.0
Employee Future Benefits	0.5	0.6
Funds From Operations	55.2	60.1
Regulatory Asset/Liability (Decrease)	7.4	(12.0)
Change in Working Capital	(0.6)	(0.8)
Cash Flow From Operations	62.0	47.4
Financing Activities:		
Decrease in Liability for Subdivision Development (Long-Te	0.0	0.0
Increase (Decrease) in New Debt	16.5	27.7
Change in Long-Term Customer Deposits, Net of Cash	0.0	0.0
Change in Other Liabilities	0.0	0.0
Change in Other Assets	0.0	0.0
Adjustment to opening working capital deficiency	0.0	0.0
Dividends - Standard	(9.9)	(9.6)
Cash Flow from Financing	6.6	18.2
Investing Activities:		
Fixed Asset Additions, Net of Capital Contributions	(85.0)	(75.0)
Cash Flow from Investing	(85.0)	(75.0)
Net Change in Cash for the Year	(16.5)	(9.5)
Cash, Beginning of Year	64.5	48.1
Cash, End of Year	48.1	38.6

PowerStream I/S
(CORRECTED).

PowerStream
(C$millions unless otherwise noted)

INCOME STATEMENT ($ Millions)	2009F	2010F
Revenue		
Cost of Power	530.3	546.9
Distribution	118.2	127.0
Fibre	0.0	0.0
Miscellaneous Revenue	8.0	7.7
Total Revenue	656.6	681.6
Less: Cost of Power	530.3	546.9
Net Revenue	**126.3**	**134.7**
Costs		
Operation & Maintenance & Administration	43.7	45.4
EBITDA	82.6	89.3
Depreciation and Amortization	34.9	38.1
EBIT	47.6	51.3
Interest expense	19.0	20.6
EBT before Extraordinary Items	28.6	30.7
EBT	28.6	30.7
Tax Rate	33.00%	32.00%
Provision for income taxes	9.5	9.8
Net Income	19.2	20.8

RETAINED EARNINGS STATEMENT ($ Millions)	2009F	2010F
Opening Retained Earnings	58.3	67.5
Add: Net Income	19.2	20.8
Deduct:		
Customer sharing for over / under earnings	0.0	0.0
Deficiency in opening working capital	0.0	0.0
Deduct: Standard Dividend	(9.9)	(9.6)
Deduct: Dividends to Holdco	0.0	0.0
Closing Retained Earnings	67.5	78.8

KT1.1

PowerStream

	2001	2002	2003	Jan. 1-May 31, 2004	June 1 - Dec. 31, 2004	2005
Net Fixed Assets (see below)						
Aurora	21,166,897	20,425,503	21,427,373	20,757,031	20,757,031	
Markham	101,097,000	100,597,077	101,860,747	107,266,269		
Richmond Hill	93,770,412	92,047,847	87,984,507	86,579,463		
Hydro Vaughan	158,962,860	158,966,090	157,018,255	157,239,269		
PowerStream					350,609,000	376,773,000
Total Net Fixed Assets	**374,997,169**	**372,036,517**	**368,290,882**	**371,842,031**	**371,366,031**	**376,773,000**
Goodwill						
Markham		16,622,000	16,622,000	16,622,000		
Hydro Vaughan		16,345,000	16,366,000	16,366,000		
PowerStream					32,988,000	32,988,000
Total Goodwill		**32,967,000**	**32,988,000**	**32,988,000**	**32,988,000**	**32,988,000**

Net Fixed Assets

		2001	2002	2003	Jan. 1-May 31, 2004
Richmond Hill		93,770,412	92,047,847	87,984,507	86,579,463
Markham	1	101,097,000	146,621,000	145,853,000	150,556,000
Deduct: 50% of Richmond Hill's net fixed assets			46,023,924	43,992,254	43,289,732
Markham's net fixed assets		101,097,000	100,597,077	101,860,747	107,266,269
Hydro Vaughan	1	158,962,860	204,990,000	201,011,000	200,529,000
Deduct: 50% of Richmond Hill's net fixed assets			46,023,924	43,992,254	43,289,732
Hydro Vaughan's net fixed assets		158,962,860	158,966,077	157,018,747	157,239,269

1. Proportionate consolidation started on January 1, 2002

PowerStream **Actual and Deemed Interest Expense**

		2001	2002	2003	Jan. 1-May 31 June 1-Dec. 31, 2004	Jan. 1-Oct. 31 Nov. 1-Dec. 31, 2005
Actual Interest from AFS						
Aurora		0	1,154,200	923,360	923,360	770,942
Markham		1,833,000	6,047,000	7,321,000	2,902,000	0
Richmond Hill		1,401,595	2,285,607	3,392,737	1,328,377	0
Hydro Vaughan		3,187,323	6,200,443	8,506,000	3,432,000	0
PowerStream		0	0	0	11,680,000	19,305,000
Total Actual Interest Expense		**6,421,918**	**15,687,250**	**20,143,097**	**20,265,737**	**20,075,942**
Deemed Interest						
Aurora		1,044,174	1,044,174	1,044,174	1,044,174	
Markham	1	5,082,484	5,082,484	5,082,484	2,110,758	
Richmond Hill	1	4,017,640	4,017,640	4,017,640	1,668,528	
Hydro Vaughan	1	6,962,384	6,962,384	6,962,384	2,891,482	
PowerStream	2	0	0	0	9,391,740	17,106,682
Total Deemed Interest		**17,106,682**	**17,106,682**	**17,106,682**	**17,106,682**	**17,106,682**
Potential Excess Interest for True-up Amount		**0**	**0**	**-3,036,415**	**-3,159,055**	**-2,969,260**

1. 2004 pro-rated by 152/366
2. 2004 pro-rated by 214/366
   2005: see Appendix 5/Sch5-29/Page2

EB-2012-0161
PowerStream Inc.

2013 Cost of Service Application

AMPCO Technical Conference Questions

Cost Allocation

Issue 7.1 Is PowerStream's proposed cost allocation methodology for 2013 appropriate?

Reference: AMPCO Interrogatory # 1

Questions

1. Part (b) - **"**PowerStream does not track assets and costs by customer class. Most of PowerStream's assets are used by most or all customer classes."

   i) Please confirm the assets used by PowerStream's original Large User compared to the assets used by the class when an additional Large User is added to the class.

   ii) Is PowerStream's original Large User aware of the change in <u>assets</u> allocated to the Large User class in 2013?

2. Part (c) - Table 1-1 shows Assets and Cost Allocated to the Large Use Class in 2009 and 2013. Please reproduce the table assuming the size of the rate class has not changed in 2013 and there is the same single large user in both 2009 and 2013.