September 27, 2016

Ms. Kirsten Walli
Ontario Energy Board
PO Box 2319 27th Floor,
2300 Yonge Street
Toronto, Ontario
M4P 1E4

Dear Ms. Walli,

Re: 2017 COS Rates Application, Undertakings and Technical Conference Questions

Please find attached BPI's responses to its technical conference undertakings and technical conference questions. BPI has attempted to update the initial responses given prior to its technical conference, identifying any updates with blue font in the attached document (with the original responses appearing in black font).

If you have any further questions, please do not hesitate to contact me at (519) 751-3522 Ext 5133 or via email at bdamboise@brantford.ca.

Sincerely,

[Original Signed By]

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cc: Randy Aiken, Aiken & Associates
Bruce Bacon, Borden Ladner Gervais
Michael Janigan, VECC Counsel
Paul Kwasnik, Brantford Power Inc.
David MacIntosh, Energy Probe
Wayne McNally, SEC Coordinator
Martha McOuat, Ontario Energy Board
Mark Rubenstein, Jay Shepherd Professional Corporation
Jay Shepherd, Jay Shepherd Professional Corporation
James Sidlofsky, Borden Ladner Gervais

Undertakings

JT1: TO FILE AN UPDATED LOAD FORECAST AND TO ADDRESS THE QUESTION OF THE 2015 CDM

Response:

BPI is submitting an updated load forecast. The complete list of changes is shown below. Please note the list represents all changes made from the original application submission.

		2016	2017
Purchased kWh's as per application		905,675,276	924,712,894
Update for YTD June 2016 purchases	1-Staff-1	12,299,263	14,366,643
Update for 2015 Verified CDM	3-VECC-21	(2,889,866)	(4,317,382)
Updated for CDM Persistence (Burman)	3-VECC-22	3,406,904	10,594,945
Updated for 2011 and 2012 CDM did not get updated in VECC 22 and 23	3-VECC-58 (TCQ)	(81,795)	(292,618)
Manual Adj't for 2016/2017	3-VECC-54 (TCQ)	-	-
Updated to most current GDP	3-EP-TCQ 2 b)	(393,401)	1,800,818
Updated for HDD/CDD	3-EP-TCQ 2 b)	1,197,624	(1,970,316)
Updated Purchase Forecast		**919,214,005**	**944,894,984**

With respect to 2015 CDM, BPI has removed the ½ year amount from the manual adjustment used in the load forecast as well as from the LRAM baseline calculation. The LRAM baseline and manual adjustment for 2017 now reflects 100% of 2016 persistence and ½ of 2017 new programs.

BPI would like to note that the estimated billed kWh in the updated load forecast for both the residential and GS<50 classes is higher than historical trends. In particular, 2017 billed kWh for the residential class, 300,576,547 kWh, is 4.5% higher than 2015 actual billed kWh which is higher than would be expected given customer growth of only 1.9% over 2015.

JT2: TO PROVIDE AN UPDATED, REVISED REVENUE REQUIREMENT WORK FORM THAT SHOWS INTERROGATORY RESPONSES THAT ARE RELATED TO THESE CHANGES, AND PROVIDE SOME DETAIL IN THE CALCULATION OF THE CHANGES

Response:

Refer to Attachment JT2-A and Attachment JT2-B.

JT3: TO PROVIDE THE FORECAST OF COSTS FOR THE TWO OTHER PROJECTS IN 6C

Response:

Project 1: Garden Avenue Infrastructure Relocation:

Capital Cost	$108,864
Capital Contribution	($29,806)
Net Capital Cost	$79,058

Project 2: Oak Park Road- Highway 403 Interchange Infrastructure Relocation

Capital Cost	$12,082
Capital Contribution	($4,078)
Net Capital Cost	$8,004

Total forecasted net capital costs for both projects: $87,062

JT4: TO UPDATE 2 ENERGY PROBE TCQ 6 WITH CAPITAL PROJECT CHANGES

Response:

Refer to Attachment JT4 for the updated App. 2-AA and App.2-AB.

JT5: TO INDICATE THE NEW AVERAGE BANK BALANCE IS IN 3-ENERGY PROBE-30, GIVEN THE REMOVAL OF THE BUILDING

Response:

BPI has updated the calculations in 3-EP-30 to adjust 2016 closing cash balance and 2017 closing cash balance to reflect the removal of the building acquisition. See Table JT5 below.

Table JT5

	2016	2017
Opening Bank Balance	$9,915,249.00	$8,805,432.69
Closing Bank Balance	$8,805,432.69	$9,492,588.23
Average Bank Balance	$9,360,340.84	$9,149,010.46
Interest Rate Applied	*1.20%*	*1.20%*
Expected Interest	$112,324.09	$109,788.13
Interest per budget & Application	$ 149,337.00	$ 125,846.00

JT6: TO PROVIDE COST ALLOCATION WITH LOAD FORECAST AND STREETLIGHT INFORMATION

Response:

An updated cost allocation model has been submitted which includes, among other changes, updated street light connections (5,767) and devices (10,118).

JT7: TO CLARIFY THE RESPONSE TO 4 ENERGY PROBE 33

Response:

The 2013 Board Approved OM&A expenses of $8,854,025 reflected the new smart metering regime that was implemented after the last rebasing in 2008. Costs related to the operations and maintenance for these smart meters became "normal" operating costs with the 2013 distribution rates that took effect March 1, 2014.

Since the implementation of the 2013 rates were delayed until 2014, BPI reallocated the smart meter OM&A incurred in 2013 to the 1556 - Smart Meter OM&A Variance account with an offsetting entry to 5695 - O&M Contra Account. The total smart meter costs incurred in 2013 were $536,025 consisting of $174,035 of OM&A and $362,000 of amortization expense. These costs were strictly 2013 costs and did not include any costs incurred prior to 2013.

This credit of $536,025 is reflected in the 2013 actual total of $8,789,985. If this adjustment to OM&A is excluded, the 2013 actual costs would be $9,326,010 ($8,789,985 + $536,025). The true OM&A costs of 2013 were $9,326,010. Table 4.2-B reflects the other differences that occurred in 2013 reconciling 2013 Board Approved to 2013 Actuals.

BPI needed to add back the $536,025 in 2014 in Table 4.2-B to reflect the fact that the 2013 starting expenses had been adjusted for the special accounting treatment for smart meter OM&A. When the smart meter variance accounts were disposed on during 2014, BPI mapped the dispositions to 4080 Distribution Revenue. As a result, 2014 OM&A expenses of $9,120,560 reflect the true OM&A costs and do not include any special accounting adjustments related to smart meters

JT 9: TO EXPLAIN THE LOWER OM&A COSTS

Response:

The lower OM&A costs for 2016 are related to the removal of the building request (including OM&A impacts) as well as adjustments to the 2016 Year End forecast for OM&A related to 2016 June YTD actuals (as requested in 1-Staff-1).

BPI took the June 2016 interim financials and identified material variances by high level line items and made adjustments to the year-end forecasts as necessary based on managements' best judgement. Because of limitations with BPI's current financial system, interim results do not reflect full accrual accounting and consequently forecasts rely more on management judgement.

Table JT9 below indicates the areas where adjustments were made. BPI notes that the figures include the new HR Manager position, and an offsetting decrease to special project. Upon review for this response, BPI has determined that there was a double-counting of the HR Manager OM&A reduction of roughly 34k, which was included as an individual adjustment to OM&A (Administrative line) for YTD as well as a building adjustment. Therefore, the total adjustments should have been $(409)k.

BPI also notes higher than expected regulatory costs, partly in relation to OEB annual fees, and partly related to the costs for this Application.

OM&A Category		Variance	
Operations		$	(85)
Billing+Collecting		$	(262)
Administrative		$	106
Regulatory		$	54
Special Projects		$	(163)
Subtotal		**$**	**(350)**
Building			(93)
Total		**$**	**(443)**

JT10: TO PROVIDE INFORMATION RE: THE DOLLARS THAT ARE REPRESENTED BY THE INCREMENTAL COST OF EMPLOYEES AND/OR CONTRACT PEOPLE

Response:

BPI has provided an analysis in tables JT10-A JT10- D to more clearly indicate the FTE changes since 2013 related to increases in permanent vs. temporary headcount, and identifying changes related to vacancies.

Vacancies represent the turnover related to positions which are intended to be re-filled, usually associated with medical leave, resignations and retirements.

The Conservation Coordinator role has not been included, as this is represents a non-utility expense. The Facility Manager role has also not been included in the analysis as the request for funding was removed with the responses to Interrogatories. Where applicable, compensation has been adjusted to remove amounts planned to be allocated to affiliates.

BPI notes that the net incremental permanent positions over the 2013-2017 period represent 1 FTE (adding the "add" and "remove" columns in each year which indicate permanent positions added or removed.

Permanent Roles in 2017

The analysis indicates that, compared to 2013, in 2017 BPI plans to have the following permanent new employees:

One Financial Analyst (included fully, but roughly equivalent contract roles in 2013);
One Communications Specialist Role (PT) (offsets Communication Coordinator previous role);
One Linesperson (offsetting assistant stock keeper role); and
One Junior Accountant (for the in-housing of some finance services previously provided via Shared Services Agreement).

The permanent new positions represent a total of $283,865.

Temporary Roles in 2017

The following temporary roles are included in 2017:

Acting Manager of Finance (only .5FTE, as .5FTE included in 2013 BA);
One Foreman Role (Succession Planning measure- unknown duration);
Manager, System Projects and Business Applications;
Acting Manager of Customer Service (half year backfill); and
Contract Customer Service Representatives (2017 complement).

The temporary new positions represent a total of $516,311.

JT10-A: 2013 to 2014 Variances in FTE

	2013 to 2014					
	Add	Remove	Vacancies	Temp.	Affiliates	
Administrative	-	-	-	-	-	
Communications	-	-	-	-	-	
Conservation	-	-	-	-	-	
Credit and Collections	-	-	-	-	-	
Customer Service	-	-	-	-	-	
Engineering- SCADA	-	(0.25)	-	-	-	Planned short term vacancy
Engineering - Construction	-	-	-	-	-	
Engineering- Systems and Stnds	-	-	-	-	-	
Facilities	-	-	-	-	-	
Finance	0.90	-	-	(0.67)	-	Contracts in Finance 2013 vs. new permanent FA position in 2014; Acting Mgr Finance- annualization from 2013
IT	-	-	-	-	-	
Operations	-	(0.92)	(0.25)	-	-	Remove Assistant Stockkeeper; total vacancy between lines staff retirements and apprentice hires.
Regulatory	-	(0.58)	(0.17)	-	-	Reg. Analyst Vacancy , Mgr. of Reg Vacancy
Settlement and Billing	-	-	-	-	-	
SLT	-	(1.04)	-	-	(0.17)	Restructuring Impact; Affiliate Allocations
Misc.	-	-	(0.25)	-	-	
Total	0.90	(2.79)	(0.67)	(0.67)	(0.17)	-3.4
						-3.4
"Add"						
Temporary	0.48	Finance- Acting Mgr Finance		Hired in 2013, increase related to annualization		
Permanent	$ 0.42	Finance- Financial Analyst		Hired in August 2014, offset contract roles worth 0.92 FTE in 2013		

JT10-B: 2014 to 2015 Variances in FTE

	2014 to 2015					
	Add	Remove	Vacancies	Temp.	Affiliates	
Administrative	-	-	-	-	(0.15)	Exec. Assistant Allocation to affiliates+ small amt of vacancy
Communications	-	-	-	-		
Conservation	-	-	(0.38)	-	-	Temporary Vacancy
Credit and Collections	-	-	-	-	-	
Customer Service	-	-	1.42	1.26	-	Contract CSRs/Junior CSRs+ Return to work following vacancies.
Engineering- SCADA	-	-	0.25	-	-	Return to work from planned absence
Engineering - Construction	-	-	-	-	-	
Engineering- Systems and Stnds	-	(1.00)	-	-	-	Resignation without replacement of manager
Facilities	-	-	-	-	-	
Finance	-	-	(0.01)	(0.56)	-	Allocations to affiliates
IT	-	-	-	-	-	
Operations	1.67	-	(0.17)	-	-	Long Term vacancy, annualization of new apprentices, 2 new linespersons (both backfill); new Foreman
Regulatory	-	-	0.25	-	-	Reg. Analyst vacancy
Metering and Settlement	-	-	(0.59)	-	-	Vacancy
SLT	(0.34)	-	-	-	-	Annualization of 2014 restructuring
misc	-	-	(0.31)	-	-	
Total	1.33	(1.00)	0.48	0.69	(0.15)	1.3
						1.3
"Add" Column						
Permanent	1.67	2 new Linespersons- replacement for long term sick leave and New foreman position				
Contract	1.26	Contract positions in CS				

JT10-C: 2015 to 2016 Variances in FTE

	2015 to 2016						
	Add	Remove	Vacancies	Temp.	Affiliates		
Administrative	-	-	-	-	-		
Communications	0.70	(0.50)	-	-	-		
Conservation	0.70	-	0.38	-	-	Annualization of vacancy; new Conservation Coordinator Position	
Credit and Collections	-	-	-	-	-		
Customer Service	-	-	-	(0.82)	-	Impact of Contracts compared to 2015 contracts	
Engineering- SCADA	-	-	-	-	-		
Engineering - Construction	-	-	-	-	-		
Engineering- Systems and Stnds	-	-	-	-	-		
Facilities	1.00	-	-	-	-		
Finance	0.46	-	0.51	1.00	0.18	New Junior Accountant Position; Filling vacancies from previous year; Temporary FA for FIS backup; Allocations to affiliates	
IT	-	-		1.00	-	Mgr. Business System Projects and Business Applications	
Operations	0.25	-	0.75	-	-	New linesperson hires in 2015 annualized; RTW mid-year for one linesperson.	
Regulatory	-	-	0.91	-	-		
Metering and Settlement	-	-	0.59	-	-	Filling Vacancy	
SLT	-	-	-	-	0.17		
Misc.	-	-	(0.15)	-	-		
Total	3.11	(0.50)	2.98	1.18	0.35	$ 7.1	
Add	**Planned FTE**					**Updated Expected FTE contribution**	**Desctiption**
Permanent	**0.70**	Communications Specialist				0.20	Hired PT Sept 12
Permanent	0.70	Conservation coordinator, PT				0.70	Hired as planned, part time start of year.
Permanent	1.00	Facility Manager				0.00	Not hired.
Permanent	0.46	Accounting Clerk, 0.46 FTE (beginning March 20:				0.17	80% BPI starting mid Oct (2.5 Months) ("Jr. Accountant:)
Temporary	1.00	Mgr System Projects and Business Applications				1.00	Hired as planned, Jan 4 2016
Temporary	1.00	FIS Backup				0.17	Expected hire: November 2016.
Temporary	0.50	2 Contracts for CIS backup in CS				0.50	2 Contracts starting October 2016
HR Manager	-	Not planned for in application via headcount, pl				0.25	Hired Oct 3, 2016

JT10-D: 2016 to 2017 Variances in FTE

	2016 to 2017						
	Add	Remove	Vacancies	Temp.	Affiliates		
Administrative	-	-	-	-	-		
Communications	-	-	-	-	-		
Conservation	-	-	-	-	-		
Credit and Collections	-	-	-	-	-		
Customer Service	-	-	-	2.26	-	Increase in contract FTE for CIS backup (incl. .5 FTE CS Mgr)	
Engineering- SCADA	-	-	-	-	-		
Engineering - Construction	-	-	-	-	-		
Engineering- Systems and Stnds	-	-	-	-	-		
Facilities	-	-	-	-	-		
Finance	-	-	-	(1.00)	0.35	Decreased allocations to affiliates; Reduction in FIS backup (which may now be needed)	
IT	-	-	-	-	-		
Operations	-	-	0.50	-	-	Annualization of RTW	
Regulatory	-	-	-	-	-		
Metering and Settlement	-	-	-	-	-		
SLT	-	-	-	-	0.23		
Misc.	-	-	0.07	-	-		
Total	-	-	0.57	1.26	0.58	2.41	
						2.40	
Add	**Planned FTE**					**Updated Expected FTE Contribution**	**Description**
Temporary	0.50	Acting Manager of Customer Service				0.50	Expected Hire: June 2017
Temporary	2.00	Customer Service Contract Staff- CIS backup				2.00	Expected hire: January 2017

JT11: TO EXPAND THIS RESPONSE OUT TO THE END OF 2017 AND THEN GIVE A NOTATION IF THEY'VE BEEN FILLED AND IF THEY HAVEN'T BEEN FILLED, WHEN IS IT PLANNED TO FILL THEM

Response:

The roles listed below are job descriptions which were not included with the answer to 4-SEC-21 which are planned to be filled. Please note, as the Facilities Manager recruitment has not been initiated and is deferred, there is no job description associated with this role. Similarly, there is no job description completed yet for the Acting Manager, Customer Service role. Please see tables JT10-C and JT-10 D for an update on the hiring dates for the 2016/2017 roles.

Junior Accountant Position- Required for the in-housing of certain functions which were previously completed via the Shared Services Agreement.

Reporting to the Manager of Finance, the Junior Accountant will process A/P, A/R, retailer payments; complete statistical reporting for Federal and Provincial Government Agencies. Other duties in this position include but are not limited to preparing and entering journal entries in accordance with documentation received, payroll, accounts payable and GL account reconciliations, interacting with internal departments to resolve any accounting issues, payroll analysis, budget to actual variance analysis and reviewing account coding on accounts payable. This position will also assist with the preparation of financial statements, budgets, year-end audit and the implementation of the new FIS. The incumbent is responsible for verification of financial data to ensure accurate and timely information is available for reporting.

Applicants must have successfully completed Successful completion of a three (3) year post-secondary diploma with an emphasis on accounting, business and/or finance and a minimum of one (1) year related work experience. Current enrolment in and successful completion of the first level of a recognized professional accounting designation program (CPA formerly CA, CMA and CGA) is desirable. The ability to perform the duties as outlined herein within a reasonable time, to work with multiple priorities and to demonstrate proven communication skills. Knowledge of spreadsheets and word processing software (preferably Word and Excel) is essential. Experience with JD Edwards or Microsoft Great Plains financial information systems is desirable. Applicants must have the skill and ability to perform the duties as outlined herein accurately and within strict deadlines with minimal supervision.

Financial Analyst Description (Note- Generic FA, not specific to FIS backup)- Required for continuity of day-to-day FA duties as FIS is implemented.

Reporting to the Manager of Finance, the Financial Analyst will be responsible for the preparation of financial statements as well as general accounting functions as they relate to the Brantford Energy Group. The incumbent is responsible for verification of financial data to ensure accurate and timely information is available for reporting. Other duties in this position include but are not limited to preparing and entering journal entries in accordance with documentation received, account reconciliations, interacting with internal departments to resolve any accounting issues, payroll analysis, budget to actual variance analysis and reviewing account coding on accounts payable.

Applicants must have a post-secondary degree with emphasis in accounting. Preference will be given to candidates with a recognized professional accounting designation CPA (CA, CMA or CGA). Experience and knowledge of the utility industry, JD Edwards financial software and Caseware/Caseview working paper/financial statement software would be considered an asset. Advanced knowledge of spreadsheets and word processing is essential. Applicants must have the skill and ability to perform the duties as outlined herein accurately and within strict deadlines with minimal supervision.

Customer Service Representative – Required for continuity of day-to-day CSR duties as resources are required for the implementation of CIS and related transition.

Reporting to the Manager of Customer Service, the Customer Service Representative (CSR) is responsible for supporting all aspects of the customer's experience with Brantford Power. With a customer-orientated attitude, the CSR will interact with customers to provide and process information in response to a variety of telephone and email inquiries, concerns and requests using superior contact handling and active listening skills. The successful candidate will have a good working knowledge of the Ontario electricity sector and will possess strong organizational and analytical skills, excellent written and verbal communications, and the ability to manage customer calls while working effectively and efficiently in a team-oriented environment.

Applicants must have successfully completed a two-year college diploma in business administration or a related field is required. A minimum of one (1) year relevant customer service experience is required, preferably in a utility customer service or call centre environment. Proficiency in the MS Office suite of applications is required. Candidates will be tested.

JT12: TO CONFIRM THAT THE AMOUNT FOR JANUARY 1ST, 2013 TO FEBRUARY 28TH, 2014 WAS NOT FORECASTED AND INCLUDED IN THE ALREADY DISPOSED AMOUNT IN THE 2013 RATE APPLICATION. ALSO TO EXPLAIN HOW THE DEBIT AMOUNT IS ARRIVED AT. ALSO, TO CONFIRM THAT YOU ARE PROPOSING TO RECOVER 50 PER CENT OF THE REQUESTED BALANCE

Response:

Please refer to 9-Staff-66 below.

JT13: TO UPDATE THE MODEL IN THE CONTINUITY SCHEDULE

Response:

Please refer to 9-Staff-68 later in this document for updated information.

Responses to Technical Conference Questions

EXHIBIT 1- GENERAL AND ADMINISTRATIVE

1-Energy Probe-TCQ 1

Ref: 1-Staff-1 & RRWF

The revised RRWF filed on September 14, 2016 has not been fully completed.

a) Please complete all sheets (such as 10. Load Forecast) based on the interrogatory responses and any further changes made as a result of the follow up questions to the interrogatory responses.

b) Please complete sheet 14. Tracking Sheet to provide a reference to the interrogatory responses that result in the changes shown for each line item.

c) Please breakout all the impacts on the 2017 revenue requirement that result from the removal of the request for building funding in 2016 and show all calculations used.

d) Please explain the change in OM&A shown in the RRWF included in each of the three change lines shown.

e) Please explain the increase in working capital of more than $4.9 million as a result of the building removal.

f) Please explain each of the three figures shown in the Other Revenues column in the change lines.

Response:

a) Please see the response to Undertaking No. JT2-A. In this RRWF document, BPI updated the document to indicate the statistics in response to the interrogatories, as well as an additional change to the load forecast related to BPI's response to Undertaking JT1.

b) Please see the response to Undertaking no. JT2-A.

c) Please see the Response to Undertaking No. JT2-B which highlights details of the changes made.

d) Please the response to Undertaking No. JT2-B which highlights details of the changes in OM&A.

e) The increase in working capital of $4.9 million was included in error as a result of the wrong "initial application" figures on tab 14 of the RRWF filed September 14, 2016. The working capital changes in Undertaking JT2-A as a result of the building are explained in Undertaking JT2-B.

f) Please see Undertaking JT2-B.

1-Energy Probe–TCQ 2

Ref: 1-Staff-1 & RRWF

The Revenue Deficiency/Sufficiency sheet in the RRWF shows an increase in distribution revenues at approved current rates of $335,486 ($16,123,389 to $16,458,875).

a) Please indicate what this increase is based on and provide references to the interrogatory responses that give rise to this change. For example, does it reflect the response to 3-VECC-21 related to the updated CDM figures?

b) If the response in part (a) is that the increase is based on the updated regression provided in the Excel file 'Brantford_Weather Regression Model_-Interrogatory Responses' that includes 6 more months of actual consumption, please explain why the regression model does not appear to have used actual data for those additional six months for all of the explanatory variables (i.e. heating and cooling degree days and GDP).

c) Please show the derivation of the increase of $2,352,243 in working capital as a result of the cost of power adjustments shown in the Tracking Form in the RRWF.

Response:

a) The increase in distribution revenues at approved current rates increased $169,075 ($16,289,800 as per the original application vs. $16,458,875). The difference is related to the adjustments made in the load forecast, as per response to 3-VECC-57, which totaled $174,258, less an adjustment to the Transformer Allowance, $5,184.

b) BPI acknowledges it should have updated for the most current information available for the GDP and HDD/CDD information.

   BPI has provided an updated weather normalized load forecast with its response to undertaking JT1, which incorporates updated HDD/CDD information and GDP variable.

   More specifically, the GDP variable has been updated with information from the 2016 Ontario Budget for the 2014, 2015, 2016 and 2017 years. The HDD and CDD have been updated to reflect 6 months of actual data in 2016. Additionally, the 10-year average weather normal data has been updated with 6 months of 2016 data.

c) As seen in the updated RRWF tracking form, the increase as a result of the cost of power adjustments is $2,184,407. This is related to the impact of the updated load forecast, as well as a correction to the WMS rate used. The updated COP model has been submitted as an attachment.

1-Energy Probe-TCQ 3

Ref: 1-Energy Probe-2

Has BPI now calculated the additional revenue that should be reflected for 2016 and 2017 as noted in the response to part (b)? If yes, please provide the figures.

Original Response:

Given that BPI will not be providing services related to the FIS in 2016, there are no revenues for 2016. BPI has not yet estimated the allocations to affiliates related to new systems for 2017.

1-Energy Probe-TCQ 4

Ref: 1-Energy Probe-8

Please reconcile the response to part (a) with the statement on page 10 of Exhibit 4, Tab 5, Schedule 1 that BPI includes its proportionate share, or $8,333 of the BEC Board of Director costs in the revenue requirement.

Original Response:

BPI's Board of Directors consists of 9 members: 3 independent and 6 which are shared with BEC. The honoraria for shared members do not get paid separately, but BPI has included 1/3 of the honoraria for the shared members, representing the cost associated with BPI.

1.0 – VECC - 49

Reference: 1-Staff 1
Revised RRWF (filed September 14, 2016)

a) Please provide a revised version of the Tracking Sheet that shows the IR references for each of the changes made.

Response:

BPI has provided IR references for the changes made in the RRWF included with its response to Undertaking No. JT2-A.

1.0 – VECC - 50

Reference: 1-VECC-2

a) Did BPI produce a report based on its salary survey? If yes please provide this survey.

Original Response

BPI did not produce a formal report with the intent of sharing with members of the LDC sector. An environmental scan was completed by Human Resources that reflected wage information. This data was completed through collaborative working groups and the independent review of available collective bargaining agreement. BPI Management shared information with its Board of Directors to consider in providing approval for a mandate for the negotiation process which has not formally concluded at this time.

EXHIBIT 2- RATE BASE

2-Energy Probe-TCQ 5

Ref: 2-Energy Probe-18

Please confirm that BPI uses different depreciation rates for the various types of meters in the "Meters" category and that it applies a higher depreciation rate for smart meters than for some other types of meters. If this cannot be confirmed, please explain fully.

Original Response:

Brantford Power (BPI) confirms that it uses different depreciation rates for various types of meters in the "Meters" category. BPI confirms that it applies a higher depreciation rate for smart meters than for some other types of meters.

BPI uses the following depreciation rates for various types of meters:

Asset Details	Useful Life Range		USoA Account Number	USoA Account Description	Current	
Category| Component | Type					Years	Rate
Residential Energy Meters	25	35				
Industrial/Commercial Energy Meters	25	35	1860	Meters	25	4%
Wholesale Energy Meters	15	30	1860	Meters	15	7%
Current & Potential Transformer (CT & PT)	35	50	1860	Meters	35	3%
Smart Meters	5	15	1860	Meters	15	7%
Repeaters - Smart Metering	10	15	1860	Meters	15	7%
Data Collectors - Smart Metering	15	20	1860	Meters	15	7%

2-Energy Probe-TCQ 6

Ref: 2-SEC-10 & 2-Energy Probe-17

a) Please confirm that the cost of the Dalhousie (Drummond-Stanley) Rebuild of $108,314 as found in Table .5-AH in Exhibit 2, Tab 5, Schedule 2 is included in the capital expenditures shown in Table 2.5-A.

b) Please confirm that this amount is also included in the in-service additions shown in the 2016 continuity schedule provided in the response to 2-Energy Probe-17. If this cannot be confirmed, please explain fully.

c) Given the response to 2-SEC-10 that the costs for this project are treated as work in progress, please explain the costs associated with this project still appear to be included in rate base in both 2016 and 2017.

Response:

a) Brantford Power (BPI) confirms the $108,314 for planned cost of the Dalhousie (Drummond-Stanley) Rebuild is included in the capital expenditures shown in Table 2.5-A.

b) BPI confirms the $108,314 noted in part a) is included in the in-service additions shown in the 2016 continuity schedule provided in response to 2-Energy Probe-17.

c) BPI completed the responses to 2-SEC-10 with respect to the 2016 material capital projects identified in Ex. 2-A-DSP. BPI updated the rate base for both 2016 and 2017 to reflect the removal of the building, land and facility manager. BPI did not update the rate base for the Dalhousie (Drummond-Stanley) Rebuild because other non-material system access projects have replaced this project in the 2016 work plan. BPI believed that the overall changes in projects being completed in 2016 would even out at the end of the year. The two projects that have replaced the Dalhousie project are:

(i) Garden Avenue infrastructure relocation at the request of the City of Brantford to be completed by mid-October and

(ii) Oak Park Road – Highway 403 Interchange infrastructure relocation at the request of the City of Brantford and the MTO to be completed before the end of the year.

Updated Response:

Please also see the responses to Undertakings JT3 and JT4.

2.0 – VECC - 51

Reference: 2-Staff-7 / E2/T1/S1/pg.11

a) BPI has removed the new building costs from the application. The costs listed in rate base are $14,750,349 (E2/T1/S1). The costs shown removed in the Summary of proposed changes (Revised_2017_Rev_Req Excel Spreadsheet) are $14,075,527. Please explain the variance.

b) Please explain (and show the calculation) for the adjustment to working capital associated with this change.

c) Has BPI removed the forecast rental revenues of $124,080 from the updated RRWF?

d) What is the expected date (year) for the revival of the building project?

Response:

a) The Initial Application line in the RRWF included errors. After correcting for this, the difference is related to the working capital allowance adjustment due to changes in OM&A and the impact of 2017 amortization expense.

Corrected starting rate base:	88,429,953
Remaining difference:	14,431,449
Expectation in IR:	14,750,349
Difference to explain:	$318,900
Amortization:	305k
WCA:	14k

b) The change is corrected and explained in BPI's response to JT2-A and JT2-B.

c) Yes, BPI confirms that the rental revenues of $124,080 have been removed.

d) The building project is still ongoing; however BPI does not expect to occupy the new building within the Bridge or Test Years.

2.0 – VECC -52

Reference: 2-EP-17 / 2-SEC-20/ 2-SEC-16

a) Please confirm that BPI has made no adjustments to its Fixed Asset Continuity Schedule for 2016 and 2017 other than those items related to the proposed new building?

b) If this is confirmed then please explain why no adjustment has been made for the deferment of the Dalhousie Drummond-Stanley project which is now deferred until 2019.

Response

a) Brantford Power (BPI) confirms that it has made no other adjustments to the Fixed Asset Continuity Schedule for 2016 and 2017 other than those items related to the proposed new building.

b) Please see response to 2-Energy Probe-TCQ 6.

2.0 – VECC - 53

Reference: 2-VECC-11

a) Please explain by how much the projects listed in the response to 2-VECC-11 will reduce outages due to defective equipment (i.e. show the past trend as compared to the expected future trend).

Response:

a) Brantford Power (BPI) has not and does not track outages with sufficient detail that will allow it to accurately identify how much any of the projects will reduce outages due to defective equipment.

EXHIBIT 3- OPERATING REVENUES

3-Energy Probe-TCQ 7

Ref: 3-Energy Probe-28 & RRWF

a) Please explain why the total other operating revenue shown in Table 3-EP-28 in the response to the interrogatory ($1,293,372) is not the amount shown in the RRWF as revenue offsets ($1,169,292).

b) If the difference is due solely to the exclusion of the net revenue in accounts 4375 and 4380, please confirm that this reflects the removal of the forecasted income associated with the building that has been removed from the application.

Response:

a) Table 3-EP-28 is before the building adjustment was made. Table 3-EP-28 was just to remove CDM related revenues (account 4375) and costs (account 4380) in all the years shown, as well as revenues/costs associated with interest on regulatory assets.

b) The amount shown in the RRWF reflects the removal of the forecasted income associated with the building that has been removed from the application.

3-Energy Probe-TCQ 8

Ref: 3-Energy Probe-29

Is the reason that the table provided in the response has no entries for accounts 4375 and 4380 is that the only non-CDM and non-new building revenues and costs included in these accounts is related to affiliate costs and that the revenue is equal to those costs?

Response:

Yes, BPI confirms that the only other revenues and costs included in these accounts are related to affiliate costs and that the revenue is equal to those costs.

Please refer to updated Appendix 2-H provided on September 9, 2016 for the breakdown of 4375 and 4380.

3-Energy Probe-TCQ 9

Ref: 3-Energy Probe-30

a) Please confirm that the $189,930 figure provided in the response to part (c) is for field collection revenue.

b) The response indicates that BPI increased its expectation for 2016 field collection charges in the updated revenue offsets included with 1-Staff-1. What is the updated forecast for 2016 and did BPI also change the forecast for 2017? If so, what is the new forecast?

c) The response to part (d) indicates that the reduction in investment income was based on declining bank balances, partly due to funding a portion of the building purchase. Given the removal of the building purchase, what is the impact on the cash balances and the forecast for investment income?

d) What adjustment did BPI make to 2016 and 2017 for investment income included in the response to 1-Staff-1.

Response:

a) Confirmed.

b) BPI did not update its forecast for 2017.

c) Please refer to BPI's response to Undertaking JT5.

d) BPI decreased 2016 investment income by $18,000. BPI did not make an adjustment to 2017 investment income resulting from the removal of the building process. As BPI has invested working capital that exceeds the working capital allowance provided at the prescribed 7.5% level, the customers are only contributing to the return on capital up to the $9,611,000 reflected in the working capital allowance.

   BPI believes it is inappropriate for the customers to benefit from investment income offsets resulting from returns on invested working capital that they have not been paying for. As BPI's cash component of its working capital is typically greater than the deemed working capital allowance, BPI is proposing that investment income offsets be limited to a value that reflects the investment income that would be earned up to the value of the working capital allowance of $9,611,000. This translates to a total investment income offset of $115,000 ($9,611,000 x 1.2%).

3.0 – VECC -54

Reference: 1-Staff 1 (Updated Load Forecast Model)

a) Please confirm that the 2016 and 2017 values used for the Negative Impact Variable include the persisting effects of 2015 CDM programs (per the Purchase Power Model and CDM Results Tabs)

b) Please confirm that the manual CDM adjustment for 2016 includes ½ of the 2015 program impacts persisting in 2016 (per the Rate Class Energy Model Tab).

c) Please confirm that the manual CDM adjustment for 2017 includes ½ of the 2015 program impacts persisting in 2017 (per the Rate Class Energy Model Tab)

d) If parts (a) through (c) are confirmed, please explain why this doesn't result in a double counting of the ½ year 2015 programs results in each of the years 2016 and 2017.

Updated Response:

a) BPI confirms that the 2016 and 2017 values used for the Negative Impact Variable include the persisting effects of 2015 CDM programs (per the Purchase Power Model and CDM Results Tabs)

b) BPI confirms that the manual CDM adjustment for 2016 includes ½ of the 2015 program impacts persisting in 2016 (per the Rate Class Energy Model Tab).

c) BPI notes that the manual CDM adjustment for 2017 includes ½ of the 2015 program impacts persisting in 2017 (per the Rate Class Energy Model Tab). This should be ½ of 2016 impacts. An adjustment has been made to reflect the change.

d) BPI confirms that there has been a double counting of the ½ year 2015 programs results in each of the years 2016 and 2017. An adjustment has been reflected in the updated Load Forecast model. Please also see the response to JT1.

3.0 - VECC - 55

Reference: 3-Energy Probe-27 b)

a) Please confirm that the first row of values shown in the response is not the results per the original application (as labelled) but the results using trend equation to establish the kW/kWh ratio.

Original Response:

a) BPI confirms that the first row of values shown in the response is not the results per the original application (as labelled) but the results using the trend equation to establish the kW/kWh ratio.

3.0 - VECC - 56

Reference: 3-Energy Probe-30 c)
3-VECC-29

a) The response states that the Specific Service Charge revenues have been increased for 2016 to account for higher field collection charges. Why wasn't the forecast for 2017 also increased?

Response:

The interrogatory in 1-Staff-1 requested changes to 2016 as a result of YTD 2016 actuals. BPI limited the changes to the 2017 Test Year to those associated with the facility relocation removal. In addition, BPI notes there have been recent measures to address electricity affordability which are expected to have an impact on the number of field collections.

3.0 - VECC - 57

Reference: 1-Staff-1
3-VECC-21
3-VECC-22 b)

a) Please itemize the changes that were made to the revised Load Forecast Model filed with the IR responses versus that filed with the original Application.

Response:

a) Please refer to the chart below with itemizes the changes that were made to the revised Load Forecast Model filed with the IR responses versus that filed with the original Application.

		2016	2017
kWh's as per application		**905,675,276**	**924,712,894**
Update for YTD June 2016 purchases	1-Staff-1	12,299,263	14,366,643
Update for 2015 Verified CDM	3-VECC-21	(2,889,866)	(4,317,382)
Updated for CDM Persistence (Burman)	3-VECC-22	3,406,904	10,594,945
Updated Load Forecast		**918,491,576**	**945,357,100**

3.0 - VECC - 58

Reference: 3-VECC-22 b)
3-VECC-23 b)
1-Staff-1 (Revised Load Forecast Model)

a) The CDM results for 2011-2013 reported in VECC 22 b) and used in the revised Load Forecast model (CDM Results Tab) do not match those reported in VECC 23 b). Please reconcile and indicate whether the Load Forecast model needs to be revised further.

Response:

BPI acknowledges the 2011 and 2012 figures did not get reflected in the Load Forecast Model (CDM Results Tab) as reflected in the response to VECC 23 b). BPI confirms the Load Forecast model needs to be revised further.

		Results Year											
		2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
	2006	2,666,105	2,666,105	2,666,105	2,666,105	463,043	463,043	423,559	423,559	397,999	397,999	376,021	376,021
	2007	0	1,387,120	1,375,497	1,375,497	1,375,497	1,374,565	1,319,406	1,319,449	1,319,406	451,387	311,035	164,898
	2008	0	0	2,696,911	2,083,518	2,083,518	2,083,518	1,953,835	1,952,703	1,818,844	1,718,921	1,280,426	950,424
	2009	0	0	0	6,943,327	6,230,629	6,230,629	6,227,931	6,110,636	5,806,438	5,738,138	5,736,648	4,440,683
	2010	0	0	0	0	4,170,820	2,995,440	2,991,631	2,989,542	2,866,698	2,447,090	2,432,987	2,367,568
Program Year	**2011**	0	0	0	0	0	4,286,345	4,273,421	4,269,480	4,164,655	4,044,925	3,842,745	3,585,982
	2012	0	0	0	0	0	0	5,854,213	5,801,327	5,778,849	5,681,217	5,580,103	5,264,741
	2013	0	0	0	0	0	0	0	6,993,979	6,908,925	6,895,581	6,806,732	6,111,099
	2014	0	0	0	0	0	0	0	0	33,821,560	33,152,890	33,032,221	32,854,801
	2015	0	0	0	0	0	0	0	0	0	7,539,722	7,402,101	7,402,101
	2016	0	0	0	0	0	0	0	0	0	0	7,730,072	7,730,072
	2017	0	0	0	0	0	0	0	0	0	0	0	15,611,676
	Total	2,666,105	4,053,225	6,738,513	13,068,447	14,323,507	17,433,541	23,043,997	29,860,675	62,883,374	68,067,869	74,531,091	86,860,067

Updated Response:

Please refer to BPI's undertaking response in JT1, which revises the CDM treatment as discussed above.

3.0 - VECC - 59

Reference: 3-VECC-24

a) What is the basis for the 6,351 connections value, i.e., is it an actual value as of a certain date?

b) How was the 9,770 value for the number of Street Light devices in 2017 established (as per the Cost Allocation Model)?

Response:

a) Brantford Power (BPI) based the 6,351 connections on the data available at the time of the rate application filing. Since the filing, BPI has met with the street light customer (SL Customer) to confirm the connections value. The SL Customer and BPI exchanged data on the connection points and streetlights contained within their respective GIS databases. BPI analyzed the data and, after consultation with the SL Customer, has identified there are 5,767 connection points as of September 2016.

b) As a result of the data analysis and consultation with the SL Customer, BPI has identified there are 10,118 streetlights as of September 2016. Based on new procedures to track the installation of street lights and connection points, BPI and the street lighting customer will be regularly tracking and updating both the number of connections and devices.

3.0 - VECC - 60

Reference: 3-VECC-27
E3/T2/S2, page 14

a) In the original Application, it was acknowledged that the LRAM calculations are done using full years' net results. In VECC 27 it was acknowledged that 2015 impacts should not be included in the LRAMVA baseline. Based on these observations, does Brantford agree that the 2017 LRAMVA baseline for the current Application should be the sum of the forecast 2016 CDM and 2017 CDM (full year) results?

b) Based on the updated Load Forecast and the forecast CDM values included please indicate what Brantford's proposed LRAMVA value is for its 2017 load forecast and provide a breakdown by customer class.

Updated Response:

a) BPI does not agree that the 2017 LRAMVA baseline for the current Application should be the sum of the forecast 2016 CDM and 2017 CDM (full year) results. BPI believes the 2017 LRAMVA baseline should be the forecast 2016 CDM plus ½ of the 2017 CDM results.

b) BPI's proposed LRAMVA value is for its 2017 load forecast broken down by customer class is show below.

Year	Residential	GS<50	GS>50	Sentinel	Streetlight	USL	Total
2017 LRAMVA kWh	840,580	805,502	13,889,828				15,535,910
2017 LRAMVA kW			35,765				35,765

EXHIBIT 4.0-OPERATING COSTS

4-Staff-55

BPI completed Appendix 2-KA, which compares OPEB amounts recovered in rates to the paid benefit amounts. From the chart, there have been excess recoveries from 2013 to 2015. What has BPI used these excess recoveries for?

Original Response:

As is the case with any item of OM&A that differs from the expected cost of service, these over or under recoveries are included in the total OM&A pool reflected in the actual OM&A results. If excess recoveries have not been required to offset other under recoveries, the after tax impact would be reported in Net Income for the particular year.

4-Energy Probe-TCQ 10

Ref: 4-Energy Probe-33

a) The response to part (a) did not answer the question. Was the $536,035 expense incurred in 2013 or 2014 or was it incurred in 2012 or previous years?

b) Please indicate whether the $362,000 in amortization expense is included in the 2013 or 2014 actual figures shown in Table 4.2-B.

c) Please indicate whether the $174,035 OM&A expense is included in the 2013 or 2014 actual figures shown in Table 4.2-B.

d) Please confirm that the response labelled as part (e) is the response to the question labelled as part (d).

e) Please provide the response to the question in part (e).

Response:

a) The expense of $536,035 was incurred in 2013.

b) The $362,000 is included in 2013 actual figures.

c) The $174,035 is included in 2013 actual figures.

d) BPI confirms this response was mislabeled.

e) The $63,700 included in the original cost drivers table (Table 4.2-B) represents the 2016-only amount which is proposed to be amortized over 5 years ($318,499, from 4.7.2-A, divided by 5). The amount of 318,499 is included in the total of $347,659 which is proposed to be amortized over 5 years.

4-Energy Probe-TCQ 11

Ref: 4-Energy Probe-38

a) What is the $25,000 difference between the $10,470,506 figure shown in Table 4-EP-38 (and in Table 4.1-A) and the figure of $10,495,506 shown as the OM&A expense in the Application column of the RRWF?

b) Please show the movement from the original $10,470,506 in OM&A expenses to the new figure of $10,670,611 shown in the RRWF. Please explain all adjustments.

Original Response:

a) The difference is due to LEAP in the amount of $25,000. This amount was not included in Table 4-EP-38 and 4.1-A, however it was correctly included in the RRWF.

b) Note that the amount of OM&A that was included in the Original application was $10,495,506. Refer below for the reconciliation.

	OM&A	
Original COS Application	10,495,506	
Updated with IR changes	10,670,511	
Difference	(175,005)	
Reconciliation		
Building Adjustments	(400,757)	Note 1
Rental Facilities Adjustment	581,823	Note 2
CDM Adjustment	(6,061)	Note 3
Remaining Difference	-	

Note 1: These adjustments relate to the removal of repairs and maintenance that were originally budgeted for the new facility.
Note 2: These adjustments related to the addback of rental facilities, since BPI is assuming no new facility in 2017
Note 3: This adjustment is to remove $6,061 from OM&A for VP Customer Service and Conservation to be recovered from IESO.

4-Energy Probe-TCQ 12

Ref: 4-Energy Probe-44

Please provide a PILS workform that reflects the loss carry forward of $159,164 being brought into the 2016 bridge year for regulatory PILS purposes.

Response:

BPI as completed and attached (Attachment 4-EP TCQ 12) the PILS workform that reflects the loss carry forward of $159,164 being brought into the 2016 bridge year for regulatory PILS purposes. However, BPI notes the remaining loss carry forward of $159,164, which BPI will use in 2016 to reduce taxes, is the remaining balance of the loss carry forward generated in 2014 related to changes in regulatory assets/liabilities. Since regulatory assets/liabilities are excluded for tax calculations for regulatory purposes, BPI does not believe the amount should be included in the calculation of PILS for regulatory purposes.

4-Energy Probe-TCQ 13

Ref: 4-Energy Probe-47

Please confirm that the property tax of $20,031 is still included in the updated forecast of OM&A of $10,670,511 shown in the revised RRWF. If this cannot be confirmed, please explain why there is no property tax shown in the RRWF.

Response:

Yes, BPI confirms that the property tax of $20,031 is included in the OM&A of $10,670,511. BPI notes that, for cost allocation purposes, the $20,031 is correctly included in account 6105 and therefore allocated according to the model's treatment for non-PILS taxes, rather than for a component of OM&A.

4.0 – VECC - 61

Reference ; 4-Staff-45 / 4-VECC-38

a) What are the annual ongoing costs of maintaining access to FIS and any other systems owned and operated by the City of Brantford, but being replaced by future BPI IT systems?

Response:

Annual ongoing costs of maintaining access to the FIS system owned and operated by the City of Brantford: $ 6,353

Other systems being replaced by BPI are not owned by the City of Brantford.

4.0 – VECC - 62

Reference; 4-SEC-20

a) Has BPI adjusted the application for the delay in developing a new CIS system?

Response:

Although BPI had put the CIS RFP on hold until completion of the FIS procurement, BPI does not foresee a delay in the procurement and subsequent implementation of the CIS system. BPI expects to implement CIS by end of 2017, as originally included in the application. Hence, no adjustment is required to the application.

4.0 - VECC - 63

Reference: 3-VECC 22 b)

a) Please confirm that the LRAM Rate Riders set out at page 193 of 339 are just for recovery of the impact of 2005-2010 programs for 2013. If not, what do they represent?

b) Please clarify what Brantford's total proposed LRAM claim by class is, what periods it is meant to cover and the resulting rate riders by class.

Response:

a) BPI confirms that the LRAM Rate Riders in the lower part of the chart set out at page 193 of 339 are just for recovery of the impact of 2006-2010 programs for 2013.

b) BPI's total proposed LRAM claim by class as shown in IR 3-VECC-22 is shown below. The proposed amount is recovery of the impact of 2011-2014 programs for 2014. The rate rider calculation, as provided in the 2017 DVA continuity schedule, has also been included.

LRAMVA Claim by Customer Class							
Customer Class	**2011-2014 CDM Program Lost Revenues in 2014**	**2014 LRAMVA Baseline**	**LRAMVA (Lost Revs-Baseline)**	**Carrying Charges**	**Total Claim**	**2017 Forecast Billing Units**	**2017 Proposed LRAM Rate Rider**
Residential	$ 67,300	$ 55,518	$ 11,782	$ 151	$ 11,933	300,579,328	$ -
General Service less than 50 kW	$ 43,794	$ 35,187	$ 8,607	$ 111	$ 8,718	102,906,032	$ 0.0001
General Service 50 to 4,999 kW	$ 180,799	$ 41,468	$ 139,332	$ 1,789	$ 141,121	1,259,313	$ 0.1121
Total	**$ 291,893**	**$ 132,172**	**$ 159,721**	**$ 2,051**	**$ 161,772**		

4.0 – VECC - 64

Reference; 4-Staff-60 a)
3-VECC-22, Attachment 3

a) Please update the response to 4-Staff 60 a) based on the revised calculations in VECC-22, Attachment 3.

Response:

a) Below is an updated (in red) response to 4-Staff 60 a) based on the revised calculations in VECC-22, Attachment 3.

BPI confirms it is requesting the amount of $118,295 for the persistence of 2006-2010 CDM savings into 2013. BPI's total request (in account 1568) is for $161,772 including carrying charges. This represents the impact of 2011 to 2014 programs in 2014. BPI is not claiming the amount of ($1,108) calculated by Burman as the differences between the LRAMVA baseline included in the 2013 COS and the 2013 Actual CDM results. BPI's Settlement Agreement in EB-2012-0109 included the agreement that no amounts for 2013 would be booked to Account 1568. The derivation of the $161,772 included for disposition in account 1568 is below:

Burman LRAMVA total (excl. carrying charges)	$ 158,612
Less: Amount calculated for 2013 impact *	$ 1,108
Sub-Total	**$159,721**
Plus Carrying Charges	$ 2,051
Total Claim	**$ 161,772**

*Please note amount of 2013 impact adjustment is a negative and is therefore added.

EXHIBIT 5- COST OF CAPITAL AND RATE OF RETURN

5-Energy Probe-TCQ 14

Ref: 5-Energy Probe-51 & RRWF

a) Please provide the Infrastructure Ontario debt rate for a 5 year term that was available when the affiliate debt was renewed.

b) Please provide the 2017 table in Appendix 2-OB that reflects the updated long term debt rate of 4.29% used in the revised RRWF.

Response:

a) BPI has the screenshot from the Infrastructure website from February 17th 2016. The debt rate for a 5 year term on this date was 1.84%.

b) Please see Table 5-EP-TCQ 14 below.

Table 5-EP-TCQ-14

Appendix 2-OB
Debt Instruments

This table must be completed for all required historical years, the bridge year and the test year.

Year 2017

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) 1
1	Promissory Note	The Corporation of the City of Brantford	Affiliated	Fixed Rate	1-Feb-11	5	$ 24,189,168	4.20%	1,015,945
2	Powerline Municipal Transformer Station B	Royal Bank	Third-Party	Fixed Rate	31-Jan-06	15	$ 2,012,583	5.51%	110,893
3	General borrowings	Ontario Infrastructure & Lands Corporation	Third-Party	Fixed Rate	3-Dec-07	25	$ 1,852,754	5.14%	95,232
4	General borrowings	Ontario Infrastructure & Lands Corporation	Third-Party	Fixed Rate	1-Dec-10	40	$ 4,517,238	4.95%	223,603
5	Smart meter borrowings	Ontario Infrastructure & Lands Corporation	Third-Party	Fixed Rate	18-Nov-09	15	$ 4,185,695	3.46%	144,825
6	General borrowings	Ontario Infrastructure & Lands Corporation	Third-Party	Fixed Rate	3-Dec-12	30	$ 3,673,452	3.90%	143,265
Total							$ 40,430,890	4.29%	1,733,763

5.0-VECC-65

Reference: 1-EP-1

a) As of September 15, 2016 the Ontario Infrastructure 30 year lending rates for Local Distribution Companies was 3.32% for serial loans and 3.40% for amortizer loans (http://www.infrastructureontario.ca/Templates/RateForm.aspx?ekfrm=2147483942&langtype=1033&sector=ldc). Please provide the source of the 3.89% shown in response to 1-EP-1.

Response:

As shown in the table, BPI consulted the Infrastructure Ontario website for rates as of December 3, 2015. BPI does not have a screen shot to confirm this, and historic rates are not available on the IO website.

5.0-VECC-66

Reference: 5-VECC-43

a) Why did BPI believe that a rate of 5.70 for the renewed promissory note was reasonable?

b) If the note shown at Exhibit 5, Attachment 5-A is not a new promissory note then please file the original (and presumably in force) note.

Response:

a) BPI did not propose the rate of 5.70% but rather 4.20%, and believes it to be reasonable because it satisfies the terms of the promissory note, and additionally, is favourable in comparison to the OEB's deemed long term debt rate at the time of renewal of 4.54%.

b) BPI wishes to correct the record with respect to this item. Attachment 5-A is the current/new promissory note. BPI's arrangement with the City of Brantford was extended in 2016 with a new note. BPI wishes to highlight that the note is affiliated debt which is not callable on demand, as can be concluded from Attachment 5-A.

EXHIBIT 9- DEFERRAL AND VARIANCE ACCOUNTS

9-Staff-66

Per the Filing Requirements dated June 28, 2012 and subsequent filing requirements, Account 1592 – sub-account HST/OVAT ITCs was to record variances up to the effective date of the rate order. BPI disposed of this sub-account in its last cost of service rate application, with the effective date of the rate order being March 1, 2014. However, in BPI's response, the balance currently being requested for disposition in this application is for January 1, 2013 to Feb. 28, 2014.

a) Can you please confirm that the amount for January 1, 2013 to Feb. 28, 2014 was not forecasted and included in the already disposed amount in BPI's 2013 rate application?
b) This account records PST savings that are to be returnable to rate payers. However, BPI is requesting a recovery of $37,559. Please explain how a debit amount of $37.6k was derived.
c) Please confirm that BPI is proposing to recover 50% of the requested balance. It appears that the revised DVA continuity schedule included the balance at 100%.

Response:

a) BPI confirms the amount for January 1, 2013 to Feb. 28, 2014 was not forecasted and included in the already disposed amount in BPI's 2013 rate application.

b) BPI acknowledges an entry error was made and the balance should be a credit amount. The DVA Continuity Schedule being submitted with this response document has been adjusted to reflect the correction.

c) BPI confirms it is proposing to dispose of 50% of the requested balance, however, BPI wishes to note that Tab 5 of the workbook is pulling in 100%. The worksheet is protected and BPI is unable to make the necessary adjustment at this time, however BPI will work with Board Staff to make this adjustment in the future.

9-Staff-67

The allocated balance for Class B customers in Account 1589 in the table is $1.46M, which corresponded to the original application where BPI proposed its own methodology in calculating the allocation of Account 1589 to Class B customers who became Class A customers in 2015. BPI revised the allocation using the OEB's DVA continuity schedule and the allocated balance for remaining Class B in the DVA continuity schedule is $1.56M. Can you confirm which one is the allocated balance BPI is proposing to dispose?

Response:

BPI confirms the chart in response to 9-Staff-67 was based on the original application. Based on all resent updates, BPI confirms it is proposing to dispose of the allocated balance for Class B customers in Account 1589 of $1.56m as per the chart below.

Rate Class	2017 Predicted kWh	Allocated Balance	Unit for Disposition	Rate Rider
Residential	20,619,742	$ 72,357	kWh	$ 0.0035
GS<50 KW	14,303,938	$ 50,194	kWh	$ 0.0035
GS>50 KW	401,225,527	$ 1,407,937	kWh	$ 0.0035
Street Light	7,460,329	$ 26,179	kWh	$ 0.0035
Sentinal Lighting	67,475	$ 237	kWh	$ 0.0035
Unmetered Scatter Load	-	$ -	kWh	$ -
Embedded Distributor	-	$ -	kWh	$ -
Total	**443,677,012**	**1,556,903**		

9-Staff-68

BPI updated the DVA continuity schedule to show the Account 1580 – CBR Class A and Class B sub-accounts separate from Account 1580 – WMS control account. Per the Accounting Guidance issued for CBR, dated July 25, 2016, if a distributor serves Class A customers, it must calculate the volumetric rate riders for non-WMP Class B customers outside of the DVA continuity schedule. BPI does have Class A customers, however, BPI has included this sub-account balance in the DVA continuity schedule for disposition, where it is rolled up into Account 1580 – WMS control account for disposition.

a) Can you explain why the sub-account was included as part of the DVA continuity schedule instead of being calculated outside the continuity schedule?
b) Please calculate rate riders accordingly.

Response:

a) The sub-account was included as part of the DVA continuity schedule instead of being calculated outside the continuity schedule in error, BPI did not use the check box at the top of the DVA Continuity Schedule.
b) The following table shows the rate riders for Class B customers. Class A customers have been billed separately for their respective portions of the Class A amount and therefore no rate rider is applicable.

Class B - 1580 - CBR						
Rate Class	2017 Predicted # of Customers	2017 Predicted kWh	2017 Predicted kW	Allocated Balance	Unit for Disposition	Rate Rider
Residential	36,433	300,579,328	-	$ 78,381	kWh	$ 0.0003
GS<50 KW	2,840	102,906,032	-	$ 26,834	kWh	$ 0.0003
GS>50 KW	451	457,195,438	1,173,736	$ 119,221	kW	$ 0.1016
Street Light	6,351	7,460,329	22,796	$ 1,945	kW	$ 0.0853
Sentinal Lighting	597	382,297	1,181	$ 100	kW	$ 0.0844
Unmetered Scatter Load	425	1,405,154	-	$ 366	kWh	$ 0.0003
Embedded Distributor	2	-	-	$ -	kW	#DIV/0!
Total	**47,099**			**$ 226,848**		

Attachments:

JT1: Updated Load Forecast (sent as live excel)

JT2-A: Updated RRWF

JT2-B: Detailed Calculations for RRWF Changes (sent as live excel)

JT4: Updated Appendix 2-AA and Appendix 2-AB

JT6: Updated Cost Allocation (sent as live excel)

JT12: Updated DVA Model (sent as live excel)

Updated Cost of Power Calculation

Attachment JT1: Updated Load Forecast (sent as live excel)

Attachment JT2-A: Updated RRWF

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and volueumetric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: *Interrogatory Responses*

	Customer and Load Forecast					Class Allocated Revenues			Fixed / Variable Splits [2]		
						From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design			Percentage to be entered as a fraction between 0 and 1		
	Customer Class From sheet 10. Load Forecast	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)
1	Residential	kWh	36,433	300,576,547	-	$ 10,646,840	$ 8,227,957	$ 2,418,884	77.28%	22.72%	$ -
2	GS < 50 kW	kWh	2,840	103,027,982	-	$ 1,934,330	$ 1,081,969	$ 852,360	55.94%	44.06%	$ 541
3	GS > 50 kW (incl. WMP))	kW	449	494,181,924	1,267,383	$ 4,817,422	$ 1,265,538	$ 3,551,884	26.27%	73.73%	$ 372,611
4	GS > xxx kW, if applicable		-	-	-	$ -					
5	Large User, if applicable		-	-	-	$ -					
6	Street Lighting	kW	5,767	7,460,329	22,796	$ 244,488	$ 102,787	$ 141,701	42.04%	57.96%	$ -
7	Sentinel Lighting	kW	597	382,297	1,181	$ 56,736	$ 31,691	$ 25,045	55.86%	44.14%	$ -
8	Unmetered Scattered Load (USL)	kWh	425	1,405,154	-	$ 83,188	$ 71,527	$ 11,661	85.98%	14.02%	$ -
9	Other class, if applicable		-	-	-	$ -					$ -
#	Embedded distributor class	kW	2	51,013,084	139,437	$ 209,029	$ 8,923	$ 200,106	4.27%	95.73%	$ 83,662
#			-	-	-						
#			-	-	-						
#			-	-	-						
#			-	-	-						
#			-	-	-						
#			-	-	-						
#			-	-	-						
#			-	-	-						
#			-	-	-						
#			-	-	-						

		Distribution Rates					Revenue Reconciliation		
		Monthly Service Charge		Volumetric Rate					
	Customer Class	Rate	No. of decimals	Rate		No. of decimals	MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership
1	Residential	$18.82	2	$0.0080	/kWh	4	$ 8,227,956.62	$ 2,404,612.3746	$10,632,568.99
2	GS < 50 kW	$31.75		$0.0083	/kWh		$ 1,081,979.01	$ 855,132.2544	$ 1,936,569.78
3	GS > 50 kW (incl. WMP))	$235.05		$3.0965	/kW		$ 1,265,525.34	$ 3,924,450.6885	$ 4,817,365.50
4	GS > xxx kW, if applicable	$0.00					$ -	$ -	$ -
5	Large User, if applicable	$0.00					$ -	$ -	$ -
6	Street Lighting	$1.49		$6.2160	/kW		$ 103,113.96	$ 141,701.6573	$ 244,815.62
7	Sentinel Lighting	$4.42		$21.2018	/kW		$ 31,674.29	$ 25,045.3668	$ 56,719.65
8	Unmetered Scattered Load (USL)	$14.02		$0.0083	/kWh		$ 71,524.46	$ 11,662.7775	$ 83,187.24
9	Other class, if applicable	$0.00					$ -	$ -	$ -
#	Embedded distributor class	$371.78		$2.0351	/kW		$ 8,922.72	$ 283,769.2489	$ 209,029.47
#							$ -	$ -	$ -
#							$ -	$ -	$ -
#							$ -	$ -	$ -
#							$ -	$ -	$ -
#							$ -	$ -	$ -
#							$ -	$ -	$ -
#							$ -	$ -	$ -
#							$ -	$ -	$ -
#							$ -	$ -	$ -
#							$ -	$ -	$ -

Total Transformer Ownership Allowance $ 456,815

Total Distribution Revenues	$17,980,256.25
Base Revenue Requirement	$17,992,035.21
Difference	-$ 11,778.96
% Difference	-0.065%

Rates recover revenue requirement

Notes:

1 Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

2 The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calcutated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Attachment JT2-B: Detailed Calculations for RRWF Changes (sent as live excel)

Attachment JT4: Updated Appendix 2-AA and Appendix 2-AB

File Number:	0
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated

ast Period: *2017*

CATEGORY	**Historical Period** (previous plan[1] & actual)										**Forecast Period** (planned)			
	2012		2013		2014		2015		2016		2017	2018	2019	2020
	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual[2]				
	$ '000		*$ '000*		*$ '000*		*$ '000*		*$ '000*		*$ '000*			
System Access	(1)	1,503,450	(1)	1,452,691	(1)	1,098,678	(1)	1,282,159	(1)	1,200,662	1,711,016	2,108,207	3,525,912	2,341,333
System Renewal	(1)	1,292,551	(1)	447,280	(1)	534,238	(1)	744,528	(1)	608,183	607,313	525,206	843,801	696,548
System Service	(1)	713,987	(1)	553,194	(1)	837,000	(1)	1,531,276	(1)	403,946	425,798	592,912	159,840	208,160
General Plant	(1)	434,228	(1)	454,692	(1)	324,327	(1)	553,348	(1)	1,383,907	1,407,853	4,252,536	808,100	235,400
TOTAL EXPENDITURE	-	3,944,217	-	2,907,857	-	2,794,244	-	4,111,311	-	3,596,698	4,151,981	7,478,861	5,337,654	3,481,441
System O&M														

Notes to the Table:

1. Historical “previous plan” data is not required unless a plan has previously been filed
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

Explanatory Notes on Variances (complete only if applicable)
Notes on shifts in forecast vs. historical budgets by category
Notes on year over year Plan vs. Actual variances for Total Expenditures
Notes on Plan vs. Actual variance trends for individual expenditure categories

Attachment JT6: Updated Cost Allocation (sent as live excel)

Attachment JT12: Updated DVA Model (sent as live excel)

Attachment: Updated Cost of Power Calculation

Electricity - Commodity		2017		Test year				%- 2015 kWh billing stats		RPP and Non-RPP Cost of Power		Total Cost Of Power
Class per Load Forecast	**2017 Forecasted Metered kWhs**	**Forecasted kW**	**2017 Proposed Loss Factor**	**Kwhs adjusted by DLF**	**RPP Prices**	**HOEP**	**Global Adjustment**	**RPP**	**Non-RPP**	**RPP $**	**Non-RPP $**	
Residential	300,576,547	NA	1.0320	310,194,996.3274	0.11141	$0.01686	$0.09086	93%	7%	$32,189,324	$ 2,291,020.38	$34,480,345
GS<50kW	103,027,982	NA	1.0320	106,324,877.8932	0.11141	$0.01686	$0.09086	86%	14%	$10,199,337	$ 1,591,790.34	$11,791,127
GS 50kW to 4999kW (excl. WMP)	487,389,546	1,254,985	1.0320	502,986,011.9286	0.11141	$0.01686	$0.09086	7%	93%	$3,870,029	$ 50,439,803.30	$54,309,832
Unmetered Scattered Load	1,405,154	NA	1.0320	1,450,118.8451	0.11141	$0.01686	$0.09086	100%	0%	$161,558	$ -	$161,558
Sentinel Lighting	382,297	1,181	1.0320	394,530.6710	0.11141	$0.01686	$0.09086	82%	18%	$36,198	$ 7,499.85	$43,698
Street Lighting	7,460,329	22,796	1.0320	7,699,059.8407	0.11141	$0.01686	$0.09086	0%	100%	$0	$ 829,342.73	$829,343
Wholesale Market Participants	6,792,378	12,398	1.0320	7,009,733.6832				0%	100%			
Embedded Distributor	51,013,084	139,437	1.0320	52,645,502.8357				-	100%	$0	$ -	$0
TOTAL	**958,047,318**	**1,430,798**		**988,704,832.0249**						$46,456,445	$ 55,159,456.59	**$101,615,902**

Transmission - Network		Volume	2017		
Class per Load Forecast		**Metric**	**Test Year**		
Residential		kWh	310,194,996	$0.0080	$2,475,580
GS<50kW		kWh	106,324,878	$0.0071	$755,416
GS 50kW to 4999kW		kW	1,254,985	$2.4377	$3,059,304
Unmetered Scattered Load		kWh	1,450,119	$0.0042	$6,069
Sentinel Lighting		kW	1,181	$2.2764	$2,689
Street Lighting		kW	22,796	$2.3454	$53,465
Wholesale Market Participants		kW	12,398	$2.4377	$30,222
Embedded Distributor		kW	139,437	$2.4377	$339,910
TOTAL					**$6,722,655**

Table ES-1: Average RPP Supply Cost Summary (for the 12 months from May 1, 2016)

RPP Supply Cost Summary
for the period from May 1, 2016 through April 30, 2017
Forecast Wholesale Electricity Price
$16.86 $107.72
Load-Weighted Price for RPP Consumers ($ / MWh)
$18.59
Impact of the Global Adjustment ($ / MWh) +
$90.86
Adjustment to Address Bias Towards Unfavourable Variance ($ / MWh) + $1.00
Adjustment to Clear Existing Variance ($ / MWh) +
$0.97
Average Supply Cost for RPP Consumers ($ / MWh) =
$111.41

Transmission - Connection		Volume	2017		
Class per Load Forecast		**Metric**	**Test Year**		
Residential		kWh	310,194,996	$0.0058	$1,806,453
GS<50kW		kWh	106,324,878	$0.0051	$541,795
GS 50kW to 4999kW		kW	1,254,985	$1.7351	$2,177,553
Unmetered Scattered Load		kWh	1,450,119	$0.0051	$7,389
Sentinel Lighting		kW	1,181	$1.6205	$1,914
Street Lighting		kW	22,796	$1.6018	$36,515
Wholesale Market Participants		kW	12,398	$1.7351	$21,512
Embedded Distributor		kW	139,437	$1.7351	$241,941
TOTAL					**$4,835,072**

Wholesale Market Service		Volume	2017		
Class per Load Forecast		**Metric**	**Test Year**		
Residential		kWh	310,194,996	$0.0036	$1,116,702
GS<50kW		kWh	106,324,878	$0.0036	$382,770
GS 50kW to 4999kW		kW	487,389,546	$0.0036	$1,754,602
Unmetered Scattered Load		kWh	1,450,119	$0.0036	$5,220
Sentinel Lighting		kW	394,531	$0.0036	$1,420
Street Lighting		kW	7,699,060	$0.0036	$27,717
Wholesale Market Participants	**WMS billed directly b**	kW	0	$0.0000	$0
Embedded Distributor		kW	0	$0.0000	$0
TOTAL					**$3,288,431**

Rural Rate Assistance		Volume	2017		
Class per Load Forecast		**Metric**	**Test Year**		
Residential		kWh	310,194,996	$0.0013	$403,253
GS<50kW		kWh	106,324,878	$0.0013	$138,222
GS 50kW to 4999kW		kW	487,389,546	$0.0013	$633,606
Unmetered Scattered Load		kWh	1,450,119	$0.0013	$1,885
Sentinel Lighting		kW	394,531	$0.0013	$513
Street Lighting		kW	7,699,060	$0.0013	$10,009
Wholesale Market Participants	**RRP Billed Directly b**	kW	0	$0.0000	$0
Embedded Distributor		kW	0	$0.0013	$0
TOTAL					**$1,187,489**

SME Charge		Volume	2017		
Class per Load Forecast		**Metric**	**Test Year**		
Residential		customers	36,433	$0.7900	$345,382
GS<50kW		customers	2,840	$0.7900	$26,922
GS 50kW to 4999kW		NA			
Unmetered Scattered Load		NA			
Sentinel Lighting		NA			
Street Lighting		NA			
Wholesale Market Participants					
Embedded Distributor		NA			
TOTAL					**$372,303**

2016	**Test Year**
4705-Power Purchased	$101,615,902
4708-Charges-WMS	$3,288,431
4714-Charges-NW	$6,722,655
4716-Charges-CN	$4,835,072
4730-Rural Rate Assistance	$1,187,489
4750-Low Voltage	$0
4751 - SME	372,303
TOTAL	**118,021,853**

monthly average

17,306,787

4006-Residential Energy Sales	34,480,344.54
4010-Commercial Energy Sales	
4015-Industrial Energy Sales	
4020-Energy Sales to Large Users	
4025-Street Lighting Energy Sales	829,342.73
4030-Sentinel Energy Sales	43,697.75
4035-General Energy Sales	66,262,516.91
4040-Other Energy Sales to Public Authorities	
4045-Energy Sales to Railroads and Railways	
4050-Revenue Adjustment	
4055-Energy Sales for Resale	
4060-Interdepartmental Energy Sales	
4062-WMS	4,475,920.34
4076-Smart Meter Entity Charges	372,303.50
4066-NW	6,722,654.59
4068-CN	4,835,072.35
4075-LV Charges	-
	$ 118,021,852.70