Exhibit 3:

Operating Revenue

TABLE OF CONTENTS

LIST OF ATTACHMENTS

3-A. EPI Load Forecast Model

3-B. Load Forecast CDM Adjustment Work Form, Board Appendix 2-I

3-C. EPI's 2015 – 2020 CDM Plan

3-D. Summary and Variances of Actual and Forecast Data, Board Appendix 2-IA

3-E. Other Operating Revenue, Board Appendix 2-H

3.1 OVERVIEW

This Exhibit provides the details of Entegrus Powerlines Inc.'s ("EPI's") operating revenues for 2010 Board Approved, 2010 Actual, 2011 Actual, 2012 Actual, 2013 Actual, 2014 Actual, 2015 Bridge Year and the 2016 Test Year. This Exhibit also provides a detailed variance analysis by rate classification for the operating revenue components. Distribution revenue excludes revenue from commodity sales.

EPI is proposing a total Service Revenue Requirement of $19,378,505 for the 2016 Test Year. This amount includes a Base Revenue Requirement of $18,189,984 plus Other Revenue of $1,188,521 as discussed in Section 3.4 below.

Other Revenue includes Specific Service Charges, Late Payment Charges, Other Operating Revenues and Other Income or Deductions. As summary of these operating revenues with a materiality analysis of variances is presented in Section 3.4.

3.2 Load Forecast

3.2.1 Introduction

The purpose of this section is to present the process used by EPI to develop its 2015 Bridge Year and 2016 Test Year weather-normalized load and customers/connections forecast utilized in the design of the 2016 proposed distribution rates.

This forecast was prepared at a combined level representing all four EPI rate zones (CK, SMP, Dutton and Newbury) in support of the rate harmonization proposed in this Application. As of January 1, 2014, EPI merged to a single settlement process with the Independent Electricity System Operator ("IESO") for all four rate zones. Accordingly, EPI does not distinguish electricity purchases between the currently maintained rate zones.

EPI has prepared a Load Forecast Model (the "Model") consistent with its understanding of the Chapter 2 Filing Requirements for Electricity Distribution Rate Applications – 2015 Edition for 2016 Rate Applications issued on July 16, 2015. A copy of the Model has been filed in Live Excel format and is included in Attachment 3-A of this Exhibit.

3.2.2 Purchased kWh Forecast

Consistent with the methodology used to prepare the approved load forecast in Chatham-Kent Hydro's ("CKH") 2010 Cost of Service Application (EB-2009-0261), EPI utilized the multivariate linear regression analysis methodology for this Application. This methodology was chosen: (i) for consistency with the CKH's 2010 Cost of Service Application; and (ii) for its accessibility and the capability of Microsoft Excel to house the fully functional model. EPI believes this approach of conducting a regression analysis on historical electricity purchases and producing an equation that will predict future purchases is appropriate.

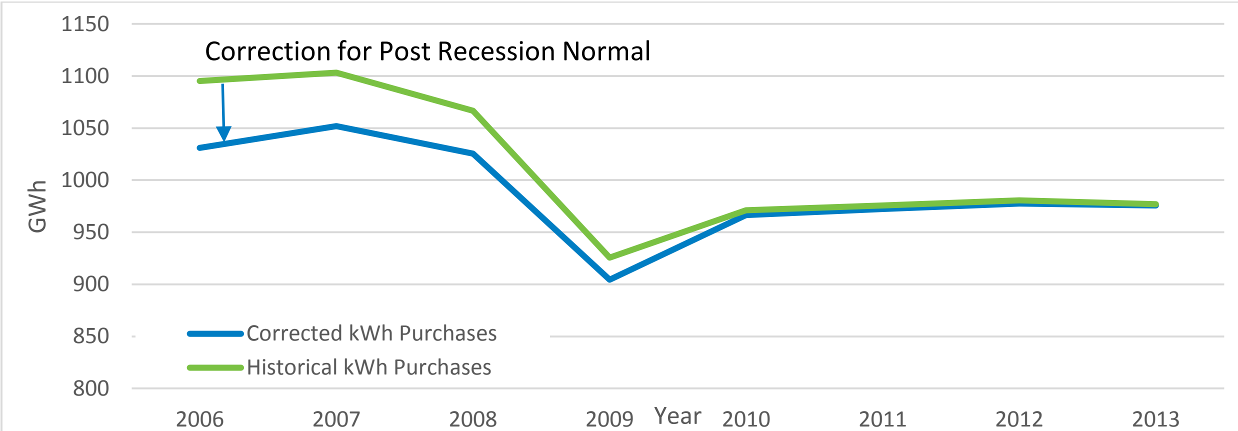
HISTORIC PURCHASES

Traditionally, kWh purchase data is accumulated by month for 10 historic years for use in the regression analysis. This includes purchase data from the IESO and Hydro One Networks Inc. ("HONI"), as well as embedded generation data. Unfortunately, EPI does not have access to reliable purchase data prior to 2006 from the former Middlesex Power Distribution ("MPDC"), Dutton Hydro Inc. ("Dutton") and Newbury Power Inc. ("Newbury"). Accordingly, EPI has utilized kWh purchase data, by month, for its entire service territory for the period of January 2006 to December 2014 as part of this regression analysis.

As described in Exhibit 7, Section 7.2.4, EPI has a unique situation with HONI at the 30M1 feeder in Tilbury. In 2010, EPI had a large RESOP solar generation project, known generically as the Tilbury Solar Farm, came online in EPI's service territory in Tilbury. This project reversed the flow of electricity at the Tilbury Transmission Station ("Tilbury TS") meter. Previously, as an embedded distributor, EPI had received an invoice from HONI for kWh purchased at this point. However, since the Tilbury Solar Farm came online, EPI has been receiving a credit invoice from HONI for the commodity and associated Global Adjustment. As part of this Application, EPI consulted with HONI on this and other matters, and EPI proposed that HONI be treated as an embedded distributor to EPI at the Tilbury point. HONI disagreed with this treatment, and asserted that the appropriate treatment is for EPI to remain as the embedded distributor to HONI at this Tilbury point. EPI has decided to accept HONI's proposed treatment (whereby EPI remains embedded to HONI at the Tilbury point). Accordingly, EPI has netted the kWh that will continue to be credited by HONI to EPI (with regard to the Tilbury point) against the associated monthly purchases, for the purpose of appropriately reducing the monthly purchases in the load forecast.

As shown in Chart 3-1 below, EPI experienced significant load loss between 2008 and 2010 as a result of the global recession. As noted in Exhibit 1, load loss was particularly experienced in Chatham-Kent, as businesses closed or curtailed production. This culminated with the closure of Chatham's largest production facility in 2010. The green line in the graph in Chart 3-1 shows that as the EPI service territory has recovered from the recession, the load has since leveled off and EPI is now experiencing a new profile at lower-than-historic levels.

CHART 3-1: EPI HISTORICAL AND CORRECTED PURCHASES



Prior to any modeling, EPI developed a correction factor to adjust for the new profile and recognize that some pre-2008 load no longer exists. Specifically, the adjustment pushes the historical purchased kWh downward, so the forecast model more accurately reflects post global recession customer consumption.

The following two adjustments were made to the historical data:

- Reduction for total customer purchases for General Service > 50 kW customers who closed in 2013, or prior to 2013 (re: column C of Purchase Forecast tab of Model), and
- Reduction for total customer purchases for customers greater than 1 MW which closed in 2013, or prior to 2013 (re: column D of Purchase Forecast tab of Model).

The corrected historical purchases are reflected in the blue line in Chart 3-1 above.

MODELLED VARIABLES

Variables included in the model are designed to provide a broad coverage of the drivers of electricity use by our customers. EPI utilized the following variables:

- Weather Conditions,
- Time
- Manufacturing, and

- Economic Adjustment Factor

WEATHER CONDITIONS

Weather impacts on load are apparent in both the winter heating season and in the summer cooling season. For that reason, EPI has included both Heating Degree Days (ex. A measure of coldness in the winter) and Cooling Degree Days (ex. a measure of summer heat) variables in the regression analysis.

As reliable electrical data is only available from 2006 onward, weather information is also evaluated over this period. Weather data is measured in degrees Celsius by the Ridgetown Automatic weather station as operated by Environment Canada. Ridgetown is a community served by EPI which is located close to the centroid of the EPI service territory. The average monthly values were used in generating forecast values.

TIME

Consumer behavior tends to change over time due to a variety of reasons. Some reasons include demographic shifts, improvements in industrial processes and changes in production. This change in consumer behavior over time is represented in the model by the year, which showed a significantly stronger T-Stat than either numeric month, or a steadily increasing monthly index. EPI has included a negative coefficient on time to assist in reflecting in the load forecast customer trends in installing more efficient manufacturing equipment, the fact more and more customers are replacing electric heat in the area and the overall general customer behavior toward conservation.

MANUFACTURING

Statistics Canada routinely collects historical economic activity for the Ontario manufacturing sector. The Ministry of Finance has established its 2014 budget forecast using a 2.5% future growth rate based on this information.

EPI has used this same 2.5% growth rate utilized by the Ministry of Finance in their regression analysis. At this time, EPI is unaware of any significant growth in its service territory to support this growth rate and such believes this somewhat optimistically captures the potential for growth within pockets of its service territory.

ECONOMIC ADJUSTMENT FACTOR

As part of CKH's 2010 COS Application (EB-2009-0261), CKH submitted a model which included two synthetic factors; the Industrial Production Factor; and the Seasonal Adjustment Factor. Both are used to model the mix of agricultural and manufacturing base in the community which are influenced by seasonal and external manufacturing demands in different ways[1]. Through a trial and error, iterative process, a set of variables which repeat annually were established. Since these variables repeated they are therefore easily predictable and were developed and used in the 2010 analysis. The variable was ultimately accepted during settlement and approved by the Board.

For the load forecast included in this Application, EPI has merged the former Seasonal Adjustment Factor and the former Industrial Production Factor described above into a single synthetic factor the "Economic Adjustment Factor." The values of this variable take both positive and negative values. Months with a positive number represent inflation of the forecast value as a result of traditional activities. Months with a negative value represent a reduction in the forecasted value.

REJECTED VARIABLES

EPI considered the following environmental variables for the Environment Canada weather stations for Chatham-Kent Wastewater Pollution Control Plant, London International Airport and Ridgetown Automatic for inclusion in the model but ultimately rejected them due to non-intuitive relationships or poor correlation (low T-Stat).

EPI reviewed the Heating Degree Days and Cooling Degree days for the London International Airport and the Chatham Airport weathers stations and rejected them in favor of the Ridgetown Automatic weather station data, which is closer to the centroid of the service territory.

[1] Chatham-Kent Hydro Inc., EB-2009-0261, COS Application, Exhibit 3, Tab 2, Schedule 1, Page 9

The following environmental variables were also evaluated, but found less significant than Heating Degree Days and Cooling Degree Days:

- Monthly Maximum Temperature;
- Monthly Minimum Temperature; and
- Monthly Average Temperature.

EPI's service territory fits within the census ER570 region. Within this region, published data on employment rates are available for the Windsor-Essex, Sarnia-Lambton and London sub-regions. EPI analyzed and tested the ER570 region and the sub-regions independently and ultimately rejected them in favor of the Ontario manufacturing factor described above. EPI felt these measures did not provide as meaningful results as the Ontario factor which resulted in strong output variables.

Economic activity in the region has historically been centered on agribusiness and automotive parts manufacturing. Based on this knowledge, EPI considered and tested the following metrics gathered by Statistics Canada for Ontario.

- Machinery manufacturing,
- Machine shops, turned product, and screw, nut and bolt manufacturing,
- Motor vehicle manufacturing, and
- Motor vehicle parts manufacturing.

The above manufacturing statistics were ultimately rejected due to their lack of overall relationship to the area. EPI ultimately choose the Economic Adjustment Factor described above as it provided the most meaningful results with strong output stats.

RESULTS

The formula following outlines the prediction model used by EPI to predict weather normal purchases for 2015 and 2016.

EPI Monthly Predicted kWh Purchases

= Intercept of 1,111,225,995

+ Time * (533,191)

+ Heating Degree Days * 19,555

+ Cooling Degree Days * 163,255

+ Manufacturing * 0.71

+ Economic Adjustment Factor * 6,721,190

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in the Load Forecast Model filed in Live Excel format or in Attachment 3-A to this Exhibit.

Based on the monthly corrected purchases and the above described variables used in the regression model, EPI expects 2015 purchases of 981,371,899 kWh and 2016 purchases of 985,050,497 kWh.

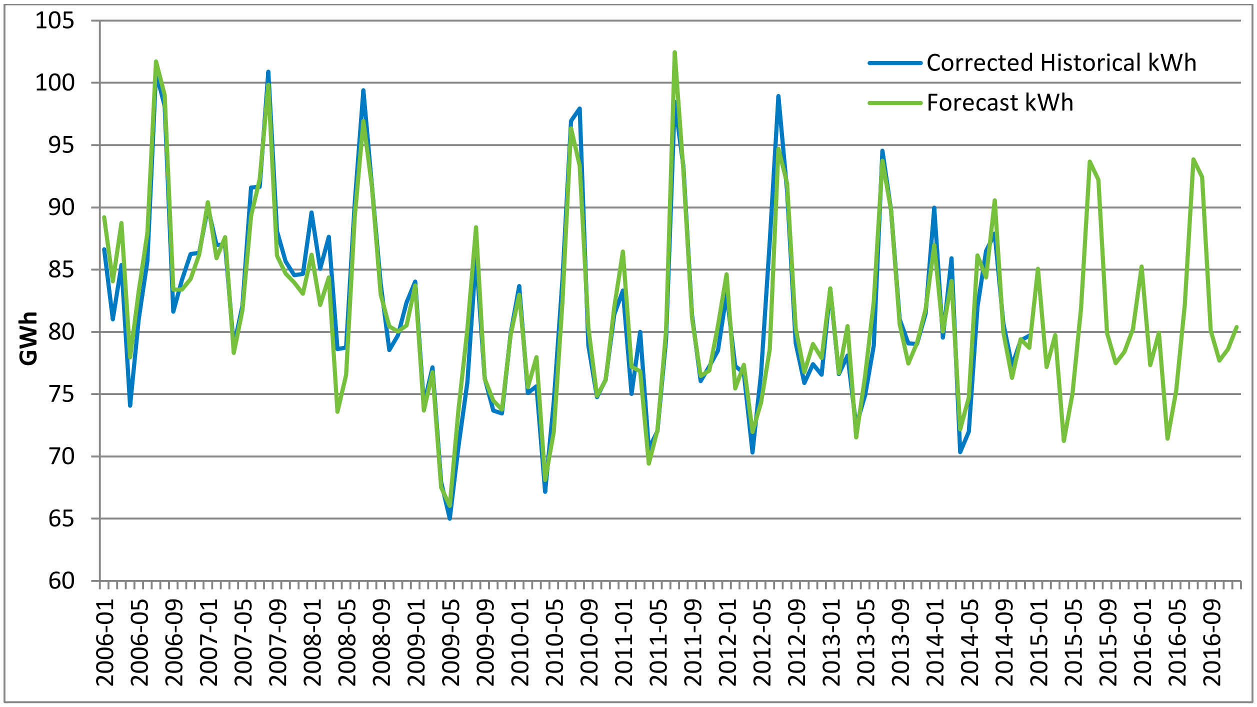
The table below shows the modeled purchases generated by the regression model for 2015 and 2016 are very close to the recent historical year purchases.

TABLE 3-1: EPI FORECAST VS. ACTUAL PURCHASES

Year	Actual Purchases	Modeled Purchases	Difference	Difference %
2006	1,095,393,373	1,049,193,051	46,200,322	0.0422
2007	1,103,377,336	1,043,199,743	60,177,593	0.0545
2008	1,066,571,963	1,004,606,523	61,965,440	0.0581
2009	925,631,873	914,212,545	11,419,328	0.0123
2010	970,978,474	961,947,493	9,030,981	0.0093
2011	968,593,688	972,522,943	(3,929,256)	(0.0041)
2012	973,607,964	962,982,436	10,625,528	0.0109
2013	970,760,692	973,593,882	(2,833,190)	(0.0029)
2014	971,112,987	973,414,830	(2,301,843)	(0.0024)
2015	-	972,164,493		
2016	-	974,498,367		

Chart 3-2 below shows the variance between the modeled purchased and the historic purchases. As shown, the pattern in the forecast years shows a very similar and expected pattern.

CHART 3-2: FORECASTED PURCHASES



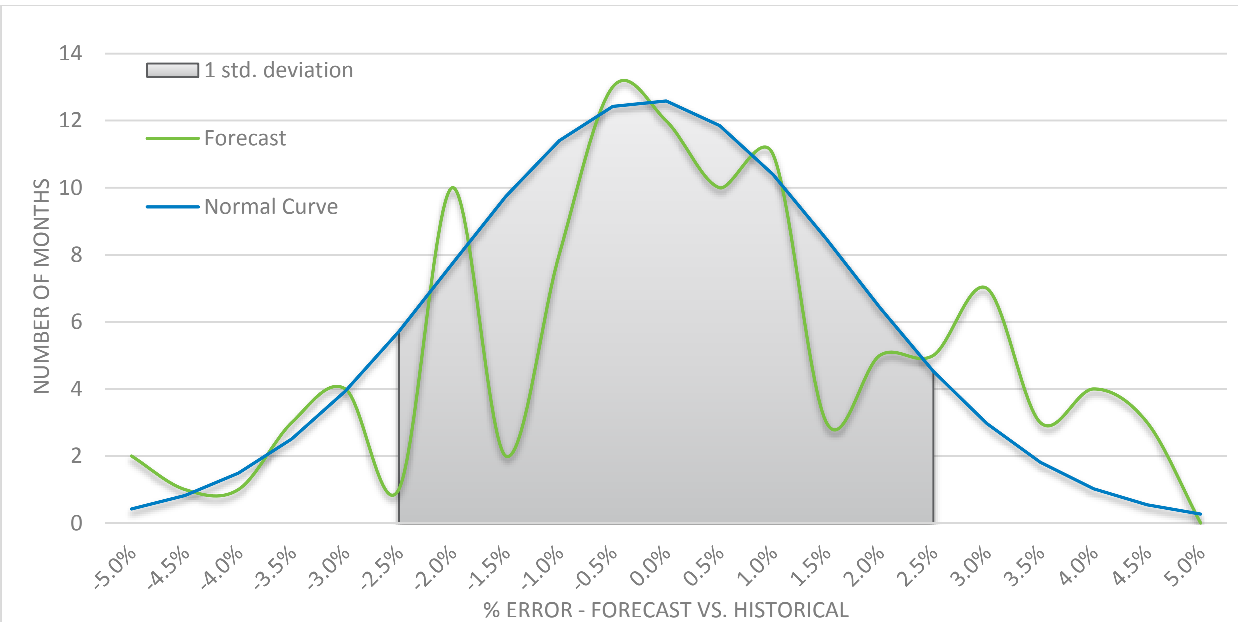
The prediction formula has the following statistical results, which generally indicates the formula has a very good fit to the actual data set.

TABLE 3-2: T-STATISTICS FOR ACCEPTED VARIABLES

Statistic	***Value***
R Square	*92.5%*
Adjusted R Square	*92.2%*
F Test	*253.0*
MAPE (monthly)	*1.8%*
Variable	***T-Stat***
Intercept	8.0
Time	-7.8
Heating Degrees	16.6
Cooling Degrees	16.0
Manufacturing (x 1,000)	13.4
Seasonal Weighting Factor	14.1

A strong indicator that the error is random, rather than systemic, is that the error within the model is normally distributed and centered on the historical value. The following table illustrates the distribution and frequency of error in the predicted values. As shown in Chart 3-3 below, 74% of the predicted values are within 2.5% of the historical values.

CHART 3-3: MODELLING ERROR



3.2.3 BILLED KWH LOAD FORECAST

To determine the weather normalized billed kWh forecast, the total weather normalized forecast purchased kWh (as discussed above) is adjusted for line losses. At this stage of the analysis, adjustments for CDM and wholesale market participants are not yet incorporated.

EPI has utilized the average loss factor from 2007 to 2014. The average loss factor during this time was 1.0399 or 3.99%, the calculation is shown in Table 3-3. Due to the reliability of the 2006 data from EPI's predecessor companies and the anomalous loss factor of 1.0157, EPI has excluded the 2006 loss factor from the average loss factor calculation below.

TABLE 3-3: AVERAGE LOSS FACTOR

Line No.	Year	Purchase kWh	Billed kWh	Loss Factor
		A	B	C
1	2007	1,103,377,336	1,055,654,062	1.0433
2	2008	1,103,377,336	1,055,654,062	1.0425
3	2009	1,066,571,963	1,021,199,819	1.0421
4	2010	925,631,873	886,643,741	1.0399
5	2011	970,978,474	932,206,592	1.0314
6	2012	968,593,688	938,179,332	1.0385
7	2013	973,607,964	936,088,111	1.0433
8	2014	970,760,692	928,696,615	1.0383
9	**Average**			**1.0399**

Prior to CDM adjustments, the calculated weather normalized billed kWh for the 2015 Bridge Year and 2016 Test Year are 934,838,752 kWh and 937,083,018 respectively.

3.2.4 HISTORICAL CUSTOMER DATA

As noted above, this load forecast was prepared for the EPI service territory in its entirety. This is inclusive of the former service territories of CKH, Middlesex Power Distribution Corporation (“MPDC”), Newbury Power (“Newbury”) and Dutton Hydro (“Dutton”).

In order to allocate the load forecast at a rate class level, EPI relied on historical rate class statistics for each former utility, as reported in the annual RRR 2.1.5 submissions to the Board. EPI specifically utilized the following RRR annual data:

- 2014: RRR reported by EPI
- 2013: RRR reported by EPI
- 2012: RRR reported by EPI
- 2011: RRR reported by CKH & MPDC
- 2010: RRR reported by CKH & MPDC
- 2009: RRR reported by CKH & MPDC

- 2008: RRR reported by CKH, MPDC, Dutton & Newbury
- 2007: RRR reported by CKH, MPDC, Dutton & Newbury
- 2006: RRR reported by CKH & MPDC. Dutton & Newbury 2007 RRR data was used as a proxy for Dutton & Newbury 2006 RRR data, as such data was not prepared or filed by the previous owners of those entities.

In order to properly prepare the following forecasts by rate class, EPI restated the following billing determinants to properly align with the anticipated migration of specific customers amongst rate classes. These migration adjustments to the originally filed RRR data were necessary to accurately predict the specific rate class billing determinants, and are described as follows:

1. As part of this Application, EPI is proposing the elimination of the CK Intermediate rate class. As such, the data reported in the annual RRR filings for this rate class from its inception in 2010 until 2014 has been merged with the General Service >50 kW rate class.
2. EPI is also proposing the elimination of the CK Intermediate with Self Generation rate class. The sole customer in this rate class will merge with a single customer from the SMP rate zone into the Large Use rate class. Due to the significant differences in the legacy rate design for these customers and to assist with clarity throughout the remainder of the Application, EPI has left them in separate columns as part of the load forecast procedure. These 2 customers will form a single Large Use class upon finalization of rate mitigation. For more information regarding the design of this rate class, please see Exhibit 7 and Exhibit 8.
3. As part of this Application, EPI is proposing a new Embedded Distributor rate class. EPI currently has one virtual Embedded Distributor point with HONI. As of June 30, 2015, this point is being General Service > 50 kW billed fixed charges only. To facilitate this change, EPI has removed the historical data for the General Service > 50 kW rate class and added it to the Embedded Distributor rate class for 2007 to 2014. No data was previously reported for 2006. For more information on the Embedded Distributor rate class, please see Exhibit 7, Section 7.2.4.
4. As part of this Application, EPI is proposing rate harmonization. As such, historically the customers in the Dutton rate zone did not have access to a General Service > 50 kW rate class.

Upon harmonization there are three eligible customers previously billed in the General Service < 50 kW rate class who are anticipated to move to the General Service > 50 kW rate class. To properly reflect this in the load forecast, the 2006 to 2014 data has been removed from the General Service < 50 kW rate class and added to the General Service > 50 kW rate class for these specific customers.

5. EPI currently has two Wholesale Market Participants ("WMP"), one customer who opted into the program in mid-2012 and one new customer who came online in late 2014. To properly allocate the billed kWh calculated above (which is driven by purchases where they are inherently excluded) and project customer numbers, these two General Service > 50 kW customers have been removed from the historical data since becoming WMP in 2012 and 2014 respectively. These customers are forecasted separately on the "WMP" tab of the load forecast model and added back to the load forecast totals for rate design purposes.

After the above-noted reclassifications, all historic data appears in the rate class in which the associated customers are anticipated to be billed upon the completion of this Application.

3.2.5 Customer/Connection Forecast by Rate Class

The forecasted number of customer/connection is based on a review of EPI's average annual historical customer/connection data. EPI utilized the customer/connection data reported in the applicable RRR submissions annually, adjusted for the reclassifications noted above in Section 3.2.4 and averaged the opening and closing balances annually. The results are presented in Table 3-4 below. All rate classes are based on the number of customers, except the Unmetered Scattered Load, Sentinel Lighting and Street Lighting rate classes, which are based on number of connections.

TABLE 3-4: HISTORIC ANNUAL AVERAGE CUSTOMER/CONNECTIONS BY YEAR

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load (Conn)	Sentinel Lighting (Conn)	Street Lighting (Conn)	Embedded Distributor	Total
2006	35,142	4,009	507	1	2	-	393	12,468	-	52,522
2007	35,190	4,001	513	3	1	-	394	12,468	1	52,571
2008	35,334	3,976	523	3	1	-	393	12,553	1	52,784
2009	35,438	3,919	517	3	1	122	390	12,784	1	53,175
2010	35,472	3,916	496	2	1	244	388	12,931	1	53,451
2011	35,628	3,907	490	1	1	245	388	12,931	1	53,592
2012	35,816	3,859	498	1	1	245	388	12,931	1	53,740
2013	35,944	3,862	499	1	1	248	441	13,103	1	54,100
2014	36,074	3,870	497	1	1	251	487	13,270	1	54,452

From the historic data, EPI then calculates the growth rate for each rate class. EPI utilizes the annual growth from the past five years (2010 to 2014) to calculate the geometric growth rate for all rate classes. EPI believes five years best represents the current economic situation of its service territory and takes into consideration the stabilization after the global recession. The results are presented below in Table 3-5.

TABLE 3-5: HISTORICAL CUSTOMER/CONNECTION GROWTH RATES BY YEAR

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load (Conn)	Sentinel Lighting (Conn)	Street Lighting (Conn)	Embedded Distributor	Total
2006	-	-	-	-	-	-	-	-	-	
2007	1.0014	0.9980	1.0118	3.0000	0.5000	-	1.0025	1.0000	-	
2008	1.0041	0.9938	1.0195	1.0000	1.0000	-	0.9975	1.0068	1.0000	
2009	1.0029	0.9857	0.9885	1.0000	1.0000	-	0.9924	1.0184	1.0000	
2010	1.0010	0.9992	0.9594	0.6667	1.0000	2.0000	0.9949	1.0115	1.0000	
2011	1.0044	0.9977	0.9879	0.5000	1.0000	1.0041	1.0000	1.0000	1.0000	
2012	1.0053	0.9877	1.0163	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	
2013	1.0036	1.0008	1.0020	1.0000	1.0000	1.0122	1.1366	1.0133	1.0000	
2014	1.0036	1.0021	0.9960	1.0000	1.0000	1.0121	1.1043	1.0127	1.0000	
Geomean	**1.0036**	**0.9975**	**0.9921**	**0.8027**	**1.0000**	**1.1552**	**1.0454**	**1.0075**	**1.0000**	

For the 2015 Bridge Year customer/connection forecast, EPI applied the resulting rate class specific geometric mean to the total year end 2014 customer/connections. Similarly, EPI then applied the resulting rate class specific geometric mean to the 2015 Bridge Year results to calculate the 2016 Test Year results.

EPI then adjusts for the 2 Wholesale Market Participant customers to provide for the total forecasted number of customers and connections for the 2015 Bridge Year and the 2016 Test year. The results are presented in Table 3-6 below.

TABLE 3-6: FORECASTED NUMBER OF CUSTOMERS/CONNECTION BY YEAR

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load (Conn)	Sentinel Lighting (Conn)	Street Lighting (Conn)	Embedded Distributor	Total
Forecasted Customers/Connections										
2015	36,203	3,860	493	1	1	290	509	13,369	1	54,727
2016	36,333	3,850	489	1	1	335	532	13,469	1	55,011
Add: WMP										
2015	-	-	2	-	-	-	-	-	-	2
2016	-	-	2	-	-	-	-	-	-	2
Total Adjusted Forecasted Customers/Connections										
2015	36,203	3,860	495	1	1	290	509	13,369	1	54,729
2016	36,333	3,850	491	1	1	335	532	13,469	1	55,013

The 2016 Test Year results are discussed below:

- Residential – EPI continues to see small increases in the Residential rate class due to small subdivision growth in the Strathroy, Mount Brydges and Parkhill area. At this time, EPI is unaware of any future major residential development plans.

- General Service – After a significant drop in General Service customers due to the global recession, the EPI service territory has been challenged to reach pre-recession numbers. Recent economic data seem to indicate a slow gradual and subtle growth uptake. Economic trends in Chatham-Kent, and to a lesser extent Middlesex, lag behind provincial economic trends. EPI is not aware of any significant future development plans. Accordingly, EPI expects to witness a continuation of the small decline in the General Service Rate classes, consistent with historic data trends.

- Large Use – Similar to the General Service rate classes, the Large Use rate class is not expected to see any significant growth and are projected to remain flat. EPI is not aware of any significant future developments.

- Unmetered Scattered Load, Sentinel Lighting and Street Lighting connections remain relatively flat due to the lack of expansion in EPI's service territory.

- Embedded Distribution – This rate class currently has one customer and is not expected to increase through 2015 and 2016.

3.2.6 Billed kWh Load Forecast by Rate Class

This section reviews the methodology utilized by EPI to calculate the forecasted load by rate class.

EPI begins with the annual historic billed kWh as reported in the applicable annual RRR submissions and adjusted the data for the reclassifications noted above in Section 3.2.4. The results are presented in Table 3-7 below.

Table 3-7: Average Historical kWh Usage by Year

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
2006	302,355,083	129,600,878	507,947,705	92,372,408	36,694,467	-	454,662	8,797,196	-	1,078,222,399
2007	299,638,406	126,763,870	498,423,262	89,275,102	27,015,842	-	445,369	8,797,782	5,294,429	1,055,654,062
2008	296,054,771	125,816,796	464,092,558	98,751,177	22,647,906	-	436,740	8,199,730	5,200,141	1,021,199,819
2009	291,091,689	114,518,667	395,794,984	53,009,042	17,181,839	1,158,647	440,153	8,235,437	5,213,283	886,643,741
2010	301,267,823	116,294,933	435,880,111	35,030,946	29,034,336	1,191,306	433,931	8,221,743	4,851,464	932,206,593
2011	299,495,986	116,705,566	444,705,629	28,996,883	34,298,990	1,249,000	353,837	8,221,874	4,151,567	938,179,332
2012	296,656,279	109,007,040	453,565,445	28,118,306	34,317,082	1,213,037	405,259	8,250,167	4,555,496	936,088,111
2013	281,071,800	105,791,729	456,115,509	39,427,413	32,247,068	1,228,666	410,160	7,792,246	4,612,024	928,696,615
2014	289,455,443	108,543,510	457,346,103	33,167,215	31,573,402	1,249,444	408,652	7,533,249	4,634,801	933,911,819

EPI then takes the annual results from Table 3-7 above and divides the annual rate class total by the respective annual customer/connection data shown in Table 3-4. The results are presented in Table 3-8 below.

Table 3-8: Average Annual Consumption per Customer/Connection

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
2006	8,604	32,327	1,001,869	92,372,408	18,347,234	-	1,157	706	-	
2007	8,515	31,683	971,585	29,758,367	27,015,842	-	1,130	706	5,294,429	
2008	8,379	31,644	887,366	32,917,059	22,647,906	-	1,111	653	5,200,141	
2009	8,214	29,221	765,561	17,669,681	17,181,839	9,497	1,129	644	5,213,283	
2010	8,493	29,697	878,791	17,515,473	29,034,336	4,882	1,118	636	4,851,464	
2011	8,406	29,871	907,563	28,996,883	34,298,990	5,098	912	636	4,151,567	
2012	8,283	28,247	910,774	28,118,306	34,317,082	4,951	1,044	638	4,555,496	
2013	7,820	27,393	914,059	39,427,413	32,247,068	4,954	930	595	4,612,024	
2014	8,024	28,047	920,213	33,167,215	31,573,402	4,978	839	568	4,634,801	

From the historical usage per customer/connection data, EPI then calculates the annual growth rate per customer/connection per year. For all rate classes except Large Use, EPI utilizes the annual growth rate from the past five years (2010 to 2014) to calculate the geometric growth rate. EPI believes five years best represents the current economic situation of its service territory and takes into consideration the stabilization after the global recession. For the Large Use rate class, EPI utilizes the annual growth rate from the past three years (2012 to 2014) to calculate the geometric growth rate. EPI believes this better reflects the current usage projections by these customers who are not forecasting any growth. The results are presented in Table 3-9 below.

Table 3-9: Historical kWh Usage Growth Rates by Year

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
2006	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2007	98.97%	98.01%	96.98%	32.22%	147.25%	0.00%	97.67%	100.00%	0.00%	
2008	98.40%	99.88%	91.33%	110.61%	83.83%	0.00%	98.32%	92.49%	98.22%	
2009	98.03%	92.34%	86.27%	53.68%	75.87%	0.00%	101.62%	98.62%	100.25%	
2010	103.40%	101.63%	114.79%	99.13%	168.98%	51.41%	99.03%	98.76%	93.06%	
2011	98.98%	100.59%	103.27%	165.55%	118.13%	104.42%	81.57%	100.00%	85.57%	
2012	98.54%	94.56%	100.35%	96.97%	100.05%	97.12%	114.47%	100.31%	109.73%	
2013	94.41%	96.98%	100.36%	140.22%	93.97%	100.06%	89.08%	93.26%	101.24%	
2014	102.61%	102.39%	100.67%	84.12%	97.91%	100.48%	90.22%	95.46%	100.49%	
Geomean	**99.54%**	**99.18%**	**103.75%**	**104.58%**	**97.28%**	**87.88%**	**94.24%**	**97.52%**	**97.67%**	

To derive the 2015 Bridge Year forecast, EPI then applied the geometric mean growth rate by class to the 2014 average consumption per customer/connection to drive the forecasted average annual kWh consumption. To determine the 2016 Test Year forecast, EPI applied the same geometric growth rate by class to the calculated 2015 Bridge Year forecasted average annual kWh usage. The results are presented in Table 3-10 below.

Table 3-10: Forecasted Average Annual kWh Usage per Customer/Connection by Year

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
2015	7,987	27,818	954,684	34,686,292	30,713,726	4,375	791	554	4,526,975	
2016	7,950	27,591	990,446	36,274,944	29,877,457	3,845	745	540	4,421,657	

EPI used the average kWh usage from Table 3-10 and multiplied it by the forecasted customer/connections from Table 3-6 to determine the non-weather normalized total kWh by rate class. The results are presented in Table 3-11 below.

Table 3-11: Forecasted Billed kWh - Weather Non-Normalized

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
2015	289,153,361	107,377,480	470,659,212	34,686,292	30,713,726	1,268,750	402,619	7,406,426	4,526,975	946,194,841
2016	288,847,350	106,225,350	484,328,094	36,274,944	29,877,457	1,288,075	396,340	7,273,260	4,421,657	958,932,527

As previously noted, the forecasted weather normalized billed kWh for the 2015 Bridge Year and the 2016 Test Year are 934,838,752 and 937,083,018 respectively. These numbers represent weather normalized billed kWh but the forecasted billed kWh shown in Table 3-11 above are based on actual weather conditions, which means they are weather non-normalized. In order to reconcile these numbers back to the macro forecast, the non-weather normalized kWh amounts identified in Table 3-11 are adjusted based on weather sensitivity factors.

To determine the weather sensitivity of the various rate classes, EPI utilized the HONI weather sensitivity data prepared in the 2006 Load Profile Study for the former CKH and the former MPDC. EPI then calculated the weighted average percentage of sensitive load and applied these percentages to the amounts calculated in Table 3-11 above to derive the total weather sensitive load by rate class. The results are presented in Table 3-12 below.

TABLE 3-12: WEATHER SENSITIVE LOAD

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
% of Load	67.0%	67.0%	33.9%							
2015	193,590,988	71,890,267	159,562,628	-	-	-	-	-	-	425,043,883
2016	193,386,110	71,118,905	164,196,645	-	-	-	-	-	-	428,701,661

EPI then allocated the necessary weather normalization adjustment among the rate classes based on their weather sensitive load calculated in Table 3-12 above. The results are presented in Table 3-13 below.

TABLE 3-13: WEATHER NORMALIZATION ADJUSTMENT

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
Percent	45.5%	16.9%	37.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
2015	(5,172,258)	(1,920,725)	(4,263,107)	-	-	-	-	-	-	(11,356,089)
Percent	45.1%	16.6%	38.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
2016	(9,856,252)	(3,624,696)	(8,368,561)	-	-	-	-	-	-	(21,849,509)

To calculate the 2015 Bridge Year and 2016 Test Year weather normalized kWh forecast, EPI added the results of Table 3-11 and the results of Table 3-13. The resulting weather normalized billed kWh forecast is presented in Table 3-14 below. This excludes any adjustments for CDM and kWh related to Wholesale Market Participants.

Table 3-14: Total Weather Normalized kWh By Rate Class

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
2015	283,981,103	105,456,755	466,396,105	34,686,292	30,713,726	1,268,750	402,619	7,406,426	4,526,975	934,838,752
2016	278,991,098	102,600,654	475,959,533	36,274,944	29,877,457	1,288,075	396,340	7,273,260	4,421,657	937,083,018

In order to properly forecast the 2015 Bridge Year and 2016 Test Year Load, EPI needs to reduce the Load Forecast for the anticipated Conservation Demand Management ("CDM") programs savings and add the forecasted kWh related to the WMP noted in Section 3.2.4 above. For more information on the CDM Adjustment and the WMP Adjustment please see Section 3.2.8 and Section 3.2.10 respectively. The results of these adjustments are presented in Table 3-15 below.

Table 3-15: CDM and WMP Adjustments

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
CDM ADJUSTMENT										
2015	(964,516)	(1,119,084)	(2,503,647)	(13,760,034)	-	-	-	(10,052)	-	(18,357,333)
2016	(1,515,089)	(2,917,890)	(3,974,394)	(25,601,118)	-	-	-	(10,052)	-	(34,018,544)
WMP ADJUSTMENT										
2015			6,613,942							6,613,942
2016			6,861,699							6,861,699

EPI's total weather normalized load forecast, including CDM and WMP, is shown in Table 3-16 below.

Table 3-16: EPI's Weather Normalized Load Forecast

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
2015	283,016,587	104,337,672	470,506,400	20,926,258	30,713,726	1,268,750	402,619	7,396,374	4,526,975	923,095,361
2016	277,476,009	99,682,764	478,846,838	10,673,826	29,877,457	1,288,075	396,340	7,263,208	4,421,657	909,926,173

3.2.7 Billed kW Load Forecast

The volumetric revenue components for General Service > 50 kW, Large Use, Sentinel Lighting, Street Lighting and Embedded Distributor are calculated based on billed kW demand. Since the load forecast is calculated based on kWh, forecasted kW for these classes must be correlated with the forecasted kWh for each class.

EPI began with the annual historic billed kW as reported in the applicable annual RRR submissions and adjusted the data for the reclassifications noted above in Section 3.2.4. The results are presented in Table 3-17 below.

Table 3-17: Historic Billed kW by Rate Class by Year

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
2006	-	-	1,526,414	228,620	72,885	-	1,897	24,792	-	1,854,608
2007	-	-	1,319,003	206,603	57,865	-	1,234	31,812	10,733	1,627,250
2008	-	-	1,276,603	210,734	51,576	-	1,222	24,235	10,432	1,574,802
2009	-	-	1,131,642	158,060	38,952	-	1,217	24,546	10,438	1,364,855
2010	-	-	1,183,053	102,526	56,098	-	1,224	24,338	10,285	1,377,524
2011	-	-	1,189,083	68,609	63,856	-	980	24,338	11,258	1,358,124
2012	-	-	1,188,171	66,670	67,537	-	1,138	24,338	10,054	1,357,908
2013	-	-	1,223,255	87,871	67,914	-	1,130	23,008	9,926	1,413,104
2014	-	-	1,181,005	81,852	65,619	-	1,144	22,342	16,051	1,368,013

EPI then calculated the annual historical ratios between the billed kW in Table 3-17 and the billed kWh in Table 3-7. EPI utilized the average from the past five years (2010 to 2014) to calculate the average kW/kWh relationships. EPI believes five years best represents the current economic situation of its service territory and takes into consideration the stabilization after the global recession. The results are presented in Table 3-18 below.

Table 3-18: Historical Billed kW/kWh Ratio by Rate Class by Year

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
2006			0.300%	0.250%	0.200%		0.420%	0.280%	0.000%	
2007			0.260%	0.230%	0.210%		0.280%	0.360%	0.200%	
2008			0.280%	0.210%	0.230%		0.280%	0.300%	0.200%	
2009			0.290%	0.300%	0.230%		0.280%	0.300%	0.200%	
2010			0.270%	0.290%	0.190%		0.280%	0.300%	0.210%	
2011			0.270%	0.240%	0.190%		0.280%	0.300%	0.270%	
2012			0.260%	0.240%	0.200%		0.280%	0.300%	0.220%	
2013			0.270%	0.220%	0.210%		0.280%	0.300%	0.220%	
2014			0.260%	0.250%	0.210%		0.280%	0.300%	0.350%	
Average			**0.266%**	**0.248%**	**0.200%**		**0.280%**	**0.300%**	**0.254%**	

To derive the 2015 Bridge Year forecast, EPI then applied the average relationship by rate class to the 2015 Bridge Year weather normalized, CDM adjusted forecast. The same approach is taken for the 2016 Test Year kW forecast. Based on the calculations in Section 3.2.10, EPI also added an adjustment to reflect the Wholesale Market Participants. The results are presented in Table 3-19 below.

TABLE 3-19: FORECASTED BILLED KW BY RATE CLASS BY YEAR

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
Total Demand Forecast (kW)										
2015	-	-	1,233,954	51,897	61,427	-	1,127	22,189	11,499	1,382,093
2016	-	-	1,255,480	26,471	59,755	-	1,110	21,790	11,231	1,375,837
WMP Adjustment										
2015	-	-	16,132	-	-	-	-	-	-	16,132
2016	-	-	16,737	-	-	-	-	-	-	16,737
Total Adjusted Demand (kW)										
2015	-	-	1,250,086	51,897	61,427	-	1,127	22,189	11,499	1,398,225
2016	-	-	1,272,217	26,471	59,755	-	1,110	21,790	11,231	1,392,574

It is apparent above that while customers/connections increase by 0.4% from 2015 to 2016, the associated kWh and kW both decline by 1.3% on a year-over-year basis. This is primarily the result of a large industrial co-generation program which is anticipated to launch in 2015, and results in a significant decline in kWh and kW for the Large Use rate class above. This large industrial co-generation project is being installed as part of the CDM programs and is further discussed under Section 3.2.8 below.

3.2.8 CDM ADJUSTMENTS

EPI has completed Board Appendix 2-I in process of developing its 2015 and 2016 Load Forecast adjustments. Please see Attachment 3-D for copy of the completed Appendix 2-I.

Consistent with the Board's Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003) dated April 26, 2012, EPI has integrated a manual adjustment into its 2015 Bridge Year and 2016 Test Year load forecast for anticipated CDM results.

The load forecast, which draws on the regression analysis of historical actual usage inherently includes some, but not all, CDM efforts. EPI has taken the following approach, consistent with Board methodology, to developing a CDM adjustment for the 2015 Bridge Year and 2016 Test Year load forecasts:

- Determine 2014 program amounts not represented in the 2014 historical data,
- Determine Old Framework program amounts outstanding,
- Determine New Framework program amounts to be included.

OLD FRAMEWORK – PERSISTENCE OF 2014 PROGRAMS

EPI engaged IndEco Strategy Consulting ("IndEco") to calculate the estimated persistence of 2014 Program savings into the 2015 Bridge Year and 2016 Test Year by rate class. Due to the timing of implementation of these programs, some, but not all, of the 2014 Program persistence would have been captured in the 2014 actual results used in the load forecast regression analysis.

In an attempt to accurately capture the remaining savings not reflected in the actual data, EPI used 50% of the calculated persistence numbers to reduce the 2015 Bridge Year and 2016 Test Year load forecasts. Table 3-20 below shows the total annual 2014 persistence based on the IESO Draft Final Results issued on July 31 2015, as provided by IndEco. In Table 3-24 below, EPI applies the 50% factor to the total annual 2014 persistence for inclusion in the load forecast.

Table 3-20: Persistence of 2014 CDM Savings by Rate Class (kWh)

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
2014	1,679,864	1,196,574	4,208,252	3,851,828				20,105		10,956,624
2015	1,675,268	1,181,877	4,132,524	3,788,169				20,105		10,797,944
2016	1,614,734	1,156,190	4,073,368	3,738,440				20,105		10,602,838

NEW FRAMEWORK TARGET BY YEAR

Based on the Conservation First Framework, issued by the Board on September 19, 2014, EPI has been tasked with CDM savings of 56.8 GWh for the period of 2015 to 2020. EPI submitted an overall plan to the IESO on April 27, 2015 detailing the timing of these expected savings. Table 3-21 below shows the planned savings by year in order for EPI to achieve its target. The approved plan is included in Attachment 3-C of this Exhibit.

TABLE 3-21: CDM PLANNED SAVINGS BY YEAR

Line No.	Description	2015	2016	2017	2018	2019	2020
1	2015 Planned Program Savings	28,775,427	28,775,427	28,775,427	28,775,427	28,396,160	28,396,160
2	2016 Planned Program Savings	-	6,218,596	6,218,596	6,218,596	6,218,596	5,611,768
3	2017 Planned Program Savings	-	-	6,049,723	6,049,723	6,049,723	6,049,723
4	2018 Planned Program Savings	-	-	-	12,078,195	12,078,195	12,078,195
5	2019 Planned Program Savings	-	-	-	-	5,165,783	5,165,783
6	2020 Planned Program Savings	-	-	-	-	-	4,777,519
7	**Total Planned Savings**	**28,775,427**	**34,994,023**	**41,043,746**	**53,121,941**	**57,908,457**	**62,079,147**
8	Total Tasked Savings						56,800,000
9	Planned Overachievement						5,279,147

Due to a large industrial co-generation project scheduled to launch in 2015, EPI determined the best way to allocate the 2015 to 2020 CDM target of 56.8 GWh is based on the planned timeline contained in Table 3-21. Table 3-22 below shows the calculation of the CDM target to be used each year.

Note that the CDM Planned Savings submitted by EPI in the plan, summarized above, exceed the savings for which EPI was tasked under the Conservation First Framework. Management recognizes that it will be measured by the latter savings, but sought to build a program with planned overachievement.

TABLE 3-22: ALLOCATION OF 2015-2020 CDM TARGET

Line No.	Description	2015	2016	2017	2018	2019	2020	Total
1	Total Planned Savings	28,775,427	34,994,023	41,043,746	53,121,941	57,908,457	62,079,147	
2	Percentage of Planned Savings per Year	45.63%	9.86%	9.59%	19.15%	8.19%	7.58%	100.00%
3	**Tasked Savings by Year**	**25,916,720**	**5,600,807**	**5,448,710**	**10,878,282**	**4,652,586**	**4,302,895**	**56,800,000**

EPI utilized the planned program savings by rate class (determined by each program) to then allocate the tasked savings from Table 3-22 to each rate class. EPI believes this approach provides an accurate calculation of the projected impact to each rate class. The results for the 2015 Bridge Year and the 2016 Test Year are presented in Table 3-23 below.

TABLE 3-23: ALLOCATION OF 2015 AND 2016 CDM TASKED SAVINGS BY RATE CLASS

Line No.	Description	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
1	**Allocation of 2015 CDM Tasked Savings**										
2	2015 Planned Savings	585,796	2,438,380	2,019,353	23,731,898	-	-	-	-	-	28,775,427
3	Percentage of Total	11.6%	48.3%	40.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100%
4	**2015 Tasked Savings**	**253,763**	**1,056,289**	**874,770**	**23,731,898**	**-**	**-**	**-**	**-**	**-**	**25,916,720**
5	**Allocation of 2016 CDM Tasked Savings**										
6	2016 Planned Savings	**1,008,064**	**2,850,161**	**2,360,371**	**-**	**-**	**-**	**-**	**-**	**-**	**6,218,596**
7	Percentage of Total	**16.2%**	**45.8%**	**38.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**100.0%**
8	**2016 Tasked Savings**	**907,918**	**2,567,012**	**2,125,879**	**-**	**-**	**-**	**-**	**-**	**-**	**5,600,809**

LOAD FORECAST CDM ADJUSTMENTS BY RATE CLASS

Using the half year rule, EPI then used the above calculations to calculate the 2015 Bridge Year and 2016 Test Year load forecast adjustments. The results are presented in Table 3-24 below.

For the 2015 Bridge Year adjustment, EPI used 50% of the 2014 Program Savings and 50% of the 2015 Tasked Savings.

For the 2016 Test Year adjustment, EPI continued to use 50% of the 2014 Program savings, 100% of the 2015 Tasked Savings and 50% of the 2016 Tasked Savings.

TABLE 3-24: 2015 AND 2016 LOAD FORECAST ADJUSTMENTS

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
2015 Load Forecast Adjustment										
2014 Programs (50%)	837,634	590,939	2,066,262	1,894,085		-	-	10,052	-	5,398,972
2015 Programs (50%)	126,882	528,145	437,385	11,865,949	-	-	-	-	-	12,958,361
Total	**964,516**	**1,119,084**	**2,503,647**	**13,760,034**	**-**	**-**	**-**	**10,052**	**-**	**18,357,333**
2016 Load Forecast Adjustment										
2014 Programs (50%)	807,367	578,095	2,036,684	1,869,220				10,052		5,301,419
2015 Programs (100%)	253,763	1,056,289	874,770	23,731,898	-	-	-	-	-	25,916,720
2016 Programs (50%)	453,959	1,283,506	1,062,940	-	-	-	-	-	-	2,800,405
Total	**1,515,089**	**2,917,890**	**3,974,394**	**25,601,118**	**-**	**-**	**-**	**10,052**	**-**	**34,018,544**

3.2.9 LRAMVA BASELINE CALCULATION

Consistent with Board Appendix 2-I, EPI has calculated the LRAMVA baseline calculation with one exception regarding Large Use CDM savings.

As discussed above, EPI has a single Large Use customer in the Chatham service territory. In 2015, this customer has planned to install a 5.2 MW nameplate behind the meter generation facility. As discussed in Exhibit 7 and Exhibit 8, EPI has consulted the customer and agreed to monthly contracted amount on which cost allocation and rate design were developed. By using this contracted amount EPI will not have any LRAMVA savings or losses associated with the Large Use customer and proposes they be excluded from the LRAMVA baseline.

EPI has prepared an adjusted baseline calculation and included the results in Table 3-25 below.

TABLE 3-25: ADJUSTED LRAMVA BASELINE

Line No.	Description	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
1	2014 Program Persistence	1,614,734	1,156,190	4,073,368	3,738,440	-	-	-	20,105	-	10,602,838
2	2015 Program Persistence	253,763	1,056,289	874,770	23,731,898	-	-	-	-	-	25,916,720
3	2016 Program Persistence	907,918	2,567,012	2,125,879	-	-	-	-	-	-	5,600,809
4	**Total LRAMVA Baseline**	**2,776,415**	**4,779,491**	**7,074,017**	**27,470,339**	**-**	**-**	**-**	**20,105**	**-**	**42,120,367**
5	Exclude Large Use (Due to Contract Agreement)				(27,470,339)						(27,470,339)
6	**Adjusted LRAMVA Baseline**	**2,776,415**	**4,779,491**	**7,074,017**	**-**	**-**	**-**	**-**	**20,105**	**-**	**14,650,028**

3.2.10 WHOLESALE MARKET PARTICIPANTS

EPI currently has two Wholesale Market Participants (“WMPs”) operating within its service territory. These are customers who buy power directly from the IESO and use the EPI distribution system to deliver the power to their business locations. They are billed transmission and distribution charges by EPI for use of its facilities in delivering power to their service addresses within Strathroy. Other charges such as commodity, Global Adjustment and wholesale market service are billed directly to the WMPs by the IESO.

The regression analysis to derive the forecast purchased kWh inherently excludes the kWh related to the WMPs. For this reason EPI has excluded their historical billed kWh data from the above allocation calculations. EPI has forecasted the kWh consumption for these customers separately based on their specific usage. The first WMP opted into the program in mid-2012 and is a General Service > 50 kW customer. The second WMP is a new customer who came online in the fall of 2014 and will be considered an Intermediate customer upon the effective date of the rates approved by the Board pursuant to this Application. Due to the current rate structure they are currently being billed as a General Service > 50 kW customer in the SMP rate zone.

To forecast the consumption of these customers, EPI utilized the 2014 actual results as applied to the previously calculated geometric mean for the applicable rate class. Since the new customer in the Intermediate class does not have 12 months of activity for 2014, EPI estimated the remaining months using the average monthly consumption based on the available 2014 data. The results are shown in Table 3-26 below.

TABLE 3-26: WMP FORECASTED KWH

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
Historical kWh										
2011			-							-
2012			1,862,328							1,862,328
2013			4,199,611							4,199,611
2014			6,375,131							6,375,131
Geometric Mean										
			103.75%							
Forecasted kWh										
2015			6,613,942							6,613,942
2016			6,861,699							6,861,699

Similar to the demand calculations above, EPI calculated the WMPs demand by comparing the actual kW demand to the actual kWh consumption and using the average applied to the above forecasted kWh amounts to derive the forecasted bill kW. The results are presented in Table 3-27 below.

TABLE 3-27: WMP FORECAST KW

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use		Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distribution	Total
Historical kW										
2011			-							-
2012			4,198							4,198
2013			9,630							9,630
2014			17,662							17,662
Percentage kW/kWh										
2011										
2012			0.23%							
2013			0.23%							
2014			0.28%							
Average			0.24%							
Total kW Forecast										
2015			16,132							16,132
2016			16,737							16,737

3.2.11 SUMMARY OF 2015 AND 2016 LOAD FORECAST

Table 3-28 below provides a summary of the total forecasted customers/connections, forecasted billed kWh and kW for all customer classes including CDM Adjustments and WMP for the 2015 Bridge Year and the 2016 Test Year.

TABLE 3-28: WEATHER NORMALIZED LOAD FORECAST BY RATE CLASS

Line No.	Rate Class	2015			2016		
		Cust/Conn	kWh	kW	Cust/Conn	kWh	kW
1	Residential	36,203	283,016,587	-	36,333	277,476,009	-
2	GS < 50 kW	3,860	104,337,672	-	3,850	99,682,764	-
3	GS > 50 - 4,999 kW	495	470,506,400	1,250,086	491	478,846,838	1,272,217
4	Large Use	2	51,639,984	113,324	2	40,551,283	86,226
5	Unmetered Scattered Load	290	1,268,750	-	335	1,288,075	-
6	Sentinel Lights	509	402,619	1,127	532	396,340	1,110
7	Street Lights	13,369	7,396,374	22,189	13,469	7,263,208	21,790
8	Embedded Distributor	1	4,526,975	11,499	1	4,421,657	11,231
9	**Total**	**54,729**	**923,095,361**	**1,398,225**	**55,013**	**909,926,173**	**1,392,574**

EPI has completed Board Appendix 2-IA, Summary and Variances of Actual and Forecast Data and has been filed in Live Excel format and is included in Attachment 3-D of this Exhibit. EPI notes the billing determinants entered in Column B of this schedule contain the EPI Board Approved Proxy restated to align with proposed rate classes. For more information about EPI's Board Approved Proxy, please see Section 3.3.2 of this Exhibit.

For the purposes of calculating the Large Use demand profile in the cost allocation study and the development of Large Use distribution rate design, EPI has adjusted the CK Large Use rate class to reflect the agreed demand kW value for its customer who will use Standby. Table 3-29 below reflects the adjustments to CK Large Use class. For more information regarding the CK Large Use cost allocation and rate design, please see Exhibit 7 and Exhibit 8 respectively.

TABLE 3-29: LOAD FORECAST FOR COST ALLOCATION & DISTRIBUTION RATE DESIGN

Line No.	Rate Class	2015			2016		
		Cust/Conn	kWh	kW	Cust/Conn	kWh	kW
1	Residential	36,203	283,016,587	-	36,333	277,476,009	-
2	GS<50	3,860	104,337,672	-	3,850	99,682,764	-
3	GS>50	495	470,506,400	1,250,086	491	478,846,838	1,272,217
4	Large Use:						
5	CK	1	34,686,292	86,400	1	36,274,944	86,400
6	SMP	1	30,713,726	61,427	1	29,877,457	59,755
7	Unmetered Scattered Load	290	1,268,750	-	335	1,288,075	-
8	Sentinel Lights	509	402,619	1,127	532	396,340	1,110
9	Street Lights	13,369	7,396,374	22,189	13,469	7,263,208	21,790
10	Embedded Distributor	1	4,526,975	11,499	1	4,421,657	11,231
11	**Total**	**54,729**	**923,095,361**	**1,432,728**	**55,013**	**909,926,173**	**1,452,503**

3.3 Accuracy of Load Forecast and Variance Analysis

3.3.1 Overview

Provided in the following sections is EPI's analysis of the accuracy of the historical load forecast covering 2010 Board Approved Proxy, historical actual results from 2010 to 2014, the 2015 Bridge Year and the 2016 Test Year. The analysis has been completed on the following basis:

- Distribution Revenue,
- Billing Determinants (customer/connection counts, billed kWh and billed kW), and
- Distribution Revenue calculated on the basis of existing rates and proposed rates.

All historical amounts reflect actual weather conditions in the year. The 2015 Bridge Year and 2016 Test Year are weather normalized. It is the understanding of EPI that there is not a Board approved method with which to weather normalize actual data. Consequently, EPI does not have a process to adjust weather actual data to a weather normalized basis. However, Section 3.2 does outline the process undertaken by EPI to forecast energy on a weather normalized basis.

3.3.2 Calculation of the 2010 Board Approved Proxy

As described in Exhibit 1, EPI's last COS (EB-2009-0261) was filed by the former CKH in 2010.

On January 1, 2012, CKH merged with the former MPDC to form EPI. The last MPDC Board Approved amounts were established using the 2006 EDR methodology in Board file EB-2005-0351. Further, in 2009, MPDC acquired Dutton Hydro ("Dutton") and Newbury Power ("Newbury"). Similar to MPDC, Dutton and Newbury were also last rebased using the 2006 EDR methodology.

Since CKH and MPDC operated separately until 2012, the CKH 2010 distribution revenues do not include MPDC, Dutton or Newbury. As a result of this organizational evolution, EPI has developed proxy 2010 Board approved distribution revenue figures. EPI wishes to stress that this does not represent an attempt to revisit or deviate from the 2010 CKH figures previously approved by the Board. Rather, it is an attempt to facilitate comparison of distribution revenues in a manner consistent with the current EPI corporate structure, in recognition that the only 2010 Board approved figures available represent only the CKH component of what is now EPI.

Accordingly, EPI's 2010 Board Approved Proxy amount represents the combined distribution revenue and billing determinants from the former CKH, MPDC, Dutton and Newbury LDCs, and is comprised of the following amounts from each of the former LDCs.

CHATHAM-KENT HYDRO INC.

The former CKH filed a Cost of Service Application (EB-2009-0261) on October 5, 2009 for rates effective May 1, 2010. In the Settlement Agreement dated May 10, 2010, all parties agreed to the following 2010 Test Year Distribution Revenue[2] and 2010 Test Year load forecast[3]. Revenue to Cost ("RTC") ratio adjustments were completed in the 2011 IRM and 2012 IRM. The rate class specific Distribution Revenue below reflects the final values after completing the RTC adjustments in 2012. Table 3-30 below provides the details by rate class. This is commonly referred to as the "CK Rate Zone".

TABLE 3-30: CKH 2010 BOARD APPROVED DISTRIBUTION REVENUE AND LOAD FORECAST

Rate Class	Total Distribution Revenue	Billing Determinants		
		Customers/ Connections	kWh	kW
Residential	$7,879,073	28,644	207,045,763	
General Service < 50 kW	$2,209,566	3,038	90,210,202	
General Service > 50 kW	$2,293,665	421	189,939,582	494,092
Intermediate	$1,254,601	28	139,888,648	382,377
Street Lighting	$250,253	10,751	5,757,195	18,365
Sentinel Lighting	$37,229	327	347,118	1,079
Unmetered Scattered Load	$29,014	194	1,081,178	
Intermediate w/Self Generation	$320,281	1	32,205,190	87,305
Total	**$14,273,682**	**43,404**	**666,474,876**	**983,218**

[2] Chatham-Kent Hydro Inc., Cost of Service Application EB-2009-0261, Updated Draft Rate Order, Appendix C, Page 5 of 6, Dated May 10, 2010.
[3] Chatham-Kent Hydro Inc., Cost of Service Application EB-2009-0261, Updated Draft Rate Order, Page 4 of 62, Dated May 10, 2010.

MIDDLESEX POWER DISTRIBUTION CORPORATION

The former MPDC was last rebased using the 2006 EDR methodology in OEB file EB-2005-0351 and received a final decision on April 26, 2006. During the IRM period from 2007 to 2010, multiple adjustments were done to the base rates including K-Factor adjustments and segregation of rates. To incorporate these many changes and provide an accurate comparison of distribution revenue, EPI has utilized the May 1, 2010 IRM approved rates multiplied by the original 2006 EDR billing determinants. This is commonly referred to as the "SMP Rate Zone." The following table provides the details of this calculation.

TABLE 3-31: MPDC BOARD APPROVED DISTRIBUTION REVENUE PROXY

Rate Class	2010 IRM (EB-2009-0202)		2006 EDR (EB-2005-0351)			Board Approved Proxy Distribution Revenue		
	Service Charge	Volumetric Rate	Cust/Conn	kWh	kW	Fixed	Variable	Total
Residential	$13.73	$0.0139	5,985	59,377,482	-	$986,089	$825,347	$1,811,436
General Service < 50 kW	$18.14	$0.0048	669	26,984,886	-	$145,628	$129,527	$275,155
General Service > 50 kW	$43.35	$1.4368	109	81,269,539	226,920	$56,702	$326,038	$382,740
Large Use	$3,660.48	$0.0539	1	42,034,923	76,871	$43,926	$4,143	$48,069
Unmetered Scattered Load	$9.08	$0.0052	49	355,531	-	$5,339	$1,849	$7,188
Street Lighting	$0.18	$0.9858	1,958	1,518,658	4,322	$4,229	$4,260	$8,489
Sentinel Lighting	$0.14	$0.5776	46	46,765	118	$77	$68	$145
Total			**8,817**	**211,587,783**	**308,230**	**$1,241,990**	**$1,291,233**	**$2,533,223**

To facilitate the comparison of customers/connections, kWh and kW, EPI has used the 2010 billing determinants as reported by MPDC in RRR 2.1.5 for the SMP, Dutton and Newbury rate zones. Table 3-32 below shows the billing determinants as related to the SMP rate zone (or the former MPDC prior to the acquisition of Dutton & Newbury.)

TABLE 3-32: MPDC 2010 BILLING DETERMINANTS

Rate Class	Customer/ Connection	kWh	kW
Residential	6,299	58,904,267	
General Service < 50 kW	662	17,998,806	
General Service > 50 kW	91	91,846,588	235,476
Large Use	1	29,034,336	56,098
Unmetered Scattered Load	51	311,683	
Street Lighting	1,958	1,458,103	4,316
Sentinel Lighting	46	42,724	119
Total	**9,108**	**199,596,507**	**296,009**

DUTTON HYDRO INC.

The former Dutton Hydro Inc. was last rebased using the 2006 EDR methodology in OEB file EB-2009-0177. Dutton received a final Decision in that Application on February 22, 2010. During the IRM period from 2007 to 2010, multiple adjustments were done to the base rates including K-Factor adjustments and segregation of rates. To capture these many changes and provide an accurate comparison of revenue requirement, EPI has utilized the May 1, 2010 IRM Approved rates multiplied by the 2006 EDR billing determinants. This is commonly referred to as the "Dutton Rate Zone". The following table provides the details of this calculation.

TABLE 3-33: DUTTON BOARD APPROVED DISTRIBUTION REVENUE PROXY

Rate Class	2010 IRM (EB-2009-0177)		2006 EDR (EB-2009-0177)			Board Approved Proxy		
	Service Charge	Volumetric Rate	Cust/Conn	kWh	kW	Fixed	Variable	Total
Residential	$12.77	$0.0121	484	4,581,560	-	$74,168	$55,437	$129,605
General Service < 50 kW	$26.08	$0.0058	82	3,727,415	2,743	$25,663	$21,619	$47,282
Sentinel Lighting	$0.94	$4.9628	1	940	1	$11	$5	$16
Street Lighting	$0.63	$2.9418	1	122,073	305	$8	$897	$905
Total			**568**	**8,431,988**	**3,049**	**$99,850**	**$77,958**	**$177,808**

To facilitate the comparison of customers/connections, kWh and kW, EPI has used the 2010 billing determinants as reported by MPDC in RRR 2.1.5 for the SMP, Dutton and Newbury rate zones. Table 3-34 below shows the billing determinants as related to the Dutton rate zone.

TABLE 3-34: DUTTON 2010 BILLING DETERMINANTS

Rate Class	Customer/ Connection	kWh	kW
Residential	517	4,619,375	
General Service < 50 kW	88	3,520,313	
Sentinel Lighting	2	882	2
Street Lighting	207	115,944	343
Total	**814**	**8,256,514**	**345**

NEWBURY POWER INC.

The former Newbury Power Inc. was last rebased using the 2006 EDR methodology in OEB file EB-2005-0392. Newbury received a final Decision in that Application on May 1, 2007. During the IRM period from 2007 to 2010, multiple adjustments were done to the base rates including K-Factor adjustments and segregation of rates. To capture these many changes and provide an accurate comparison of revenue requirement, EPI has utilized the May 1, 2010 IRM Approved rates multiplied by the 2006 EDR billing determinants. This is commonly referred to as the "Newbury rate zone." The following table provides the details of this calculation.

TABLE 3-35: NEWBURY BOARD APPROVED DISTRIBUTION REVENUE PROXY

Rate Class	2010 IRM (EB-2009-0203)		2006 EDR (EB-2005-0392)			Board Approved Proxy		
	Service Charge	Volumetric Rate	Cust/Conn	kWh	kW	Fixed	Variable	Total
Residential	$11.90	$0.0120	160	1,741,618	-	$22,848	$20,899	$43,747
General Service < 50 kW	$21.78	$0.0108	25	630,122	-	$6,534	$6,805	$13,339
General Service > 50 kW	$265.33	$1.3339	4	1,676,116	7,182	$12,736	$9,580	$22,316
Street Lighting	$0.81	$3.3753	68	52,896	175	$661	$591	$1,252
Total			**257**	**4,100,752**	**7,357**	**$42,779**	**$37,875**	**$80,654**

To facilitate the comparison of customers/connections, kWh and kW, EPI has used the 2010 billing determinants as reported by MPDC in RRR 2.1.5 for the SMP, Dutton and Newbury rate zones. Table 3-36 below shows the billing determinants as related to the Newbury rate zone.

TABLE 3-36: NEWBURY 2010 BILLING DETERMINANTS

Rate Class	Customer/ Connection	kWh	kW
Residential	168	1,471,602	
General Service < 50 kW	31	499,285	
General Service > 50 kW	4	1,611,160	3,908
Street Lighting	87	55,055	163
Total	**290**	**3,637,102**	**4,071**

EPI BOARD APPROVED PROXY

The following table provides the aggregated CKH, MPDC, Dutton and Newbury Distribution Revenue and Customer/Connections, kWh and KW Board Approved Proxy totals. These aggregated Board Approved Proxy figures will be utilized in the variance analysis in the next section.

TABLE 3-37: EPI 2010 BOARD APPROVED PROXY

Rate Class	Distribution Revenue Fixed	Distribution Revenue Variable	Distribution Revenue Total	Customers/ Connections	kWh	kW
Residential	$7,221,908	$2,641,953	$9,863,861	35,628	272,041,007	-
General Service < 50 kW	$1,378,163	$1,167,180	$2,545,342	3,819	112,228,606	-
General Service > 50 kW	$545,233	$1,515,570	$2,060,803	516	283,397,330	733,476
Intermediate	$40,844	$2,011,426	$2,052,270	28	139,888,648	382,377
Intermediate w/Self Generation	$13,200	$220,888	$234,088	1	32,205,190	87,305
Large Use	$43,926	$4,143	$48,069	1	29,034,336	56,098
Unmetered Scattered Load	$23,062	$2,539	$25,601	245	1,392,861	-
Sentinel Lighting	$24,309	$547	$24,856	375	390,724	1,200
Street Lighting	$185,520	$24,958	$210,478	13,003	7,386,297	23,187
Total	**$9,476,163**	**$7,589,205**	**$17,065,368**	**53,616**	**877,964,999**	**1,283,643**

3.3.3 DISTRIBUTION REVENUE VARIANCE ANALYSIS

OVERVIEW

The following variance analysis has been provided based on EPI's materiality threshold per the materiality calculation being noted in Exhibit 1, Section 1.8 of this Application. EPI has chosen to use $90,000 as its basis for variance analysis of Distribution Revenue.

Table 3-38 below shows the variances by rate class for Distribution Revenue. Variances outside of the materiality threshold are discussed in detail below.

Total distribution revenue amounts tie to those filed in RRR 2.1.7 annually and to the audited financial statements, unless otherwise noted. EPI accrues for unbilled revenue at the end of each period, which is later reversed and replaced with the actual results.

TABLE 3-38: DISTRIBUTION REVENUE VARIANCE ANALYSIS

Line No.	Rate Class	2010 BAP	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual
1	Residential	$9,863,861	$10,269,057	$10,349,225	$10,379,429	$10,578,439	$10,744,304
2	General Service < 50 kW	$2,545,342	$2,593,012	$2,625,817	$2,569,377	$2,902,359	$3,045,561
3	General Service > 50 kW	$2,698,721	$2,659,416	$2,595,731	$2,939,943	$3,277,458	$3,210,103
4	Intermediate	$1,254,601	$1,212,581	$1,419,372	$1,181,845	$1,095,837	$1,111,202
5	Intermediate w/Self Generation	$320,281	$198,521	$212,106	$229,834	$294,696	$310,900
6	Large Use	$48,069	$20,837	$9,335	$7,231	$7,566	$9,330
7	Unmetered Scattered Load	$36,202	$24,089	$29,313	$32,975	$34,792	$35,492
8	Sentinel Lighting	$37,390	$23,271	$23,305	$30,063	$31,747	$32,815
9	Street Lighting	$260,898	$186,636	$221,844	$239,204	$245,113	$248,030
10	**Total**	**$17,065,367**	**$17,187,421**	**$17,486,048**	**$17,609,902**	**$18,468,007**	**$18,747,737**
11			**2010 BAP vs. 2010 Actual**	**2010 Actual vs. 2011 Actual**	**2011 Actual vs. 2012 Actual**	**2012 Actual vs. 2013 Actual**	**2013 Actual vs. 2014 Actual**
12	Residential		$405,197	$80,167	$30,204	$199,010	$165,864
13	General Service < 50 kW		$47,670	$32,804	-$56,439	$332,982	$143,202
14	General Service > 50 kW		-$39,305	-$63,685	$344,212	$337,514	-$67,355
15	Intermediate		-$42,020	$206,791	-$237,527	-$86,008	$15,366
16	Intermediate w/Self Generation		-$121,760	$13,585	$17,728	$64,862	$16,204
17	Large Use		-$27,232	-$11,503	-$2,103	$335	$1,764
18	Unmetered Scattered Load		-$12,113	$5,224	$3,662	$1,818	$700
19	Sentinel Lighting		-$14,120	$34	$6,758	$1,684	$1,068
20	Street Lighting		-$74,263	$35,209	$17,360	$5,909	$2,917
21	**Total**		**$122,054**	**$298,627**	**$123,854**	**$858,105**	**$279,730**

2010 BOARD APPROVED PROXY VS. 2010 ACTUAL RESULTS

EPI experienced an increase of 2010 actual distribution revenue of $122,054 from the 2010 Board Approved Proxy.

The increase in distribution revenue from 2010 BAP to 2010 Actual can be attributed to the volumetric increase in 2010.

Table 3-39 below shows a comparison of the 2010 Board Approved Proxy billing determinants versus the year end billing determinants as filed in RRR 2.1.5.

TABLE 3-39: 2010 BAP VS. 2010 ACTUAL BILLING DETERMINANTS

Rate Class	Customer/ Connections	kWh	kW	Customer/ Connections	kWh	kW	Customer/ Connections	kWh	kW
	2010 BAP			2010 Actual Results			Variance		
Residential	35,628	272,041,007	-	35,496	301,267,823	-	(132)	29,226,816	-
General Service < 50 kW	3,819	112,228,606	-	3,955	117,581,666	-	136	5,353,060	-
General Service > 50 kW	516	283,397,330	733,476	481	380,225,251	1,037,760	(35)	96,827,921	304,284
Intermediate	28	139,888,648	382,377	15	71,112,112	183,786	(13)	(68,776,536)	(198,591)
Intermediate w/Self Generation	1	32,205,190	87,305	1	16,602,633	44,183	-	(15,602,557)	(43,122)
Large Use	1	29,034,336	56,098	2	35,570,129	83,844	1	6,535,793	27,746
Unmetered Scattered Load	245	1,392,861	-	245	1,191,306	-	-	(201,555)	-
Sentinel Lighting	375	390,724	1,200	388	433,931	1,224	13	43,207	24
Street Lighting	13,003	7,386,297	23,187	12,931	8,221,743	24,338	(72)	835,446	1,151
Total	**53,616**	**877,964,999**	**1,283,643**	**53,514**	**932,206,593**	**1,375,135**	**(102)**	**54,241,594**	**91,492**

2010 ACTUAL RESULTS VS. 2011 ACTUAL RESULTS

In 2011, EPI experienced an increase in distribution revenue of $298,627 over 2010 actuals.

While the total kWh and kW did not vary significantly year-over-year, the increase in distribution revenue is primarily attributable to a change in mix between the low volume rate classes (Residential and Small Commercial) versus the higher volume Intermediate and Intermediate with Self Generation rate classes, as shown in Table 3-41 below.

The following additional reasons contributed to the increase:

- An increase in the number of Residential customers in the CK and SMP Rate Zones,
- Full year impact of Cost of Service rates for CK, and
- Annual mechanistic IRM inflation of rates effect May 1, 2011 of 0.38%, reflective of the CK and MPDC “Cohort 1” stretch factor (efficiency) ranking statuses

TABLE 3-40: 2010 ACTUAL VS. 2011 ACTUAL BILLING DETERMINANTS

Rate Class	Customer/ Connections	kWh	kW	Customer/ Connections	kWh	kW	Customer/ Connections	kWh	kW
	2010 Actual Results			2011 Actual Results			Variance		
Residential	35,496	301,267,823	-	35,760	299,495,986	-	264	(1,771,837)	-
General Service < 50 kW	3,955	117,581,666	-	3,865	117,915,433	-	(90)	333,767	-
General Service > 50 kW	481	380,225,251	1,037,760	479	333,268,072	906,404	(2)	(46,957,179)	(131,356)
Intermediate	15	71,112,112	183,786	14	114,379,257	290,985	(1)	43,267,145	107,199
Intermediate w/Self Generation	1	16,602,633	44,183	1	28,996,883	68,609	-	12,394,250	24,426
Large Use	2	35,570,129	83,844	1	34,298,990	63,856	(1)	(1,271,139)	(19,988)
Unmetered Scattered Load	245	1,191,306	-	245	1,249,000	-	-	57,694	-
Sentinel Lighting	388	433,931	1,224	388	353,837	980	-	(80,094)	(244)
Street Lighting	12,931	8,221,743	24,338	12,931	8,221,874	24,338	-	131	0
Total	**53,514**	**932,206,593**	**1,375,135**	**53,684**	**938,179,332**	**1,355,172**	**170**	**5,972,739**	**(19,963)**

2011 ACTUAL RESULTS VS. 2012 ACTUAL RESULTS

In 2012, EPI experienced an increase in distribution revenue of $123,854 from 2011.

Although EPI experienced some customer movement between General Service < 50 kW, General Service > 50 kW and Intermediate rate classes, this variance is within the range expected for the 2012 IRM price cap index adjustment. The increase is primarily driven by the 2012 IRM price cap index of 1.08%, consistent with the continued Cohort 1 stretch factor (efficiency) ranking statuses.

The following table shows 2011 Actual year end billing determinants versus the 2012 year end billing determinants. During 2012, EPI experienced a small increase in Residential customers, while total kWh billed remained relatively flat.

TABLE 3-41: 2011 ACTUAL VS. 2012 ACTUAL BILLING DETERMINANTS

Rate Class	Customer/ Connections	kWh	kW	Customer/ Connections	kWh	kW	Customer/ Connections	kWh	kW
	2011 Actual Results			2012 Actual Results			Variance		
Residential	35,760	299,495,986	-	35,872	296,656,279	-	112	(2,839,707)	-
General Service < 50 kW	3,865	117,915,433	-	3,858	110,156,226	-	(7)	(7,759,207)	-
General Service > 50 kW	479	333,268,072	906,404	487	344,334,971	920,518	8	11,066,899	14,114
Intermediate	14	114,379,257	290,985	13	114,499,112	278,788	(1)	119,855	(12,197)
Intermediate w/Self Generation	1	28,996,883	68,609	1	28,118,306	66,670	-	(878,577)	(1,939)
Large Use	1	34,298,990	63,856	1	34,317,082	67,537	-	18,092	3,681
Unmetered Scattered Load	245	1,249,000	-	245	1,213,037	-	-	(35,963)	-
Sentinel Lighting	388	353,837	980	388	405,259	1,138	-	51,422	158
Street Lighting	12,931	8,221,874	24,338	12,931	8,250,167	24,338	-	28,293	-
Total	**53,684**	**938,179,332**	**1,355,172**	**53,796**	**937,950,439**	**1,358,989**	**112**	**(228,893)**	**3,817**

2012 ACTUAL RESULTS VS. 2013 ACTUAL RESULTS

In 2013, EPI experienced increased distribution revenue of $858,105 from 2012.

Note that the total 2013 distribution revenue of $18,468,007 ties to the distribution revenue reported on EPI's audited financial statements but does not tie to the distribution revenue reported in RRR 2.1.7. The distribution revenue reported in RRR 2.1.7 of $18,699,867 inadvertently included SSS Administration revenue of $150,788 and an adjustment from Other Revenue of $81,072. These amounts have been properly excluded from distribution revenue for purposes of this Application and are discussed in the Other Revenue section below.

A significant driver of the 2013 distribution revenue increase relates to smart meter disposition. On November 1, 2012, EPI received approval from the Board for final disposition of costs related to its

Smart Meter implementation (EB-2012-0289). In the Board's decision, Smart Meter Incremental Revenue Requirement Riders ("SMIRRs") were approved for all rate zones. The SMIRRs were effective from November 1, 2012 until the next Cost of Service rebasing (i.e. the current application). A significant portion of the increase experienced in 2013 is the result of the full year impact of these rate riders. Approximately $475k can be attributed to these ongoing rate riders.

In 2013, EPI also recognized distribution revenue related to the disposition of the Lost Revenue Adjustment Mechanism ("LRAM"). This resulted in approximately $155k.

On April 4, 2013, EPI received approval from the Board for an IRM adjustment to rates effective May 1, 2013. This IRM adjustment included a Price Cap Index Adjustment for 0.68%, consistent with the continued Cohort 1 stretch factor (efficiency) ranking statuses. This translates into approximately $120k of additional revenue.

The remaining increase is related to the changes in billing determinants. From Table 3-42 below, it is apparent that while total kWh were slightly down, there was an overall increase in year-over-year kW demand, particularly in the General Service > 50 kW and the Intermediate with Self Generation rate classes.

TABLE 3-42: 2012 ACTUAL VS. 2013 ACTUAL BILLING DETERMINANTS

Rate Class	Customer/ Connections	kWh	kW	Customer/ Connections	kWh	kW	Customer/ Connections	kWh	kW
	2012 Actual Results			2013 Actual Results			Variance		
Residential	35,872	296,656,279	-	36,016	281,071,800	-	144	(15,584,479)	-
General Service < 50 kW	3,858	110,156,226	-	3,872	107,026,648	-	14	(3,129,578)	-
General Service > 50 kW	487	344,334,971	920,518	482	351,270,575	961,307	(5)	6,935,604	40,789
Intermediate	13	114,499,112	278,788	13	112,421,651	278,345	-	(2,077,461)	(443)
Intermediate w/Self Generation	1	28,118,306	66,670	1	39,427,413	87,871	-	11,309,107	21,201
Large Use	1	34,317,082	67,537	1	32,247,068	67,914	-	(2,070,014)	377
Unmetered Scattered Load	245	1,213,037	-	251	1,228,666	-	6	15,629	-
Sentinel Lighting	388	405,259	1,138	493	410,160	1,130	105	4,901	(8)
Street Lighting	12,931	8,250,167	24,338	13,274	7,792,246	23,008	343	(457,921)	(1,330)
Total	**53,796**	**937,950,439**	**1,358,989**	**54,403**	**932,896,227**	**1,419,575**	**607**	**(5,054,212)**	**60,586**

2013 ACTUAL RESULTS VS. 2014 ACTUAL RESULTS

In 2014, EPI experienced an increase in distribution revenue of $279,730 from 2013 actual results.

On March 13, 2014, EPI received approval from the Board for an IRM adjustment to rates effective May 1, 2014. The increase is primarily driven by this IRM adjustment, which included a Price Cap Index

Adjustment for 1.55%. The Price Cap Index of 1.55% is consistent with EPI's ranking in the second of five cohorts in the Board's annual stretch factor (efficiency) rankings.

The remaining variance can be explained by the billing determinant variances experienced in 2014. As shown in Table 3-43 below, EPI experienced minimal growth in the number of Residential customers and some increase in the kWh consumption for the Residential and General Service < 50 kW rate classes, but decreased kW demand in all other rate classes.

TABLE 3-43: 2013 ACTUAL VS. 2014 ACTUAL BILLING DETERMINANTS

Rate Class	Customer/ Connections	kWh	kW	Customer/ Connections	kWh	kW	Customer/ Connections	kWh	kW
	2013 Actual Results			2014 Actual Results			Variance		
Residential	36,016	281,071,800	-	36,131	289,455,443	-	115	8,383,643	-
General Service < 50 kW	3,872	107,026,648	-	3,874	109,826,277	-	2	2,799,629	-
General Service > 50 kW	482	351,270,575	961,307	486	353,341,398	938,382	4	2,070,823	(22,925)
Intermediate	13	112,421,651	278,345	12	113,731,870	273,287	(1)	1,310,219	(5,058)
Intermediate w/Self Generation	1	39,427,413	87,871	1	33,167,215	81,852	-	(6,260,198)	(6,019)
Large Use	1	32,247,068	67,914	1	31,573,402	65,619	-	(673,666)	(2,295)
Unmetered Scattered Load	251	1,228,666	-	250	1,249,444	-	(1)	20,778	-
Sentinel Lighting	493	410,160	1,130	481	408,652	1,144	(12)	(1,508)	14
Street Lighting	13,274	7,792,246	23,008	13,266	7,533,249	22,342	(8)	(258,997)	(666)
Total	**54,403**	**932,896,227**	**1,419,575**	**54,502**	**940,286,951**	**1,382,627**	**99**	**7,390,724**	**(36,948)**

3.3.4 2015 & 2016 DISTRIBUTION REVENUE AT EXISTING RATES

As previously noted, EPI represents a merger of the four former utilities, which has resulted in the current maintenance of four separate rate zones as follows:

- CK Rate Zone,
- SMP Rate Zone,
- Dutton Rate Zone, and
- Newbury Rate Zone.

In order to facilitate the calculation of Distribution Revenue at existing rates, EPI calculated you the percentage of 2014 customers, kWh and kW by rate zone and by rate class. EPI then applied these percentages to the 2016 Loaf Forecast to determine a Load Forecast for each rate zone. EPI then multiple the 2016 load by rate zone by the 2015 IRM Approved Rates (EB-2014-0064) by rate zone. For purposes of this variance analysis and consistency, EPI has included the SMIRR riders and the Shared Tax Savings rate riders as then directly impact Distribution Revenue.

2014 ACTUAL RESULTS VS. 2015 FORECAST AT EXISTING RATES

Based on the weighted average rates discussed above the proposed 2015 Load Forecast, EPI would expect to receive an increase in Distribution Revenue of $66,348.

TABLE 3-44: 2014 ACTUAL VS 2015 BY AT EXISTING RATES DISTRIBUTION REVENUE

Rate Class	Distribution Revenue Total	Distribution Revenue Total	Distribution Revenue Total
	2014 Actual	2015 Bridge	Variance
Residential	$10,744,304	$10,937,019	$192,715
General Service < 50 kW	$3,045,561	$2,979,955	-$65,606
General Service > 50 kW	$3,210,103	$3,199,467	-$10,636
Intermediate	$1,111,202	$1,177,804	$66,602
Intermediate w/Self Generation	$310,900	$165,839	-$145,062
Large Use	$9,330	$12,550	$3,220
Unmetered Scattered Load	$35,492	$39,762	$4,270
Sentinel Lighting	$32,815	$46,133	$13,318
Street Lighting	$248,030	$253,947	$5,917
Embedded Distribution		$1,610	$1,610
Total	**$18,747,737**	**$18,814,085**	**$66,348**

On March 19, 2015, EPI received approval from the Board for an IRM adjustment to rates effective May 1, 2014 (EB-2014-0064). The increase is primarily driven by the annual IRM adjustment, which included a Price Cap Index Adjustment for 1.45%. The Price Cap Index of 1.45% is consistent with EPI's ranking in the second of five cohorts in the Board's annual stretch factor (efficiency) rankings.

The remaining offsetting variance can be explained by the billing determinant variances forecasted for 2015. As shown in Table 3-45 below, EPI expected to have minimal growth of customers, a noted decline in kWh due to expected CDM savings and an increase in demand for General Service >50 customers.

TABLE 3-45: 2014 ACTUAL VS. 2015 BY BILLING DETERMINANTS

Rate Class	Customer/ Connections	kWh	kW	Customer/ Connections	kWh	kW	Customer/ Connections	kWh	kW
	2014 Actual Results			2015 Bridge Year at Existing Rates			Variance		
Residential	36,131	289,455,443		36,202	283,016,587		71	(6,438,856)	-
General Service < 50 kW	3,874	109,826,277		3,861	104,337,672		(13)	(5,488,605)	-
General Service > 50 kW	486		938,382	482		966,562	(4)	-	28,180
Intermediate	12		273,287	12		283,524	-	-	10,237
Intermediate w/Self Generation	1		81,852	1		51,897	-	-	(29,955)
Large Use	1		65,619	1		61,427	-	-	(4,192)
Unmetered Scattered Load	250	1,249,444		290	1,268,750		40	19,306	-
Sentinel Lighting	481		1,144	509		1,127	28	-	(17)
Street Lighting	13,266		22,342	13,369		22,189	103	-	(153)
Embedded Distribution				1		11,231	1	-	11,231
Total	**54,502**	**400,531,165**	**1,382,627**	**54,728**	**388,623,009**	**1,397,957**	**226**	**(11,908,156)**	**15,331**

2015 FORECAST AT EXISTING RATES VS. 2016 FORECAST AT EXISTING RATES

Based on the weighted average existing rates discussed above, EPI would anticipate a decrease in distribution revenue from the 2015 Bridge Year to the 2016 Test Year of $77,924.

TABLE 3-46: 2015 BY VS 2016 TY DISTRIBUTION REVENUE AT EXISTING RATES

Rate Class	Distribution Revenue Total	Distribution Revenue Total	Distribution Revenue Total
	2015 Bridge	2016 Test	Variance
Residential	$10,937,019	$10,911,948	-$25,070
General Service < 50 kW	$2,979,955	$2,925,951	-$54,004
General Service > 50 kW	$3,199,467	$3,220,026	$20,559
Intermediate	$1,177,804	$1,221,387	$43,582
Intermediate w/Self Generation	$165,839	$92,734	-$73,105
Large Use	$12,550	$13,465	$915
Unmetered Scattered Load	$39,762	$45,606	$5,844
Sentinel Lighting	$46,133	$48,222	$2,089
Street Lighting	$253,947	$255,212	$1,265
Embedded Distribution	$1,610	$1,610	$0
Total	**$18,814,085**	**$18,736,161**	**-$77,924**

EPI expects to continue to see a small increase in Residential customers and General Service kW demand but the distribution revenue gains are expected to be fully offset in the volumetric reductions for Residential, small General Service and the Intermediate with Self Generation customer associated with CDM efforts.

TABLE 3-47: 2015 BY VS 2016 TEST YEAR BILL DETERMINANTS

Rate Class	Customer/ Connections	kWh	kW	Customer/ Connections	kWh	kW	Customer/ Connections	kWh	kW
	2015 Bridge Year at Existing Rates			2016 Test Year at Existing Rates			Variance		
Residential	36,202	283,016,587	-	36,333	277,476,009		131	(5,540,578)	-
General Service < 50 kW	3,861	104,337,672	-	3,850	99,682,764		(11)	(4,654,908)	-
General Service > 50 kW	482	-	966,562	478		978,072	(4)	-	11,510
Intermediate	12	-	283,524	12		294,145	-	-	10,621
Intermediate w/Self Generation	1	-	51,897	1		26,471	-	-	(25,426)
Large Use	1	-	61,427	1		59,755	-	-	(1,672)
Unmetered Scattered Load	290	1,268,750	-	335	1,288,075		45	19,325	-
Sentinel Lighting	509	-	1,127	532		1,110	23	-	(17)
Street Lighting	13,369	-	22,189	13,469		21,790	100	-	(399)
Embedded Distribution	1	-	11,231	1		11,231	-	-	-
Total	**54,728**	**388,623,009**	**1,397,957**	**55,012**	**378,446,848**	**1,392,574**	**284**	**(10,176,161)**	**(5,384)**

2015 & 2016 DISTRIBUTION REVENUE EXCLUDING SMIRR & SHARED TAX SAVINGS

Consistent with the Board Filing Requirements for the Revenue Requirement calculation and Cost Allocation Model, EPI has calculated the 2015 and 2016 Distribution Revenue at existing 2015 distribution rates excluding the SMIRR rate riders ("RRs") and Shared Tax Savings RRs. The results are presented in Table 3-48 below.

TABLE 3-48: 2015 AND 2016 DISTRIBUTION REVENUE FOR RRWF & CA MODEL

Line No.	Description	2015 Distribution Revenue Excluding RR	2016 Distribution Revenue Excluding RR
1	Residential	$10,677,392.62	$10,650,078.96
2	General Service <50	$2,578,954.02	$2,525,657.65
3	General Service >50	$4,220,449.86	$4,399,012.00
4	Large User	$179,659.12	$106,949.08
5	Unmetered Scattered Load Connections	$39,982.37	$45,829.75
6	Sentinel Lighting Connections	$46,393.59	$48,476.65
7	Street Lighting Connections	$255,279.60	$256,508.76
8	Embedded Distributor	$1,474.32	$1,474.32
9	**Total**	**$17,999,585.50**	**$18,033,987.17**

3.3.5 2016 DISTRIBUTION REVENUE AT PROPOSED RATES

The proposed test year distribution revenue is a reflection of this 2016 COS Application and the Proposed Base Revenue Requirement of EPI.

2015 FORECAST AT EXISTING RATES (INCLUDING RRS) VS. 2016 FORECAST AT PROPOSED RATES

Table 3-49 below compares the 2015 Forecast at existing rates versus the 2016 forecast at proposed rates. The 2015 distribution revenue in Table 3-49 also includes distribution revenue arising from SMIRR and offsetting tax sharing rate riders.

TABLE 3-49: 2015 AT EXISTING VS. 2016 AT PROPOSED RATES DISTRIBUTION REVENUE

Rate Class	2014 Actual Distribution Revenue	2015 BY at Existing Rates Distribution Revenue	2016 BY at Proposed Rates Distribution Revenue	Variance 2015 vs. 2016
Residential	$10,744,304	$10,937,019	$10,856,703	-$80,316
General Service < 50 kW	$3,045,561	$2,979,955	$2,330,283	-$649,671
General Service > 50 kW	$3,210,103	$3,199,467	$4,437,064	$1,237,597
Intermediate	$1,111,202	$1,177,804		-$1,177,804
Intermediate w/Self Generation	$310,900	$165,839		-$165,839
Large Use	$9,330	$12,550	$265,776	$253,226
Unmetered Scattered Load	$35,492	$39,762	$34,893	-$4,869
Sentinel Lighting	$32,815	$46,133	$48,896	$2,763
Street Lighting	$248,030	$253,947	$215,553	-$38,394
Embedded Distribution	$0	$1,610	$814	-$796
Total	**$18,747,737**	**$18,814,085**	**$18,189,982**	**-$624,103**

It is apparent in Table 3-49 that the revenue is decreasing by $624,103. This is primarily attributable to decreases in the depreciation and taxes consistent with MIFRS transition, as well as, an expected decrease in volumes relates to CDM savings planned for 2016. However, when calculating Revenue Deficiency/Sufficiency, Board Filing Requirements indicate that SMIRR RRs and Tax Sharing RRs be removed the revenue at existing rates calculation. However, the impact of SMIRR RRs (by virtue of inclusion in Rate Base) and Tax Sharing RRs (by virtue of updated Income Tax/PILs Model calculation) are rolled into Distribution Rates as of the 2016 TY. While EPI views Table 3-49 above as comparable in terms of year-over-year Distribution Revenue, it has completed Table 3-50 below to show revenue at existing rates with SMIRR RRs and Tax Sharing RRs excluded, and thereby calculate a variance somewhat consistent with the Revenue Deficiency.

TABLE 3-50: 2015 AT EXISTING RATES (EXCLUDING RR) VS. 2016 AT PROPOSED RATES

Rate Class	2014 Actual Distribution Revenue	2015 BY at Existing Rates Distribution Revenue	2016 BY at Proposed Rates Distribution Revenue	Variance 2015 vs. 2016
Residential	$10,744,304	$10,677,393	$10,856,703	$179,310
General Service < 50 kW	$3,045,561	$2,578,954	$2,330,283	-$248,671
General Service > 50 kW	$3,210,103	$3,035,189	$4,437,064	$1,401,875
Intermediate	$1,111,202	$1,185,261	$0	-$1,185,261
Intermediate w/Self Generation	$310,900	$166,887	$0	-$166,887
Large Use	$9,330	$12,772	$265,776	$253,004
Unmetered Scattered Load	$35,492	$39,982	$34,893	-$5,089
Sentinel Lighting	$32,815	$46,394	$48,896	$2,502
Street Lighting	$248,030	$255,280	$215,553	-$39,727
Embedded Distribution	$0	$1,474	$814	-$660
Total	**$18,747,737**	**$17,999,586**	**$18,189,982**	**$190,396**

Table 3-51 below shows the forecasted change in billing determinants from the 2015 BY to the 2016 TY based on the Load Forecast including CDM.

TABLE 3-51: 2015 FORECASTED BILLING DETERMINANTS VS. 2016 FORECASTED BILLING DETERMINANTS

Rate Class	Customer/ Connections	kWh	kW	Customer/ Connections	kWh	kW	Customer/ Connections	kWh	kW
	2015 Bridge Year at Existing Rates			2016 Test Year at Proposed Rates			Variance		
Residential	36,202	283,016,587	-	36,333	277,476,009		131	(5,540,578)	-
General Service < 50 kW	3,861	104,337,672	-	3,850	99,682,764		(11)	(4,654,908)	-
General Service > 50 kW	482	-	966,562	491		1,272,217	9	-	305,655
Intermediate	12	-	283,524				(12)	-	(283,524)
Intermediate w/Self Generation	1	-	51,897				(1)	-	(51,897)
Large Use	1	-	61,427	2		86,226	1	-	24,799
Unmetered Scattered Load	290	1,268,750	-	335	1,288,075		45	19,325	-
Sentinel Lighting	509	-	1,127	532		1,110	23	-	(17)
Street Lighting	13,369	-	22,189	13,469		21,790	100	-	(399)
Embedded Distribution	1	-	11,231	1		11,231	-	-	-
Total	**54,728**	**388,623,009**	**1,397,957**	**55,013**	**378,446,848**	**1,392,574**	**285**	**(10,176,161)**	**(5,384)**

3.4 OTHER REVENUE

3.4.1 OVERVIEW

Other Revenue is any revenue that is distribution in nature but that is sourced from means other than distribution rates. EPI currently earns and forecasts to continue earn Other Revenue. Other Revenues comprises four major categories: Specific Service Charges, Late Payment Charges, Other Operating Revenues and Other Income or Deductions.

Table 3-52 below provides a high level summary and comparison of these four categories for the Board Approved Proxy, the Historic Years 2010 through 2014, the 2015 Bridge Year and 2016 Test Year. EPI notes, it has made some reclassifications within Other Revenue components for some years to allow for consistent year-over-year comparisons. None of these reclassifications are material in nature and do not change total Other Revenue.

TABLE 3-52: SUMMARY OF OTHER REVENUE

Line No.	Description	2010 Board Approved Proxy	2010 Actual Results	2011 Actual Results	2012 Actual Results	2013 Actual Results	2014 Actual Results	2015 Bridge Year	2016 Test Year
1	Specific Service Charges	$444,844	$332,660	$273,269	$371,529	$291,864	$311,708	$322,188	$327,731
2	Late Payment Charges	$241,439	$242,342	$247,833	$258,141	$252,224	$312,004	$250,000	$250,000
3	Other Operating Revenues	$672,862	$537,011	$585,525	$540,084	$565,407	$573,893	$429,383	$436,738
4	Other Income or Deductions	$299,388	$884,684	$570,146	$332,509	-$372,733	-$1,213,138	-$961,442	$350,552
5	**Total**	**$1,658,532**	**$1,996,697**	**$1,676,773**	**$1,502,263**	**$736,762**	**-$15,533**	**$40,128**	**$1,365,021**

More details of Other Revenue amounts earned and expected to be earned in the Bridge and Test Years can be found in OEB Appendix 2-H, included as Attachment 3-E to this Exhibit. Please note that EPI has added additional lines to this schedule to assist with the reconciliation of Other Revenue to the Other Revenue offset used in the Revenue Requirement calculation. The Table 3-53 below shows the reconciliation between total Other Revenue and the amount of Other Revenue utilized in the Revenue Requirement calculation.

TABLE 3-53: OTHER REVENUE FOR REVENUE REQUIREMENT CALCULATION

Line No.	Description	2010 Board Approved Proxy	2010 Actual Results	2011 Actual Results	2012 Actual Results	2013 Actual Results	2014 Actual Results	2015 Bridge Year	2016 Test Year
1	Total Other Revenue	$1,658,532	$1,996,697	$1,676,773	$1,502,263	$736,762	-$15,533	$40,128	$1,365,021
2	Exclude:								
3	Non Regulated Revenue	$0	-$535,871	$53,971	-$11,110	$464	-$139,190	-$111,500	-$111,500
4	Non Regulated Expenses	$0	$0	$0	$4,661	$20,206	$35,571	$35,000	$35,000
5	Deferral Account Interest	$0	$0	-$117,574	-$112,704	-$95,784	-$107,867	-$100,000	-$100,000
6	IFRS Adjustment	$0	$0	$0	$0	$602,341	$1,677,655	$1,305,434	$0
7	**Adjusted Other Revenue**	**$1,658,532**	**$1,460,826**	**$1,613,170**	**$1,383,111**	**$1,263,988**	**$1,450,636**	**$1,169,062**	**$1,188,521**

3.4.2 CALCULATION OF THE 2010 BOARD APPROVED PROXY AMOUNT

As described in Exhibit 1, EPI's last Cost of Service (EB-2009-0261) was filed by the former CKH.

On January 1, 2012, CKH merged with the former MPDC to form EPI. The last MPDC Board Approved Other Revenue was established using the 2006 EDR methodology in OEB file EB-2005-0351. Further, in 2009, MPDC acquired Dutton and Newbury. Similar to MPDC, Dutton and Newbury were also last rebased using the 2006 EDR methodology.

Since CKH and MPDC operated separately until 2012, the CKH 2010 Other Revenue amounts do not include MPDC, Dutton or Newbury. As a result of this organizational evolution, EPI has developed proxy 2010 Board Approved Other Revenue Proxy Figures. EPI wishes to stress that this does not represent an attempt to revisit or deviate from the 2010 CKH figures previously approved by the Board. Rather, it is an attempt to facilitate comparison of Other Revenues in a manner consistent with the current EPI corporate structure, in recognition that the only 2010 Board Approved figures available represent only the CKH component of what is now EPI.

Accordingly, the 2010 Board Approved Other Revenue Proxy amount represents the Other Revenue amounts from the former CKH, MPDC, Dutton and Newbury LDCs. . The Board Approved Proxy allows for more appropriate Board Approved comparisons and is comprised of the following amounts from each of the former LDCs.

CHATHAM-KENT HYDRO INC.

The former CKH filed a Cost of Service Application (EB-2009-0261) on October 5, 2009 for rates effective May 1, 2010. In the Settlement Agreement dated May 10, 2010, all parties agreed to the total Other Revenue of $1,302,450[4]. Table 3-54 provides a breakdown by each account.

TABLE 3-54: CKH 2010 BOARD APPROVED OTHER REVENUE

Line No.	USoA	Description	Per Settlement	Reallocate	Adjusted Total
1	4235	Specific Service Charges	$494,368	-$114,376	$379,992
2	4225	Late Payment Charges	$198,861	$0	$198,861
3		**Other Operating Revenue**			
4	4082	Retail Services Revenues	$65,004	$0	$65,004
5	4084	Service Transaction Requests (STR) Revenues	$1,996	$0	$1,996
6	4086	SSS Administration Revenue	$105,000	$0	$105,000
7	4090	Electric Services Incidental to Energy Sales	$0	$0	$0
8	4205	Interdepartmental Rents	$156,996	$0	$156,996
9	4210	Rent from Electric Property	$126,996	$0	$126,996
10	4215	Other Utility Operating Income	$0	$0	$0
11	4220	Other Electric Revenues	$9,996	$0	$9,996
12		**Subtotal**	**$465,988**	**$0**	**$465,988**
13		**Other Income or Deductions**			
14	4305	Regulatory Debits	$0	$0	$0
15	4325	Revenues from Merchandise	$0	$0	$0
16	4355	Gain on Disposition of Utility and Other Property	$0	$0	$0
17	4360	Loss on Disposition of Utility and Other Property	$40,000	$0	$40,000
18	4375	Revenues from Non Rate-Regulated Utility Operations	$0	$114,376	$114,376
19	4380	Expenses of Non Rate-Regulated Utility Operations	$0	$0	$0
20	4390	Miscellaneous Non-Operating Income	$30,996	$0	$30,996
21	4405	Interest and Dividend Income	$72,237	$0	$72,237
22		**Subtotal**	**$143,233**	**$114,376**	**$257,609**
23		**Grand Total**	**$1,302,450**	**$0**	**$1,302,450**

Account 4235 included $114,376 of approved revenue related to storm assistance. To align with actual reporting and for purposes of comparison, EPI has reclassified this amount from Account 4235 to Account 4375 in the above table.

[4] Chatham-Kent Hydro Inc., Cost of Service Application EB-2009-0261, Updated Draft Rate Order, Page 5 of 62, Dated May 10, 2010.

MIDDLESEX POWER DISTRIBUTION CORPORATION

The former MPDC was last rebased using the 2006 EDR methodology in OEB file EB-2005-0351 and received a final decision on April 26, 2006. MPDC was approved for Other Revenue of $314,258[5]. In order to facilitate the variance analysis below, EPI has inflated the Other Revenue amounts for each of the years 2007, 2008, 2009 and 2010 by the annual Board Approved IRM inflation factors used in MPDC's annual applications. Table 3-55 below provides a breakdown by account and appropriate inflation calculation.

TABLE 3-55: CALCULATION OF MPDC 2010 BOARD APPROVED OTHER REVENUE

Line No.	USoA	Description	2006 EDR	Reallocate	Adjusted Total	2007 Inflated	2008 Inflated	2009 Inflated	2010 Inflated
1		Inflation Rates				1.009	1.011	1.013	1.003
2	4235	Specific Service Charges	$94,572	-$34,352	$60,220	$60,762	$61,430	$62,229	$62,416
3	4225	Late Payment Charges	$33,650		$33,650	$33,953	$34,326	$34,773	$34,877
4		**Other Operating Revenue**							
5	4082	Retail Services Revenues	$9,590		$9,590	$9,676	$9,783	$9,910	$9,940
6	4084	Service Transaction Requests (STR) Revenues	$82		$82	$82	$83	$84	$85
7	4086	SSS Administration Revenue			$0	$0	$0	$0	$0
8	4090	Electric Services Incidental to Energy Sales	$23,459		$23,459	$23,670	$23,930	$24,241	$24,314
9	4205	Interdepartmental Rents			$0	$0	$0	$0	$0
10	4210	Rent from Electric Property	$46,662	$34,352	$81,014	$81,744	$82,643	$83,717	$83,968
11	4215	Other Utility Operating Income	$15,351		$15,351	$15,490	$15,660	$15,864	$15,911
12	4220	Other Electric Revenues	$51,359		$51,359	$51,822	$52,392	$53,073	$53,232
13		**Subtotal**	**$146,504**	**$34,352**	**$180,856**	**$182,483**	**$184,491**	**$186,889**	**$187,450**
14		**Other Income or Deductions**							
15	4305	Regulatory Debits			$0	$0	$0	$0	$0
16	4325	Revenues from Merchandise	$2,100		$2,100	$2,119	$2,142	$2,170	$2,177
17	4355	Gain on Disposition of Utility and Other Property	$13,389		$13,389	$13,509	$13,658	$13,835	$13,877
18	4360	Loss on Disposition of Utility and Other Property			$0	$0	$0	$0	$0
19	4375	Revenues from Non Rate-Regulated Utility Operations			$0	$0	$0	$0	$0
20	4380	Expenses of Non Rate-Regulated Utility Operations			$0	$0	$0	$0	$0
21	4390	Miscellaneous Non-Operating Income	$7,652		$7,652	$7,721	$7,806	$7,907	$7,931
22	4405	Interest and Dividend Income	$16,392		$16,392	$16,539	$16,721	$16,939	$16,990
23		**Subtotal**	**$39,532**	**$0**	**$39,532**	**$39,888**	**$40,327**	**$40,851**	**$40,974**
24		**Grand Total**	**$314,258**	**$0**	**$314,258**	**$317,086**	**$320,574**	**$324,742**	**$325,716**

Account 4235 included $34,352 of approved revenue related to pole rentals. To align with actual reporting and for purposes of comparison, EPI has restated this amount from Account 4235 to Account 4210 in the above table.

[5] Middlesex Power Distribution Corporation, 2006 EDR EB-2005-0351, MPDC EB 2005 0351 EDR 2006 Model updated Feb08(version 2.1 cleared) Decision.xls, Tab 5-5 Base Revenue Requirement

DUTTON HYDRO INC.

The former Dutton Hydro Inc. was last rebased using the 2006 EDR methodology in OEB file EB-2009-0177 and received a final decision on February 22, 2010. Dutton was approved for Other Revenue of $21,497. In order to facilitate the variance analysis below, EPI has inflated the Other Revenue amounts for each of the years 2007, 2008, 2009 and 2010 by the annual Board Approved IRM inflation factors used their annual applications. Table 3-56 below provides a breakdown by account and appropriate inflation.

TABLE 3-56: CALCULATION OF DUTTON HYDRO'S 2010 BOARD APPROVED OTHER REVENUE

Line No.	USoA	Description	2006 EDR	Reallocate	Adjusted Total	2007 Inflated	2008 Inflated	2009 Inflated	2010 Inflated
1		Inflation Rates				1.009	1.011	1.013	1.003
2	4235	Specific Service Charges	$5,226	-$3,911	$1,315	$1,327	$1,341	$1,359	$1,363
3	4225	Late Payment Charges	$2,909		$2,909	$2,935	$2,967	$3,006	$3,015
4		**Other Operating Revenue**							
5	4082	Retail Services Revenues	$9,312		$9,312	$9,396	$9,499	$9,622	$9,651
6	4084	Service Transaction Requests (STR) Revenues	$0		$0	$0	$0	$0	$0
7	4086	SSS Administration Revenue	$0		$0	$0	$0	$0	$0
8	4090	Electric Services Incidental to Energy Sales	$0		$0	$0	$0	$0	$0
9	4205	Interdepartmental Rents	$0		$0	$0	$0	$0	$0
10	4210	Rent from Electric Property	$0	$3,911	$3,911	$3,946	$3,990	$4,042	$4,054
11	4215	Other Utility Operating Income	$4,050		$4,050	$4,086	$4,131	$4,185	$4,198
12	4220	Other Electric Revenues	$0		$0	$0	$0	$0	$0
13		**Subtotal**	**$13,362**	**$3,911**	**$17,273**	**$17,428**	**$17,620**	**$17,849**	**$17,903**
14		**Other Income or Deductions**							
15	4305	Regulatory Debits	$0		$0	$0	$0	$0	$0
16	4325	Revenues from Merchandise	$0		$0	$0	$0	$0	$0
17	4355	Gain on Disposition of Utility and Other Property	$0		$0	$0	$0	$0	$0
18	4360	Loss on Disposition of Utility and Other Property	$0		$0	$0	$0	$0	$0
19	4375	Revenues from Non Rate-Regulated Utility Operations	$0		$0	$0	$0	$0	$0
20	4380	Expenses of Non Rate-Regulated Utility Operations	$0		$0	$0	$0	$0	$0
21	4390	Miscellaneous Non-Operating Income	$0		$0	$0	$0	$0	$0
22	4405	Interest and Dividend Income	$0		$0	$0	$0	$0	$0
23		**Subtotal**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
24		**Grand Total**	**$21,497**	**$0**	**$21,497**	**$21,690**	**$21,929**	**$22,214**	**$22,281**

Account 4235 included $34,352 of approved revenue related to pole rentals. To align with actual reporting and for purposes of comparison, EPI has reallocated this amount from Account 4235 to Account 4210 in the above table.

NEWBURY POWER INC.

The former Newbury Power Inc. was last rebased using the 2006 EDR methodology in OEB file EB-2005-0392 and received a final decision on May 1, 2007. Newbury was approved for Other Revenue of $7,801. In order to facilitate the variance analysis below, EPI has inflated the Other Revenue amounts for each of the years 2007, 2008, 2009 and 2010 by the annual Board Approved IRM inflation factors as utilized in their annual applications. Table 3-57 below provides a breakdown by account and appropriate inflation.

TABLE 3-57: CALCULATION OF NEWBURY POWER'S 2010 BOARD APPROVED OTHER REVENUE

Line No.	USoA	Description	2006 EDR	Reallocate	Adjusted Total	2007 Inflated	2008 Inflated	2009 Inflated	2010 Inflated
1		Inflation Rates				1.009	1.011	1.013	1.003
2	4235	Specific Service Charges	$1,035		$1,035	$1,044	$1,056	$1,070	$1,073
3	4225	Late Payment Charges	$4,521		$4,521	$4,562	$4,612	$4,672	$4,686
4		**Other Operating Revenue**							
5	4082	Retail Services Revenues	$0		$0	$0	$0	$0	$0
6	4084	Service Transaction Requests (STR) Revenues	$0		$0	$0	$0	$0	$0
7	4086	SSS Administration Revenue	$0		$0	$0	$0	$0	$0
8	4090	Electric Services Incidental to Energy Sales	$0		$0	$0	$0	$0	$0
9	4205	Interdepartmental Rents	$0		$0	$0	$0	$0	$0
10	4210	Rent from Electric Property	$1,468		$1,468	$1,481	$1,498	$1,517	$1,522
11	4215	Other Utility Operating Income	$0		$0	$0	$0	$0	$0
12	4220	Other Electric Revenues	$0		$0	$0	$0	$0	$0
13		**Subtotal**	**$1,468**	**$0**	**$1,468**	**$1,481**	**$1,498**	**$1,517**	**$1,522**
14		**Other Income or Deductions**							
15	4305	Regulatory Debits	$0		$0	$0	$0	$0	$0
16	4325	Revenues from Merchandise	$0		$0	$0	$0	$0	$0
17	4355	Gain on Disposition of Utility and Other Property	$0		$0	$0	$0	$0	$0
18	4360	Loss on Disposition of Utility and Other Property	$0		$0	$0	$0	$0	$0
19	4375	Revenues from Non Rate-Regulated Utility Operations	$0		$0	$0	$0	$0	$0
20	4380	Expenses of Non Rate-Regulated Utility Operations	$0		$0	$0	$0	$0	$0
21	4390	Miscellaneous Non-Operating Income	$0		$0	$0	$0	$0	$0
22	4405	Interest and Dividend Income	$777		$777	$784	$793	$803	$805
23		**Subtotal**	**$777**	**$0**	**$777**	**$784**	**$793**	**$803**	**$805**
24		**Grand Total**	**$7,801**	**$0**	**$7,801**	**$7,871**	**$7,958**	**$8,061**	**$8,085**

EPI has made no reallocations in the above table.

EPI BOARD APPROVED PROXY

The following table provides the aggregated CKH, MPDC, Dutton and Newbury Other Revenue Board Approved Proxy totals, based on Table 3-54, Table 3-55, Table 3-56 and Table 3-57 above.

TABLE 3-58: EPI 2010 BOARD APPROVED PROXY OTHER REVENUE

Line No.	USoA	Description	CKH	MPDC	Dutton	Newbury	Total
1	4235	Specific Service Charges	$494,368	$62,416	$1,363	$1,073	$559,219
2	4225	Late Payment Charges	$198,861	$34,877	$3,015	$4,686	$241,439
3		**Other Operating Revenue**					
4	4082	Retail Services Revenues	$65,004	$9,940	$9,651	$0	$84,595
5	4084	Service Transaction Requests (STR) Revenues	$1,996	$85	$0	$0	$2,081
6	4086	SSS Administration Revenue	$105,000	$0	$0	$0	$105,000
7	4090	Electric Services Incidental to Energy Sales	$0	$24,314	$0	$0	$24,314
8	4205	Interdepartmental Rents	$156,996	$0	$0	$0	$156,996
9	4210	Rent from Electric Property	$126,996	$83,968	$4,054	$1,522	$216,540
10	4215	Other Utility Operating Income	$0	$15,911	$4,198	$0	$20,109
11	4220	Other Electric Revenues	$9,996	$53,232	$0	$0	$63,228
12		**Subtotal**	**$465,988**	**$187,450**	**$17,903**	**$1,522**	**$672,862**
13		**Other Income or Deductions**					
14	4305	Regulatory Debits	$0	$0	$0	$0	$0
15	4325	Revenues from Merchandise	$0	$2,177	$0	$0	$2,177
16	4355	Gain on Disposition of Utility and Other Property	$0	$13,877	$0	$0	$13,877
17	4360	Loss on Disposition of Utility and Other Property	$40,000	$0	$0	$0	$40,000
18	4375	Revenues from Non Rate-Regulated Utility Operations	$0	$0	$0	$0	$0
19	4380	Expenses of Non Rate-Regulated Utility Operations	$0	$0	$0	$0	$0
20	4390	Miscellaneous Non-Operating Income	$30,996	$7,931	$0	$0	$38,927
21	4405	Interest and Dividend Income	$72,237	$16,990	$0	$805	$90,032
22		**Subtotal**	**$143,233**	**$40,974**	**$0**	**$805**	**$185,012**
23		**Grand Total**	**$1,302,450**	**$325,716**	**$22,281**	**$8,085**	**$1,658,532**

3.4.3 OTHER REVENUE VARIANCE ANALYSIS

The following variance analysis has been provided based on EPI's materiality threshold per the materiality calculation being noted in Exhibit 1, Section 1.8 of this Application. EPI has chosen to use $90,000 as its basis for variance analysis of Other Revenues.

Table 3-59 below shows the variances by major Other Revenue category. Variances outside of the materiality threshold are discussed in detail below.

TABLE 3-59: OTHER REVENUE VARIANCE ANALYSIS

Line No.	Description	2010 Board Approved Proxy	2010 Actual Results	2011 Actual Results	2012 Actual Results	2013 Actual Results	2014 Actual Results	2015 Bridge Year	2016 Test Year
1	Specific Service Charges	$444,844	$332,660	$273,269	$371,529	$291,864	$311,708	$322,188	$327,731
2	Late Payment Charges	$241,439	$242,342	$247,833	$258,141	$252,224	$312,004	$250,000	$250,000
3	Other Operating Revenues	$672,862	$537,011	$585,525	$540,084	$565,407	$573,893	$429,383	$436,738
4	Other Income or Deductions	$299,388	$884,684	$570,146	$332,509	-$372,733	-$1,213,138	-$961,442	$350,552
5	**Total**	**$1,658,532**	**$1,996,697**	**$1,676,773**	**$1,502,263**	**$736,762**	**-$15,533**	**$40,128**	**$1,365,021**
			2010 BA v. 2010 Act	**2010 Act v. 2011 Act**	**2011 Act v. 2012 Act**	**2012 Act v. 2013 Act**	**2013 Act v. 2014 Act**	**2014 Act v. 2015 BY**	**2015 BY v. 2016 TY**
6	Specific Service Charges		-$112,184	-$59,391	$98,260	-$79,665	$19,844	$10,480	$5,544
7	Late Payment Charges		$904	$5,491	$10,308	-$5,918	$59,781	-$62,004	$0
8	Other Operating Revenues		-$135,850	$48,514	-$45,441	$25,323	$8,485	-$144,510	$7,355
9	Other Income or Deductions		$585,296	-$314,538	-$237,637	-$705,242	-$840,404	$251,696	$1,311,994
10	**Total**		**$338,165**	**-$319,924**	**-$174,510**	**-$765,502**	**-$752,295**	**$55,661**	**$1,324,893**

2010 BOARD APPROVED PROXY VS. 2010 ACTUAL

EPI experienced an overall increase in Other Revenue between the 2010 Board Approved Proxy and the 2010 Actual results of $338,165 as shown in Table 3-60 below.

TABLE 3-60: 2010 BOARD APPROVED PROXY VS. 2010 ACTUAL

Line No.	USoA	USoA Description	2010 BAP	2010 Act	Variance
1	4235	Specific Service Charges	$444,844	$332,660	-$112,184
2	4225	Late Payment Charges	$241,439	$242,342	$904
3	4082	Retail Services Revenues	$84,595	$75,486	-$9,109
4	4084	Service Transaction Requests (STR) Revenues	$2,081	$2,500	$419
5	4086	SSS Administration Revenue	$105,000	$135,456	$30,456
6	4090	Electric Services Incidental to Energy Sales	$24,314	$0	-$24,314
7	4205	Interdepartmental Rents	$156,996	$156,996	$0
8	4210	Rent from Electric Property	$216,539	$156,557	-$59,983
9	4215	Other Utility Operating Income	$20,109	$0	-$20,109
10	4220	Other Electric Revenues	$63,228	$10,016	-$53,212
11	4305	Regulatory Debits	$0	$0	$0
12	4325	Revenues from Merchandise	$2,177	$0	-$2,177
13	4355	Gain on Disposition of Utility and Other Property	$13,877	$45,485	$31,609
14	4360	Loss on Disposition of Utility and Other Property	$40,000	-$118,373	-$158,373
15	4375	Revenues from Non Rate-Regulated Utility Operations	$114,376	$800,310	$685,935
16	4380	Expenses of Non Rate-Regulated Utility Operations	$0	$0	$0
17	4390	Miscellaneous Non-Operating Income	$38,927	$29,530	-$9,397
18	4405	Interest and Dividend Income	$90,032	$127,731	$37,699
19		**Grand Total**	**$1,658,532**	**$1,996,697**	**$338,165**

ACCOUNT 4235: SPECIFIC SERVICE CHARGES

EPI experienced a decrease in Specific Service Charge revenue of $112,184. This variance is fully attributable to the former CKH rate zone. This primarily relates to a reduction in Account Setup Charges and Reconnection Fees activity.

ACCOUNT 4360: LOSS ON DISPOSITION OF UTILITY AND OTHER PROPERTY

In the 2010 CKH Cost of Service application, the former CKH had inadvertently included $40,000 of revenue in Account 4360 (which is intended to track losses on asset dispositions, rather than revenue). In 2010, the former CKH had losses on asset dispositions of $3,750 and had recorded the approved disposition of stranded meters related to the implementation Smart Meters for $114,623. This was approved as part of the CKH 2010 Cost of Service Application (EB-2009-0261).

ACCOUNT 4375: REVENUES FROM NON RATE REGULATED UTLITY OPERATIONS

In 2010, EPI experienced a significant increase in Revenues from Non-Rate-Regulated Operations due to two activities:

- The completion of the first round of CDM funding. As these programs came to a close, CKH and MPDC completed funding reconciliations and made their final submissions to the Ontario Power Authority. The completion of this exercise resulted in additional revenue from the OPA being recorded of $535,870.
- Water and sewer billing activities completed by the former MPDC on behalf of the Municipality of Strathroy-Caradoc for $258,685.

2010 ACTUAL VS. 2011 ACTUAL

EPI experienced an overall decrease in Other Revenue between the 2010 Actual results and the 2011 Actual results of $319,924 as shown in Table 3-61 below.

TABLE 3-61: 2010 ACTUAL VS. 2011 ACTUAL OTHER REVENUE

Line No.	USoA	USoA Description	2010 Act	2011 Act	Variance
1	4235	Specific Service Charges	$332,660	$273,269	-$59,391
2	4225	Late Payment Charges	$242,342	$247,833	$5,491
3	4082	Retail Services Revenues	$75,486	$63,044	-$12,442
4	4084	Service Transaction Requests (STR) Revenues	$2,500	$1,385	-$1,115
5	4086	SSS Administration Revenue	$135,456	$144,362	$8,906
6	4090	Electric Services Incidental to Energy Sales	$0	$0	$0
7	4205	Interdepartmental Rents	$156,996	$175,601	$18,605
8	4210	Rent from Electric Property	$156,557	$198,385	$41,828
9	4215	Other Utility Operating Income	$0	$0	$0
10	4220	Other Electric Revenues	$10,016	$2,749	-$7,268
11	4305	Regulatory Debits	$0	$0	$0
12	4325	Revenues from Merchandise	$0	$0	$0
13	4355	Gain on Disposition of Utility and Other Property	$45,485	$109,158	$63,673
14	4360	Loss on Disposition of Utility and Other Property	-$118,373	$0	$118,373
15	4375	Revenues from Non Rate-Regulated Utility Operations	$800,310	$262,232	-$538,078
16	4380	Expenses of Non Rate-Regulated Utility Operations	$0	$0	$0
17	4390	Miscellaneous Non-Operating Income	$29,530	$65,751	$36,221
18	4405	Interest and Dividend Income	$127,731	$133,005	$5,274
19		**Grand Total**	**$1,996,697**	**$1,676,773**	**-$319,924**

ACCOUNT 4360: LOSS ON DISPOSITION OF UTILITY AND OTHER PROPERTY

There were no Losses on Dispositions reported in 2011. This variance primarily relates to the 2010 actual disposition of Stranded Smart Meters, as described above.

ACCOUNT 4375: REVENUES FROM NON RATE REGULATED UTILITY OPERATIONS

2011 Actual results are lower than 2010 Actual results due to $535,871 of CDM revenue realized in 2010 related to the previous CDM programs. There was actually a small CDM loss recorded in 2011. Removing this amount from 2010 leaves a residual balance of $264,439, which is in line with the amount recognized in 2011.

2011 ACTUALS RESULTS VERSUS 2012 ACTUAL RESULTS

EPI experienced an overall decrease in Other Revenue between the 2011 Actual results and the 2012 Actual results of $174,510 as shown in Table 3-62 below.

TABLE 3-62: 2011 ACTUAL RESULTS VS. 2012 ACTUAL RESULTS

Line No.	USoA	USoA Description	2011 Act	2012 Act	Variance
1	4235	Specific Service Charges	$273,269	$371,529	$98,260
2	4225	Late Payment Charges	$247,833	$258,141	$10,308
3	4082	Retail Services Revenues	$63,044	$53,186	-$9,859
4	4084	Service Transaction Requests (STR) Revenues	$1,385	$1,462	$77
5	4086	SSS Administration Revenue	$144,362	$142,532	-$1,831
6	4090	Electric Services Incidental to Energy Sales	$0	$0	$0
7	4205	Interdepartmental Rents	$175,601	$179,109	$3,508
8	4210	Rent from Electric Property	$198,385	$159,245	-$39,139
9	4215	Other Utility Operating Income	$0	$0	$0
10	4220	Other Electric Revenues	$2,749	$4,551	$1,802
11	4305	Regulatory Debits	$0	$0	$0
12	4325	Revenues from Merchandise	$0	$0	$0
13	4355	Gain on Disposition of Utility and Other Property	$109,158	$73,609	-$35,549
14	4360	Loss on Disposition of Utility and Other Property	$0	$0	$0
15	4375	Revenues from Non Rate-Regulated Utility Operations	$262,232	$120,557	-$141,675
16	4380	Expenses of Non Rate-Regulated Utility Operations	$0	-$61,363	-$61,363
17	4390	Miscellaneous Non-Operating Income	$65,751	$61,327	-$4,424
18	4405	Interest and Dividend Income	$133,005	$138,379	$5,374
19		**Grand Total**	**$1,676,773**	**$1,502,263**	**-$174,510**

ACCOUNT 4235: SPECIFIC SERVICE CHARGES

For Account 4235, 2012 Actual results increased by $98,260. This is a result of in an increase in the volume of occupancy change requests as well as an increase in the sale of materials related to recoverable jobs.

ACCOUNT 4375: REVENUES FROM NON RATE REGULATED UTILITY OPERATIONS

As described in Exhibit 1, in 2012 CKH and MPDC merged to become EPI. Upon completion of this merger, the water and sewer billing activates previously completed by MPDC were moved to Entegrus Services Inc. (“ESI”), EPI’s unregulated affiliate services company. This change in resulted in a decrease of $276,348 from 2011 to 2012, which was partially offset by revenue earned for storm assistance related to Hurricane Sandy in October 2012 for $73,521.

2012 ACTUAL RESULTS VERSUS 2013 ACTUAL RESULTS

EPI experienced an overall decrease in Other Revenue between the 2012 Actual results and the 2013 Actual results of $765,502 as shown in Table 3-63 below.

TABLE 3-63: 2012 ACTUAL RESULTS VS. 2013 ACTUAL RESULTS

Line No.	USoA	USoA Description	2012 Act	2013 Act	Variance
1	4235	Specific Service Charges	$371,529	$291,864	-$79,665
2	4225	Late Payment Charges	$258,141	$252,224	-$5,918
3	4082	Retail Services Revenues	$53,186	$45,160	-$8,025
4	4084	Service Transaction Requests (STR) Revenues	$1,462	$1,194	-$268
5	4086	SSS Administration Revenue	$142,532	$150,788	$8,257
6	4090	Electric Services Incidental to Energy Sales	$0	$0	$0
7	4205	Interdepartmental Rents	$179,109	$196,468	$17,359
8	4210	Rent from Electric Property	$159,245	$164,701	$5,455
9	4215	Other Utility Operating Income	$0	$0	$0
10	4220	Other Electric Revenues	$4,551	$7,096	$2,545
11	4305	Regulatory Debits	$0	-$602,341	-$602,341
12	4325	Revenues from Merchandise	$0	$0	$0
13	4355	Gain on Disposition of Utility and Other Property	$73,609	$180,353	$106,744
14	4360	Loss on Disposition of Utility and Other Property	$0	-$85,222	-$85,222
15	4375	Revenues from Non Rate-Regulated Utility Operations	$120,557	$44,202	-$76,355
16	4380	Expenses of Non Rate-Regulated Utility Operations	-$61,363	-$27,034	$34,328
17	4390	Miscellaneous Non-Operating Income	$61,327	$21,525	-$39,802
18	4405	Interest and Dividend Income	$138,379	$95,784	-$42,595
19		**Grand Total**	**$1,502,263**	**$736,762**	**-$765,502**

ACCOUNT 4305: REGULATORY DEBITS

As directed by the Board, in 2013 EPI moved to Revised Canadian Generally Accepted Accounting Principles (“RCGAAP”). The amount of $602,341 booked to account 4305 represents the financial differences arising upon conversion, as relating to depreciation and capitalization polices. The amount of $602,341 represents the offsetting entry to Account 1576 as prescribed by the Board in its “Accounts Procedures Handbook Frequently Asked Questions July 2012” issued on July 17, 2012.

ACCOUNT 4355: GAIN ON DISPOSITION OF UTILITY AND OTHER PROPERTY

The increase primarily relates to EPI's successful disposition in 2013 of property in Tilbury which previously accommodated the Tilbury Public Works Commission (prior to amalgamation of Chatham-Kent and the formation of CKH).

2013 ACTUAL RESULTS VERSUS 2014 ACTUAL RESULTS

EPI experienced an overall decrease in Other Revenue between the 2012 Actual results and the 2013 Actual results of $752,295 as shown in Table 3-64 below.

TABLE 3-64: 2013 ACTUAL RESULTS VS. 2014 ACTUAL RESULTS

Line No.	USoA	USoA Description	2013 Act	2014 Act	Variance
1	4235	Specific Service Charges	$291,864	$311,708	$19,844
2	4225	Late Payment Charges	$252,224	$312,004	$59,781
3	4082	Retail Services Revenues	$45,160	$37,977	-$7,184
4	4084	Service Transaction Requests (STR) Revenues	$1,194	$773	-$421
5	4086	SSS Administration Revenue	$150,788	$151,936	$1,147
6	4090	Electric Services Incidental to Energy Sales	$0	$0	$0
7	4205	Interdepartmental Rents	$196,468	$200,760	$4,292
8	4210	Rent from Electric Property	$164,701	$176,427	$11,726
9	4215	Other Utility Operating Income	$0	$0	$0
10	4220	Other Electric Revenues	$7,096	$6,020	-$1,076
11	4305	Regulatory Debits	-$602,341	-$1,677,655	-$1,075,315
12	4325	Revenues from Merchandise	$0	$0	$0
13	4355	Gain on Disposition of Utility and Other Property	$180,353	$38,787	-$141,566
14	4360	Loss on Disposition of Utility and Other Property	-$85,222	$0	$85,222
15	4375	Revenues from Non Rate-Regulated Utility Operations	$44,202	$262,013	$217,811
16	4380	Expenses of Non Rate-Regulated Utility Operations	-$27,034	-$50,155	-$23,121
17	4390	Miscellaneous Non-Operating Income	$21,525	$16,007	-$5,519
18	4405	Interest and Dividend Income	$95,784	$197,867	$102,083
19		**Grand Total**	**$736,762**	**-$15,533**	**-$752,295**

ACCOUNT 4305: REGULATORY DEBITS

As described above, Account 4305 represents the financial differences arising as a result of changes to account depreciation and/or capitalization polices related to the implementation of Modified International Financial Reporting Standards ("MIFRS"). The variance of $1,075,315 ties to the 2014 depreciation and capitalization adjustments between CGAAP and MIFRS.

ACCOUNT 4355: GAIN ON DISPOSITION OF UTILITY AND OTHER PROPERTY

The reduction of revenue in Account 4355 relates to the one-time nature of the 2013 Tilbury property disposition. The gains reflected in Account 4355 in 2014 are more reflective of a typical activity level.

ACCOUNT 4375: REVENUES FROM NON RATE REGULATED UTILITY OPERATIONS

Account 4375 increased by $217,811. This primarily relates to the following non rate regulated activities:

- EPI recognized $87,476 of CDM related revenue in 2014. This is the result of finalizing activities from the 2010 to 2014 framework.
- In late 2014, EPI began receiving revenue for a joint bio-gas renewable generation project. This revenue account for $41,150 of increased revenue in 2014.
- EPI completed street lighting upgrade projects in Tilbury and Dresden for increased revenue of $40,131.

ACCOUNT 4405: INTEREST AND DIVIDEND INCOME

In 2014, EPI received additional one-time interest revenue of $90,000 related to a retroactive tax adjustment.

2014 ACTUAL RESULTS VERSUS 2015 BRIDGE YEAR

EPI anticipates experiencing an overall increase in Other Revenue between the 2014 Actual results and the 2015 Bridge Year of $107,186 as shown in Table 3-65 below.

TABLE 3-65: 2014 ACTUAL RESULTS VS. 2015 BRIDGE YEAR

Line No.	USoA	USoA Description	2014 Act	2015 BY	Variance
1	4235	Specific Service Charges	$311,708	$322,188	$10,480
2	4225	Late Payment Charges	$312,004	$250,000	-$62,004
3	4082	Retail Services Revenues	$37,977	$37,877	-$100
4	4084	Service Transaction Requests (STR) Revenues	$773	$1,492	$719
5	4086	SSS Administration Revenue	$151,936	$154,974	$3,039
6	4090	Electric Services Incidental to Energy Sales	$0	$0	$0
7	4205	Interdepartmental Rents	$200,760	$49,072	-$151,688
8	4210	Rent from Electric Property	$176,427	$179,760	$3,333
9	4215	Other Utility Operating Income	$0	$0	$0
10	4220	Other Electric Revenues	$6,020	$6,208	$188
11	4305	Regulatory Debits	-$1,677,655	-$1,305,434	$372,221
12	4325	Revenues from Merchandise	$0	$0	$0
13	4355	Gain on Disposition of Utility and Other Property	$38,787	$50,000	$11,214
14	4360	Loss on Disposition of Utility and Other Property	$0	$0	$0
15	4375	Revenues from Non Rate-Regulated Utility Operations	$262,013	$198,992	-$63,021
16	4380	Expenses of Non Rate-Regulated Utility Operations	-$50,155	-$35,000	$15,155
17	4390	Miscellaneous Non-Operating Income	$16,007	$30,000	$13,993
18	4405	Interest and Dividend Income	$197,867	$100,000	-$97,867
19		**Grand Total**	**-$15,533**	**$40,128**	**$55,661**

ACCOUNT 4205: INTERDEPARTMENTAL RENTS

As described in Exhibit 1, on January 1, 2015, the employees and related assets of Entegrus Services Inc. ("ESI") were transferred to EPI. Previously, ESI was an unregulated affiliate which provided customer service and administrative support to EPI. The reduction in Account 4205 relates to the interdepartmental rent previously received from ESI for space rented in EPI's head office at 320 Queen Street, Chatham.

ACCOUNT 4305: REGULATORY DEBITS

As described above, Account 4305 represents the financial differences arising as a result of changes to account depreciation and/or capitalization polices related to the implementation of MIFRS. The variance of $372,221 ties to the 2015 depreciation and capitalization adjustments between CGAAP and MIFRS

ACCOUNT 4405: INTEREST AND DIVIDEND INCOME

The anticipated decrease in 2015 is due to the one-time tax adjustment interest in 2014, as described above.

2015 BRIDGE YEAR VERSUS 2016 TEST YEAR

EPI anticipates an overall increase in Other Revenue between the 2015 Bridge Year and the 2016 Test Year of $1,319,349, as shown in Table 3-66 below.

TABLE 3-66: 2015 BRIDGE YEAR VS. 2016 TEST YEAR

Line No.	USoA	USoA Description	2015 BY	2016 TY	Variance
1	4235	Specific Service Charges	$322,188	$327,731	$5,544
2	4225	Late Payment Charges	$250,000	$250,000	$0
3	4082	Retail Services Revenues	$37,877	$37,877	$0
4	4084	Service Transaction Requests (STR) Revenues	$1,492	$1,492	$0
5	4086	SSS Administration Revenue	$154,974	$158,074	$3,099
6	4090	Electric Services Incidental to Energy Sales	$0	$0	$0
7	4205	Interdepartmental Rents	$49,072	$49,808	$736
8	4210	Rent from Electric Property	$179,760	$183,155	$3,395
9	4215	Other Utility Operating Income	$0	$0	$0
10	4220	Other Electric Revenues	$6,208	$6,332	$124
11	4305	Regulatory Debits	-$1,305,434	$0	$1,305,434
12	4325	Revenues from Merchandise	$0	$0	$0
13	4355	Gain on Disposition of Utility and Other Property	$50,000	$50,000	$0
14	4360	Loss on Disposition of Utility and Other Property	$0	$0	$0
15	4375	Revenues from Non Rate-Regulated Utility Operations	$198,992	$205,552	$6,560
16	4380	Expenses of Non Rate-Regulated Utility Operations	-$35,000	-$35,000	$0
17	4390	Miscellaneous Non-Operating Income	$30,000	$30,000	$0
18	4405	Interest and Dividend Income	$100,000	$100,000	$0
19		**Grand Total**	**$40,128**	**$1,365,021**	**$1,324,893**

ACCOUNT 4305: REGULATORY DEBITS

EPI has submitted the current application on a MIFRS basis, as consistent with the Board's direction. With rates now to be set on an MIFRS basis, EPI anticipates disposing of its Account 4305 balance in the current Application. Accordingly, as of May 1, 2016, EPI anticipates no longer charging amounts to Account 4035.

3.4.4 Specific Service Charges

EPI proposes the following Specific Service Charges ("SSCs") as presented in Table 3-67. For more details regarding the currently approved and the proposed Specific Service Charges, please see Exhibit 8, Section 8.8.3.

Table 3-67: EPI 2016 Proposed SSCs

Line No.	Description	Unit	Rate
1	**CUSTOMER ADMINISTRATION**		
2	Arrears Certificate	$	$15.00
3	Statement of Account	$	$15.00
4	Easement Letter	$	$15.00
5	Credit Reference/Credit Check (plus credit agency costs)	$	$15.00
6	Returned Cheque Charge (plus bank charges)	$	$15.00
7	Account Set Up Charge/Change of Occupancy Charge	$	$30.00
8	Meter dispute Charge plus Measurement Canada fees (if meter found correct	$	$30.00
9	**NON-PAYMENT OF ACCOUNT**		
10	Late Payment – per month	%	1.50%
11	Late Payment – per annum	%	19.56%
12	Disconnect/Reconnect at meter – during regular hours	$	$65.00
13	Disconnect/Reconnect at meter – after regular hours	$	$185.00
14	**OTHER CHARGES**		
15	Temporary Service install and remove – overhead – no transformer	$	$500.00
16	Temporary Service install & remove – overhead – with transformer	$	$1,000.00
17	Specific Charge for Access to the Power Poles - per pole/year	$	$22.35
18	Switching for company maintenance – Charge based on Time and Materials	$	T&M

3.4.5 Affiliate Transactions

EPI receives building rent for office space utilized by Entegrus Inc., Entegrus Services Inc. ("ESI") and Entegrus Transmission Inc. ("ETI"). The associated amount is recorded in Account 4205, this is the only item recorded in Account 4205.

In 2010, EPI received building space rent income related to a meter shop that was recorded in Account 4210. During 2010 this meter shop was closed and EPI no longer received any rent related to this transaction.

EPI provides financial, human resources ("HR"), communications and information technology ("IT") services to ESI and ETI. The amounts received from these services are recorded in Account 4375.

Effective January 1, 2015, EPI provides water and wastewater meter reading, billing, collecting, general customer administration and field service representative services to the Chatham Kent Public Utilities Commission. The amounts received from these services are recorded in Account 4375.

EPI provides streetlight maintenance services to the municipalities its serves on a cost-based price. The cost-base includes actual materials, labour and burdens, truck time and allocated overheads. The amounts received from these services are recorded in Account 4375.

ATTACHMENT 3-A

EPI Load Forecast Model

Entegrus Powerlines Inc.
EB-2015-0061, Cost of Service Application
2015 & 2016 kWh Purchases Forecast

Date	Historical Purchases	Large Lost kWh	Small Lost kWh	Corrected Historical kWh	Year	CK Heating Degrees	CK Cooling Degrees	Manufacting (x 1,000)	Economic Adjustment Factor	Forecast kWh	Forecast % Error	Absolute Forecast % Error
2006-01	92,275,262	4,080,530	1,554,253	86,640,479	2006	514	-	48,705,740	0.42	89,216,823	2.974%	2.888%
2006-02	85,895,794	3,698,719	1,201,808	80,995,267	2006	578	-	48,533,977	(0.51)	84,073,449	3.800%	3.661%
2006-03	91,568,196	4,382,302	1,811,912	85,373,982	2006	512	-	51,567,190	0.06	88,743,770	3.947%	3.797%
2006-04	79,308,311	3,964,442	1,283,786	74,060,083	2006	298	-	49,484,981	(0.69)	77,945,996	5.247%	4.985%
2006-05	86,611,523	4,321,758	1,263,782	81,025,982	2006	146	29	50,769,986	(0.29)	83,257,082	2.754%	2.680%
2006-06	91,680,970	4,360,326	1,625,892	85,694,752	2006	36	40	51,542,946	0.37	87,939,718	2.620%	2.553%
2006-07	105,876,113	3,930,918	1,131,202	100,813,993	2006	6	126	45,043,016	1.13	101,718,967	0.898%	0.890%
2006-08	104,632,862	4,748,541	1,744,246	98,140,075	2006	10	67	50,664,482	1.54	99,017,333	0.894%	0.886%
2006-09	87,025,571	4,018,354	1,395,584	81,611,633	2006	89	8	48,620,316	0.61	83,409,333	2.203%	2.155%
2006-10	89,135,907	3,794,587	1,169,193	84,172,126	2006	294	2	48,023,316	0.23	83,405,159	-0.911%	0.920%
2006-11	91,093,979	3,731,626	1,118,962	86,243,392	2006	378	-	49,712,772	(0.02)	84,250,824	-2.310%	2.365%
2006-12	90,288,887	2,986,153	957,900	86,344,834	2006	492	-	48,603,292	0.05	86,214,597	-0.151%	0.151%
2007-01	94,700,936	3,572,942	1,116,756	90,011,238	2007	633	-	47,937,774	0.42	90,401,380	0.433%	0.433%
2007-02	91,441,925	3,562,267	888,613	86,991,045	2007	743	-	47,414,981	(0.51)	85,924,274	-1.226%	1.226%
2007-03	91,789,983	3,623,410	1,189,210	86,977,363	2007	485	-	51,609,130	0.06	87,614,683	0.733%	0.733%
2007-04	82,921,569	3,224,312	854,277	78,842,981	2007	352	-	49,374,218	(0.69)	78,299,796	-0.689%	0.689%
2007-05	85,875,464	3,090,739	686,928	82,097,798	2007	138	25	50,724,181	(0.29)	81,736,430	-0.440%	0.440%
2007-06	95,885,760	3,366,406	935,416	91,583,937	2007	30	66	48,667,556	0.37	89,318,916	-2.473%	2.473%
2007-07	95,780,411	3,496,125	640,251	91,644,035	2007	17	68	45,502,574	1.13	92,261,160	0.673%	0.673%
2007-08	106,146,791	4,247,266	1,013,037	100,886,488	2007	14	87	48,002,098	1.54	99,846,382	-1.031%	1.031%
2007-09	92,664,788	3,717,096	860,376	88,087,316	2007	64	40	46,749,201	0.61	86,109,318	-2.245%	2.245%
2007-10	89,956,146	3,438,961	866,901	85,650,284	2007	144	30	48,531,421	0.23	84,673,765	-1.140%	1.140%
2007-11	88,189,942	2,960,291	675,074	84,554,577	2007	446	-	48,279,982	(0.02)	83,963,402	-0.699%	0.699%
2007-12	88,023,622	2,804,858	569,647	84,649,117	2007	624	-	41,182,527	0.05	83,050,237	-1.889%	1.889%
2008-01	93,493,709	3,315,214	578,744	89,599,752	2008	637	-	42,681,474	0.42	86,197,066	-3.798%	3.798%
2008-02	89,086,654	3,234,025	798,075	85,054,553	2008	670	-	44,980,567	(0.51)	82,166,584	-3.395%	3.395%
2008-03	91,324,558	3,367,292	324,813	87,632,452	2008	607	-	44,399,361	0.06	84,383,598	-3.707%	3.707%
2008-04	82,206,529	3,326,521	272,733	78,607,276	2008	279	-	45,575,941	(0.69)	73,587,628	-6.386%	6.386%
2008-05	82,342,887	3,166,230	423,731	78,752,926	2008	212	4	46,853,489	(0.29)	76,531,028	-2.821%	2.821%
2008-06	94,261,624	3,589,957	324,925	90,346,742	2008	22	73	48,111,832	0.37	89,241,343	-1.224%	1.224%
2008-07	102,930,302	3,283,392	229,772	99,417,138	2008	9	97	46,431,669	1.13	96,937,180	-2.494%	2.494%
2008-08	95,324,173	3,144,913	519,978	91,659,282	2008	23	46	46,291,039	1.54	91,583,347	-0.083%	0.083%
2008-09	86,959,025	2,760,354	317,351	83,881,321	2008	65	25	46,613,408	0.61	82,999,381	-1.051%	1.051%
2008-10	81,389,670	2,369,885	468,384	78,551,400	2008	291	0	45,988,896	0.23	80,431,150	2.393%	2.393%
2008-11	82,439,299	2,358,680	367,796	79,712,822	2008	452	-	43,334,946	(0.02)	80,030,383	0.398%	0.398%
2008-12	84,813,533	2,136,379	299,356	82,377,798	2008	657	-	37,504,764	0.05	80,517,835	-2.258%	2.258%
2009-01	87,308,876	3,023,378	257,414	84,028,084	2009	872	-	33,349,265	0.42	83,729,171	-0.356%	0.356%

Entegrus Powerlines Inc.
EB-2015-0061, Cost of Service Application
2015 & 2016 kWh Purchases Forecast

Date	Historical Purchases	Large Lost kWh	Small Lost kWh	Corrected Historical kWh	Year	CK Heating Degrees	CK Cooling Degrees	Manufacting (x 1,000)	Economic Adjustment Factor	Forecast kWh	Forecast % Error	Absolute Forecast % Error
2009-02	77,097,974	2,605,509	337,006	74,155,459	2009	610	-	35,341,102	(0.51)	73,676,689	-0.646%	0.646%
2009-03	79,993,358	2,599,571	251,363	77,142,423	2009	525	-	36,682,400	0.06	76,776,019	-0.475%	0.475%
2009-04	70,555,972	2,127,458	468,804	67,959,710	2009	307	2	36,521,367	(0.69)	67,502,694	-0.672%	0.672%
2009-05	67,517,058	2,083,264	440,550	64,993,245	2009	160	4	34,102,278	(0.29)	66,023,548	1.585%	1.585%
2009-06	72,770,575	1,692,830	292,499	70,785,246	2009	53	32	35,283,385	0.37	73,694,582	4.110%	4.110%
2009-07	76,889,947	654,890	281,046	75,954,011	2009	24	38	36,559,330	1.13	80,206,073	5.598%	5.598%
2009-08	87,060,730	677,717	267,655	86,115,358	2009	24	72	36,544,471	1.54	88,406,898	2.661%	2.661%
2009-09	77,242,678	682,957	256,989	76,302,732	2009	77	19	38,926,914	0.61	76,245,457	-0.075%	0.075%
2009-10	74,523,817	666,503	167,840	73,689,474	2009	291	-	38,337,783	0.23	74,475,560	1.067%	1.067%
2009-11	74,187,824	516,763	218,905	73,452,157	2009	353	-	38,015,352	(0.02)	73,757,071	0.415%	0.415%
2009-12	80,483,064	579,144	85,111	79,818,809	2009	634	-	37,905,631	0.05	79,718,783	-0.125%	0.125%
2010-01	84,309,599	620,679	-	83,688,920	2010	727	-	37,285,840	0.42	82,974,112	-0.854%	0.854%
2010-02	75,616,771	531,013	-	75,085,758	2010	637	-	38,195,753	(0.51)	75,553,735	0.623%	0.623%
2010-03	76,144,148	500,342	-	75,643,806	2010	453	-	41,328,149	0.06	77,963,867	3.067%	3.067%
2010-04	67,578,857	418,759	-	67,160,099	2010	246	-	40,413,693	(0.69)	68,112,756	1.418%	1.418%
2010-05	74,789,718	397,678	-	74,392,041	2010	117	20	41,055,161	(0.29)	71,952,595	-3.279%	3.279%
2010-06	84,514,689	383,438	-	84,131,251	2010	23	63	42,286,604	0.37	82,364,182	-2.100%	2.100%
2010-07	97,389,830	461,310	-	96,928,520	2010	7	136	38,393,943	1.13	96,343,760	-0.603%	0.603%
2010-08	98,212,442	273,585	-	97,938,858	2010	5	88	41,231,739	1.54	93,354,102	-4.681%	4.681%
2010-09	79,192,860	256,467	-	78,936,393	2010	88	35	41,624,078	0.61	80,359,449	1.803%	1.803%
2010-10	75,023,854	271,066	-	74,752,788	2010	224	-	41,735,406	0.23	74,870,180	0.157%	0.157%
2010-11	76,439,083	298,587	-	76,140,496	2010	414	-	40,600,131	(0.02)	76,123,810	-0.022%	0.022%
2010-12	81,766,622	377,747	-	81,388,875	2010	708	-	39,964,231	0.05	81,974,945	0.720%	0.720%
2011-01	83,706,926	384,377	-	83,322,549	2011	791	-	41,385,749	0.42	86,467,424	3.774%	3.774%
2011-02	75,367,135	349,597	-	75,017,537	2011	675	-	40,385,682	(0.51)	77,194,442	2.902%	2.902%
2011-03	80,344,898	340,424	-	80,004,474	2011	347	-	43,636,079	0.06	76,850,190	-3.943%	3.943%
2011-04	70,865,313	269,468	-	70,595,845	2011	341	-	40,502,825	(0.69)	69,420,452	-1.665%	1.665%
2011-05	72,286,372	252,421	-	72,033,951	2011	145	20	41,346,450	(0.29)	72,102,560	0.095%	0.095%
2011-06	79,668,878	239,946	-	79,428,932	2011	28	53	42,150,675	0.37	80,109,244	0.857%	0.857%
2011-07	98,736,540	254,827	-	98,481,713	2011	0	170	40,454,374	1.13	102,457,957	4.038%	4.038%
2011-08	93,571,080	256,562	-	93,314,518	2011	5	76	44,495,143	1.54	92,968,911	-0.370%	0.370%
2011-09	81,593,770	232,499	-	81,361,271	2011	78	33	44,495,209	0.61	81,100,090	-0.321%	0.321%
2011-10	76,273,618	224,362	-	76,049,255	2011	228	-	44,798,937	0.23	76,461,921	0.543%	0.543%
2011-11	77,445,743	224,929	-	77,220,814	2011	334	-	44,900,275	(0.02)	76,890,207	-0.428%	0.428%
2011-12	78,733,416	257,071	-	78,476,345	2011	508	-	44,435,561	0.05	80,499,545	2.578%	2.578%
2012-01	83,350,471	296,560	-	83,053,911	2012	613	-	44,700,072	0.42	84,623,234	1.890%	1.890%
2012-02	77,534,216	270,659	-	77,263,557	2012	530	-	42,889,850	(0.51)	75,451,148	-2.346%	2.346%

Entegrus Powerlines Inc.
EB-2015-0061, Cost of Service Application
2015 & 2016 kWh Purchases Forecast

Date	Historical Purchases	Large Lost kWh	Small Lost kWh	Corrected Historical kWh	Year	CK Heating Degrees	CK Cooling Degrees	Manufacting (x 1,000)	Economic Adjustment Factor	Forecast kWh	Forecast % Error	Absolute Forecast % Error
2012-03	76,965,961	273,221	-	76,692,740	2012	321	-	46,011,356	0.06	77,348,441	0.855%	0.855%
2012-04	70,563,283	239,875	-	70,323,408	2012	329	-	45,391,465	(0.69)	71,953,233	2.318%	2.318%
2012-05	76,978,073	242,770	-	76,735,303	2012	85	19	47,528,183	(0.29)	74,347,318	-3.112%	3.112%
2012-06	87,498,949	228,550	-	87,270,400	2012	1	29	47,227,131	0.37	78,624,169	-9.907%	9.907%
2012-07	99,161,585	203,413	-	98,958,172	2012	-	116	42,833,426	1.13	94,702,062	-4.301%	4.301%
2012-08	91,562,639	236,207	-	91,326,432	2012	10	64	46,525,071	1.54	91,955,404	0.689%	0.689%
2012-09	79,318,222	221,821	-	79,096,400	2012	101	27	44,793,226	0.61	80,290,283	1.509%	1.509%
2012-10	76,122,125	224,739	-	75,897,386	2012	238	3	45,235,573	0.23	76,766,803	1.146%	1.146%
2012-11	77,701,976	291,203	-	77,410,773	2012	438	-	45,914,231	(0.02)	79,019,385	2.078%	2.078%
2012-12	76,850,465	282,595	-	76,567,870	2012	501	-	41,774,375	0.05	77,900,958	1.741%	1.741%
2013-01	83,735,388	285,594	-	83,449,794	2013	639	-	43,255,833	0.42	83,508,759	0.071%	0.071%
2013-02	76,915,646	315,743	-	76,599,903	2013	617	-	43,116,627	(0.51)	76,694,502	0.123%	0.123%
2013-03	78,384,467	283,012	-	78,101,455	2013	548	-	44,960,463	0.06	80,472,233	3.036%	3.036%
2013-04	72,681,683	197,773	-	72,483,911	2013	354	-	44,976,603	(0.69)	71,517,665	-1.333%	1.333%
2013-05	75,087,149	164,779	-	74,922,369	2013	123	35	46,651,790	(0.29)	76,477,792	2.076%	2.076%
2013-06	79,035,305	127,637	-	78,907,668	2013	42	59	45,335,122	0.37	82,452,600	4.493%	4.493%
2013-07	94,541,770	-	-	94,541,770	2013	11	106	44,400,265	1.13	93,745,720	-0.842%	0.842%
2013-08	89,781,915	-	-	89,781,915	2013	19	59	45,231,055	1.54	89,776,515	-0.006%	0.006%
2013-09	80,998,234	-	-	80,998,234	2013	89	31	45,667,260	0.61	80,585,358	-0.510%	0.510%
2013-10	79,087,294	-	-	79,087,294	2013	196	9	46,815,382	0.23	77,447,958	-2.073%	2.073%
2013-11	79,031,975	-	-	79,031,975	2013	453	-	46,503,422	(0.02)	79,097,117	0.082%	0.082%
2013-12	81,479,866	-	-	81,479,866	2013	649	-	44,126,783	0.05	81,817,664	0.415%	0.415%
2014-01	89,964,155	-	-	89,964,155	2014	826	-	43,836,746	0.42	86,975,598	-3.322%	3.322%
2014-02	79,548,214	-	-	79,548,214	2014	758	-	44,788,193	(0.51)	80,018,273	0.591%	0.591%
2014-03	85,916,309	-	-	85,916,309	2014	657	-	47,969,252	0.06	84,082,629	-2.134%	2.134%
2014-04	70,343,410	-	-	70,343,410	2014	342	-	47,134,140	(0.69)	72,158,883	2.581%	2.581%
2014-05	71,981,984	-	-	71,981,984	2014	141	14	49,398,644	(0.29)	74,733,965	3.823%	3.823%
2014-06	82,005,910	-	-	82,005,910	2014	19	74	48,856,376	0.37	86,139,183	5.040%	5.040%
2014-07	86,507,061	-	-	86,507,061	2014	16	49	44,707,267	1.13	84,380,055	-2.459%	2.459%
2014-08	87,881,428	-	-	87,881,428	2014	17	60	47,025,015	1.54	90,562,665	3.051%	3.051%
2014-09	80,675,294	-	-	80,675,294	2014	97	27	46,360,999	0.61	79,962,274	-0.884%	0.884%
2014-10	77,280,642	-	-	77,280,642	2014	232	-	47,176,114	0.23	76,293,182	-1.278%	1.278%
2014-11	79,307,673	-	-	79,307,673	2014	469	-	47,364,047	(0.02)	79,400,737	0.117%	0.117%
2014-12	79,700,907	-	-	79,700,907	2014	527	-	44,024,343	0.05	78,707,385	-1.247%	1.247%
2015-01				-	2015	678	-	46,204,336	0.42	85,071,392		
2015-02				-	2015	632	-	45,180,277	(0.51)	77,177,695		
2015-03				-	2015	475	-	47,788,634	0.06	79,737,788		

Entegrus Powerlines Inc.
EB-2015-0061, Cost of Service Application
2015 & 2016 kWh Purchases Forecast

Date	Historical Purchases	Large Lost kWh	Small Lost kWh	Corrected Historical kWh	Year	CK Heating Degrees	CK Cooling Degrees	Manufacting (x 1,000)	Economic Adjustment Factor	Forecast kWh	Forecast % Error	Absolute Forecast % Error
2015-04				-	2015	313	0	47,471,476	(0.69)	71,231,064		
2015-05				-	2015	141	20	49,473,917	(0.29)	75,042,759		
2015-06				-	2015	29	52	48,624,109	0.37	81,980,972		
2015-07				-	2015	9	107	45,824,948	1.13	93,687,455		
2015-08				-	2015	14	70	48,200,640	1.54	92,223,141		
2015-09				-	2015	81	27	47,520,024	0.61	79,904,226		
2015-10				-	2015	238	5	48,355,517	0.23	77,491,800		
2015-11				-	2015	408	-	48,548,148	(0.02)	78,391,806		
2015-12				-	2015	597	-	45,124,952	0.05	80,224,394		
2016-01				-	2016	678	-	47,359,445	0.42	85,245,834		
2016-02				-	2016	632	-	46,309,784	(0.51)	77,334,368		
2016-03				-	2016	475	-	48,983,350	0.06	79,939,719		
2016-04				-	2016	313	0	48,658,263	(0.69)	71,427,492		
2016-05				-	2016	141	20	50,710,765	(0.29)	75,273,932		
2016-06				-	2016	29	52	49,839,711	0.37	82,197,400		
2016-07				-	2016	9	107	46,970,572	1.13	93,855,314		
2016-08				-	2016	14	70	49,405,656	1.54	92,432,221		
2016-09				-	2016	81	27	48,708,025	0.61	80,101,497		
2016-10				-	2016	238	5	49,564,405	0.23	77,703,567		
2016-11				-	2016	408	-	49,761,852	(0.02)	78,606,916		
2016-12				-	2016	597	-	46,253,076	0.05	80,380,107		

Entegrus Powerlines Inc.
EB-2015-0061, Cost of Service Application
Regression Analysis

Regression Statistics	
Multiple R	96.21%
R Square	92.56%
Adjusted R Square	92.19%
Standard Error	2145168.805
Observations	108

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	5	5.83832E+15	1.16766E+15	253.7433304	7.21755E-56
Residual	102	4.69378E+14	4.60175E+12	0	0
Total	107	6.30769E+15	0	0	0

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	1,300,695,332	162,375,764	8	0	978,623,775	1,622,766,890	978,623,775	1,622,766,890
Time	(627,256)	80,627	(8)	0	(787,179)	(467,334)	(787,179)	(467,334)
Heating Degrees	19,738	1,186	17	0	17,385	22,090	17,385	22,090
Cooling Degrees	161,357	10,064	16	0	141,395	181,319	141,395	181,319
Manufacturing (x 1,000)	1	0	13	0	1	1	1	1
Economic Adjustment Factor	6,778,225	481,058	14	0	5,824,049	7,732,402	5,824,049	7,732,402

Variable	*T-Stat*
Intercept	8.0
Time	-7.8
Heating Degrees	16.6
Cooling Degrees	16.0
Manufacturing (x 1,000)	13.4
Economic Adjustment Factor	14.1

Entegrus Powerlines Inc.
EB-2015-0061, Cost of Service Application
2016 Load Forecast Accuracy & Loss Factor

Forecast Accuracy

Year	Actual Purchases	Modeled Purchases	Difference	Difference %
2006	1,095,393,373	1,049,193,051	46,200,322	0.0422
2007	1,103,377,336	1,043,199,743	60,177,593	0.0545
2008	1,066,571,963	1,004,606,523	61,965,440	0.0581
2009	925,631,873	914,212,545	11,419,328	0.0123
2010	970,978,474	961,947,493	9,030,981	0.0093
2011	968,593,688	972,522,943	(3,929,256)	(0.0041)
2012	973,607,964	962,982,436	10,625,528	0.0109
2013	970,760,692	973,593,882	(2,833,190)	(0.0029)
2014	971,112,987	973,414,830	(2,301,843)	(0.0024)
2015	-	972,164,493		
2016	-	974,498,367		

Determination of Loss Factor

Year	Actual Purchases	Total Billed	Losses	Loss Factor
2006	1,095,393,373	1,078,222,399	17,170,974	1.0157
2007	1,103,377,336	1,055,654,062	47,723,274	1.0433
2008	1,066,571,963	1,021,199,819	45,372,144	1.0425
2009	925,631,873	886,643,741	38,988,132	1.0421
2010	970,978,474	932,206,593	38,771,881	1.0399
2011	968,593,688	938,179,332	30,414,356	1.0314
2012	973,607,964	936,088,111	37,519,853	1.0385
2013	970,760,692	928,696,615	42,064,077	1.0433
2014	971,112,987	933,911,819	37,201,168	1.0383
2015	-	934,838,752		1.0399
2016	-	937,083,018		1.0399

Notes:
1) Average Loss Factor utilized for 2015 and 2016 Total Billed calculation is the average of 2007 to 2014 actual loss factors.

Entegrus Powerlines Inc.
EB-2015-0061, Cost of Service Application
Forecast Number of Customer/Connections

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load (Conn)	Sentinel Lighting (Conn)	Street Lighting (Conn)	Embedded Distributor	Total
Restated Average Annual Customers/Connections										
2006	35,142	4,009	507	1	2	-	393	12,468	-	52,522
2007	35,190	4,001	513	3	1	-	394	12,468	1	52,571
2008	35,334	3,976	523	3	1	-	393	12,553	1	52,784
2009	35,438	3,919	517	3	1	122	390	12,784	1	53,175
2010	35,472	3,916	496	2	1	244	388	12,931	1	53,451
2011	35,628	3,907	490	1	1	245	388	12,931	1	53,592
2012	35,816	3,859	498	1	1	245	388	12,931	1	53,740
2013	35,944	3,862	499	1	1	248	441	13,103	1	54,100
2014	36,074	3,870	497	1	1	251	487	13,270	1	54,452
Average	**35,560**	**3,924**	**504**	**2**	**1**	**151**	**407**	**12,827**	**1**	**53,376**
Customer Growth Rate										
2006	-	-	-	-	-	-	-	-	-	
2007	1.0014	0.9980	1.0118	3.0000	0.5000	-	1.0025	1.0000	-	
2008	1.0041	0.9938	1.0195	1.0000	1.0000	-	0.9975	1.0068	1.0000	
2009	1.0029	0.9857	0.9885	1.0000	1.0000	-	0.9924	1.0184	1.0000	
2010	1.0010	0.9992	0.9594	0.6667	1.0000	2.0000	0.9949	1.0115	1.0000	
2011	1.0044	0.9977	0.9879	0.5000	1.0000	1.0041	1.0000	1.0000	1.0000	
2012	1.0053	0.9877	1.0163	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	
2013	1.0036	1.0008	1.0020	1.0000	1.0000	1.0122	1.1366	1.0133	1.0000	
2014	1.0036	1.0021	0.9960	1.0000	1.0000	1.0121	1.1043	1.0127	1.0000	
Geomean	**1.0036**	**0.9975**	**0.9921**	**0.8027**	**1.0000**	**1.1552**	**1.0454**	**1.0075**	**1.0000**	
Forecasted Customers/Connections										
2015	36,203	3,860	493	1	1	290	509	13,369	1	54,727
2016	36,333	3,850	489	1	1	335	532	13,469	1	55,011

Entegrus Powerlines Inc.
EB-2015-0061, Cost of Service Application
Forecast Consumption by Rate Class (kWh)

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
Restated Consumption (kWh)										
2006	302,355,083	129,600,878	507,947,705	92,372,408	36,694,467	-	454,662	8,797,196	-	1,078,222,399
2007	299,638,406	126,763,870	498,423,262	89,275,102	27,015,842	-	445,369	8,797,782	5,294,429	1,055,654,062
2008	296,054,771	125,816,796	464,092,558	98,751,177	22,647,906	-	436,740	8,199,730	5,200,141	1,021,199,819
2009	291,091,689	114,518,667	395,794,984	53,009,042	17,181,839	1,158,647	440,153	8,235,437	5,213,283	886,643,741
2010	301,267,823	116,294,933	435,880,111	35,030,946	29,034,336	1,191,306	433,931	8,221,743	4,851,464	932,206,593
2011	299,495,986	116,705,566	444,705,629	28,996,883	34,298,990	1,249,000	353,837	8,221,874	4,151,567	938,179,332
2012	296,656,279	109,007,040	453,565,445	28,118,306	34,317,082	1,213,037	405,259	8,250,167	4,555,496	936,088,111
2013	281,071,800	105,791,729	456,115,509	39,427,413	32,247,068	1,228,666	410,160	7,792,246	4,612,024	928,696,615
2014	289,455,443	108,543,510	457,346,103	33,167,215	31,573,402	1,249,444	408,652	7,533,249	4,634,801	933,911,819
Average Consumption per Customer (kWh)										
2006	8,604	32,327	1,001,869	92,372,408	18,347,234	-	1,157	706	-	
2007	8,515	31,683	971,585	29,758,367	27,015,842	-	1,130	706	5,294,429	
2008	8,379	31,644	887,366	32,917,059	22,647,906	-	1,111	653	5,200,141	
2009	8,214	29,221	765,561	17,669,681	17,181,839	9,497	1,129	644	5,213,283	
2010	8,493	29,697	878,791	17,515,473	29,034,336	4,882	1,118	636	4,851,464	
2011	8,406	29,871	907,563	28,996,883	34,298,990	5,098	912	636	4,151,567	
2012	8,283	28,247	910,774	28,118,306	34,317,082	4,951	1,044	638	4,555,496	
2013	7,820	27,393	914,059	39,427,413	32,247,068	4,954	930	595	4,612,024	
2014	8,024	28,047	920,213	33,167,215	31,573,402	4,978	839	568	4,634,801	
Average Growth per Customer										
2006	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2007	98.97%	98.01%	96.98%	32.22%	147.25%	0.00%	97.67%	100.00%	0.00%	
2008	98.40%	99.88%	91.33%	110.61%	83.83%	0.00%	98.32%	92.49%	98.22%	
2009	98.03%	92.34%	86.27%	53.68%	75.87%	0.00%	101.62%	98.62%	100.25%	
2010	103.40%	101.63%	114.79%	99.13%	168.98%	51.41%	99.03%	98.76%	93.06%	
2011	98.98%	100.59%	103.27%	165.55%	118.13%	104.42%	81.57%	100.00%	85.57%	
2012	98.54%	94.56%	100.35%	96.97%	100.05%	97.12%	114.47%	100.31%	109.73%	
2013	94.41%	96.98%	100.36%	140.22%	93.97%	100.06%	89.08%	93.26%	101.24%	
2014	102.61%	102.39%	100.67%	84.12%	97.91%	100.48%	90.22%	95.46%	100.49%	
Geomean	**99.54%**	**99.18%**	**103.75%**	**104.58%**	**97.28%**	**87.88%**	**94.24%**	**97.52%**	**97.67%**	
Forecasted Average Consumption per Customer (kWh)										
2015	7,987	27,818	954,684	34,686,292	30,713,726	4,375	791	554	4,526,975	
2016	7,950	27,591	990,446	36,274,944	29,877,457	3,845	745	540	4,421,657	

Entegrus Powerlines Inc.
EB-2015-0061, Cost of Service Application
Forecast Consumption by Rate Class (kWh)

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
Calculated Consumption Non-Weather Adjusted (kWh)										
2015	289,153,361	107,377,480	470,659,212	34,686,292	30,713,726	1,268,750	402,619	7,406,426	4,526,975	946,194,841
2016	288,847,350	106,225,350	484,328,094	36,274,944	29,877,457	1,288,075	396,340	7,273,260	4,421,657	958,932,527
Calculation of Weather Sensitive Load										
% of Load	67.0%	67.0%	33.9%							
2015	193,590,988	71,890,267	159,562,628	-	-	-	-	-	-	425,043,883
2016	193,386,110	71,118,905	164,196,645	-	-	-	-	-	-	428,701,661
Allocation of Weather Adjustment										
Percent	45.5%	16.9%	37.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
2015	(5,172,258)	(1,920,725)	(4,263,107)	-	-	-	-	-	-	(11,356,089)
Percent	45.1%	16.6%	38.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
2016	(9,856,252)	(3,624,696)	(8,368,561)	-	-	-	-	-	-	(21,849,509)
TOTAL NORMALIZED LOAD FORECAST										
2015	283,981,103	105,456,755	466,396,105	34,686,292	30,713,726	1,268,750	402,619	7,406,426	4,526,975	934,838,752
2016	278,991,098	102,600,654	475,959,533	36,274,944	29,877,457	1,288,075	396,340	7,273,260	4,421,657	937,083,018
CDM ADJUSTMENT										
2015	(964,516)	(1,119,084)	(2,503,647)	(13,760,034)	-	-	-	(10,052)	-	(18,357,333)
2016	(1,515,089)	(2,917,890)	(3,974,394)	(25,601,118)	-	-	-	(10,052)	-	(34,018,544)
WMP ADJUSTMENT										
2015			6,613,942							6,613,942
2016			6,861,699							6,861,699
TOTAL ADJUSTED WEATHER NORMALIZED LOAD FORECAST										
2015	283,016,587	104,337,672	470,506,400	20,926,258	30,713,726	1,268,750	402,619	7,396,374	4,526,975	923,095,361
2016	277,476,009	99,682,764	478,846,838	10,673,826	29,877,457	1,288,075	396,340	7,263,208	4,421,657	909,926,173

Entegrus Powerlines Inc.
EB-2015-0061, Cost of Service Application
Forecast Demand by Rate Class (kW)

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
Restated Demand (kW)										
2006	-	-	1,526,414	228,620	72,885	-	1,897	24,792	-	1,854,608
2007	-	-	1,319,003	206,603	57,865	-	1,234	31,812	10,733	1,627,250
2008	-	-	1,276,603	210,734	51,576	-	1,222	24,235	10,432	1,574,802
2009	-	-	1,131,642	158,060	38,952	-	1,217	24,546	10,438	1,364,855
2010	-	-	1,183,053	102,526	56,098	-	1,224	24,338	10,285	1,377,524
2011	-	-	1,189,083	68,609	63,856	-	980	24,338	11,258	1,358,124
2012	-	-	1,188,171	66,670	67,537	-	1,138	24,338	10,054	1,357,908
2013	-	-	1,223,255	87,871	67,914	-	1,130	23,008	9,926	1,413,104
2014	-	-	1,181,005	81,852	65,619	-	1,144	22,342	16,051	1,368,013
Average	**-**	**-**	**1,246,470**	**134,616**	**60,256**	**-**	**1,243**	**24,861**	**9,909**	**1,477,354**
Percentage of kW to kWh										
2006			0.300%	0.250%	0.200%		0.420%	0.280%	0.000%	
2007			0.260%	0.230%	0.210%		0.280%	0.360%	0.200%	
2008			0.280%	0.210%	0.230%		0.280%	0.300%	0.200%	
2009			0.290%	0.300%	0.230%		0.280%	0.300%	0.200%	
2010			0.270%	0.290%	0.190%		0.280%	0.300%	0.210%	
2011			0.270%	0.240%	0.190%		0.280%	0.300%	0.270%	
2012			0.260%	0.240%	0.200%		0.280%	0.300%	0.220%	
2013			0.270%	0.220%	0.210%		0.280%	0.300%	0.220%	
2014			0.260%	0.250%	0.210%		0.280%	0.300%	0.350%	
Average			**0.266%**	**0.248%**	**0.200%**		**0.280%**	**0.300%**	**0.254%**	
Total Demand Forecast (kW)										
2015	-	-	1,233,954	51,897	61,427	-	1,127	22,189	11,499	1,382,093
2016	-	-	1,255,480	26,471	59,755	-	1,110	21,790	11,231	1,375,837

Entegrus Powerlines Inc.
EB-2015-0061, Cost of Service Application
Calculation of CDM Adjustment for the Load Forecast

Allocation of Tasked Savings by Year

Description	2015	2016	2017	2018	2019	2020	TOTAL
Planned Program Savings by Year							
2015 Programs	28,775,427	28,775,427	28,775,427	28,775,427	28,396,160	28,396,160	
2016 Programs		6,218,596	6,218,596	6,218,596	6,218,596	5,611,768	
2017 Programs		-	6,049,723	6,049,723	6,049,723	6,049,723	
2018 Programs		-	-	12,078,195	12,078,195	12,078,195	
2019 Programs		-	-	-	5,165,783	5,165,783	
2020 Programs		-	-	-	-	4,777,519	
Total Planned Programs	**28,775,427**	**34,994,023**	**41,043,746**	**53,121,941**	**57,908,457**	**62,079,147**	
Annual % of Planned	**45.63%**	**9.86%**	**9.59%**	**19.15%**	**8.19%**	**7.58%**	100.00%
Allocated Tasked Savings	**25,916,720**	**5,600,807**	**5,448,710**	**10,878,282**	**4,652,586**	**4,302,895**	**56,800,000**

Allocation of 2015 & 2016 Tasked Savings by Rate Class

Description	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
Allocation of 2015 Tasked Savings										
New Framework Programs	145,989	508,864	421,417							1,076,270
Old Framework Programs	439,807	1,929,516	1,597,936	23,731,898						27,699,157
2015 Planned Savings	**585,796**	**2,438,380**	**2,019,353**	**23,731,898**	**-**	**-**	**-**	**-**	**-**	**28,775,427**
% Allocator	11.6%	48.3%	40.0%							
2015 Tasked Savings	**253,763**	**1,056,289**	**874,770**	**23,731,898**	**-**					**25,916,720**
Allocation of 2016 Tasked Savings										
New Framework Programs	1,008,064	2,850,161	2,360,371							6,218,596
2016 Planned Savings	**1,008,064**	**2,850,161**	**2,360,371**	**-**	**-**	**-**	**-**	**-**	**-**	**6,218,596**
% Allocator	16.21%	45.83%	37.96%							
2016 Tasked Savings	**907,918**	**2,567,012**	**2,125,879**	**-**						**5,600,809**

Calculation of Load Forecast Adjustment by Rate Class

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
2015 Load Forecast Adjustment										
2014 Programs (50%)	837,634	590,939	2,066,262	1,894,085		-	-	10,052	-	5,398,972
2015 Programs (50%)	126,882	528,145	437,385	11,865,949	-	-	-	-	-	12,958,361
Total	**964,516**	**1,119,084**	**2,503,647**	**13,760,034**	**-**	**-**	**-**	**10,052**	**-**	**18,357,333**
2016 Load Forecast Adjustment										
2014 Programs (50%)	807,367	578,095	2,036,684	1,869,220				10,052		5,301,419
2015 Programs (100%)	253,763	1,056,289	874,770	23,731,898	-	-	-	-	-	25,916,720
2016 Programs (50%)	453,959	1,283,506	1,062,940	-	-	-	-	-	-	2,800,405
Total	**1,515,089**	**2,917,890**	**3,974,394**	**25,601,118**	**-**	**-**	**-**	**10,052**	**-**	**34,018,544**

Entegrus Powerlines Inc.
EB-2015-0061, Cost of Service Application
Calculation of Wholesale Market Participant

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
Historical kWh										
2011			-							-
2012			1,862,328							1,862,328
2013			4,199,611							4,199,611
2014			6,375,131							6,375,131
Geometric Mean										
			103.75%							
Forecasted kWh										
2015			6,613,942							6,613,942
2016			6,861,699							6,861,699

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use		Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distribution	Total
Historical kW										
2011			-							-
2012			4,198							4,198
2013			9,630							9,630
2014			17,662							17,662
Percentage kW/kWh										
2011										
2012			0.23%							
2013			0.23%							
2014			0.28%							
Average			0.24%							
Total kW Forecast										
2015			16,132							16,132
2016			16,737							16,737

Entegrus Powerlines Inc.
EB-2015-0061, Cost of Service Application
Historical and Weather Normalized Load Forecast

Description	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Forecasted	2016 Forecasted
Reconciliation of Purchases											
Actual kWh Purchases	1,095,393,373	1,103,377,336	1,066,571,963	925,631,873	970,978,474	968,593,688	973,607,964	970,760,692	971,112,987		
Predicted Purchases	1,049,193,051	1,043,199,743	1,004,606,523	914,212,545	961,947,493	972,522,943	962,982,436	973,593,882	973,414,830	972,164,493	974,498,367
CDM Adjustment (Not in Model)										(18,357,333)	(34,018,544)
Adjusted Predicted Purchases	1,049,193,051	1,043,199,743	1,004,606,523	914,212,545	961,947,493	972,522,943	962,982,436	973,593,882	973,414,830	953,807,160	940,479,823
Percent Difference from Actual	4.218%	5.454%	5.810%	1.234%	0.930%	-0.406%	1.091%	-0.292%	-0.237%		
Billed kWh	1,078,222,399	1,055,654,062	1,021,199,819	886,643,741	932,206,593	938,179,332	936,088,111	928,696,615	933,911,819	923,095,361	909,926,173
Billed kWh by Rate Class											
Residential											
Customers	35,142	35,190	35,334	35,438	35,472	35,628	35,816	35,944	36,074	36,203	36,333
kWh	302,355,083	299,638,406	296,054,771	291,091,689	301,267,823	299,495,986	296,656,279	281,071,800	289,455,443	283,016,587	277,476,009
kW	-	-	-	-	-	-	-	-	-	-	-
General Service < 50 kW											
Customers	4,009	4,001	3,976	3,919	3,916	3,907	3,859	3,862	3,870	3,860	3,850
kWh	129,600,878	126,763,870	125,816,796	114,518,667	116,294,933	116,705,566	109,007,040	105,791,729	108,543,510	104,337,672	99,682,764
kW	-	-	-	-	-	-	-	-	-	-	-
General Service > 50 kW											
Customers	507	513	523	517	496	490	498	499	497	495	491
kWh	507,947,705	498,423,262	464,092,558	395,794,984	435,880,111	444,705,629	453,565,445	456,115,509	457,346,103	470,506,400	478,846,838
kW	1,526,414	1,319,003	1,276,603	1,131,642	1,183,053	1,189,083	1,188,171	1,223,255	1,181,005	1,250,086	1,272,217
Large Use											
Customers	3	4	4	4	3	2	2	2	2	2	2
kWh	129,066,875	116,290,944	121,399,083	70,190,881	64,065,282	63,295,873	62,435,388	71,674,481	64,740,617	51,639,984	40,551,283
kW	301,505	264,468	262,310	197,012	158,624	132,465	134,207	155,785	147,471	113,324	86,226
USL											
Connections	-	-	-	122	244	245	245	248	251	290	335
kWh	-	-	-	1,158,647	1,191,306	1,249,000	1,213,037	1,228,666	1,249,444	1,268,750	1,288,075
kW	-	-	-	-	-	-	-	-	-	-	-
Sentinel Lighting											
Connections	393	394	393	390	388	388	388	441	487	509	532
kWh	454,662	445,369	436,740	440,153	433,931	353,837	405,259	410,160	408,652	402,619	396,340
kW	1,897	1,234	1,222	1,217	1,224	980	1,138	1,130	1,144	1,127	1,110
Street Lighting											
Connections	12,468	12,468	12,553	12,784	12,931	12,931	12,931	13,103	13,270	13,369	13,469
kWh	8,797,196	8,797,782	8,199,730	8,235,437	8,221,743	8,221,874	8,250,167	7,792,246	7,533,249	7,396,374	7,263,208
kW	24,792	31,812	24,235	24,546	24,338	24,338	24,338	23,008	22,342	22,189	21,790
Embedded Distributor											
Customers	-	1	1	1	1	1	1	1	1	1	1
kWh	-	5,294,429	5,200,141	5,213,283	4,851,464	4,151,567	4,555,496	4,612,024	4,634,801	4,526,975	4,421,657
kW	-	10,733	10,432	10,438	10,285	11,258	10,054	9,926	16,051	11,499	11,231
TOTAL											
Customers	52,522	52,571	52,784	53,175	53,451	53,592	53,740	54,100	54,452	54,729	55,013
kWh	1,078,222,399	1,055,654,062	1,021,199,819	886,643,741	932,206,593	938,179,332	936,088,111	928,696,615	933,911,819	923,095,361	909,926,173
kW	1,854,608	1,627,250	1,574,802	1,364,855	1,377,524	1,358,124	1,357,908	1,413,104	1,368,013	1,398,225	1,392,574

ATTACHMENT 3-B

Load Forecast CDM Adjustment

Work Form

Board Appendix 2-I

File Number:	EB-2015-0061
Exhibit:	3
Attachment:	3-B
Page:	1 of 4
Date:	28-Aug-15

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 2015 and 2016	
		46,530,000					
	2011	**2012**	**2013**	**2014**	**Total**	**2015**	**2016**
2011 CDM Programs	5.19%	5.09%	5.09%	5.03%	20.41%		
2012 CDM Programs		12.09%	12.04%	11.81%	35.94%		
2013 CDM Programs			9.50%	9.36%	18.85%		
2014 CDM Programs				23.36%	23.36%		
Total in Year	**5.19%**	**17.18%**	**26.63%**	**49.56%**	**98.56%**		
		kWh					
2011 CDM Programs	2,592,000.00	2,545,000.00	2,545,000.00	2,513,000.00	10,195,000.00		
2012 CDM Programs		6,039,000.00	6,014,000.00	5,899,000.00	17,952,000.00		
2013 CDM Programs		177,000.00	4,743,000.00	4,674,000.00	9,594,000.00		
2014 CDM Programs			542,000.00	11,669,000.00	12,211,000.00	10,797,944	10,602,838
Total in Year	**2,592,000.00**	**8,761,000.00**	**13,844,000.00**	**24,755,000.00**	**49,952,000.00**		

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

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: 56,800,000							
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
%							
2015 CDM Programs	45.63%						45.63%
2016 CDM Programs		9.86%					9.86%
2017 CDM Programs			9.59%				9.59%
2018 CDM Programs				19.15%			19.15%
2019 CDM Programs					8.19%		8.19%
2020 CDM Programs						7.58%	7.58%
Total in Year	**45.63%**	**9.86%**	**9.59%**	**19.15%**	**8.19%**	**7.58%**	**100.00%**
kWh							
2015 CDM Programs	25,916,720.00						25,916,720.00
2016 CDM Programs		5,600,807.00					5,600,807.00
2017 CDM Programs			5,448,710.00				5,448,710.00
2018 CDM Programs				10,878,282.00			10,878,282.00
2019 CDM Programs					4,652,586.00		4,652,586.00
2020 CDM Programs						4,302,895.00	4,302,895.00
Total in Year	**25,916,720.00**	**5,600,807.00**	**5,448,710.00**	**10,878,282.00**	**4,652,586.00**	**4,302,895.00**	**56,800,000.00**

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	-	-		
2011 CDM program	**3,224,697**	**2,592,371**		
2012 CDM program	**7,417,877**	**6,039,297**		
2013 CDM program	**6,117,864**	**4,743,174**		
2014 CDM program	**14,921,160**	**11,668,889**		
2006 to 2014 OPA CDM programs: Persistence to 2016	31,681,598	25,043,731	6,637,867	0.00%

File Number:	EB-2015-0061
Exhibit:	3
Attachment:	3-B
Page:	3 of 4
Date:	28-Aug-15

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

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	2015	
Weight Factor for each year's CDM program impact on 2014 load forecast	**0**	**0**	**0**	**0.5**	**1**	**0.5**	Distributor can select "0", "0.5", or "1" from drop-down list
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.*	*Full year impact of persistence of 2015 programs on 2015 load forecast. 2015 CDM program impacts are not in the base forecast.*	*Only 50% of 2016 CDM programs are assumed to impact the 2016 load forecast based on the "half-year" rule.*	

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

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	**2012**	**2013**	**2014**	**2015**	**2016**	**Total for 2016**
	kWh						
Amount used for CDM threshold for LRAMVA (2014)	2,513,000.00	5,899,000.00	4,674,000.00	11,669,000.00			
CDM adjustment for test year forecast (per Board Decision in distributor's most recent Cost of Service Application) (enter as negative)	-	-	-	-			
Amount used for CDM threshold for LRAMVA (2016)				10,602,837.56	25,916,720.00	5,600,807.00	42,120,364.56
Manual Adjustment for 2016 Load Forecast (billed basis)	-	-	-	5,301,418.78	25,916,720.00	2,800,403.50	34,018,542.28
Proposed Loss Factor (TLF)	3.25%	Format: X.XX%					
Manual Adjustment for 2016 Load Forecast (system purchased basis)	-	-	-	5,473,714.89	26,759,013.40	2,891,416.61	35,124,144.90

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.

ATTACHMENT 3-C

EPI's 2015 – 2020 CDM Plan

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

A. General Information

1.

CDM Plan Submission Date: ***(DD-Mon-YYYY)***	
CDM Plan Version	1

2.

LDC INFORMATION										
	LDC 1	**LDC 2**	**LDC 3**	**LDC 4**	**LDC 5**	**LCD 6**	**LCD 7**	**LCD 8**	**LCD 9**	**LCD 10**
LDC Name:	Entegrus Powerlines Inc.									
Company Representative:										
Name:	Margaret Rodd									
Title:	Director, Communications and Conservation									
Email Address:	margaret.rodd@entegrus.com									
Phone Number (XXX-XXX-XXXX):	519-352-6300 x306									

3.

Primary Contact for CDM Plan	
Name:	Margaret Rodd
LDC Name:	Entegrus Powerlines Inc.
Title:	Director, Communications and Conservation
Email Address:	margaret.rodd@entegrus.com
Phone Number (XXX-XXX-XXXX):	519-352-6300 x306

Estimated Start Date of CDM Plan: ***(DD-Mon-YYYY)***	1-Oct-2015

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

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

B. LDC Authorization

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

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

C. CDM Plan Summary

TABLE 1: SUMMARY OF CDM PORTFOLIO SAVINGS AND BUDGET

		CDM PLAN TOTAL	LDC 1	LDC 2	LDC 3	LDC 4	LDC 5	LCD 6	LCD 7	LCD 8	LCD 9	LCD 10
a.	**Allocated LDC CDM Plan Target (MWh)** *Indicate total CDM Plan Target allocated to LDC(s)*	**56,830**	56,830.0									
b.	**CDM Plan MWh Savings** *Calculated as part of CDM Plan*	**62,079**	62,079	0	0	0	0	0	0	0	0	0
c.	**Allocated LDC CDM Plan Budget ($)** *Indicate total budget allocated to LDC*	**$14,695,867**	$14,695,867.00									
d.	**Total CDM Plan Budget ($)** *Calculated as part of CDM Plan*	**$13,843,474**	$13,843,474	0	0	0	0	0	0	0	0	0

f.	**CDM Plan Cost Effectiveness** *Indicate annual portfolio-level Cost Effectiveness for CDM Plan as determined by LDC(s) using output from Cost-Effectiveness Tool*		Total Resource Cost (TRC)			Program Administrator Cost (PAC)			Levelized Cost
		Program Year	**Benefits ($)**	**Costs ($)**	**Ratio**	**Benefits ($)**	**Costs ($)**	**Ratio**	**($/kWh)**
		2015	$26,545,300.72	12,815,430	2.1	$22,934,726.89	$600,540.11	38.2	$0.002
		2016	$5,066,856.90	4,248,958	1.2	$4,201,850.57	$2,399,802.58	1.8	$0.035
		2017	$5,313,567.99	4,053,651	1.3	$4,424,324.15	$2,343,204.01	1.9	$0.036
		2018	$11,604,508.61	5,803,167	2.0	$9,939,982.31	$3,204,778.90	3.1	$0.022
		2019	$4,849,247.16	3,699,573	1.3	$4,081,981.15	$2,305,544.84	1.8	$0.041
		2020	$4,421,802.02	3,471,526	1.3	$3,743,363.89	$2,228,761.94	1.7	$0.042
		CDM Plan Total	**$57,801,283**	**$34,092,306**	1.7	**$49,326,229**	**$13,082,632**	3.8	**$0.017**

g	**Plan Cost Effectiveness-Exceptions Rationale** *Complete this section if proposed plan <u>does not</u> meet minimum Cost-Effectiveness Thresholds set out in CDM Plan Submission and Review Criteria Rules.*	

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

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

LDC 1:	Entegrus Powerlines Inc.

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program: Residential	Low-income	Small business	Commercial (inc. Multi-F	Agricultural	Institutional	Industrial	2015 Anticipated Annual Budget ($)	2015 Energy Savings (MWh)	2016 Anticipated Annual Budget ($)	2016 Energy Savings (MWh)	2017 Anticipated Annual Budget ($)	2017 Energy Savings (MWh)	2018 Anticipated Annual Budget ($)	2018 Energy Savings (MWh)	2019 Anticipated Annual Budget ($)	2019 Energy Savings (MWh)	2020 Anticipated Annual Budget ($)	2020 Energy Savings (MWh)	Total 2015 - 2020: Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs	Retrofit			1-Oct-2015			Yes	Yes	Yes	Yes	Yes	$228,117	835.5	$1,013,783	4,450.0	$922,853	4,144.5	$909,332	3,808.5	$859,136	3,349.2	$857,482	3,135.9	$4,790,702	19,723.6
	Heating and Cooling			1-Oct-2015	Yes							$97,096	46.1	$395,951	252.6	$421,905	302.9	$434,758	327.6	$447,661	352.3	$369,166	329.1	$2,166,537	1,610.7
	Coupon Program			1-Oct-2015	Yes							$138,845	75.4	$329,699	296.0	$334,243	292.3	$339,585	291.7	$345,162	291.7	$350,850	291.7	$1,838,384	1,538.9
	New Construction Program			1-Oct-2015	Yes							$44,752	0.0	$101,207	9.2	$103,156	9.2	$105,145	9.2	$107,172	9.2	$109,241	9.2	$570,673	46.0
	Home Assistance Program			1-Oct-2015		Yes						$41,420	24.5	$151,522	96.7	$152,252	96.7	$152,997	96.7	$153,756	96.7	$154,531	96.7	$806,479	507.9
	High Performance New Construction			1-Oct-2015				Yes		Yes		$6,440	0.0	$36,436	57.0	$36,791	57.0	$37,152	57.0	$37,521	57.0	$37,897	57.0	$192,238	285.0
	Audit Funding Program			1-Oct-2015				Yes	Yes	Yes	Yes	$13,100	94.8	$60,337	606.8	$60,691	606.8	$45,071	379.3	$45,439	379.3	$35,161	227.6	$259,798	1,592.9
	Process and Systems Upgrades Program			1-Oct-2015				Yes	Yes	Yes	Yes	$30,770	0.0	$83,833	0.0	$85,510	0.0	$967,220	6,477.8	$88,965	0.0	$90,744	0.0	$1,347,043	6,477.8
			SMB Future Program	1-Jan-2016			Yes					$0	0.0	$275,030	450.2	$320,468	540.3	$409,678	630.3	$410,784	630.3	$455,662	630.3	$1,871,622	2,881.5
FCR TOTAL												$600,540	1,076.3	$2,447,799	6,218.6	$2,437,869	6,049.7	$3,400,937	12,078.2	$2,495,596	5,165.8	$2,460,733	4,777.5	$13,843,474	34,664.4
Pay for Performance Programs																									
P4P TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*	Retrofit Initiative												2,828.8												2,828.8
	Heating and Cooling Initiative												138.2												138.2
	Conservation Instant Coupon Booklet												41.2												41.2
	Bi-Annual Retailer Event												185.0												185.0
	Residential New Construction												1.8												1.8
	Low Income Home Assistance Program												73.5												73.5
	Audit Funding												284.5												0.0
	Process and Systems Upgrades Program												23,731.9												23,731.9
	Direct Install Lighting												414.2												414.2
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	27,699.1											0.0	27,414.7
TARGET GAP TOTAL																								0.0	
CDM PLAN TOTAL												$600,540	28,775.4	$2,447,799	6,218.6	$2,437,869	6,049.7	$3,400,937	12,078.2	$2,495,596	5,165.8	$2,460,733	4,777.5	$13,843,474	62,079.1
MINIMUM ANNUAL SAVINGS CHECK													True		True		True		True		True		False		

E. Proposed Local and Regional Pilot CDM Programs

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

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

a.	**Program Name**	SMB Future Program	*Use same "Program name" included in other worksheets*	
b.	**Program Type**	Proposed Regional Program		
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***	1-Jan-2016		
c.	**Customer Segment(s) Served by Programs**	Small Business		
d.	**Participating LDCs** ***(if applicable)***	Entegrus Powerlines Inc.		
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*	The SMB Future Program palceholder has been placed into the CDM Plan to represent the future iteration of the Direct Install Lighting Program. At this time, the current DIL program is being redesigned within the commercial and institutional working group and it is expected to be ready for Provincial implementation by January 1, 2016. Entegrus Powerlines is planning to offer the new version of the Direct Install Lighting program (which current indications show will now include non-lighitng measures) once the program rules are completed and the program is ready to be implemented by LDCs.		

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

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs** ***(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

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

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs** ***(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

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

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs** ***(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

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

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs** ***(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

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

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs** ***(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

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

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs** ***(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

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

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs** ***(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

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

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs** ***(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

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

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs** ***(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

F. Detailed Information on Collaboration and Regional Planning

ADDITIONAL DETAILED INFORMATION	
Regional LDC(s) Collaboration *Description of how the LDC(s) will collaborate with other LDCs. If collaboration will not occur, description of why it will not occur.*	Entegrus has been in talks with a neighbouring group of LDCs which has informally named itself the "West LDC Collaboration Group." The members of this group represent shoulder to shoulder LDCs. Our customers quite often intermingle between territories for work, home and play. The Group has held a series of very productive meetings through Q4 2014 and Q1 2015. Through these meetings, the group has identified 4 areas where further collaboration opportunities will be explored: • Customer Marketing • Custom or Pilot Program Design • Shared Services including I.T. needs, technical reviews, and sales or account management resources: The group has discussed creating shared resources which have similar skillsets to Key Account Managers and Entegrus' Energy Efficiency Advisors. • Joint Requests for Proposals (RFPs): Discussions have brought up the opportunity for the Group to submit joint RFPs for the shared service delivery of the Home Assistance Program (and its future replacement) along with the Small Business Lighting Program and it future iteration, and/or marketing/event needs. Entegrus will submit its own plan initially and will consider a joint plan submission sometime in the future. The West group is continuing to pursue collaboration in the following form: assign a subcommittee to each topic listed above for the exploration of next steps. Each LDCs can elect to participate in these committees or not and have no obligation to do so.
Gas Collaboration *Description of how the LDC(s) will collaborate with other gas utility programs delivered in service area (if applicable). If collaboration will not occur, description of why it will not occur.*	Entegrus Powerlines and Union Gas have held a series of discussions on the possibilities of collaboration in late 2014. The meetings were held on Oct 7th, 22nd, and Nov 5th. The conversations focused mostly around the low income program, although there was some discussion regarding a residential thermostat program. In addition to the above discussions, Entegrus has been informed that Union has elected to stop the delivery of the High Performance New Construction Program on its behalf. In the near future there is a low likelihood that Union and Entegrus will participate in collaboration efforts in a customized fashion. Entegrus is open to continuing its discussions with Union and exploring more standard options that focus on the broader group of LDCs. One such possibility is working collaboratively on customer benchmarking and other market and customer research.
CDM Contribution to Regional Planning *Description of how the CDM Plan considers the electricity needs and investments identified in other plans or planned initiatives, completed or underway within the LDC(s)' service area or region. This may included Integrated Regional Resource Plans or Municipal Community Energy Plans.*	Entegrus Powerlines participates in the IESO driven regional planning activities to develop integrated regional resource plans. These plans are developed in consultation with all affected LDC's and the IESO to ensure adequate electrical supply is available for the next 20 years. Entegrus' service territory straddles three IESO planning zones. One of these regional plans is now complete (Windsor-Essex), one is under way (London Region), and one is scheduled for next group (Chatham-Sarnia). Entegrus has been involved from the beginning, and continues to be involved in the Leamington SECTR application. Entegrus is a member of the planning committee for the development of the Chatham-Kent Community Energy Plan, and has reached out to the municipalities of Middlesex-Caradoc and Elgin to offer our support and expertise in the development of their Community Energy Plans as well. Entegrus will continue to align their efforts to meet provincially mandated CDM targets with their commitment to both informing the IESO regional planning processes as well as leveraging this resource to strengthen the regional impact of CDM.

G. Additional Documentation for CDM Plan (If applicable)

ADDITIONAL INFORMATION AND DOCUMENTATION	
Programs *Opportunity to provide any additional information on assumptions used for budgets and/or savings for approved 2015-2020 province-wide programs*	The proposed start date for all programs is October 1st, 2015 except for the next iteration of the Direct Install Lighting (DIL) Program (labelled SMB Future Program) which Entegrus is assuming will be in market on January 1, 2016. Given the proposed start dates, it is assumed that 3/4 of the savings from all programs, except DIL, will be captured under the 2011-2014 Framework extension and funded under the Transition Funding Agreement. Consequentially, only 1/4 of the 2015 program costs (except DIL) were assigned to the Conservation First Framework budget. The DIL Program is to be funded for all of 2015 under the Transition Funding Agreement. Assumptions for program volumes were based on historical program performance, conservative increases in program participation rates and Entegrus' view on the evolution of certain programs. The majority of the Plan and cost effectiveness testing is based on the IESO Archetypes provided in the Cost Effectiveness Testing Tool. Entegrus has provided details on a forecasted CHP project along with a street lighting project individually in order to capture the unique cost and savings characteristics of these larger projects. As for the administration budget, Entegrus's 2014 costs were used as the baseline. As for labour costs, the budget was based on Entegrus' current staffing compliment along with planned headcount additions. Costs were increased over time based on inflation, forecasted large projects and studies, and an increase in application or customer volumes.
Approved Local and/or Regional Programs and Pilot Programs *Opportunity to provide any additional information on assumptions used for budgets and/or savings for approved 2015-2020 local or regional programs or pilot programs*	
Proposed Local and/or Regional Programs and Pilot Programs *Opportunity to provide additional information on assumptions used for forecast budgets and/or savings for proposed programs or pilot programs*	
Programs from 2011-2014/2015 CDM Framework *Opportunity to provide any additional information on assumptions used for budgets and/or savings from existing 2011-2014/2015 CDM Programs*	Entegrus is currently awaiting the completion of a 4.2MW CHP project which is to be funded under the 2011-2014/2015 Framework. At this time, the project is anticipated to be in-service before December 31st, 2015.
Programs funded through Pay-for-Performance *Opportunity to provide any additional information on assumptions used for budgets and/or savings for Pay for Performance Programs*	
Other *Additional assumptions used in the CDM Plan*	

ATTACHMENT 3-D

Summary and Variances of Actual and Forecast Data

Board Appendix 2-IA

File Number:	EB-2015-0061
Exhibit:	3
Attachment:	3-D
Page:	1 of 1
Date:	28-Aug-15

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

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

	2010 Board Approved Proxy	2010	2011	2012	2013	2014	2015 Bridge	2016 Test
Residential								
# of Customers	35,628	35,472	35,628	35,816	35,944	36,074	36,203	36,333
kWh	272,041,007	301,267,823	299,495,986	296,656,279	281,071,800	289,455,443	283,016,587	277,476,009
kW	-	-	-	-	-	-	-	-
Variance Analysis								
# of Customers		-0.44%	0.00%	0.53%	0.89%	1.25%	1.61%	1.98%
kWh		10.74%	10.09%	9.05%	3.32%	6.40%	4.03%	2.00%
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
General Service < 50 kW								
# of Customers	3,819	3,916	3,907	3,859	3,862	3,870	3,860	3,850
kWh	112,228,606	116,294,933	116,705,566	109,007,040	105,791,729	108,543,510	104,337,672	99,682,764
kW	-	-	-	-	-	-	-	-
Variance Analysis								
# of Customers		2.54%	2.30%	1.05%	1.13%	1.34%	1.07%	0.81%
kWh		3.62%	3.99%	-2.87%	-5.74%	-3.28%	-7.03%	-11.18%
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
General Service > 50 kW								
# of Customers	543	497	491	498	499	497	495	491
kWh	418,434,515	447,772,631	444,705,629	453,565,445	456,115,509	457,346,103	470,506,400	478,846,838
kW	1,105,568	1,213,650	1,189,083	1,188,171	1,223,255	1,181,005	1,250,086	1,272,217
Variance Analysis								
# of Customers		-8.47%	-9.58%	-8.29%	-8.10%	-8.47%	-8.84%	-9.58%
kWh		7.01%	6.28%	8.40%	9.01%	9.30%	12.44%	14.44%
kW		9.78%	7.55%	7.47%	10.64%	6.82%	13.07%	15.07%
Large Use								
# of Customers	2	2	2	2	2	2	2	2
kWh	61,239,526	52,172,761	63,295,873	62,435,388	71,674,481	64,740,617	51,639,984	40,551,283
kW	143,403	128,027	132,465	134,207	155,785	147,471	113,324	86,226
Variance Analysis								
# of Customers		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kWh		-14.81%	3.36%	1.95%	17.04%	5.72%	-15.68%	-33.78%
kW		-10.72%	-7.63%	-6.41%	8.63%	2.84%	-20.98%	-39.87%
Unmetered Scattered Load								
# of Connections	245	244	245	245	248	251	290	335
kWh	1,392,861	1,191,306	1,249,000	1,213,037	1,228,666	1,249,444	1,268,750	1,288,075
kW		-	-	-	-	-	-	-
Variance Analysis								
# of Connections		-0.41%	0.00%	0.00%	1.22%	2.45%	18.37%	36.73%
kWh		-14.47%	-10.33%	-12.91%	-11.79%	-10.30%	-8.91%	-7.52%
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Sentinel Lighting								
# of Connections	375	388	388	388	441	487	509	532
kWh	390,724	433,931	353,837	405,259	410,160	408,652	402,619	396,340
kW	1,200	1,224	980	1,138	1,130	1,144	1,127	1,110
Variance Analysis								
# of Connections		3.47%	3.47%	3.47%	17.60%	29.87%	35.73%	41.87%
kWh		11.06%	-9.44%	3.72%	4.97%	4.59%	3.04%	1.44%
kW		2.00%	-18.33%	-5.17%	-5.83%	-4.67%	-6.08%	-7.50%
Street Lighting								
# of Connections	13,003	12,931	12,931	12,931	13,103	13,270	13,369	13,469
kWh	7,386,297	8,221,743	8,221,874	8,250,167	7,792,246	7,533,249	7,396,374	7,263,208
kW	23,187	24,338	24,338	24,338	23,008	22,342	22,189	21,790
Variance Analysis								
# of Connections		-0.55%	-0.55%	-0.55%	0.77%	2.05%	2.81%	3.58%
kWh		11.31%	11.31%	11.70%	5.50%	1.99%	0.14%	-1.67%
kW		4.96%	4.96%	4.96%	-0.77%	-3.64%	-4.30%	-6.02%
Embedded Distributor								
# of Customers	1	1	1	1	1	1	1	1
kWh	4,851,463	4,851,464	4,151,567	4,555,496	4,612,024	4,634,801	4,526,975	4,421,657
kW	10,285	10,285	11,258	10,054	9,926	16,051	11,499	11,231
Variance Analysis								
# of Customers		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kWh		0.00%	-14.43%	-6.10%	-4.94%	-4.47%	-6.69%	-8.86%
kW		0.00%	9.46%	-2.25%	-3.49%	56.06%	11.80%	9.20%

Totals

Customers / Connections	53,616	53,451	53,593	53,740	54,100	54,452	54,729	55,013
kWh	877,964,999	932,206,592	938,179,332	936,088,111	928,696,615	933,911,819	923,095,361	909,926,173
kW from applicable classes	1,283,643	1,377,524	1,358,124	1,357,908	1,413,104	1,368,013	1,398,225	1,392,574

Totals - Variance

Customers / Connections		-0.31%	-0.04%	0.23%	0.90%	1.56%	2.08%	2.61%
kWh		6.18%	6.86%	6.62%	5.78%	6.37%	5.14%	3.64%
kW from applicable classes		7.31%	5.80%	5.79%	10.09%	6.57%	8.93%	8.49%

ATTACHMENT 3-E

Other Operating Revenue

Board Appendix 2-H

File Number:	EB-2015-0061
Exhibit:	3
Attachment:	3-E
Page:	1 of 3
Date:	28-Aug-15

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
		2010	2011	2011	2013	2013	2014	2015	2016
	Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
4235	**Specific Service Charges**	$332,660	$273,269	$371,529	$291,864	$291,864	$311,708	$322,188	$327,731
4225	**Late Payment Charges**	$242,342	$247,833	$258,141	$252,224	$252,224	$312,004	$250,000	$250,000
4082	**Retail Services Revenues**	$75,486	$63,044	$53,186	$45,160	$45,160	$37,977	$37,877	$37,877
4084	**Service Transaction Requests (STR) Revenues**	$2,500	$1,385	$1,462	$1,194	$1,194	$773	$1,492	$1,492
4086	**SSS Administration Revenue**	$135,456	$144,362	$142,532	$150,788	$150,788	$151,936	$154,974	$158,074
4090	**Electric Services Incidental to Energy Sales**	$0	$0	$0	$0	$0	$0	$0	$0
4205	**Interdepartmental Rents**	$156,996	$175,601	$179,109	$196,468	$196,468	$200,760	$49,072	$49,808
4210	**Rent from Electric Property**	$156,557	$198,385	$159,245	$164,701	$164,701	$176,427	$179,760	$183,155
4215	**Other Utility Operating Income**	$0	$0	$0	$0	$0	$0	$0	$0
4220	**Other Electric Revenues**	$10,016	$2,749	$4,551	$7,096	$7,096	$6,020	$6,208	$6,332
4305	**Regulatory Debits**	$0	$0	$0	$0	-$602,341	-$1,677,655	-$1,305,434	$0
4325	**Revenues from Merchandise**	$0	$0	$0	$0	$0	$0	$0	$0
4355	**Gain on Disposition of Utility and Other Property**	$45,485	$109,158	$73,609	$180,353	$180,353	$38,787	$50,000	$50,000
4360	**Loss on Disposition of Utility and Other Property**	-$118,373	$0	$0	-$85,222	-$85,222	$0	$0	$0
4375	**Revenues from Non Rate-Regulated Utility Operations**	$800,310	$262,232	$120,557	$44,202	$44,202	$262,013	$198,992	$205,552
4380	**Expenses of Non Rate-Regulated Utility Operations**	$0	$0	-$61,363	-$27,034	-$27,034	-$50,155	-$35,000	-$35,000
4390	Miscellaneous Non-Operating Income	$29,530	$65,751	$61,327	$21,525	$21,525	$16,007	$30,000	$30,000
4405	Interest and Dividend Income	$127,731	$133,005	$138,379	$95,784	$95,784	$197,867	$100,000	$100,000
Specific Service Charges		$332,660	$273,269	$371,529	$291,864	$291,864	$311,708	$322,188	$327,731
Late Payment Charges		$242,342	$247,833	$258,141	$252,224	$252,224	$312,004	$250,000	$250,000
Other Operating Revenues		$537,011	$585,525	$540,084	$565,407	-$36,933	-$1,103,763	-$876,051	$436,738
Other Income or Deductions		$884,684	$570,146	$332,509	$229,607	$229,607	$464,518	$343,992	$350,552
Total		$1,996,697	$1,676,773	$1,502,263	$1,339,103	$736,762	-$15,533	$40,128	$1,365,021

Description	**Account(s)**
Specific Service Charges:	4235
Late Payment Charges:	4225
Other Distribution Revenues:	4080, 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Income and Expenses:	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4415

Note: Add all applicable accounts listed above to the table and include all relevant information.

Account Breakdown Details

For each "Other Operating Revenue" and "Other Income or Deductions" Account, a detailed breakdown of the account components is required. See the example below for Account 4405, Interest and Dividend Income.

Account 4082: Retail Service Revenues

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2010	2011	2011	2013	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Standard Charge	$ -	$ 17,365	$ 14,230	$ 11,437	$ 11,437	$ 100	$ -	$ -
Monthly Fixed Charge	$ 6,920	$ 2,140	$ 4,180	$ 4,300	$ 4,300	$ 4,540	$ 4,540	$ 4,540
Monthly Variable Charge	$ 43,261	$ 27,323	$ 21,797	$ 18,519	$ 18,519	$ 20,854	$ 20,854	$ 20,854
Bill Ready Charge	$ 25,306	$ 16,217	$ 12,979	$ 10,905	$ 10,905	$ 12,483	$ 12,483	$ 12,483
Total	$ 75,486	$ 63,044	$ 53,186	$ 45,160	$ 45,160	$ 37,977	$ 37,877	$ 37,877

Account 4084 - Service Transaction Requests (STR) Revenues

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2010	2011	2011	2013	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Request Fee	$ 1,217	$ 776	$ 660	$ 669	$ 669	$ 308	$ 740	$ 740
Process Fee	$ 1,283	$ 609	$ 802	$ 525	$ 525	$ 465	$ 751	$ 751
Total	$ 2,500	$ 1,385	$ 1,462	$ 1,194	$ 1,194	$ 773	$ 1,492	$ 1,492

Account 4086 - SSS Administration

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2010	2011	2011	2013	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
SSS Administration	$ 135,456	$ 144,362	$ 142,532	$ 150,788	$ 150,788	$ 151,936	$ 154,974	$ 158,074
Total	$ 135,456	$ 144,362	$ 142,532	$ 150,788	$ 150,788	$ 151,936	$ 154,974	$ 158,074

Account 4205 - Interdepartmental Rents

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2010	2011	2011	2013	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Building Rent	$ 156,996	$ 175,601	$ 179,109	$ 196,468	$ 196,468	$ 200,760	$ 49,072	$ 49,808
Total	$ 156,996	$ 175,601	$ 179,109	$ 196,468	$ 196,468	$ 200,760	$ 49,072	$ 49,808

File Number:	EB-2015-0061
Exhibit:	3
Attachment:	3-E
Page:	2 of 3
Date:	28-Aug-15

Appendix 2-H
Other Operating Revenue

Account 4210 - Rent from Electric Property

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2010	**2011**	**2011**	**2013**	**2013**	**2014**	**2015**	**2016**
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Building Rent	$ 5,400							
Pole Joint Use	$ 151,157	$ 198,385	$ 159,245	$ 159,699	$ 159,699	$ 166,431	$ 169,760	$ 173,155
Distribution Land Rental				$ 5,002	$ 5,002	$ 9,996	$ 10,000	$ 10,000
Total	$ 156,557	$ 198,385	$ 159,245	$ 164,701	$ 164,701	$ 176,427	$ 179,760	$ 183,155

Account 4220 Other Electric Revenus

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2010	**2011**	**2011**	**2013**	**2013**	**2014**	**2015**	**2016**
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Misc.	$ 5,391	$ 470	$ 651	$ 2,296	$ 2,296	$ 3,095	$ 2,428	$ 2,477
Private Locates	$ 4,625	$ 2,279	$ 3,900	$ 4,800	$ 4,800	$ 2,925	$ 3,780	$ 3,855
Total	$ 10,016	$ 2,749	$ 4,551	$ 7,096	$ 7,096	$ 6,020	$ 6,208	$ 6,332

Account 4305 Regulatory Debits

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2010	**2011**	**2011**	**2013**	**2013**	**2014**	**2015**	**2016**
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
IFRS Adjustment					-$ 602,341	-$ 1,677,655	-$ 1,305,434	$ -
Total	$ -	$ -	$ -	$ -	-$ 602,341	-$ 1,677,655	-$ 1,305,434	$ -

Account 4355 - Gain on Disposition of Utility and Other Property

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2010	**2011**	**2011**	**2013**	**2013**	**2014**	**2015**	**2016**
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Fixed Asset Disposition	$ 45,485	$ 109,158	$ 73,609	$ 180,353	$ 180,353	$ 38,787	$ 50,000	$ 50,000
Total	$ 45,485	$ 109,158	$ 73,609	$ 180,353	$ 180,353	$ 38,787	$ 50,000	$ 50,000

Account 4360 - Loss on Disposition of Utility and Other Property

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2010	**2011**	**2011**	**2013**	**2013**	**2014**	**2015**	**2016**
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Fixed Asset Disposition	-$ 118,373	$ -	$ -	-$ 85,222	-$ 85,222	$ -	$ -	$ -
Total	-$ 118,373	$ -	$ -	-$ 85,222	-$ 85,222	$ -	$ -	$ -

Account 4375 - Revenues from Non Rate-Regulated Utility Operations

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2010	**2011**	**2011**	**2013**	**2013**	**2014**	**2015**	**2016**
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Unregulated:								
CDM	$ 535,871	-$ 53,971	$ -	-$ 10,925	-$ 10,925	$ 87,476	$ -	$ -
Solar Generation	$ -	$ -	$ 11,110	$ 10,461	$ 10,461	$ 10,564	$ 10,000	$ 10,000
BioGas Generation	$ -	$ -	$ -	$ -	$ -	$ 41,150	$ 101,500	$ 101,500
Regulated:								
Water/Sewer Billing	$ 228,685	$ 276,348	$ -	$ -	$ -	$ -	$ 42,492	$ 48,646
Street Lighting Maintenance	$ 35,754	$ 39,855	$ 35,926	$ 43,786	$ 43,786	$ 74,991	$ 35,000	$ 35,000
Low Voltage Transmission Work	$ -	$ -	$ -	$ -	$ -	$ 8,212	$ 10,000	$ 10,406
Storm Assisstence	$ -	$ -	$ 73,521	$ -	$ -	$ 3,619	$ -	$ -
Misc.	$ -	$ -	$ -	$ 879	$ 879	$ 36,000	$ -	$ -
Total	$ 800,310	$ 262,232	$ 120,557	$ 44,202	$ 44,202	$ 262,013	$ 198,992	$ 205,552

Account 4380 - Expenses of Non Rate-Regulated Utility Operations

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2010	**2011**	**2011**	**2013**	**2013**	**2014**	**2015**	**2016**
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Solar Depreciation	$ -	$ -	-$ 4,661	-$ 20,206	-$ 20,206	-$ 35,571	-$ 35,000	-$ 35,000
Misc.	$ -	$ 0	-$ 56,702	-$ 6,828	-$ 6,828	-$ 14,584	$ -	$ -
Total	$ -	$ 0	-$ 61,363	-$ 27,034	-$ 27,034	-$ 50,155	-$ 35,000	-$ 35,000

Account 4390 - Miscellaneous Non-Operating Income

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2010	**2011**	**2011**	**2013**	**2013**	**2014**	**2015**	**2016**
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Sale of Scrap	$ 29,530	$ 65,751	$ 61,327	$ 21,525	$ 21,525	$ 16,007	$ 30,000	$ 30,000
Total	$ 29,530	$ 65,751	$ 61,327	$ 21,525	$ 21,525	$ 16,007	$ 30,000	$ 30,000

File Number:	EB-2015-0061
Exhibit:	3
Attachment:	3-E
Page:	3 of 3
Date:	28-Aug-15

Appendix 2-H
Other Operating Revenue

Account 4405 - Interest and Dividend Income

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2010	2011	2011	2013	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Interest on Regulatory Assets	$ 88,809	$ 117,574	$ 112,704	$ 95,784	$ 95,784	$ 107,867	$ 100,000	$ 100,000
Interest Earned	$ 38,922	$ 15,430	$ 25,675	$ -	$ -	$ 90,000	$ -	$ -
Total	$ 127,731	$ 133,005	$ 138,379	$ 95,784	$ 95,784	$ 197,867	$ 100,000	$ 100,000

Notes:

1 List and specify any other interest revenue.

2 In the transition year to IFRS, the applicant is to present information in both MIFRS and CGAAP. For the typical applicant that adopted IFRS on January 1, 2015, 2014 must be presented in both a CGAAP and MIFRS basis.