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3.0 Operating Revenue

3.1.1 Operating Revenue

Overview

This exhibit provides the details of BPI's operating revenue for 2013 Board Approved, 2013 Actual, 2014 Actual, 2015 Actual, the 2016 Bride year and the 2017 Test Year. This exhibit also provides a detailed variance analysis by rate class of the operating revenue components. Distribution revenue excludes revenues from commodity sales.

BPI is proposing a total Service Revenue Requirement of $20,245,835 for the 2017 Test Year. This amount includes a Base Revenue Requirement of $18,910,832 plus revenue offsets of $1,335,003 to be recovered through Other Distribution Revenue.

A summary of all operating revenue is presented below in Table 3.1-A and provides a comparison of total revenues from the 2013 Board Approved year to the 2017 Test Year.

Table 3.1-A – Historical Comparison of Total Revenue

	2013 Board Approved (Base RR)	2013 Actual	2014 Actual (CGAAP)	2014 Actual (MIFRS)	2015 Actual	2016 Bridge	2017 Test-Existing Rates	2017 Test - Proposed Rates
Distribution Revenues								
Residential	$ 9,042,952	$ 8,324,144	$ 9,389,728	$ 9,389,728	$ 9,469,916	$ 9,546,914	$ 9,607,740	$ 11,153,627
GS<50 kW	$ 1,510,543	$ 1,389,970	$ 1,684,534	$ 1,684,534	$ 1,505,985	$ 1,581,136	$ 1,590,044	$ 1,845,883
GS>50 kW	$ 4,720,273	$ 4,826,642	$ 4,709,456	$ 4,709,456	$ 4,978,567	$ 4,671,542	$ 4,684,378	$ 5,282,238
Street Lighting	$ 149,052	$ 131,785	$ 143,613	$ 143,613	$ 147,825	$ 153,858	$ 118,415	$ 228,441
Sentinel Lighting	$ 55,467	$ 30,839	$ 67,184	$ 67,184	$ 57,233	$ 51,658	$ 51,959	$ 60,320
Unmetered Scattered Load	$ 76,128	$ 71,675	$ 76,992	$ 76,992	$ 72,723	$ 76,184	$ 76,184	$ 88,442
Embedded Distributor	$ 272,147	$ 271,927	$ 310,759	$ 310,759	$ 251,610	$ 153,142	$ 161,080	$ 251,881
Total Distribution Revenue	***$ 15,826,562***	***$ 15,046,982***	***$ 16,382,266***	***$ 16,382,266***	***$ 16,483,859***	***$ 16,234,433***	***$ 16,289,800***	***$ 18,910,832***
SSS Admin Charge Included in Dist Revs		$ 106,572	$ 108,547	$ 108,547	$ 111,559			
Standby Revenue Included in Dist Revs		$ 69,074	$ 68,259	$ 68,259	$ 1,728			
Other Revenue								
Late Payment Charges	$ 149,427	$ 152,695	$ 207,146	$ 207,146	$ 219,014	$ 226,236	$ 235,599	$ 235,599
Specific Service Charges	$ 451,561	$ 441,756	$ 539,109	$ 539,109	$ 650,019	$ 496,272	$ 506,195	$ 506,195
Other Revenue	$ 453,958	$ 424,473	$ 314,321	$ 314,321	$ 425,263	$ 104,771	$ 481,479	$ 481,479
SSS Administration Charge	$ 104,830	$ -	$ -	$ -	$ -	$ 110,820	$ 111,730	$ 111,730
Standby Revenue	$ 60,224	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Revenue	***$ 1,220,000***	***$ 1,018,924***	***$ 1,060,576***	***$ 1,060,576***	***$ 1,294,297***	***$ 938,099***	***$ 1,335,003***	***$ 1,335,003***
Total Operating Revenue	**$ 17,046,562**	**$ 16,065,906**	**$ 17,442,842**	**$ 17,442,842**	**$ 17,778,156**	**$ 17,172,532**	**$ 17,624,803**	**$ 20,245,835**

Throughput Revenue

Information related to BPI's throughput revenue includes details on the weather normalized load forecasting methodology reflecting expected CDM results and a forecast of customers by rate class based on the historical number of customers billed throughout the year.

A detailed variance analysis on the historical throughput revenue is also provided in this Exhibit.

Other Revenue

Other revenue includes Standard Service Supply (SSS) Administration charges, Late Payment charges and Miscellaneous Service revenue. Please note in the above Table 3.1-A, SSS Administration charges and Standby charges are included with distribution revenues actual results for historical years. These charges are calculated and shown separately for forecast years 2016 and 2017. Standby charges stopped during 2015. There are no new proposed Specific Service Charges or proposed changes to rate or application of existing Specific Service Charge.

A detailed variance analysis on the other revenue is set out later in this Exhibit.

3.2 Load and Revenue Forecasts

3.2.1 Load and Revenue Forecasts

Weather Normalized and Customer/Connection Forecast

The purpose of this evidence is to present the process used by BPI to prepare the weather normalized load and customer/connection forecast used to design the proposed 2017 electricity distribution rates.

In summary, BPI has used the same Board Approved Load Forecast model and methodology as in BPI's 2013 cost of Service application file number EB-2012-0109 (i.e. a Multivariate Regression Model). This regression analysis methodology is also used by a number of distributors in cost of service applications to determine a prediction model. With regard to the overall process of load forecasting, BPI submits conducting a regression analysis on historical electricity purchases to produce an equation to predict purchases is appropriate. BPI has the data for the amount of electricity (in kWh) purchased from the IESO and other suppliers for use by BPI's customers. With a regression analysis these purchases can be related to other monthly explanatory variables such as heating degree days and cooling degree days which occur in the same month. The results of the regression analysis produce an equation that predicts the purchases based on the explanatory variables. This prediction model is then used as the basis to forecast the total level of weather normalized purchases for the Bridge Year and the Test Year which is converted to billed kWh by class. A detailed explanation of the process is provided later in this Exhibit.

During the review process of previous COS applications, for other applicants, Intervenors expressed concerns with the load forecasting weather normalized process being used in this application. Intervenors suggested the weather normalization should be conducted on an individual rate class basis and the regression analysis would be based on monthly consumed kWh by rate class. In attempting to use the method suggested, BPI found it produced statistically weak results. In BPI's view this would not be an appropriate basis for its load forecast.

In addition, Board staff and Intervenors expressed concern the regression analysis assigned coefficients to some variables that were counter intuitive. For example, the customer variable would have a negative coefficient assigned to it which meant as the number of customers increased the energy forecast decreased. Further, the regression analysis indicated some of the variables used in the load forecasting formula were not statistically significant and should not have been included in the equation. Based on the Board's approval of this methodology in a number of previous cost of service applications and based on the discussion that follows, BPI submits its load forecasting methodology is reasonable at this time for the purposes of this Application.

The following Table 3.2-A provides the material to support the weather normalized load forecast used by BPI in this Application.

Table 3.2-A – Summary of Load and Customer/Connection Forecast

Year	Billed kWh	Growth	Percent change	Customer/ Connection count	Growth	Percent change
2013 Board Approved	961,331,688					
2006	987,570,495			45,843		
2007	1,004,831,701	17,261,206	1.7%	46,923	1,080	2.4%
2008	977,884,255	(26,947,446)	-2.7%	47,560	637	1.4%
2009	912,366,781	(65,517,474)	-6.7%	47,945	386	0.8%
2010	917,169,662	4,802,881	0.5%	48,362	417	0.9%
2011	919,260,512	2,090,850	0.2%	48,827	466	1.0%
2012	936,319,334	17,058,822	1.9%	49,287	460	0.9%
2013	926,349,236	(9,970,098)	-1.1%	49,691	405	0.8%
2014	889,619,639	(36,729,597)	-4.0%	50,130	439	0.9%
2015	904,891,892	15,272,253	1.7%	50,646	516	1.0%
2016 - Bridge Normalized	871,280,777	(33,611,115)	-3.7%	51,141	496	1.0%
2017 - Test Normalized	878,061,508	6,780,731	0.8%	51,677	535	1.0%

The information in Table 3.2-A above provides weather actual data from 2006 to 2015 while the 2016 Bridge year and 2017 Test year is weather normalized. BPI understands there is not a Board approved method to properly adjust actual data to a weather normal basis. Therefore, based on the process outlined in this Exhibit, a process to forecast energy on a weather normalized basis has been developed and used in this Application.

Total customer and connections are on a yearly average basis and streetlight, sentinel lights and unmetered loads are measured as connections.

Actual and forecasted billed amounts and numbers of customers/connections by rate class are shown in Table 3.2-B. Customer usage by rate class is shown in Table 3.2-C.

Table 3.2-B – Billed Energy by Rate Class

Year	Residential	GS<50	GS>50	Sentinel	Streetlight	USL	Total
2013 Board Approved	282,405,197	98,068,763	533,404,014	443,490	7,553,004	1,454,727	923,329,195
2006	281,767,239	102,615,621	594,077,901	-	6,975,374	2,134,360	987,570,495
2007	285,310,578	105,113,198	605,456,649	-	7,101,501	1,849,775	1,004,831,701
2008	278,923,645	104,110,563	585,927,516	-	7,240,798	1,681,733	977,884,255
2009	275,417,341	99,603,717	528,476,684	-	7,316,579	1,552,460	912,366,781
2010	287,357,342	98,691,975	521,725,747	480,615	7,354,351	1,559,632	917,169,662
2011	291,380,972	99,001,655	519,515,098	475,427	7,330,830	1,556,530	919,260,512
2012	287,058,174	100,340,238	539,521,215	459,394	7,395,374	1,544,939	936,319,334
2013	282,501,947	99,838,335	534,621,114	448,778	7,386,717	1,552,345	926,349,236
2014	282,925,750	99,356,580	497,985,709	445,147	7,378,259	1,528,194	889,619,639
2015	287,594,336	100,078,635	507,886,846	446,247	7,369,714	1,516,114	904,891,892
2016 Bridge Normalized	279,510,225	96,560,220	485,949,556	386,312	7,414,883	1,459,580	871,280,777
2017 Test Normalized	291,567,897	99,837,652	477,408,179	382,297	7,460,329	1,405,154	878,061,508

Table 3.2-C – Number of Customers/Connections

Year	Residential	GS<50	GS>50	Sentinel	Streetlight	USL	Total
2013 Board Approved	35,364	2,764	420	635	10,355	437	49,975
2006	32,800	2,546	399	277	9,366	456	45,843
2007	33,264	2,640	409	569	9,602	439	46,923
2008	33,684	2,702	407	585	9,740	442	47,560
2009	33,947	2,704	409	590	9,852	444	47,945
2010	34,256	2,688	417	603	9,953	446	48,362
2011	34,643	2,709	421	621	9,988	446	48,827
2012	34,938	2,728	419	625	10,134	443	49,287
2013	35,226	2,749	424	625	10,232	438	49,691
2014	35,479	2,772	432	622	10,392	434	50,130
2015	35,744	2,784	438	619	10,632	431	50,646
2016 Bridge Normalized	36,086	2,812	442	591	6,351	428	46,710
2017 Test Normalized	36,433	2,840	447	597	6,351	425	47,093

BPI has previously identified some anomalous billing treatment for the Sentinel lights class resulting in incomplete data for 2006 through 2009 related to billed kWh.

3.2.2 Forecast Methodology - Multivariate Regression Model

BPI's weather normalized load forecast is developed in a three-step process. First, a total system weather normalized purchased energy forecast is developed based on a multivariate regression model incorporating historical load, weather, calendar, economic data, as well as a "negative impact variable" . Second, the weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast. Next, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer. For the rate classes having weather sensitive load, the forecasted billed energy is adjusted to ensure the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast determined from the regression model. The forecast of customers by rate class is determined using a geometric mean analysis. For those rate classes that use kW for the distribution volumetric billing determinant an adjustment factor is applied to class energy forecast based on the historical relationship between kW and kWh. The forecast is also adjusted for expected conservation and Demand Management ("CDM") results for 2016 and 2017. The load forecast for the 2017 Test Year is summarized in Table 3.2-A.

A detailed explanation of the load forecasting process follows.

Purchased kWh Load Forecast

An equation to predict total system purchased energy is developed using a multivariate regression model with the following independent variables: weather (heating and cooling degree days), days in the month, Real Ontario GDP, Negative Impact Variable, and several monthly flag variables. The monthly flag variables control for seasonal variability in power purchases during the spring and fall months beyond variability caused by heating Degree Days ("HDD") and Cooling Degree Days ("CDD"). The regression model uses monthly kWh and monthly values of independent variables from January 2006 to December 2015 to determine the monthly regression coefficients. This provides 120 monthly data points representing a reasonable data set for use in a regression analysis.

BPI submits for weather normalization purposes it is appropriate to determine the average weather conditions from January 2006 to December 2015 as this reflects the time period over which the regression analysis has been conducted. However, in accordance with the filing requirements, BPI has also provided a sensitivity analysis showing the impact on the 2017 forecast of purchases assuming weather normal conditions are based on a 20 year trend of weather data below in Table 3.2-D.

Table 3.2-D – Predicted Purchases based on 10 Year and 20 Year Average

Year	Actual	Predicted	% Difference
2006	1,022.8	990	-3.3%
2007	1,043.0	1,011	-3.2%
2008	1,013.4	991	-2.3%
2009	940.8	955	1.5%
2010	950.8	974	2.4%
2011	944.9	984	4.0%
2012	964.4	985	2.1%
2013	961.3	969	0.8%
2014	913.5	924	1.1%
2015	920.5	893	-3.1%
2017 Weather Nornal - 10 year average		925	
2017 Weather Nornal - 20 year average		925	

The multivariate regression model has determined drivers of year-over-year changes in BPI's load growth. These include weather (including fall and spring monthly flags), economic conditions (Ontario Real GDP Monthly), number of days in the month, and Negative Impact Variable. These factors are captured within the multivariate regression model.

Weather impacts on load are apparent in both the winter heating season and the summer cooling season. For that reason both Heating Degree Days (a measure of coldness in winter) and Cooling Degree Days (a measure of summer heat) are modeled.

The following outlines the prediction model used by BPI to predict weather normal purchases for 2016 and 2017:

BPI's Monthly Predicted Weather Normal Purchases =

(29,865,741.66)

+ Heating Degree Days x 16,419.91

+ Colling Degree Days x 125,379.64

+ Number of Days in Month x 1,795,333.39

+ Real Ontario GDP x 368,436.30

+ April Flag x (3,839,799.44)

+ May Flag x (2,806,041.26)

+ Negative Impact Variable x (2.74)

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Attachment 3-A.

The sources of data for the various data points are:

a) Environment Canada website was used for the monthly Heating Degree Day and Cooling Degree Day information. Weather data was taken from the Pearson Airport CS Station. The base numbers from which HDDs and CDDs are measured is 18° C.
b) The calendar provided information related to number of days in the month, including consideration of leap years.
c) The Negative Impact Variable grows each month at a constant value over the year. The variable not only reflects the impact of CDM on the load forecast but it also reflects the impact of economic conditions within the service area.
d) The Ontario Real GDP Monthly % variable is an indicator of province-wide economic growth. Annual Ontario Real GDP growth, from the sources below, has been converted to monthly growth rates:
    - 2006 rate: 2008 Ontario Economic Outlook and Fiscal Review, Ontario Ministry of Finance.

- 2007 to 2008 rate: 2010 Ontario Economic Outlook and Fiscal Review - 2010 Fall Update
- 2009 rate: 2012 Ontario Economic Outlook and Fiscal Review - 2012 Fall Update
- 2010 rate: 2013 Ontario Economic Outlook and Fiscal Review - 2013 Fall Update
- 2011 rate: 2014 Ontario Economic Outlook and Fiscal Review - 2014 Fall Update
- 2012 - 2017 rates: 2015 Ontario Budget

e) For the years 2006 to 2015, the addition of the monthly negative impact variable shown in Attachment 3-A of this Exhibit will equal the net Energy Savings from the OPA (now IESO) 2006-2014 final CDM Results for BPI, as well as BPI's planned 2015 results. These values reflect the net energy savings from 2006-2015 programs and how the savings from these programs have persisted from 2007 to 2015. The following table outlines the results and persistent impact of 2006-2010 OPA Final CDM Results as well as 2011 thru 2015 programs.

Table 3.2-E – Results and persistent Impact of CDM Program Results

Year	2006-2010 OPA Programs	2011-2014 Programs	20015-2017 Forecast Programs	Total kWh Savings
2006	2,666,105			2,666,105
2007	4,053,225			4,053,225
2008	6,738,513			6,738,513
2009	13,068,447			13,068,447
2010	14,323,507			14,323,507
2011	13,147,196	4,515,774		17,662,970
2012	12,916,363	9,866,347		22,782,709
2013	12,795,202	14,941,621		27,736,823
2014	12,209,385	50,834,407		63,043,792
2015 Forecast	10,753,535	50,834,407	5,239,000	66,826,942
2016 Bridge	10,137,117	50,834,407	12,969,072	73,940,596
2017 Test	8,299,595	50,834,407	28,580,748	87,714,750

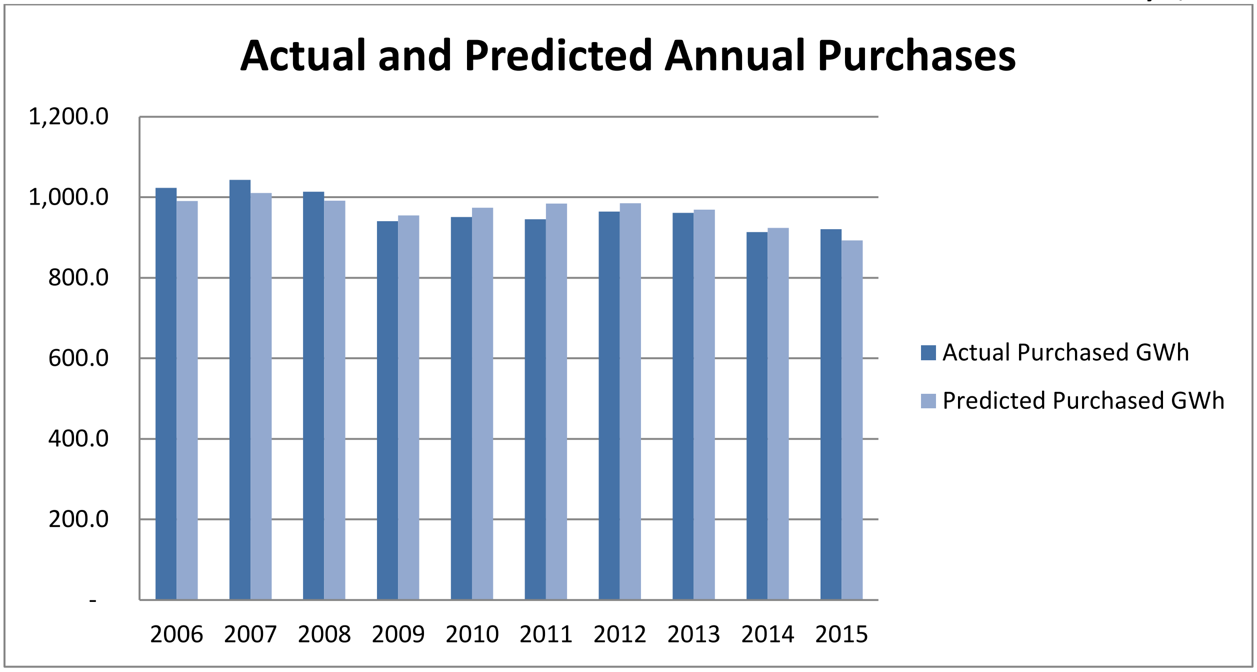
The impact of 2017 CDM programs has not been included in the Negative Impact variable since they do not impact the actual purchases used in the regression analysis. A discussion on how the load forecast is adjusted for 2017 programs and how LRAM variance account values are determined by rate class is provided later in this schedule.

The prediction formula has the following statistical results:

Table 3.2-F – Regression Statistics

Multiple R	0.91
R Square	0.83
Adjusted R Square	0.82
ANOVA	
	df
Regression	7.00
Residual	112.00
Total	119.00
	t Stat
Intercept	(1.57)
Heating Degree Days	11.36
Cooling Degree Days	15.51
Ontario Real GDP Monthly %	3.03
Number of Days in Month	5.59
apr	(4.01)
may	(2.83)
Trend Variable	(6.77)

The annual results of the above prediction formula compared to the actual annual purchases from 2006 to 2015 are shown in the chart below. The chart indicates the resulting prediction equation appears to be reasonable.



The following Table 3.2-G outlines the data supporting the above chart.

Table 3.2-G – Total System Purchases (GWh)

Year	Actual	Predicted	% Difference
2006	1,022.8	990	-3.3%
2007	1,043.0	1,011	-3.2%
2008	1,013.4	991	-2.3%
2009	940.8	955	1.5%
2010	950.8	974	2.4%
2011	944.9	984	4.0%
2012	964.4	985	2.1%
2013	961.3	969	0.8%
2014	913.5	924	1.1%
2015	920.5	893	-3.1%
2017 Weather Nornal - 10 year average		925	
2017 Weather Nornal - 20 year average		925	

The weather normalized amount for 2017 is determined by using 2017 independent variables in the prediction formula on a monthly basis together with the average monthly heating degree days and cooling degree days from January 2006 to December 2015. The 2017 weather normalized 20 year trend value reflects the trend in monthly heating degree days and cooling degree days from January 1996 to December 2015.

The weather normal ten year average has been used as the purchased forecast in this Application for the purposes of determining a billed kWh load forecast which is used to design rates. The ten year average has been used as this is consistent with the period of time over which the regression analysis was conducted.

Billed kWh Load Forecast

To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast is adjusted by a historical loss factor. This adjustment has been made by BPI using the average loss factor from 2006 to 2015 of 1.0318. With this average loss factor the total weather normalized billed energy will be 896.2 GWh for 2017 and 878.1 GWh after the forecast adjustment for sentinel lights and the adjustment for CDM discussed below.

Billed kWh Load forecast and Customer/Connection Forecast by Rate Class

Since the total weather normalized billed energy amount is known, this amount needs to be distributed by rate class for rate design purposes taking into consideration the customer/connection forecast and expected usage per customer by rate class.

The next step in the forecasting process is to determine a customer/connection forecast. The customer/connection forecast is based on reviewing historical customer/connection data available and as shown in the following table.

Table 3.2-H – Historical Number of Customer/Connections

Year	Residential	GS<50	GS>50	Sentinel	Streetlight	USL	Total
2013 Board Approved	35,364	2,764	420	635	10,355	437	49,975
2006	32,800	2,546	399	277	9,366	456	45,843
2007	33,264	2,640	409	569	9,602	439	46,923
2008	33,684	2,702	407	585	9,740	442	47,560
2009	33,947	2,704	409	590	9,852	444	47,945
2010	34,256	2,688	417	603	9,953	446	48,362
2011	34,643	2,709	421	621	9,988	446	48,827
2012	34,938	2,728	419	625	10,134	443	49,287
2013	35,226	2,749	424	625	10,232	438	49,691
2014	35,479	2,772	432	622	10,392	434	50,130
2015	35,744	2,784	438	619	10,632	431	50,646

From the historical customer/connection data the growth rates in customer/connections can be evaluated. The growth rates are provided in the following table. The geometric mean growth rate in number of customers is also provided. The geometric mean approach provides the average compounding growth rate from 2006 to 2015.

Table 3.2-I – Historical Growth in Customers by Rate Class

Year	Residential	GS<50	GS>50	Streetlight	Sentinel	USL
2006						
2007	1.41%	3.69%	2.63%	2.52%		-3.62%
2008	1.26%	2.35%	-0.49%	1.44%	2.81%	0.68%
2009	0.78%	0.06%	0.37%	1.15%	0.85%	0.45%
2010	0.91%	-0.59%	2.08%	1.03%	2.12%	0.34%
2011	1.13%	0.80%	0.96%	0.35%	2.99%	0.00%
2012	0.85%	0.70%	-0.48%	1.46%	0.73%	-0.67%
2013	0.82%	0.75%	1.07%	0.96%	-0.08%	-1.13%
2014	0.72%	0.84%	2.01%	1.57%	-0.48%	-0.80%
2015	0.75%	0.45%	1.27%	2.30%	-0.48%	-0.81%
Geomean	0.96%	1.00%	1.04%	1.42%	1.05%	-0.63%

The numbers for projected customers by rate class for 2016 and 2017 were determined by increasing the 2015 actual number of customers in each class by the geomean rate calculated above. With the exception of the Sentinel Light class, the forecasted results shown in Table 3.2-J below consistently trend with actual results from the past 5 years. As a result of consultations with its unmetered load customers, the Sentinel light connections forecast was reduced by 34 after applying the geomean rate to the 2015 number, as customers identified connections which were removed. BPI has not changed the definition or composition of any of the rate classes.

Table 3.2-J – Projected Customers by Rate Class

Year	Residential	GS<50	GS>50	Streetlight	Sentinel	USL
2016	36,086	2,812	442	10,782	591	428
2017	36,433	2,840	447	10,935	597	425

The next step in the process is to review the historical customer/connection usage and to reflect this usage per customer in the forecast. The following table provides the average annual usage per customer/connection by rate class from 2006 to 2015.

Table 3.2-K – Historical Annual Usage per Customer/Connection by Rate Class

Year	Residential	GS<50	GS>50	Streetlight	Sentinel	USL
2006	8,590	40,305	1,490,785	745	-	4,686
2007	8,577	39,816	1,480,334	740	-	4,214
2008	8,281	38,531	1,439,625	743	-	3,805
2009	8,113	36,843	1,293,701	743	-	3,497
2010	8,389	36,723	1,251,141	739	798	3,501
2011	8,411	36,545	1,234,003	734	766	3,494
2012	8,216	36,782	1,287,640	730	735	3,491
2013	8,020	36,325	1,262,388	722	719	3,548
2014	7,974	35,849	1,152,745	710	716	3,521
2015	8,046	35,948	1,160,884	693	721	3,522

As can be seen from the above table, usage per customer/connection has generally declined over the past 5 years. BPI's view is this decline is partially due to the CDM programs as well as from changing individual usage caused by a variety of factors including weather and the economy. BPI's customer base is sensitive to weather and during the summer months a substantial amount of air conditioning is used throughout the service territory. From the historical usage per customer/connection data the growth rate in usage per customer/connection can be derived as shown in the following table. The geometric mean growth rate has also been provided.

Table 3.2-L – Historical Annual Customer/Connection Usage Growth by Rate Class

Year	Residential	GS<50	GS>50	Streetlight	Sentinel	USL
2006						
2007	-0.15%	-1.21%	-0.70%	-0.69%		-10.08%
2008	-3.46%	-3.23%	-2.75%	0.52%		-9.70%
2009	-2.02%	-4.38%	-10.14%	-0.10%		-8.10%
2010	3.39%	-0.33%	-3.29%	-0.50%		0.12%
2011	0.27%	-0.48%	-1.37%	-0.67%	-3.95%	-0.20%
2012	-2.32%	0.65%	4.35%	-0.57%	-4.07%	-0.07%
2013	-2.39%	-1.24%	-1.96%	-1.07%	-2.23%	1.63%
2014	-0.57%	-1.31%	-8.69%	-1.66%	-0.33%	-0.76%
2015	0.90%	0.27%	0.71%	-2.37%	0.73%	0.02%
Geomean	-0.72%	-1.26%	-2.74%	-0.79%	-1.99%	-3.12%

For the forecast of usage per customer/connection the historical geometric mean was applied to the 2015 usage to determine the 2016 and 2017 forecast. The resulting usage forecast is shown in the following table.

Table 3.2-M – Projected Annual Usage per Customer/Connection by Rate Class

Year	Residential	GS<50	GS>50	Streetlight	Sentinel	USL
2016	7,988	35,494	1,129,066	688	707	3,412
2017	7,930	35,045	1,098,120	682	693	3,305

With the preceding information the non-weather normalized billed energy forecast can be determined by applying the forecast number of customer/connections from Table 3.2-J by the forecast annual usage per customer/connection from Table 3.2-M. The resulting non-weather normalized billed energy forecast is shown below.

Table 3.2-N – Projected Non-Weather Normal Billed energy by Rate Class (GWh)

Year	Residential	GS<50	GS>50	Streetlight	Sentinel	USL	Total
2016	288.2	99.8	499.1	7.4	0.4	1.5	896.5
2017	288.9	99.5	490.5	7.5	0.4	1.4	888.2

The non-weather normalized billed energy forecast has been determined but this needs to be adjusted in order to align with the total weather normalized billed energy forecast. As previously determined, the total weather normalized billed energy forecast for 2016 and 2017 is 877.8 GWh and 896.2 GWh respectively.

The difference between the non-weather normalized and the weather normalized forecasts are (18.7) GWh for 2016 and 8.0 GWh for 2017. The remaining difference is assumed to be associated with moving the forecast from a non-weather normalized to a weather normalized basis and this amount will be assigned to those rate classes that are weather sensitive. Based on the weather normalization work completed by Hydro One for BPI for the cost allocation information filing used to support the Application, it was determined the weather sensitivity by rate class is as follows:

Table 3.2-O – Weather Sensitivity by Rate Class

	Residential	GS<50	GS>50	Streetlight	Sentinel	USL
Weather Sensitivity Percent	67.00%	67.00%	34.00%	0.00%	0.00%	0.00%

For the GS>50 kW class the weather sensitivity amount of 34% was provided in the weather normalization work completed by Hydro One. For the Residential and GS<50 kW classes it has been assumed in cost of service applications prior to 2013 that these two classes are 100% weather sensitive. Intervenors expressed concern with this assumption and have suggested sensitivity of 100% for these classes in not appropriate. BPI agrees with this position but also submits the weather sensitivity for the Residential and GS<50 kW classes should be higher than the GS>50 kW class. As a result BPI has assumed the weather sensitivity for the Residential and GS<50 kW classes to be mid-way between 100% and 34%, therefore 67%.

The difference between the non-weather normalized and the weather normalized forecast of (18.7) GWh for 2016 and 8.0 GWh for 2017 have been assigned on a pro rata basis to each rate class based on the above level of weather sensitivity.

CDM Adjustment

A manual adjustment has been made to reflect the impact of 2015, 2016 and 2017 CDM programs on the load forecast. The calculation of the 2017 manual adjustment is consistent with the calculation in Appendix 2-I: Load Forecast CDM. The annual expected savings and timing for the 2015 to 2020 period are consistent with the annual savings in BPI's CDM Plan for 2015 to 2020. BPI believes this is the most reliable indicator of future expected savings and will enable the achievement of BPI's 2015-2020 CDM target. BPI has included in the 2017 manual CDM adjustment a half-year of the 2015 savings, representing the remainder of savings expected to persist into 2017 which were not present in the 2015 billed/purchased power data which underpins the base forecast (as only a half year of savings impact is assumed in the initial year of a program), full year persistence related to 2016 programs has been included in the 2017 manual adjustment, and only a half-year of 2017 programs. The calculations assume 100% persistence from one year to the next for 2015-2020 programs.

The following table outlines the savings from 2015 through 2020 CDM programs in order to achieve the 2015 to 2020 CDM target assigned to BPI.

Table 3.2-P – 5 Year Expected (2015-2020) kWh Target Results

6 Year (2015-2020) kWh Target:							
54,372,015							
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
%							
2015 CDM Programs	9.64%						9.64%
2016 CDM Programs		14.22%					14.22%
2017 CDM Programs			28.71%				28.71%
2018 CDM Programs				24.56%			24.56%
2019 CDM Programs					11.45%		11.45%
2020 CDM Programs						11.42%	11.42%
Total in Year	**9.64%**	**14.22%**	**28.71%**	**24.56%**	**11.45%**	**11.42%**	**100.00%**
kWh							
2015 CDM Programs	5,239,000.00	5,239,000.00					10,478,000.00
2016 CDM Programs		7,730,071.71					7,730,071.71
2017 CDM Programs			15,611,676.18	15,611,676.18			31,223,352.36
2018 CDM Programs				13,356,198.98			13,356,198.98
2019 CDM Programs					6,228,066.87		6,228,066.87
2020 CDM Programs						6,207,000.93	6,207,000.93
Total in Year	**5,239,000.00**	**12,969,071.71**	**15,611,676.18**	**28,967,875.16**	**6,228,066.87**	**6,207,000.93**	**54,372,014.66**

It is assumed the savings achieved in 2015 thru 2017 from 2011 to 2014 programs will persist. In addition, savings from programs in 2015, 2016 and 2017 are assumed to be 5,239,000, 7,730,072 and 15,611,676 respectively which are the forecast savings in the first three years of the 2015-2020 CDM target assigned to BPI. The following table summarizes the expected savings in 2015 thru 2017 from 2011 to 2017 programs.

Table 3.2-Q – 4 Year (2011-2014) Expected kWh Target Results with 2015 thru 2017 Expected Results

4 year 2011 to 2014 Target						2015	2016	2017
48,920,000								
	2011	**2012**	**2013**	**2014**	**Total**			
2011 Programs	9.2%	9.2%	9.2%	9.0%	36.6%			
2012 Programs		11.0%	11.0%	11.0%	32.9%			
2013 Programs			10.4%	10.4%	20.8%			
2014 Programs				73.6%	73.6%			
Total in Year	**9.2%**	**20.2%**	**30.5%**	**103.9%**	**163.9%**			
kWh								
2011 Programs	4,515,774	4,502,851	4,498,762	4,394,084	17,911,471	4,394,084	4,394,084	4,394,084
2012 Programs		5,363,496	5,363,496	5,363,496	16,090,488	5,363,496	5,363,496	5,363,496
2013 Programs			5,079,363	5,079,363	10,158,726	5,079,363	5,079,363	5,079,363
2014 Programs				35,997,464	35,997,464	35,997,464	35,997,464	35,997,464
Total	**4,515,774**	**9,866,347**	**14,941,621**	**50,834,407**	**80,158,149**	**50,834,407**	**50,834,407**	**50,834,407**
2015 Programs						5,239,000	5,239,000	5,239,000
2016 Programs							7,730,072	7,730,072
2017 Programs								15,611,676
Total	**4,515,774**	**9,866,347**	**14,941,621**	**50,834,407**	**80,158,149**	**56,073,407**	**63,803,479**	**79,415,155**

Since the regression analysis is based on actual power purchased data up to and including 2015 actual data, it is assumed any savings from programs initiated up to and including 2015 are reflected in the prediction equation resulting from the regression analysis. However, for 2015 it is assumed only one half of the full year results provided by the IESO actually occur since they were initiated throughout the year. This has been classified as the half year rule for CDM purposes. It also suggests only one half of the 2015 reported full year results from programs initiated in 2015 are reflected in the actual 2015 power purchases.

As a result the 2017 manual adjustment for CDM savings will be one half of 2015 programs that persist into 2017 (i.e. ½ of 5,239,000) plus a full year of 2016 programs (i.e. 7,730,072) plus one half of 2017 programs (i.e. ½ of 15,611,676) for a total of 18,155,410 kWh on a net basis.

BPI has allocated the CDM savings to the Residential, GS<50 kW and GS>50 kW rate classes in the same proportion as the kWh savings being proposed in BPI's proposed LRAMVA for 2014. The savings in this report are weighted heavily toward the General Service 50 to 4,999 kW customer class, however this is in line with the expected savings going forward from BPI's 2015-2020 CDM Plan. The class splits are show in the following table.

Table 3.2-R – Allocation of CDM Savings

	Total
Residential	5.4%
GS<50 kW	5.2%
GS>50 kW	89.4%

In accordance with the Guidelines for Electricity distributor conservation and Demand management (EB-2012-0003), issued April 26, 2012 ("CDM Guidelines"), it is BPI's understanding expected CDM savings in 2017 from 2015 to 2016 programs will need to be established for lost revenue adjustment mechanism ("LRAM") variance account purposes as part of this Application. BPI also understands the IESO will measure CDM results on a full year net basis. Consistent with past practices, it is expected the full year net level of savings will be used for LRAM variance calculations. As a result, it is BPI's view the units used for the 2017 LRAM variance account should also be on a full year net basis. Based on the information above and as per Chapter 2 Appendix 2I LF_CDM, BPI expects to achieve 18,155,410 net kWh savings in 2017 from 2015 to 2017 CDM programs. For LRAM variance account purposes, the following table shows how this expected savings has been allocated to rate classes. The expected kW savings has also been provided for those classes billed distribution charges on a kW basis using the average kW/kWh ratios from table 3.2-V.

Table 3.2-S – Expected CDM Savings by Rate Class for LRAM Variance Account

Year	Residential	GS<50	GS>50	Sentinel	Streetlight	USL	Total
2017 LRAMVA kWh	982,309	941,317	16,231,783				18,155,410
2017 LRAMVA kW			41,928				41,928

The following table outlines how the classes have been adjusted to align the non-weather normalized forecast with the weather normalized forecast.

Table 3.2-T – Alignment of Non-Weather Normalized and Weather Normalized Forecasts

	Residential	GS<50	GS>50	Sentinel	Streetlight	USL	Total
2016							
Non-Weather Corrected Forecast	288,249,185	99,800,648	499,117,637	417,917	7,414,883	1,459,580	896,459,850
Weather Sensitivity %	*67.0%*	*67.0%*	*34.0%*	-	-	-	
Allocation of Weather Sensitive Amount	(8,388,110)	(2,904,219)	(7,370,604)	-	-	-	(18,662,933)
CDM % Allocated per Class	*5.4%*	*5.2%*	*89.4%*	*0.0%*	*0.0%*	*0.0%*	
Allocation of CDM Amount	(350,850)	(336,209)	(5,797,477)	-	-	-	(6,484,536)
Weather Corrected Forecast	**279,510,225**	**96,560,220**	**485,949,556**	**417,917**	**7,414,883**	**1,459,580**	**871,312,381**
2017							
Non-Weather Corrected Forecast	288,905,525	99,523,433	490,499,839	413,902	7,460,329	1,405,154	888,208,182
Weather Sensitivity %	*67.0%*	*67.0%*	*34.0%*	-	-	-	
Allocation of Weather Sensitive Amount	3,644,681	1,255,536	3,140,123	-	-	-	8,040,340
CDM % Allocated per Class	*5.4%*	*5.2%*	*89.4%*	*0.0%*	*0.0%*	*0.0%*	
Allocation of CDM Amount	(982,309)	(941,317)	(16,231,783)	-	-	-	(18,155,410)
Weather Corrected Forecast	**291,567,897**	**99,837,652**	**477,408,179**	**413,902**	**7,460,329**	**1,405,154**	**878,093,112**

Billed kW Load Forecast

There are three rate classes that charge volumetric distribution on a per kW basis. These include GS>50 kW, Streetlights, and Sentinel Lighting. As a result the energy forecast for these classes needs to be converted to a kW basis for rate setting purposes. The forecast of kW for these classes is based on a review of the historical ratio of kW to kWh and applying the average ratio to the forecasted kWh to produce the required kW.

Table 3.2-U outlines the annual demand units by applicable rate class.

Table 3.2-U – Historical kW per Applicable Class

Year	GS>50	Sentinel	Streetlight	Total
2006	1,481,343	-	21,299	1,502,642
2007	1,489,946	-	21,758	1,511,704
2008	1,450,726	-	22,064	1,472,790
2009	1,326,770	-	22,380	1,349,150
2010	1,323,482	1,534	22,480	1,347,497
2011	1,344,251	1,487	22,428	1,368,166
2012	1,398,784	1,392	22,533	1,422,709
2013	1,395,148	1,385	22,581	1,419,114
2014	1,368,652	1,361	22,553	1,392,566
2015	1,388,241	1,359	22,527	1,412,127

The following table illustrates the historical ratio of kW/kWh as well as the average ratio for 2006 to 2015.

Table 3.2-V – Historical kW/kWh Ratio by Class

Year	GS>50	Sentinel	Streetlight
2006	0.2494%		0.3053%
2007	0.2461%		0.3064%
2008	0.2476%		0.3047%
2009	0.2511%		0.3059%
2010	0.2537%	0.3192%	0.3057%
2011	0.2588%	0.3128%	0.3059%
2012	0.2593%	0.3030%	0.3047%
2013	0.2610%	0.3086%	0.3057%
2014	0.2748%	0.3057%	0.3057%
2015	0.2733%	0.3045%	0.3057%
Average	0.2575%	0.3090%	0.3056%

The average ratio was applied to the weather normalized billed energy forecast in Table 3.2-T to provide the forecast of kW by rate class as shown below.

Table 3.2-W – Forecast kW per Applicable Class

Year	GS>50	Sentinel	Streetlight
2016	1,251,277	1,291	22,657
2017	1,229,284	1,279	22,796

In addition to the forecasts per class set out above, which are calculated in BPI's load forecast regression analysis, BPI has also forecast the Test Year billing determinants expected for its Embedded Distributor class and its Wholesale Market Participants (WMPs), which are part of the General Service 50 to 4,999 kW class. The forecast kW usage for the Embedded Distributor class is 132,260 kW for 2016 and 139,437 kW for 2017. This forecast is based on historic actual billings, adjusted by the growth factors from a Peak Load per Feeder forecast provided by EN+ on December 24, 2015. EN+ has notified BPI that it will not require one of its existing three connections beginning in 2016, and BPI has adjusted the forecast number of connections from 3 to 2 accordingly. The forecast of 12,398 kW for 2016 and 2017 for WMPs is consistent with 2015 actuals. Throughout the Rate Design and Cost Allocation portions of the Application, the General Service 50 to 4,999 kW forecast should be inclusive of WMP billings.

The table below is extracted from Appendix 2-IA and provides a summary of the load forecast on a billing determinants basis by rate class. Appendix 2-IA is also included as part of this application.

Table 3.2-X – Summary and Variances of Actual and Forecast Data

Appendix 2-IA
Summary and Variances of Actual and Forecast Data

Replace "Rate Class #" with the appropriate rate classification.

	2013 Board Approved	2013	2014	2015	2016 Bridge	2017 Test
Residential						
# of Customers	35,364	35,226	35,479	35,744	36,086	36,433
kWh	282,405,197	282,501,947	282,925,750	287,594,336	279,510,225	291,567,897
kW						
Variance Analysis						
# of Customers		-0.39%	0.33%	1.07%	2.04%	3.02%
kWh		0.03%	0.18%	1.84%	-1.03%	3.24%
kW		0.00%	0.00%	0.00%	0.00%	0.00%
General Service <50 kW						
# of Customers	2,764	2,749	2,772	2,784	2,812	2,840
kWh	98,068,763	99,838,335	99,356,580	100,078,635	96,560,220	99,837,652
kW						
Variance Analysis						
# of Customers		-0.56%	0.27%	0.72%	1.73%	2.74%
kWh		1.80%	1.31%	2.05%	-1.54%	1.80%
kW		0.00%	0.00%	0.00%	0.00%	0.00%
General Service 50-4999						
# of Customers	420	424	432	438	442	447
kWh	533,404,014	534,621,114	497,985,709	507,886,846	485,949,556	477,408,179
kW	1,357,900	1,395,148	1,368,652	1,388,241	1,251,277	1,229,284
Variance Analysis						
# of Customers		0.83%	2.86%	4.17%	5.25%	6.35%
kWh		0.23%	-6.64%	-4.78%	-8.90%	-10.50%
kW		2.74%	0.79%	2.23%	-7.85%	-9.47%
Sentinel Lights						
# of Connections	635	625	622	619	591	597
kWh	443,490	448,778	445,147	446,247	386,312	382,297
kW	1,356	1,385	1,361	1,359	1,194	1,181
Variance Analysis						
# of Connections		-1.65%	-2.13%	-2.60%	-6.93%	-5.96%
kWh		1.19%	0.37%	0.62%	-12.89%	-13.80%
kW		2.14%	0.37%	0.22%	-11.97%	-12.88%
Street Lights						
# of Connections	10,355	10,232	10,392	10,632	6,351	6,351
kWh	7,553,004	7,386,717	7,378,259	7,369,714	7,414,883	7,460,329
kW	23,455	22,581	22,553	22,527	22,657	22,796
Variance Analysis						
# of Connections		-1.19%	0.36%	2.67%	-38.67%	-38.67%
kWh		-2.20%	-2.31%	-2.43%	-1.83%	-1.23%
kW		-3.73%	-3.85%	-3.96%	-3.40%	-2.81%

Unmetered Scattered Load						
# of Connections	437	438	434	431	428	425
kWh	1,454,727	1,552,345	1,528,194	1,516,114	1,459,580	1,405,154
kW						
Variance Analysis						
# of Connections		0.11%	-0.69%	-1.49%	-2.10%	-2.72%
kWh		6.71%	5.05%	4.22%	0.33%	-3.41%
kW		0.00%	0.00%	0.00%	0.00%	0.00%

Embedded Distributor						
# of Connections	3	3	3	3	2	2
kWh *EST		-	-	52,024,995	48,387,203	51,013,084
kW	158,473	159,286	164,324	142,203	132,260	139,437
Variance Analysis						
# of Connections		0.00%	0.00%	0.00%	-33.33%	-33.33%
kWh		0.00%	0.00%	0.00%	0.00%	0.00%
kW		0.51%	3.69%	-10.27%	-16.54%	-12.01%

Wholesale Market Participants (Billed under GS>50 kW for Dist. Rates)						
# of Customers	-	2	2	2	2	2
kWh *EST	-	-	-	6,792,378	6,792,378	6,792,378
kW	-	13,590	12,737	12,398	12,398	12,398
Variance Analysis						
# of Customers		0.00%	0.00%	0.00%	0.00%	0.00%
kWh		0.00%	0.00%	0.00%	0.00%	0.00%
kW		0.00%	0.00%	0.00%	0.00%	0.00%

Standby Class						
# of Customers	1					
kWh						
kW	36,000					
Variance Analysis						
# of Customers		-100.00%	-100.00%	-100.00%	-100.00%	-100.00%
kWh		0.00%	0.00%	0.00%	0.00%	0.00%
kW		-100.00%	-100.00%	-100.00%	-100.00%	-100.00%

Totals

Customers / Connections	49,979	49,696	50,135	50,651	46,714	47,097
kWh	923,329,195	926,349,236	889,619,639	963,709,264	926,460,357	935,866,969
kW from applicable classes	1,577,184	1,591,990	1,569,627	1,566,728	1,419,786	1,405,097

Totals - Variance

Customers / Connections		-0.57%	0.31%	1.34%	-6.53%	-5.77%
kWh		0.33%	-3.65%	4.37%	0.34%	1.36%
kW from applicable classes		0.94%	-0.48%	-0.66%	-9.98%	-10.91%

3.3 Accuracy of load forecast and Variance Analysis

3.3.1 Variance Analysis of Distribution Revenue and Billing Determinants

The following discussion provides a variance analysis on BPI's Distribution Revenue and Billing Determinants. The variance analysis will compare 2013 Actual to 2013 Board Approved and a year over year comparison of actuals for years; 2014 to 2013, 2015 to 2014, 2016 Bridge year to 2015, and 2017 Test year to 2016 Bridge year. The distribution Revenue variance analysis is based on information provided in Table 3.1-A. The Billing Determinant variance analysis is based on data provided in Table 3.3-A. The overall variance analysis has been provided based on BPI's materiality of $100,000 as calculated in Exhibit 1 of this application.

2013 Actual vs 2013 Board Approved

Table 3.3-A – Distribution Revenue 2013 Actual vs 2013 Board Approved

Distribution Revenue	2013 Board Approved	2013 Actual	Variance
Residential	$ 9,042,952	$ 8,324,144	$ (718,808)
General Service Less than 50 kW	$ 1,510,543	$ 1,389,970	$ (120,573)
General Service 50 to 4,999 kW	$ 4,720,273	$ 4,826,642	$ 106,369
Street Light	$ 149,052	$ 131,785	$ (17,267)
Sentinel Lighting	$ 55,467	$ 30,839	$ (24,628)
Unmetered Scattered Load	$ 76,128	$ 71,675	$ (4,453)
Embedded Distributor	$ 272,147	$ 271,927	$ (220)
Total	$ 15,826,562	$ 15,046,982	$ (779,580)

The significant drivers creating the variances between 2013 Board Approved and 2013 Actual distribution revenues were the delay in the effective date of the 2013 Board Approved Rates as well as the repayment of Account 1562 – Deferred Payment in Lieu of Taxes (Account 1562).

2013 Cost of Service rates were not in effect until March 1, 2014, therefore, the 2013 Board Approved distribution revenues above would not have been reflected in any BPI 2013 billings.

On April 19, 2012, the OEB issued the Decision and Order for BPI's 2012 IRM (EB-2011-0147). In this Decision and Order, BPI was instructed to repay $2,021,450 for Account 1562. This rate rider was in effect from May 1, 2012 to April 30, 2013. BPI had reported Account 1562 using Alternative 3 detailed in the April 2003 OEB Accounting Procedures Handbook Frequently Asked Questions. This alternative created Account 1563 – Deferred PILs contra account (Account 1563) which offset the balance in Account 1562. The repayments to the customers decreased distribution revenue in 2012 and 2013 by $1,347,633 and $673,817 respectively.

For the Residential class, the actual 2013 revenue was ($718,808) lower than the expected revenues based on the Board Approved revenues. The delay in the effective date for the 2013 Board Approved rates accounts for ($269,400) of the variance. The repayment of Account 1562 during 2013 accounted for ($447,100) of the variance.

For the General Service Less than 50KW (GS<50KW), the actual 2013 revenue was ($120,573) lower than the expected revenues based on the Board Approved revenues. The delay in the effective date for the 2013 Board Approved rates accounts for ($48,000) of the variance. The repayment of Account 1562 during 2013 accounted for ($81,960) of the variance.

For the General Service Greater than 50KW (GS>50KW), the actual 2013 revenue was $106,369 higher than the expected revenues based on the Board Approved revenues. The delay in the effective date for the 2013 Board Approved rates resulted in a decrease in 2013 revenues of ($162,890). The repayment of Account 1562 during 2013 decreased 2013 revenues by ($302,140). Transformer Allowances paid during 2013 were proportionately allocated to all customer classes for 4080 distribution revenue reporting purposes on the 2013 RRR reporting. This mapping difference accounts for $592,268 of the variance.

The decreases in the other rate classes fall below the $100,000 materiality threshold.

Table 3.3-B – Billing Determinants – 2013 Actual vs. 2013 Board Approved

	Customers/Connections			kWh		kW		
	2013 Board Approved	2013 Actual	Variance	2013 Board Approved	2013 Actual	2013 Board Approved	2013 Actual	Volumetric Variance
Residential	35,364	35,226	(139)	282,405,197	282,501,947			96,750
General Service Less than 50 kW	2,764	2,749	(16)	98,068,763	99,838,335			1,769,572
General Service 50 to 4,999 kW	420	424	4			1,357,900	1,408,738	50,838
Street Light	10,355	10,232	(124)			23,455	22,581	(874)
Sentinel Lighting	635	625	(11)			1,356	1,385	29
Unmetered Scattered Load	437	438	1	1,454,727	1,552,345			97,618
Embedded Distributor	3	3	-			158,473	159,286	813
Total	49,978	49,694	(284)	381,928,687	383,892,627	1,541,184	1,591,990	2,014,746

In its 2013 Load Forecast, BPI used historic data for kW Demand based on the monthly kW used rather than the kW Billed. The resulting forecast was therefore a forecast of kW used, which was lower in comparison to kW billed. Aside from the impact from customer/connection variances, this is the main reason for the variances shown in table 3.3-B above.

BPI has adjusted the demand data used for its 2017 Load Forecast to reflect the historic kW billed.

2013 Actual vs 2014 Actual

Table 3.3-C – 2014 Actual vs. 2013 Actual

Distribution Revenue	2013 Actual	2014 Actual	Variance
Residential	$ 8,324,144	$ 9,389,728	$ 1,065,584
General Service Less than 50 kW	$ 1,389,970	$ 1,684,534	$ 294,564
General Service 50 to 4,999 kW	$ 4,826,642	$ 4,709,456	$ (117,186)
Street Light	$ 131,785	$ 143,613	$ 11,828
Sentinel Lighting	$ 30,839	$ 67,184	$ 36,345
Unmetered Scattered Load	$ 71,675	$ 76,992	$ 5,317
Embedded Distributor	$ 271,927	$ 310,759	$ 38,832
Total	$ 15,046,982	$ 16,382,266	$ 1,335,284

BPI received 2013 Board Approved rates effective March 1, 2014. In the 2013 COS rate application, BPI disposed of the deferral and variance accounts related to the Ministry of Energy's Smart Meter initiative. This disposition increased 2014 distribution revenues for Residential and General Service Les than 50KW as detailed below.

As detailed above, 2013 revenues were decreased by the disposition of Account 1562. The rate rider repaying deferred PILs was in effect until April 30, 2013.

For the Residential class, 2014 Actual distribution revenues were $1,065,584 higher than 2013 Actual. The main driver for this increase was the Smart Meter deferral and variance account disposition which increased revenues by $494,150. The 2013 Board Approved rates which were effective March 1, 2014 resulted in an increase in revenue of $225,580. The rate rider for Account 1562 which was not in effect in 2014, resulted in 2014 being $447,100 higher than 2013. This variance was offset by lower revenues related to LRAM of $96,700.

The GS<50KW customer class reported an increase in distribution revenues of $294,564 in 2014 over 2013. The main driver for this increase was the Smart Meter deferral and variance account disposition which increased revenues by $132,600. The 2013 Board Approved rates which were effective March 1, 2014 resulted in an increase in revenue of $40,100. The rate rider for Account 1562 which was not in effect in 2014, resulted in 2014 being $81,960 higher than 2013. Revenues were increased by $13,400 related to changes in customer count, consumption and LRAM.

The GS>50KW customer class reported a decrease in distribution revenues of ($117,186) in 2014 over 2013. The main driver for this decrease was the mapping of transformer allowance to this customer account whereas in 2013, the transformer allowance was proportionately allocated to all customer classes. This accounted for a decrease of ($488,257) in 2014. This decrease was offset by several increases. The 2013 Board Approved rates which were effective March 1, 2014 resulted in an increase in revenue of $121,600. The rate rider for Account 1562 which was not in effect in 2014, resulted in 2014 being $302,140 higher than 2013. Revenues were increased by $24,100 related to changes in customer count but decreased by ($79,500) as a result in lower KW demand.

The variances in the other rate classes fall below the $100,000 materiality threshold.

Table 3.3-D – Billing Determinants – 2014 Actual vs. 2013 Actual

	Customers/Connections			kWh		kW		Volumetric Variance
	2013 Actual	2014 Actual	Variance	2013 Actual	2014 Actual	2013 Actual	2014 Actual	
Residential	35,226	35,479	254	282,501,947	282,925,750	-		423,803
General Service Less than 50 kW	2,749	2,772	23	99,838,335	99,356,580	-		(481,755)
General Service 50 to 4,999 kW	426	434	9	-		1,408,738	1,381,389	(27,349)
Street Light	10,232	10,392	161	-		22,581	22,553	(28)
Sentinel Lighting	625	622	(3)	-		1,385	1,361	(24)
Unmetered Scattered Load	438	434	(4)	1,552,345	1,528,194	-		(24,151)
Embedded Distributor	3	3	-	-		159,286	164,324	5,038
Total	49,696	50,135	439	383,892,627	383,810,524	1,591,990	1,569,627	(104,466)

Table 3.3-D above shows the billing determinant variances for 2014 actual versus 2013 actual. While there were increases in customers/connections driving increased usage, this was offset by significant CDM saving during the year as can be seen in Table 3.2-Q. Also offsetting the impact of higher customers/connections is the CDD in 2014. Note from table 3.2-F CDD is statistically significant in explaining kWh/kW billed. In 2014 the CDD were approximately 20% less than in 2013 likely resulting in low usage of air conditioning by the Residential and GS<50 kW customer classes. This can also help explain information in table 3.2-K which show the average usage per customer decline in 2014.

2014 Actual vs 2015 Actual

Table 3.3-E – 2015 Actual vs. 2014 Actual

Distribution Revenue	2014 Actual	2015 Actual	Variance
Residential	$ 9,389,728	$ 9,427,645	$ 37,917
General Service Less than 50 kW	$ 1,684,534	$ 1,576,623	$ (107,911)
General Service 50 to 4,999 kW	$ 4,709,456	$ 4,951,361	$ 241,905
Street Light	$ 143,613	$ 145,183	$ 1,570
Sentinel Lighting	$ 67,184	$ 58,893	$ (8,291)
Unmetered Scattered Load	$ 76,992	$ 77,396	$ 404
Embedded Distributor	$ 310,759	$ 246,758	$ (64,001)
Total	$ 16,382,266	$ 16,483,859	$ 101,593

The GS<50KW customer class reported a decrease in distribution revenues of (108,431) in 2015 over 2014. The main driver for this decrease was the Smart Meter deferral and variance account disposition in 2014 which increased 2014 revenues by $132,600. The ($132,600) decrease for 2015 was partially offset by increases in revenue related to rate increases, customer growth and increased consumption. These three items increased 2015 revenue $29,850 over 2014.

The GS>50KW customer class reported an increase in distribution revenues of $327,273 in 2015 over 2014. The main driver for this increase was the estimated LRAM adjustment for the industrial class of $181,100. Transformer allowances paid to BPI's embedded distributor were mapped to GS>50KW in 2014. These payments have been remapped to Embedded Distributor for 2015 thus increasing 2015 revenues by $85,322. Distribution revenues for 2015 were also $69,450 higher than 2014 as a result of rate increases.

Embedded Distributor revenues are ($148,849) lower in 2015 than 2014. The primary driver in this decrease is the remapping of the transformer allowance from the GS>50KW class which reduced 2015 revenues by ($85,322). Revenues were also lower because of a decrease in demand of 22,121 KW which decreased revenue by ($37,100). In 2010 the OEB issued a Decision and Order (EB-2009-0063) adjusting the distribution rates that had been approved in BPI's 2008 COS rate application. This decision allowed BPI to record differences between the 2008 Board Approved rates for the Embedded Distributor and the new rates issued with EB-2009-0063 in a deferral and variance account (Account 1508). The revised rates were in effect until March 1, 2014 allowing two months of 2014 revenue differential to be recorded in Account 1508. The reclass to Account 1508 during 2014 contributed to a decrease in 2015 revenues compared to 2014 of ($23,675).

The variances in the other rate classes fall below the $100,000 materiality threshold.

Table 3.3-F – Billing Determinants – 2015 Actual vs. 2014 Actual

	Customers/Connections			kWh		kW		Volumetric Variance
	2014 Actual	2015 Actual	Variance	2014 Actual	2015 Actual	2014 Actual	2015 Actual	
Residential	35,479	35,744	265	282,925,750	287,594,336	-		4,668,586
General Service Less than 50 kW	2,772	2,784	13	99,356,580	100,078,635	-		722,055
General Service 50 to 4,999 kW	434	440	6	-		1,381,389	1,400,639	19,250
Street Light	10,392	10,632	240	-		22,553	22,527	(26)
Sentinel Lighting	622	619	(3)	-		1,361	1,359	(2)
Unmetered Scattered Load	434	431	(4)	1,528,194	1,516,114	-		(12,080)
Embedded Distributor	3	3	-	-		164,324	142,203	(22,121)
Total	50,135	50,651	516	383,810,524	389,189,085	1,569,627	1,566,728	5,375,662

Table 3.3-F shows the billing determinant variances for 2015 over 2014. Increase in customers (assuming the average usage per customer) explains approximately half the variance for the Residential and GS<50 kW customers. Additionally, the CDD for 2015 was approximately 33% higher than 2014. As discussed above, CDD are statistically significant in explaining kWh/kW movement as it indicates the likelihood of greater usage of air conditioning by customers, especially in the Residential and GS<50 kW classes. The increase in kW for the GS>50 kW can be explained by the increase in customers.

2015 Actual vs 2016 Bridge Year

Table 3.3-G – 2016 Bridge vs. 2015 Actual

Distribution Revenue	2015 Actual	2016 Bridge	Variance
Residential	$ 9,427,645	$ 9,414,279	$ (13,366)
General Service Less than 50 kW	$ 1,576,103	$ 1,558,521	$ (17,582)
General Service 50 to 4,999 kW	$ 5,036,729	$ 4,732,386	$ (304,342)
Street Light	$ 145,183	$ 153,457	$ 8,273
Sentinel Lighting	$ 58,893	$ 51,899	$ (6,994)
Unmetered Scattered Load	$ 77,396	$ 77,010	$ (386)
Embedded Distributor	$ 161,910	$ 153,142	$ (8,767)
Total	$ 16,483,859	$ 16,140,694	$ (343,165)

The GS>50KW customer class anticipates a decrease in distribution revenues of ($304,342) in 2016 over 2015. The main driver for this decrease is the expected decrease in demand which results in lower revenues of ($330,030). The expected decrease in revenue is offset by an expected increase of $23,652 resulting from customer growth.

The variances in the other rate classes fall below the $100,000 materiality threshold.

Table 3.3-H – Billing Determinants – 2016 Bridge vs. 2015 Actual

	Customers/Connections			kWh		kW		Volumetric Variance
	2015 Actual	2016 Bridge	Variance	2015 Actual	2016 Bridge	2015 Actual	2016 Bridge	
Residential	35,744	36,086	343	287,594,336	279,510,225	-		(8,084,111)
General Service Less than 50 kW	2,784	2,812	28	100,078,635	96,560,220	-		(3,518,415)
General Service 50 to 4,999 kW	440	444	5	-		1,400,639	1,263,675	(136,964)
Street Light	10,632	10,632	-	-		22,527	22,657	130
Sentinel Lighting	619	591	(28)	-		1,359	1,194	(165)
Unmetered Scattered Load	431	428	(3)	1,516,114	1,459,580	-		(56,534)
Embedded Distributor	3	2	(1)	-		142,203	132,260	(9,943)
Total	50,651	50,995	344	389,189,085	377,530,025	1,566,728	1,419,786	(11,806,002)

In the above table BPI is showing large decreases for 2016 in the Residential and GS<50 kW classes despite an increase in customers. A significant portion of the variance is attributable to expected CDM savings for 2016.

2016 Bridge Year vs 2017 Test Year

Table 3.3-I compares revenues for the 2016 Bridge year with the 2017 test year at current rates and table 3.3-J shows the comparison of the 2016 Bridge year to the 2017 Test year based on proposed rates. You can see the impact of volume changes in table 3.3-I since the rates are held constant. The residential class is showing the largest impact from volumes of $193,461. The remainder of the variances shown in table 3.3-J are due to increasing rates.

Table 3.3-I – 2017 Test (at current rates) vs. 2016 Bridge

Distribution Revenue	2016 Bridge	2017 Test	Variance
Residential	$ 9,414,279	$ 9,607,740	$ 193,461
General Service Less than 50 kW	$ 1,558,521	$ 1,590,044	$ 31,523
General Service 50 to 4,999 kW	$ 4,732,386	$ 4,684,378	$ (48,009)
Street Light	$ 153,457	$ 118,415	$ (35,042)
Sentinel Lighting	$ 51,899	$ 51,959	$ 60
Unmetered Scattered Load	$ 77,010	$ 76,184	$ (826)
Embedded Distributor	$ 153,142	$ 161,080	$ 7,938
Total	$ 16,140,694	$ 16,289,800	$ 149,106

Table 3.3-J – 2017 Test (at proposed rates) vs. 2016 Bridge

Distribution Revenue	2016 Bridge	2017 Test	Variance
Residential	$ 9,414,279	$ 11,153,627	$ 1,739,348
General Service Less than 50 kW	$ 1,558,521	$ 1,845,883	$ 287,361
General Service 50 to 4,999 kW	$ 4,732,386	$ 5,282,238	$ 549,852
Street Light	$ 153,457	$ 228,441	$ 74,984
Sentinel Lighting	$ 51,899	$ 60,320	$ 8,420
Unmetered Scattered Load	$ 77,010	$ 88,442	$ 11,432
Embedded Distributor	$ 153,142	$ 251,881	$ 98,739
Total	$ 16,140,694	$ 18,910,832	$ 2,770,138

Table 3.3-K – Billing Determinants – 2017 Test vs. 2016 Bridge

	Customers/Connections			kWh		kW		Volumetric Variance
	2016 Bridge	2017 Test	Variance	2016 Bridge	2017 Test	2016 Bridge	2017 Test	
Residential	36,086	36,433	346	279,510,225	291,567,897	-		12,057,672
General Service Less than 50 kW	2,812	2,840	28	96,560,220	99,837,652	-		3,277,432
General Service 50 to 4,999 kW	444	449	5	-		1,263,675	1,241,682	(21,993)
Street Light	10,632	6,351	(4,281)	-		22,657	22,796	139
Sentinel Lighting	591	597	6	-		1,194	1,181	(12)
Unmetered Scattered Load	428	425	(3)	1,459,580	1,405,154	-		(54,426)
Embedded Distributor	2	2	-	-		132,260	139,437	7,177
Total	50,995	47,097	(3,898)	377,530,025	392,810,702	1,419,786	1,405,097	15,265,988

The decline in streetlight connections is the result of recent discussions with the City of Brantford where it was determined the number of streetlight connections was incorrect. BPI and the City of Brantford have agreed billings beginning in 2017 will reflect the updated number of connections. There is no effect on kW related to this adjustment. With respect to the volumetric variance, an increase in customers as well as changes in the regression variables are contributing to the increase.

3.4 Other Revenue

3.4.1 Variance Analysis of Other Revenue

Table 3.4-A below is Appendix 2-H-Other Operating Revenue.

Table 3.4-A – Appendix 2-H- Other Operating Revenue

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2013 Actual	Actual Year[2]	Actual Year[2]	Actual Year	Bridge Year[2]	Test Year
		2013	2014	2014	2015	2016	2017
	Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
4235	Specific Service Charges	-$ 441,756	-$ 539,109	-$ 539,109	-$ 650,019	-$ 496,272	-$ 506,195
4225	Late Payment Charges	-$ 152,695	-$ 207,146	-$ 207,146	-$ 219,014	-$ 226,236	-$ 235,599
4080	SSS Revenue	-$ 106,572	-$ 108,547	-$ 108,547	-$ 111,559	-$ 110,820	-$ 111,730
4082	Retail Services Revenues	-$ 36,888	-$ 46,483	-$ 46,483	-$ 44,303	-$ 41,369	-$ 41,376
4084	Service Tax Requests	-$ 17,103	-$ 16,257	-$ 16,257	-$ 15,882	-$ 9,506	-$ 9,589
4090	Electric Services Incidental to Energy Sales	$ -	$ -	$ -	$ -	$ -	$ -
4205	Interdepartmental Rents	$ -	$ -	$ -	$ -	$ -	$ -
4210	Rent from Electic Property	-$ 107,996	-$ 108,645	-$ 108,645	-$ 109,740	-$ 99,527	-$ 101,517
4215	Other Utility Operating Income	$ -	$ -	$ -	$ -	$ -	$ -
4220	Other Electric Revenues	$ -	$ 929	$ 929	$ -	$ -	$ -
4240	Provision for Rate Refunds	$ -	$ -	$ -	$ -	$ -	$ -
4245	Government Assistance Directly Credited to Income	$ -	$ -	$ -	$ -	$ -	$ -
4305	Regulatory Debits	$ -	$ -	$ -	$ -	$ -	$ -
4310	Regulatory Credits	$ -	$ -	$ -	$ -	$ -	$ -
4315	Revenues from Electric Plant Leased to Others	$ -	$ -	$ -	$ -	$ -	$ -
4320	Expenses of Electric Plant Leased to Others	$ -	$ -	$ -	$ -	$ -	$ -
4325	Revenues from Merchandise, Jobbing, Etc.	$ -	$ -	$ -	$ -	$ -	$ -
4330	Costs and Expenses of Merchandising, Jobbing, Etc	$ -	$ -	$ -	$ -	$ -	$ -
4335	Profits and Losses from Financial Instrument Hedges	$ -	$ -		$ -	$ -	$ -
4340	Profits and Losses from Financial Instrument Investments	$ -	$ -	$ -	$ -	$ -	$ -
4345	Gains from Disposition of Future Use Utility Plant	$ -	$ -	$ -	$ -	$ -	$ -
4350	Losses from Disposition of Future Use Utility Plant	$ -	$ -	$ -	$ -	$ -	$ -
4355	Gain on Disposition of Utility and Other Property	-$ 12,687	-$ 13,477	-$ 13,477	-$ 39,464	-$ 15,000	-$ 15,000
4360	Loss on Disposition of Utility and Other Property	$ -	$ -	$ -	$ -	$ -	$ -
4365	Gains from Disposition of Allowances for Emission	$ -	$ -	$ -	$ -	$ -	$ -
4370	Losses from Disposition of Allowances for Emission	$ -	$ -	$ -	$ -	$ -	$ -
4375	Revenues from Non-Utility Operations	-$ 2,985,434	-$ 3,493,082	-$ 3,493,082	-$ 2,947,370	-$ 1,995,482	-$ 2,620,669
4380	Expenses from Non-Utility Operations	$ 3,097,191	$ 3,618,390	$ 3,618,390	$ 2,990,804	$ 2,283,608	$ 2,496,589
4385	Expenses of Non-Utility Operations	$ -	$ -	$ -	$ -	$ -	$ -
4390	Miscellaneous Non-Operating Income	-$ 7,493	-$ 6,511	-$ 6,511	-$ 56,029	-$ 15,000	-$ 15,300
4395	Rate-Payer Benefit Including Interest	$ -	$ -	$ -	$ -	$ -	$ -
4398	Foreign Exchange Gains and Losses, Including Amortization	$ -	$ -	$ -	$ -	$ -	$ -
4405	Interest and Dividend Income	-$ 354,063	-$ 249,186	-$ 249,186	-$ 203,279	-$ 212,495	-$ 174,617
4415	Equity in Earnings of Subsidiary Companies	$ -	$ -		$ -	$ -	$ -
Specific Service Charges		-$ 441,756	-$ 539,109	-$ 539,109	-$ 650,019	-$ 496,272	-$ 506,195
Late Payment Charges		-$ 152,695	-$ 207,146	-$ 207,146	-$ 219,014	-$ 226,236	-$ 235,599
Other Operating Revenues		-$ 268,559	-$ 279,002	-$ 279,002	-$ 281,484	-$ 261,222	-$ 264,212
Other Income or Deductions		-$ 262,486	-$ 143,866	-$ 143,866	-$ 255,338	$ 45,631	-$ 328,997
Total		-$ 1,125,496	-$ 1,169,123	-$ 1,169,123	-$ 1,405,856	-$ 938,099	-$ 1,335,003

Account 4080 -SSS Revenue

	2013 Actual	Actual Year[2]	Actual Year[2]	Actual Year	Bridge Year[2]	Test Year
	2013	2014	2014	2015	2016	2017
Reporting Basis	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
RESIDENTIAL REV - SSS	-$ 96,602	-$ 98,395	-$ 98,395	-$ 99,745	-$ 100,530	-$ 101,410
GEN SERV <50KW REV - SSS	-$ 7,556	-$ 7,684	-$ 7,684	-$ 7,732	-$ 7,770	-$ 7,800
G. S. UNMETERED REV SSS	-$ 1,316	-$ 1,299	-$ 1,299	-$ 1,293	-$ 1,320	-$ 1,320
GEN SERV >50KW REV - SSS	-$ 978	-$ 1,050	-$ 1,050	-$ 1,065	-$ 1,080	-$ 1,080
STREET LIGHT REV - SSS	-$ 3	-$ 3	-$ 3	-$ 3	$ -	$ -
SENTINEL LIGHT REV - SSS	-$ 111	-$ 111	-$ 111	-$ 1,717	-$ 120	-$ 120
GEN SERV>5000KW REV - SSS	-$ 7	-$ 7	-$ 7	-$ 4	$ -	$ -
Total	-$ 106,572	-$ 108,549	-$ 108,549	-$ 111,559	-$ 110,820	-$ 111,730

Account 4082 -Retail Services Revenue

	2013 Actual	Actual Year[2]	Actual Year[2]	Actual Year	Bridge Year[2]	Test Year
	2013	2014	2014	2015	2016	2017
Reporting Basis	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
RSVA ADJUSTMENT	$ 238	-$ 12,763	-$ 12,763	-$ 12,398	-$ 8,801	-$ 8,808
RTLR(9)-STANDARD CHARGE	$ -	$ -	$ -	-$ 100	$ -	$ -
RTLR(9)-DCBR BILL READY CHARGE	-$ 12,026	-$ 10,714	-$ 10,714	-$ 9,932	-$ 10,236	-$ 10,236
RTLR(9)-MONTHLY FIXED CHARGE	-$ 4,260	-$ 4,109	-$ 4,109	-$ 4,332	-$ 4,320	-$ 4,320
RTLR(9)-MONTHLY VARIABLE CHRG	-$ 20,840	-$ 18,898	-$ 18,898	-$ 17,542	-$ 18,012	-$ 18,012
Total	-$ 36,888	-$ 46,483	-$ 46,483	-$ 44,303	-$ 41,369	-$ 41,376

Account 4084 -Service Tax Requests

	2013 Actual	Actual Year[2]	Actual Year[2]	Actual Year	Bridge Year[2]	Test Year
	2013	2014	2014	2015	2016	2017
Reporting Basis	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
RSVA ADJUSTMENT	-$ 16,105	-$ 15,390	-$ 15,390	-$ 15,147	-$ 9,098	-$ 9,181
RTLR(9)-ACCEPT FEE	-$ 571	-$ 511	-$ 511	-$ 443	-$ 252	-$ 252
RTLR(9)-REQUEST FEE	-$ 427	-$ 355	-$ 355	-$ 293	-$ 156	-$ 156
Total	-$ 17,103	-$ 16,257	-$ 16,257	-$ 15,882	-$ 9,506	-$ 9,589

Account 4220 -Other Electric Revenue

	2013 Actual	Actual Year[2]	Actual Year[2]	Actual Year	Bridge Year[2]	Test Year
	2013	2014	2014	2015	2016	2017
Reporting Basis	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
OCCUPANCY/COLLECTION REVENUE	$ -	$ 929	$ 929	$ -	$ -	$ -
Total	$ -	$ 929	$ 929	$ -	$ -	$ -

Account 4405 - Interest and Dividend Income

	2013 Actual	Actual Year[2]	Actual Year[2]	Actual Year	Bridge Year[2]	Test Year
	2013	2014	2014	2015	2016	2017
Reporting Basis	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
INTEREST ON INCOME TAXES	-$ 6,701	$ -	$ -			
INTEREST ON A/R	-$ 4,298	$ 497	$ 497	-$ 7,027	-$ 7,000	-$ 7,140
INVESTMENT INCOME	-$ 199,521	-$ 173,887	-$ 173,887	-$ 126,219	-$ 149,337	-$ 125,846
REG ASSET INTEREST REVENUE	-$ 143,543	-$ 75,796	-$ 75,796	-$ 70,033	-$ 56,158	-$ 41,631
Total	-$ 354,063	-$ 249,186	-$ 249,186	-$ 203,279	-$ 212,495	-$ 174,617

Account 4210 - Rent from Electric Property

	2013 Actual	Actual Year[2]	Actual Year[2]	Actual Year	Bridge Year[2]	Test Year
	2013	2014	2014	2015	2016	2017
Reporting Basis	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Pole Rental Revenues Affiliates	-$ 45,125	-$ 45,773	-$ 45,773	-$ 46,399	-$ 47,624	-$ 48,576
Pole Rental Revenues Other	-$ 62,872	-$ 62,872	-$ 62,872	-$ 63,341	-$ 51,903	-$ 52,941
Total	-$ 107,996	-$ 108,645	-$ 108,645	-$ 109,740	-$ 99,527	-$ 101,517

Account 4225 - Late Payment Charges

	2013 Actual	Actual Year[2]	Actual Year[2]	Actual Year	Bridge Year[2]	Test Year
	2013	2014	2014	2015	2016	2017
Reporting Basis	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Late Payment Charges	-$ 152,695	$ 207,146	$ 207,146	-$ 219,014	-$ 226,236	-$ 235,599
1 **Total**	-$ 152,695	$ 207,146	$ 207,146	-$ 219,014	-$ 226,236	-$ 235,599

Account 4235 - Miscellaneous Service Revenues

	2013 Actual	Actual Year[2]	Actual Year[2]	Actual Year	Bridge Year[2]	Test Year
	2013	2014	2014	2015	2016	2017
Reporting Basis	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
ARREARS CERTIFICATE REVENUE	-$ 1,340	-$ 435	-$ 435	-$ 126	-$ 135	-$ 135
CREDIT CHECK FEE	-$ 2,865	-$ 2,870	-$ 2,870	-$ 3,240	-$ 3,583	-$ 3,655
RETURNED CHEQUE CHARGE	-$ 5,715	-$ 5,795	-$ 5,795	-$ 5,026	-$ 5,891	-$ 6,009
NEW A/C SET UP FEE	-$ 158,745	-$ 156,060	-$ 156,060	-$ 163,072	-$ 160,222	-$ 163,426
FIELD COLLECTION CHARGE	-$ 244,886	-$ 333,900	-$ 333,900	-$ 440,550	-$ 289,393	-$ 295,181
RECONNECTION CHARGE	-$ 12,555	-$ 17,095	-$ 17,095	-$ 15,743	-$ 15,984	-$ 16,304
ELECTRIC RECONNECT AFTER HOURS	-$ 8,325	-$ 14,245	-$ 14,245	-$ 12,580	-$ 12,077	-$ 12,319
RECONNECT AT POLE	-$ 925	$ -	$ -			
TEMP HYDRO SERVICE CHARGE	-$ 2,500	-$ 3,000	-$ 3,000	-$ 3,500	-$ 3,121	-$ 3,183
TEMP U/G SERVICE CHARGE	$ -	-$ 600	-$ 600	-$ 300		
ENERGY SALES	-$ 3,901	-$ 5,109	-$ 5,109	-$ 5,822	-$ 5,866	-$ 5,983
OTHER	$ -	$ -	$ -	-$ 60	$ -	$ -
Total	-$ 441,756	-$ 539,109	-$ 539,109	-$ 650,019	-$ 496,272	-$ 506,195

Account 4355-Gain on Disposition of Utility and Other Property

	2013 Actual	Actual Year[2]	Actual Year[2]	Actual Year	Bridge Year[2]	Test Year
	2013	2014	2014	2015	2016	2017
Reporting Basis	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Gain on Disposition of Utility and Other Property	-$ 12,687	-$ 13,477	-$ 13,477	-$ 39,464	-$ 15,000	-$ 15,000
Total	-$ 12,687	-$ 13,477	-$ 13,477	-$ 39,464	-$ 15,000	-$ 15,000

Account 4375- Revenue from Non-Utility Operations

	2013 Actual	Actual Year[2]	Actual Year[2]	Actual Year	Bridge Year[2]	Test Year
	2013	2014	2014	2015	2016	2017
Reporting Basis	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Affiliate Allocations	$ -	-$ 85,811	-$ 85,811	-$ 410,229	-$ 384,269	-$ 302,417
New Building Rental Income- Non-Utility					-$ 30,981	-$ 124,080
CDM Bonus	-$ 2,985,434	-$ 3,407,271	-$ 3,407,271	-$ 2,537,141	-$ 1,580,232	-$ 1,604,367
Adjustment to offset BEC Management Fees in 4380						-$ 104,532
Adjustment to offset New Building Operational Cost-Non-Utility in 4380						-$ 485,273
Total	-$ 2,985,434	-$ 3,493,082	-$ 3,493,082	-$ 2,947,370	-$ 1,995,482	-$ 2,620,669

Account 4380-Expenses from Non-Utility Operations

	2013 Actual	Actual Year[2]	Actual Year[2]	Actual Year	Bridge Year[2]	Test Year
	2013	2014	2014	2015	2016	2017
Reporting Basis	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
CDM Bonus	$ 2,978,691	$ 3,407,271	$ 3,407,271	$ 2,283,588	$ 1,580,232	$ 1,604,367
Bad Debt Expense	$ -	$ -	$ -	$ 136,261	$ 96,810	$ -
New Building Operational Cost- Non-Utility	$ -	$ -	$ -	$ -	$ 118,939	$ 485,273
Affiliate Allocations	$ -	$ 85,811	$ 85,811	$ 410,229	$ 384,269	$ 302,417
BEC Management Fees	$ 118,500	$ 125,308	$ 125,308	$ 160,727	$ 103,357	$ 104,532
Total	$ 3,097,191	$ 3,618,390	$ 3,618,390	$ 2,990,805	$ 2,283,608	$ 2,496,589

Account 4390-Miscellaneous Non-Operating Income

	2013 Actual	Actual Year[2]	Actual Year[2]	Actual Year	Bridge Year[2]	Test Year
	2013	2014	2014	2015	2016	2017
Reporting Basis	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Sales of Scrap	-$ 7,493	-$ 6,511	-$ 6,511	-$ 15,410	-$ 15,000	-$ 15,300
Other	$ -	$ -	$ -	-$ 40,619	$ -	$ -
Total	-$ 7,493	-$ 6,511	-$ 6,511	-$ 56,029	-$ 15,000	-$ 15,300

Table 3.4-B below provides the variances on the Other Revenue included in BPI’s Operating Revenue.

Table 3.4-B – Total Other Revenue

USoA #	USoA Description	2013 Actual 2013	Actual Year² 2014	Variance 2014 vs 2013	Actual Year² 2014	Variance 2014 IFRS vs CGAAP	Actual Year 2015	Variance 2015 vs 2014	Bridge Year² 2016	Variance 2016 Bridge vs 2015	Test Year 2017	Variance 2017 Test vs 2016 Bridge
	Reporting Basis	CGAAP	CGAAP		MIFRS		MIFRS		MIFRS		MIFRS	
4235	Specific Service Charges	(441,756)	(539,109)	(97,353)	(539,109)	-	(650,019)	(110,910)	(496,272)	153,747	(506,195)	(9,923)
4225	Late Payment Charges	(152,695)	(207,146)	(54,452)	(207,146)	-	(219,014)	(11,868)	(226,236)	(7,222)	(235,599)	(9,363)
4080	SSS Revenue	(106,572)	(108,547)		(108,547)		(111,559)		(110,820)		(111,730)	
4082	Retail Services Revenues	(36,888)	(46,483)	(9,595)	(46,483)	-	(44,303)	2,179	(41,369)	2,934	(41,376)	(7)
4084	Service Tax Requests	(17,103)	(16,257)	846	(16,257)	-	(15,882)	374	(9,506)	6,376	(9,589)	(83)
4090	Electric Services Incidental to Energy Sales	-	-	-	-	-	-	-	-	-	-	-
4205	Interdepartmental Rents	-	-	-	-	-	-	-	-	-	-	-
4210	Rent from Electic Property	(107,996)	(108,645)	(648)	(108,645)	-	(109,740)	(1,095)	(99,527)	10,213	(101,517)	(1,990)
4215	Other Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
4220	Other Electric Revenues	-	929	929	929	-	-	(929)	-	-	-	-
4240	Provision for Rate Refunds	-	-	-	-	-	-	-	-	-	-	-
4245	Government Assistance Directly Credited to Income	-	-	-	-	-	-	-	-	-	-	-
4305	Regulatory Debits	-	-	-	-	-	-	-	-	-	-	-
4310	Regulatory Credits	-	-	-	-	-	-	-	-	-	-	-
4315	Revenues from Electric Plant Leased to Others	-	-	-	-	-	-	-	-	-	-	-
4320	Expenses of Electric Plant Leased to Others	-	-	-	-	-	-	-	-	-	-	-
4325	Revenues from Merchandise, Jobbing, Etc.	-	-	-	-	-	-	-	-	-	-	-
4330	Costs and Expenses of Merchandising, Jobbing, Etc	-	-	-	-	-	-	-	-	-	-	-
4335	Profits and Losses from Financial Instrument Hedges	-	-	-	-	-	-	-	-	-	-	-
4340	Profits and Losses from Financial Instrument Investments	-	-	-	-	-	-	-	-	-	-	-
4345	Gains from Disposition of Future Use Utility Plant	-	-	-	-	-	-	-	-	-	-	-
4350	Losses from Disposition of Future Use Utility Plant	-	-	-	-	-	-	-	-	-	-	-
4355	Gain on Disposition of Utility and Other Property	(12,687)	(13,477)	(790)	(13,477)	-	(39,464)	(25,987)	(15,000)	24,464	(15,000)	-
4360	Loss on Disposition of Utility and Other Property	-	-	-	-	-	-	-	-	-	-	-
4365	Gains from Disposition of Allowances for Emission	-	-	-	-	-	-	-	-	-	-	-
4370	Losses from Disposition of Allowances for Emission	-	-	-	-	-	-	-	-	-	-	-
4375	Revenues from Non-Utility Operations	(2,985,434)	(3,493,082)	(507,648)	(3,493,082)	-	(2,947,370)	545,712	(1,995,482)	951,888	(2,620,669)	(625,187)
4380	Expenses from Non-Utility Operations	3,097,191	3,618,390	521,199	3,618,390	-	2,990,804	(627,587)	2,283,608	(707,196)	2,496,589	212,981
4385	Expenses of Non-Utility Operations	-	-	-	-	-	-	-	-	-	-	-
4390	Miscellaneous Non-Operating Income	(7,493)	(6,511)	982	(6,511)	-	(56,029)	(49,518)	(15,000)	41,029	(15,300)	(300)
4395	Rate-Payer Benefit Including Interest	-	-	-	-	-	-	-	-	-	-	-
4398	Foreign Exchange Gains and Losses, Including Amortization	-	-	-	-	-	-	-	-	-	-	-
4405	Interest and Dividend Income	(354,063)	(249,186)	104,877	(249,186)	-	(203,279)	45,907	(212,495)	(9,216)	(174,617)	37,878
4415	Equity in Earnings of Subsidiary Companies	-	-	-	-	-	-	-	-	-	-	-
Specific Service Charges		(441,756)	(539,109)		(539,109)		(650,019)		(496,272)		(506,195)	
Late Payment Charges		(152,695)	(207,146)		(207,146)		(219,014)		(226,236)		(235,599)	
Other Operating Revenues		(268,559)	(279,002)		(279,002)		(281,484)		(261,222)		(264,212)	
Other Income or Deductions		(262,486)	(143,866)		(143,866)		(255,338)		45,631		(328,997)	
Total		(1,125,496)	(1,169,123)	-	(1,169,123)		(1,405,856)		(938,099)		(1,335,003)	

Each variance above the materiality threshold of $100,000 as calculated in Exhibit 1 is highlighted in gray and an explanation for the variance is provided below.

Table 3.4-C - Variances in Other Revenue - 2013 Actual vs. 2014 Actual

USoA #	USoA Description	2013 Actual 2013	Actual Year² 2014	Variance 2014 vs 2013
	Reporting Basis	CGAAP	CGAAP	
4375	Revenues from Non-Utility Operations	(2,985,434)	(3,493,082)	(507,648)
4380	Expenses from Non-Utility Operations	3,097,191	3,618,390	521,199
4405	Interest and Dividend Income	(354,063)	(249,186)	104,877

Revenues from non-utility operations increased by $507,648 and the offsetting expenses for non-utility operations increased by $521,199, for a net decrease of $13,551. This decrease is offset by Revenues from the IESO (formally the OPA) sanctioned programs area that were recorded in USoA Account 4375. In 2014, Conservation and Demand Management (CDM) programs had an increase of funds being spent.

Interest and dividend income decreased in 2014 by $104,877 primarily due to the regulatory asset interest revenue decreasing. This decrease was attributable to the smart meters being transferred from regulatory assets to property, plant and equipment in 2014. In 2013, they were included in regulatory assets, and therefore they were generating interest income in 2013.

Table 3.4-D - Variances in Other Revenue - 2014 Actual vs. 2015 Actual

USoA #	USoA Description	Actual Year[2]	Actual Year	Variance 2015 vs 2014
		2014	2015	
	Reporting Basis	MIFRS	MIFRS	
4235	Specific Service Charges	(539,109)	(650,019)	(110,910)
4375	Revenues from Non-Utility Operations	(3,493,082)	(2,947,370)	545,712
4380	Expenses from Non-Utility Operations	3,618,390	2,990,804	(627,587)

Specific Service Charges increased by $110,910 in 2015 due to field connection charges. This is due to an increase in disconnection notices in 2015.

Revenues from non-utility operations decreased by $545,712 and the offsetting expenses for non-utility operations decreased by $627,587, for a net decrease of $81,875. This decrease is offset by Revenues from the IESO (formally the OPA) sanctioned programs area that were recorded in USoA Account 4375. In 2015, Conservation and Demand Management (CDM) programs had a decrease of funds being spent.

Table 3.4-E - Variances in Other Revenue - 2015 Actual vs. 2016 Bridge Year

USoA #	USoA Description	Actual Year	Bridge Year[2]	Variance 2016 Bridge vs 2015
		2015	2016	
	Reporting Basis	MIFRS	MIFRS	
4235	Specific Service Charges	(650,019)	(496,272)	153,747
4375	Revenues from Non-Utility Operations	(2,947,370)	(1,995,482)	951,888
4380	Expenses from Non-Utility Operations	2,990,804	2,283,608	(707,196)

Specific Service Charges decreased by $153,747 in 2015 due to field connection charges. BPI expects field connection charges to decrease in 2016 because there is a new program (Ontario Electricity Support Program (“OESP”)) being put in place to assist low income customers which was being implemented in 2016.

Revenues from non-utility operations decreased by $951,888 and the offsetting expenses for non-utility operations decreased by $707,196, for a net increase of $244,692. This decrease is offset by Revenues from the IESO (formally the OPA) sanctioned programs area that were recorded in USoA Account 4375. In 2016, it is projected that Conservation and Demand Management (CDM) programs will decrease funds being spent.

Table 3.4-F - Variances in Other Revenue - 2016 Bridge Year vs. 2017 Test Year

USoA #	USoA Description	Bridge Year[2]	Test Year	Variance 2017 Test vs 2016 Bridge
		2016	2017	
	Reporting Basis	MIFRS	MIFRS	
4375	Revenues from Non-Utility Operations	(1,995,482)	(2,620,669)	(625,187)
4380	Expenses from Non-Utility Operations	2,283,608	2,496,589	212,981

Revenues from non-utility operations increased by $625,187 from 2016 to 2017. This is primarily due to $485,273 in New Building Operational Costs-Non Utility and $104,532 for BEC Management Fees. BPI has included these amounts in 4375 in order to offset 4380 so that these amounts are not being included in BPI’s revenue requirement. The offsetting expenses for non-utility operations increased by $212,981, primarily attributable to the increase in new building operational costs- non utility. In 2016, these costs are only budgeted for 3 months, as the projected closing date for the new building is October 2016. In 2017, there is a full year being budgeted for which causes the increase in costs.

BPI is not proposing any new specific service charges, or changes to rates of existing specific service charges therefore this section is not applicable to BPI.

The following table, table 3.4-G, outlines BPI’s Revenue and Expenses related to affiliate transactions, shared services and corporate cost allocations. For a complete description of the nature of the service provided to affiliated entities, refer to Exhibit 4, Section 2.4.3.2 Shared Services and Corporate Allocation.

Table 3.4-G – Revenue from Affiliates

Account 4375- Revenue from Non-Utility Operations					
Transaction	2013 Actual	2014 Actual	2015 Actual	2016 Bridge Year	2017 Test Year
Executive Services	-	(77,348)	(241,188)	(169,213)	(100,213)
Financial Services	-	(8,463)	(169,041)	(215,056)	(202,204)
Total 4375	**-**	**(85,811)**	**(410,229)**	**(384,269)**	**(302,417)**

Account 4380-Expenses from Non-Utility Operations					
Transaction	2013 Actual	2014 Actual	2015 Actual	2016 Bridge Year	2017 Test Year
Executive Services	-	77,348	241,188	169,213	100,213
Financial Services	-	8,463	169,041	215,056	202,204
Total 4375	**-**	**85,811**	**410,229**	**384,269**	**302,417**

List of Attachments

Attachment 3-1 - Monthly Data used in Regression Model

Attachment 3-2 – Appendix 2-I- Load Forecast CDM Adjustment Work Form

Attachment 3-A

Monthly Data used in Regression Model

	Purchased	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	apr	may	Negative Impact Variable	Predicted Purchases
Jan-06	88,782,670	551.80	-	134.3	31	0	0	17,090	84,266,604
Feb-06	82,652,726	604.30	-	134.5	28	0	0	34,181	79,797,740
Mar-06	87,287,263	516.60	-	134.8	31	0	0	51,271	83,799,016
Apr-06	76,130,011	293.30	-	135.1	30	1	0	68,362	74,552,829
May-06	81,448,519	136.90	26.00	135.4	31	0	1	85,452	78,129,440
Jun-06	86,666,222	19.50	73.60	135.6	30	0	0	102,543	83,236,456
Jul-06	96,205,464	-	167.30	135.9	31	0	0	119,633	96,515,818
Aug-06	91,965,539	4.20	101.60	136.2	31	0	0	136,723	88,403,697
Sep-06	78,075,371	80.90	12.90	136.5	30	0	0	153,814	76,803,166
Oct-06	81,808,423	288.30	1.10	136.8	31	0	0	170,904	80,581,291
Nov-06	83,973,333	382.20	-	137.0	30	0	0	187,995	80,246,865
Dec-06	87,799,550	500.50	-	**137.3**	31	0	0	205,085	84,041,883
Jan-07	92,807,711	647.10	-	137.6	31	0	0	216,606	86,501,059
Feb-07	87,369,732	740.10	-	137.8	28	0	0	228,127	82,694,265
Mar-07	89,810,436	546.70	-	138.0	31	0	0	239,648	84,956,949
Apr-07	80,121,095	356.40	-	138.2	30	1	0	251,169	76,249,540
May-07	80,608,589	136.40	22.40	138.5	31	0	1	262,690	78,327,326
Jun-07	89,502,716	16.50	99.20	138.7	30	0	0	274,212	87,051,153
Jul-07	89,014,824	3.20	106.10	138.9	31	0	0	285,733	89,546,070
Aug-07	94,084,356	5.20	141.00	139.2	31	0	0	297,254	94,007,648
Sep-07	82,681,855	36.90	47.50	139.4	30	0	0	308,775	81,062,957
Oct-07	83,253,588	137.70	19.80	139.6	31	0	0	320,296	81,093,668
Nov-07	85,256,947	462.50	-	139.8	30	0	0	331,817	82,202,412
Dec-07	88,503,147	630.70	-	**140.1**	31	0	0	343,338	86,813,121
Jan-08	91,586,649	623.50	-	140.0	31	0	0	359,620	86,611,450
Feb-08	87,242,239	674.70	-	139.9	**29**	0	0	375,902	83,778,064
Mar-08	88,370,234	610.20	-	139.8	31	0	0	392,184	86,226,258
Apr-08	79,320,755	253.90	-	139.7	30	1	0	408,466	74,657,352
May-08	77,025,833	193.50	2.50	139.5	31	0	1	424,748	76,724,799
Jun-08	84,090,015	22.70	71.50	139.4	30	0	0	441,030	83,498,881
Jul-08	91,739,839	1.00	111.00	139.3	31	0	0	457,312	89,807,126
Aug-08	85,561,377	12.70	64.00	139.2	31	0	0	473,595	84,023,152
Sep-08	81,335,600	59.00	26.70	139.1	30	0	0	489,877	78,228,186
Oct-08	79,888,372	278.60	-	139.0	31	0	0	506,159	80,198,509
Nov-08	81,455,826	451.60	-	138.9	30	0	0	522,441	81,160,664
Dec-08	85,806,592	654.60	-	**138.8**	31	0	0	538,723	86,206,111
Jan-09	90,223,487	830.20	-	138.4	31	0	0	578,878	88,841,075
Feb-09	77,995,973	606.40	-	138.1	28	0	0	619,033	79,532,303
Mar-09	80,993,879	533.80	-	137.7	31	0	0	659,189	83,478,594
Apr-09	72,518,420	305.80	1.20	137.3	30	1	0	699,344	74,002,927
May-09	72,158,813	158.80	6.90	136.9	31	0	1	739,499	74,886,077
Jun-09	76,645,030	49.30	34.20	136.6	30	0	0	779,654	77,275,161
Jul-09	77,751,228	6.20	43.70	136.2	31	0	0	819,810	79,307,763
Aug-09	84,421,103	9.80	91.00	135.8	31	0	0	859,965	85,051,562
Sep-09	74,688,913	55.20	20.90	135.5	30	0	0	900,120	74,967,177
Oct-09	75,437,058	287.80	-	135.1	31	0	0	940,275	77,716,310
Nov-09	75,196,070	361.20	-	134.7	30	0	0	980,431	76,881,527
Dec-09	82,800,231	631.30	-	**134.4**	31	0	0	1,020,586	82,867,572
Jan-10	85,740,318	720.00	-	134.7	31	0	0	1,020,471	84,458,457
Feb-10	76,200,453	598.30	-	135.1	28	0	0	1,020,357	77,208,958
Mar-10	78,025,071	422.80	-	135.5	31	0	0	1,020,242	79,848,431
Apr-10	69,790,834	225.10	-	135.8	30	1	0	1,020,128	71,102,616
May-10	76,066,070	107.90	45.70	136.2	31	0	1	1,020,013	77,873,043
Jun-10	79,225,718	21.70	58.70	136.6	30	0	0	1,019,899	79,234,557
Jul-10	89,977,040	1.80	164.90	136.9	31	0	0	1,019,784	94,155,087
Aug-10	88,856,918	2.10	138.80	137.3	31	0	0	1,019,670	91,024,609
Sep-10	74,349,622	78.10	31.50	137.7	30	0	0	1,019,555	77,161,327
Oct-10	73,264,038	241.60	-	138.1	31	0	0	1,019,441	77,829,602
Nov-10	76,397,905	405.30	-	138.4	30	0	0	1,019,326	78,860,326
Dec-10	82,865,127	676.20	-	**138.8**	31	0	0	1,019,212	85,242,304
Jan-11	86,054,286	775.30	-	139.1	31	0	0	1,059,911	86,867,584
Feb-11	76,331,650	654.20	-	139.4	28	0	0	1,100,610	79,491,435
Mar-11	80,293,454	572.80	-	139.7	31	0	0	1,141,309	83,539,392

Apr-11	71,266,778	332.30	-	140.0	30	1	0	1,182,009	73,954,043
May-11	72,652,306	134.10	13.00	140.3	31	0	1	1,222,708	75,157,653
Jun-11	76,886,232	19.00	52.20	140.6	30	0	0	1,263,407	79,192,556
Jul-11	93,432,708	-	198.50	140.9	31	0	0	1,304,107	99,018,435
Aug-11	86,792,643	-	122.20	141.2	31	0	0	1,344,806	89,451,687
Sep-11	75,561,451	48.20	39.70	141.5	30	0	0	1,385,505	78,103,930
Oct-11	73,210,552	235.50	2.40	141.8	31	0	0	1,426,204	78,298,247
Nov-11	74,362,595	342.10	-	142.1	30	0	0	1,466,904	77,952,800
Dec-11	78,058,079	534.00	-	**142.4**	31	0	0	1,507,603	82,899,788
Jan-12	83,475,292	610.80	-	142.6	31	0	0	1,533,369	84,164,048
Feb-12	76,561,560	532.00	-	142.8	**29**	0	0	1,559,134	79,282,807
Mar-12	76,020,278	349.40	0.20	143.0	31	0	0	1,584,900	79,903,693
Apr-12	69,885,112	321.70	-	143.2	30	1	0	1,610,666	73,792,175
May-12	77,152,267	81.30	36.70	143.4	31	0	1	1,636,432	77,278,981
Jun-12	83,683,997	23.20	101.60	143.6	30	0	0	1,662,197	85,476,562
Jul-12	97,430,291	-	190.10	143.8	31	0	0	1,687,963	97,990,887
Aug-12	90,717,699	2.00	112.10	144.0	31	0	0	1,713,729	88,248,055
Sep-12	77,862,575	85.00	35.60	144.2	30	0	0	1,739,494	78,228,075
Oct-12	75,966,062	242.50	1.10	144.4	31	0	0	1,765,260	78,288,096
Nov-12	77,579,681	434.00	-	144.6	30	0	0	1,791,026	79,503,512
Dec-12	78,044,417	533.50	-	**144.8**	31	0	0	1,816,791	82,936,986
Jan-13	84,721,792	624.40	-	145.0	31	0	0	1,860,325	84,367,823
Feb-13	76,515,852	631.50	-	145.1	28	0	0	1,903,859	79,036,735
Mar-13	80,320,040	554.80	-	145.3	31	0	0	1,947,393	83,101,720
Apr-13	73,854,215	358.60	-	145.5	30	1	0	1,990,927	74,183,455
May-13	75,766,818	109.10	23.10	145.6	31	0	1	2,034,461	75,750,565
Jun-13	79,605,453	33.00	59.60	145.8	30	0	0	2,077,995	80,026,654
Jul-13	91,347,063	1.30	120.80	145.9	31	0	0	2,121,529	88,913,350
Aug-13	86,194,914	4.40	93.80	146.1	31	0	0	2,165,063	85,517,705
Sep-13	77,473,370	83.00	28.10	146.2	30	0	0	2,208,597	76,714,298
Oct-13	76,800,879	208.50	0.40	146.4	31	0	0	2,252,130	77,036,142
Nov-13	77,253,769	478.20	-	146.6	30	0	0	2,295,664	79,557,995
Dec-13	81,481,313	687.90	-	**146.7**	31	0	0	2,339,198	84,735,536
Jan-14	87,110,628	825.90	-	147.0	31	0	0	2,556,822	86,503,729
Feb-14	75,310,896	737.10	-	147.2	28	0	0	2,774,446	79,162,065
Mar-14	79,598,362	690.60	-	147.5	31	0	0	2,992,071	83,287,142
Apr-14	69,107,663	356.90	-	147.8	30	1	0	3,209,695	71,675,467
May-14	69,871,028	132.10	11.90	148.1	31	0	1	3,427,319	71,808,341
Jun-14	77,517,702	14.10	68.10	148.3	30	0	0	3,644,943	77,430,975
Jul-14	79,980,082	4.00	71.00	148.6	31	0	0	3,862,567	78,927,387
Aug-14	78,148,912	8.80	81.80	148.9	31	0	0	4,080,191	79,863,802
Sep-14	73,189,575	69.70	30.10	149.1	30	0	0	4,297,815	72,089,993
Oct-14	72,005,492	224.30	1.30	149.4	31	0	0	4,515,439	72,316,771
Nov-14	74,401,961	482.10	-	149.7	30	0	0	4,733,064	74,095,537
Dec-14	77,304,485	557.30	-	**149.9**	31	0	0	4,950,688	76,629,870
Jan-15	84,626,741	792.40	-	150.3	31	0	0	5,012,216	80,444,511
Feb-15	77,436,620	856.80	-	150.6	28	0	0	5,073,744	76,070,546
Mar-15	78,097,659	615.50	-	150.9	31	0	0	5,135,272	77,449,289
Apr-15	68,989,290	313.70	-	151.3	30	1	0	5,196,800	66,813,769
May-15	73,375,077	89.30	34.10	151.6	31	0	1	5,258,328	70,189,095
Jun-15	75,340,519	33.80	32.30	152.0	30	0	0	5,319,856	70,018,505
Jul-15	85,365,000	4.00	114.30	152.3	31	0	0	5,381,384	81,561,623
Aug-15	81,751,306	4.40	88.60	152.6	31	0	0	5,442,912	78,302,177
Sep-15	79,343,691	31.10	81.90	153.0	30	0	0	5,504,440	76,061,733
Oct-15	71,236,446	249.80	-	153.3	31	0	0	5,565,968	71,136,305
Nov-15	71,636,024	345.00	-	153.7	30	0	0	5,627,497	70,861,224
Dec-15	73,291,493	429.70	-	**154.0**	31	0	0	5,689,025	74,004,680
Jan-16		700.14	0.00	154.3	31	0	0	5,662,643	78,629,758
Feb-16		663.54	0.00	154.6	**29**	0	0	5,636,261	74,622,823
Mar-16		541.32	0.02	154.9	31	0	0	5,609,880	76,394,079
Apr-16		311.77	0.12	155.2	30	1	0	5,583,498	67,187,440
May-16		127.94	22.23	155.5	31	0	1	5,557,116	69,955,573
Jun-16		25.28	65.10	155.8	30	0	0	5,530,735	74,841,232
Jul-16		2.15	128.77	156.1	31	0	0	5,504,353	84,425,512
Aug-16		5.36	103.49	156.4	31	0	0	5,477,971	81,494,665
Sep-16		62.71	35.49	156.8	30	0	0	5,451,589	72,301,464
Oct-16		239.46	2.61	157.1	31	0	0	5,425,208	73,063,027

Nov-16	414.42	0.00	157.4	30	0	0	5,398,826	73,999,998
Dec-16	583.57	0.00	**157.7**	31	0	0	5,372,444	78,759,704
Jan-17	700.14	0.00	158.0	31	0	0	5,371,209	80,782,609
Feb-17	663.54	0.00	158.3	28	0	0	5,369,974	74,904,667
Mar-17	541.32	0.02	158.5	31	0	0	5,368,739	78,395,552
Apr-17	311.77	0.12	158.8	30	1	0	5,367,504	69,113,178
May-17	127.94	22.23	159.1	31	0	1	5,366,269	71,805,545
Jun-17	25.28	65.10	159.4	30	0	0	5,365,034	76,615,407
Jul-17	2.15	128.77	159.7	31	0	0	5,363,799	86,123,859
Aug-17	5.36	103.49	160.0	31	0	0	5,362,564	83,117,152
Sep-17	62.71	35.49	160.3	30	0	0	5,361,329	73,848,062
Oct-17	239.46	2.61	160.6	31	0	0	5,360,094	74,533,702
Nov-17	414.42	0.00	160.9	30	0	0	5,358,859	75,394,720
Dec-17	583.57	0.00	**161.2**	31	0	0	5,357,624	80,078,441
		Weather Normal						

2006	1,022,795,092.01	990,374,803.38
2007	1,043,014,996.70	1,010,506,168.26
2008	1,013,423,329.72	991,120,552.27
2009	940,830,205.04	954,808,047.26
2010	950,759,112.65	973,999,317.25
2011	944,902,732.12	983,927,551.07
2012	964,379,230.71	985,093,877.03
2013	961,335,479.00	968,941,978.11
2014	913,546,785.36	923,791,078.69
2015	920,489,866.98	892,913,456.95
2016		905,675,275.53
2017		924,712,893.61

Total to 2015	9,675,476,830.28

Attachment 3-B

Appendix 2-I-Load Forecast CDM Adjustment Work Form

File Number:	2016-0058
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-I
Load Forecast CDM Adjustment Work Form (2016)

2014 is the last year of the current four year (2011-2014) CDM program, and 2015 is the first year of a new six year (2015-2020) CDM program, per the Ministerial directives of March 31, 2014. With 2016, there is a need to recognize the full year impact of the current 2011-2014 CDM program, as well as to estimate reasonable impacts for each year for the new 2015-2020 CDM program. These are combined to estimate the adjustment for CDM program impacts on the 2016 load forecast.

Appendix 2-I was developed to help determine what would be the amount of CDM savings needed in each year to cumulatively achieve the four year 2011-2014 CDM target. This then determined the amount of kWh (and with translation, kW of demand) savings that were converted in dollars balances for the LRAMVA, and also to determine the related adjustment to the load forecast to account for OPA-reported savings. Beginning for the 2015 year, it has been adjusted because of the persistence of 2011-2014 CDM programs will be an adjustment to the load forecast in addition to the estimated savings for the first year (2015) for the new 2015-2020 CDM plan.

It is assumed that the new six year (2015-2020) CDM program will work similar to the existing 2011-2014 CDM program, meaning that distributors will offer programs each year that, cumulatively over the six years (from January 1, 2015 to December 31, 2020) will cumulatively achieve the new six year CDM target. This is the approach contemplated in the Ministerial directive letters of March 31, 2014 to the Board and to the OPA. Thus, distributors will be able to offer programs on a basis so that cumulatively over the period, the impacts, including persistence, of the CDM programs will accumulate towards achieving each distributor's 2015-2020 CDM target.

With this approach, it is necessary to account for estimated savings for the last year of the current program, particularly the estimated savings for new CDM programs offered in 2014, as well as the estimated savings for new CDM programs that the distributor will offer in 2015 towards achievement of the new six year (2015-2020) CDM program. This necessitates expansion of this Appendix 2-I to deal with both the 2011-2014 and 2015-2020 CDM plans. It is expected that this approach will be updated each year.

2011-2014 CDM Program - 2014, last year of the current CDM plan

Input the 2011-2014 CDM target in Cell B21.

Input the measured results for 2011 CDM programs for each of the years 2011 and persistence into 2012, 2013 and 2014 into cells B31 to E31. These results are taken from the final 2011 CDM Report issued by the OPA for that distributor in the fall of 2012.

Measured results for 2012 CDM programs for each of the years 2012 and persistence into 2013 and 2014 are input into cells C32 to E32. These results are taken from the final 2012 CDM Report issued by the OPA for that distributor in the fall of 2013.

Measured results for 2013 CDM programs for each of the years 2013 and persistence into 2014 are input into cells C33 to E33. These results are taken from the final 2013 CDM Report issued by the OPA for that distributor in the fall of 2014. Until that report is issued, the distributor should use the results from the preliminary 2013 CDM Report issued in the spring of 2014.

Measured results for 2014 CDM programs for each of the years 2013 and persistence into 2014 are input into cells C33 to E33. These results are taken from the final 2013 CDM Report issued by the OPA for that distributor in the fall of 2014. Until that report is issued, the distributor should use the results from the preliminary 2013 CDM Report issued in the spring of 2014. The distributor also needs to input the persistence of 2014 CDM programs into 2015 and 2016 in cells G45 and G46.

	4 Year (2011-2014) kWh Target:					Persistence of 2014 CDM Program into 2016 and 2017	
	100,000						
	2011	**2012**	**2013**	**2014**	**Total**	**2016**	**2017**
2011 CDM Programs	5.63%	5.62%	5.61%	5.48%	22.35%		
2012 CDM Programs		6.69%	6.69%	6.69%	20.07%		
2013 CDM Programs			6.34%	6.34%	12.67%		
2014 CDM Programs				44.91%	44.91%		
Total in Year	**5.63%**	**12.31%**	**18.64%**	**63.42%**	**100.00%**		
	kWh						
2011 CDM Programs	4,515,774.00	4,502,850.92	4,498,762.09	4,394,084.26	17,911,471.27	17,911,471.27	17,911,471.27
2012 CDM Programs		5,363,496.00	5,363,496.00	5,363,496.00	16,090,488.00	16,090,488.00	16,090,488.00
2013 CDM Programs			5,079,363.00	5,079,363.00	10,158,726.00	10,158,726.00	10,158,726.00
2014 CDM Programs				35,997,464.00	35,997,464.00	35,997,464.00	35,997,464.00
Total in Year	**4,515,774.00**	**9,866,346.92**	**14,941,621.09**	**50,834,407.26**	**80,158,149.27**		

2015-2020 CDM Program - 2016, second year of the current CDM plan

For the first year of the new 2015-2020 CDM plan, it is assumed that each year's program will achieve an equal amount of new CDM savings. The new targets for 2015-2020 do not take into account persistence beyond the first year, but the IESO will encourage distributors to promote and implement CDM plans that will have longer term persistence of savings. This results in each year's program being about 1/6 (18.67%) of the cumulative 2015-2020 CDM target for kWh savings. A distributor may propose an alternative approach but would be expected to document in its application why it believes that its proposal is more reasonable. In its proposal, the distributor should ensure that the sum of the results for each year's CDM program from 2015 to 2020 add up to its 2015-2020 CDM target as established by the IESO.

6 Year (2015-2020) kWh Target:							
54,372,015							
	2015	2016	2017	2018	2019	2020	Total
%							
2015 CDM Programs	9.64%						9.64%
2016 CDM Programs		14.22%					14.22%
2017 CDM Programs			28.71%				28.71%
2018 CDM Programs				24.56%			24.56%
2019 CDM Programs					11.45%		11.45%
2020 CDM Programs						11.42%	11.42%
Total in Year	**9.64%**	**14.22%**	**28.71%**	**24.56%**	**11.45%**	**11.42%**	**100.00%**
kWh							
2015 CDM Programs	5,239,000.00						5,239,000.00
2016 CDM Programs		7,730,071.71					7,730,071.71
2017 CDM Programs			15,611,676.18				15,611,676.18
2018 CDM Programs				13,356,198.98			13,356,198.98
2019 CDM Programs					6,228,066.87		6,228,066.87
2020 CDM Programs						6,207,000.93	6,207,000.93
Total in Year	**5,239,000.00**	**7,730,071.71**	**15,611,676.18**	**13,356,198.98**	**6,228,066.87**	**6,207,000.93**	**54,372,014.66**

Determination of 2016 Load Forecast Adjustment

The Board has determined that the "net" number should be used in its Decision and Order with respect to Centre Wellington Hydro Ltd.'s 2013 Cost of Service rates (EB-2012-0113). This approach has also been used in Settlement Agreements accepted by the Board in other 2013 and 2-14 applications. The distributor should select whether the adjustment is done on a "net" or "gross" basis, but must support a proposal for the adjustment being done on a "gross" basis. Sheet 2-I defaults to the adjustment being done on a "net" basis consistent with Board policy and practice.

From each of the 2006-2010 CDM Final Report, and the 2011, 2012, 2013 and 2014 CDM Final Reports, issued by the OPA (now IESO) for the distributor, the distributor should input the "gross" and "net" results of the cumulative CDM savings for 2014 into cells D84 to E88. The model will calculate the cumulative savings for all programs from 2006 to 2012 and determine the "net" to "gross" factor "g".

Net-to-Gross Conversion				
Is CDM adjustment being done on a "net" or "gross" basis?				**net**
Persistence of Historical CDM programs to 2014	**"Gross" kWh**	**"Net" kWh**	**Difference kWh**	**Conversion Factor ('g')**
2006-2010 CDM programs		**8,299,595.00**		
2011 CDM program		**4,394,084.00**		
2012 CDM program		**5,363,496.00**		
2013 CDM program		**5,079,363.00**		
2014 CDM program		**35,997,464.00**		
2006 to 2014 OPA CDM programs: Persistence to 2016	0	59134002	-59134002	0.00%

The default values represent the factor that each year's CDM program is factored into the manual CDM adjustment. Distributors can choose alternative weights of "0", "0.5" or "1" from the drop-down menu for each cell, but must support its alternatives.

These factors do not mean that CDM programs are excluded, but the assumption that impacts of previous year CDM programs are already implicitly reflected in the actual data for the historical years that are the basis for the load forecast prior to any manual CDM adjustment for the 2016 test year.

Weight Factor for Inclusion in CDM Adjustment to 2014 Load Forecast

	2011	2012	2013	2014	2015	2016	2017
Weight Factor for each year's CDM program impact on 2014 load forecast	**0**	**0**	**0**	**0**	**0.5**	**1**	**0.5**
Default Value selection rationale.	*Full year persistence of 2011 CDM programs on 2015 load forecast. Full impact assumed because of 50% impact in 2011 (first year) but full year persistence impact on 2012 and 2013, and thus reflected in base forecast before the CDM adjustment.*	*Full year persistence of 2012 CDM programs on 2015 load forecast. Full impact assumed because of 50% impact in 2012 (first year) but full year persistence impact on 2013, and thus reflected in base forecast before the CDM adjustment.*	*Default is 0, but one option is for full year impact of persistence of 2013 CDM programs on 2015 load forecast, but 50% impact in base forecast (first year impact of 2013 CDM programs on 2013 load forecast, which is part of the data for the load forecast.*	*Default is 0, but one option is for full year impact of persistence of 2014 CDM programs on 2014 load forecast, but 50% impact in base forecast (first year impact of 2014 CDM programs on 2014 actuals, which is part of the data for the load forecast.*	*Half - year impact of 2015 programs is expected to be included in the base 2017 forecast, the additional half-year of expected persistence is included as a manualadjustment*	*Full year impact of persistence of 2016 programs on 2017 load forecast. 2016 CDM program impacts are not in the base forecast.*	*Only 50% of 2017 CDM programs are assumed to impact the 2017 load forecast based on the "half-year" rule.*

2011-2014 and 2015-2020 LRAMVA and 2015 CDM adjustment to Load Forecast

One manual adjustment for CDM impacts to the 2015 load forecast is made. However, the distributor will have two associated annualized CDM impacts, one for the 2011-2014 CDM program and the second for the 2015-2020 CDM plan. In addition, the distributor needs to reflect the CDM adjustment that was explicitly factored into its 2011 load forecast in its 2011 cost of service application (assuming that it rebased in that year). this amount, and equal persistence for 2012, 2013 and 2014 is used as an offset to determine what the net balance of the 2011-2014 LRAMVA balance should be for disposition.

The Amount used for the CDM threshold of the LRAMVA is the kWh that will be used to determine the base amount for the LRAMVA balance for 2014, for assessing performance against the four-year target. The base amount for 2011-2013 is 0 (zero) for 2014 Cost of Service applications, as the utility rebased prior to the 2011-2014 CDM programs, and there was no adjustment to reflect the impacts of the 2011-2014 programs on the load forecast used to determine their last cost of service-based rates.

The proposed loss factor should correspond with the loss factor calculated in Appendix 2-R

The Manual Adjustment for the 2016 Load Forecast is the amount manually subtracted from the load forecast derived from the base forecast from historical data.

If the distributor has developed their load forecast on a system purchased basis, then the manual adjustment should be on system purchased basis, including the adjustment for losses. If the load forecast has been developed on a billed basis, either on a system basis or on a class-specific basis, the manual adjustment should be on a billed basis, excluding losses.

The distributor should determine the allocation of the savings to all customer classes in a reasonable manner (e.g. taking into account what programs and what OPA-measured impacts were directed at specific customer classes), for both the LRAMVA and for the load forecast adjustment.

	2011 kWh	2012	2013	2014	2015	2016	2017	Total for 2017
Amount used for CDM threshold for LRAMVA (2014)	4,394,084.26	5,363,496.00	5,079,363.00	35,997,464.00				
forecast (per Board Decision in distributor's most recent Cost of Service Application) (enter as negative)	- 4,498,762.00	- 5,232,705.00	- 5,077,709.00	-				
Amount used for CDM threshold for LRAMVA (2017)				35,997,464.00	5,239,000.00	7,730,071.71	15,611,676.18	48,966,535.71
Manual Adjustment for 2017 Load Forecast (billed basis)	-	-	-	-	2,619,500.00	7,730,071.71	7,805,838.09	18,155,409.80
Proposed Loss Factor (TLF)	3.20%	Format: X.XX%						
Manual Adjustment for 2016 Load Forecast (system purchased basis)	-	-	-	-	2,703,324.00	7,977,434.01	8,055,624.91	10,680,758.01

Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g). The Weight factor is also used calculate the impact of each year's program on the CDM adjustment to the 2016 load forecast.