Exhibit	Tab	Schedule	Appendix	Contents
7 – Cost Allocation				
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COST ALLOCATION OVERVIEW

COST ALLOCATION STUDY REQUIREMENTS

The Board's requirements for Exhibit 7 - Cost Allocation are contained in section 2.10 of the Filing Requirements. Horizon Utilities' filing follows the Board's *Review of Electricity Distribution Cost Allocation Policy* (EB-2010-0219) (the "Cost Allocation Review") dated March 31, 2011.

In its previous (2011) Cost of Service Application, Horizon Utilities' 2011 Cost Allocation Model ("2011 Horizon Model") used the structure of the Board's 2006 Cost Allocation Model ("2006 Board CA Model") for the 2011 cost allocation study. The 2006 Board CA model was used for Horizon Utilities' 2006 Cost Allocation Information Filing ("CAIF"). The 2011 Horizon Model was prepared in accordance with the September 29, 2006 Board report entitled *Cost Allocation: Board Directions on Cost Allocation Methodology for Electricity Distributors* (the "Directions"), the subsequent (November 15, 2006) *Cost Allocation Informational Filing Guidelines for Electricity Distributors* (the "Guidelines"), and the *Cost Allocation Review: User Instruction for the Cost Allocation Model for Electricity Distributors* (the "Instructions").

For purposes of its 2015-2019 Custom IR Application, which is comprised of five test years, Horizon Utilities has prepared a cost allocation model for each of the five test years using the Board's v 3.1 Cost Allocation Model ("Board 3.1 CA Model") and complied with the internal documentation contained in the that model. The Board 3.1 CA Models have been used to determine the proportion of Horizon Utilities' total revenue requirement that is recoverable from each rate class in each year. The revenue-to-cost ratios for each class for each test year have been determined using the total revenues over costs in each respective test year.

In preparation for this Application, Horizon Utilities engaged Elenchus Research Associates Inc. (Elenchus) to undertake a review of Horizon Utilities' 2011 CA Model that included a detailed examination of the actual facilities included in the accounts that serve as inputs to the model to determine whether there could be refinements that would better reflect the principle of cost causality in allocating costs to customers. The final report from Elenchus is filed as *Horizon Utilities 2015-2019 Cost Allocation and Rate Design Study ("The CA Report")* in Appendix 7-1.

This review identified two significant areas of concern with respect to allocating costs consistent with the principle of cost causality. First, it was determined that the largest customers in Horizon Utilities' Large Use customer class are served exclusively with dedicated facilities, and maintaining these customers in the current Large Use class results in them being allocated costs for pooled distribution facilities that they do not use. Second, it was determined that certain accounts defined as "primary assets" in the 2011 Horizon Model included both secondary and primary assets when examined on a sub-account basis. Consequently, Horizon Utilities is proposing the introduction of a new customer class and changes to the allocation of sub-accounts to customer classes, to conform more consistently to the principle of cost causality. The proposed changes are further described below.

New Customer Class

In order to appropriately address cost causation, and the uniqueness of some of its customers, Horizon Utilities is proposing a new Large Use 2 ("LU (2)") customer class, for customers with demand over 15 MW, who also are served by dedicated assets.

Presently, Horizon Utilities serves 4 customers that meet the criteria of the proposed LU (2) class. These customers are served by dedicated feeders, and do not participate in the use of the pooled assets, because of their size. Customers who meet the criteria of the proposed LU (2) class are presently allocated costs for distribution facilities that they do not use, and that are used by the other customers in the Large Use class and customers in other rate classes.

Horizon Utilities has identified the costs associated with the customers who meet the criteria of the LU (2) class. Consistent with the configuration of Horizon Utilities' distribution system, the feeders used by the LU (2) rate class are allocated by means of direct allocation in the OEB's Cost Allocation Model (Worksheet I9 – Direct Allocation), and correspondingly this rate class does not attract allocation of the shared primary or secondary asset pools.

Table 7-1 compares the Test Year revenues proposed to be collected from the LU (2) class to the revenues that would be collected from this group of customers if the new rate class were not created. The introduction of the LU (2) customer class and the removal of costs related to assets that these customers do not use reduces the costs allocated to these customers by nearly $4 Million per year. Appendix 2P further illustrates the difference between maintaining these customers in the Large Use class and moving them to the proposed LU (2) class.

Table 7-1: LU (2) Revenues at Proposed Rates vs. LU (2) Revenues at LU (1) Rates

	Revenue Requirement as LU (1) Customers A	Revenue Requirement as LU (2) Customers B	Revenue Difference as LU (1) Customers A-B
2015	$4,085,475	$480,086	$3,605,389
2016	$4,332,153	$580,573	$3,751,579
2017	$4,496,349	$782,837	$3,713,512
2018	$4,616,370	$804,863	$3,811,507
2019	$4,808,926	$838,452	$3,970,474

The introduction of this class results in a rate structure that better addresses the cost causality of each customer class. In addition, there is concern that, absent the proposed rate class, some of these customers may choose to make related investments to directly connect to Hydro One, leaving Horizon Utilities with stranded assets, and significantly less volume throughput. Retention of these customers will reduce the risk of a larger burden of costs on the remaining customer classes.

Presently, all customers that qualify for the LU (2) rate class have demands over 20 MW, while the largest of the remaining Large Use customers' demands is less than 10 MW. It is expected that customers under the threshold are unlikely to cross over, and those above are unlikely to cross under. Unlike the members of the proposed LU (2) customer class, pooled assets are used to distribute power to the remaining Large Use customer class ("LU (1)").

Allocation of Sub-Accounts

Elenchus determined that certain accounts that are treated as primary assets included sub-accounts that, when examined on a disaggregated basis, were in fact secondary assets. Consequently, it was determined that the allocation of costs to Horizon Utilities' customer classes would be of greater adherence with the principle of cost causality if the sub-accounts that comprised primary and secondary costs were separated as inputs in the cost allocation model and allocated appropriately to Horizon Utilities' customer classes. Horizon Utilities agrees with the recommendation made by Elenchus and has refelected these changes in the 2015 – 2019 CA Models.

Updates to Horizon Utilities' Cost Allocation Model

Elenchus determined updated demand allocators for each year, providing advice on the methodology for preparing a cost allocation study, and performing a final review of the completed models. In addressing these matters, Elenchus and Horizon Utilities were guided by the Filing Requirements and the Cost Allocation Review which set out the Board's policies in relation to specific cost allocation matters for electricity distributors.[1]

Load and Customer Information

The Horizon Utilities 2015-2019 CA Models have been prepared using the following load and load profile information:

Annual Loads (kW and kWh, as appropriate) and customer counts: The 2015-2019 load forecast and customer counts by class provided in Exhibit 3, Tab 2, Schedule 1 were also used for the 2015-2019 CA Models.

Street Lighting Connections: The 2015-2019 connections (unmetered) for the Street Lighting class are calculated using a ratio of 1.3141 Devices : 1 Connection. This ratio is based on the results of a 2013 audit of the number of daisy chained devices in the City of Hamilton. The scope of this audit included a physical count of the number of daisy chained devices in the City of Hamilton. In addition, a review of GIS records in the City of St. Catharines was completed to inform the calculation of this ratio. Table 7-2 provides the derivation of ratio of 1.3141 Devices : 1 Connection.

[1] Ontario Energy Board, *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667), November 28, 2007, page 1.

Table 7-2: Calculation of Ratio of Devices:Connections[2]

	Known Connections	Unknown Connections Assumed at 3:1 Daisy Chaining	Total Connections	Devices	Ratio of Devices per Connection
City of Hamilton	21,779	6,204	27,983	37,119	1.3265
City of St. Catharines	10,245	1,669	11,914	15,308	1.2849
Total	**32,024**	**7,873**	**39,897**	**52,427**	**1.3141**

Hourly load profile: The hourly load profiles prepared by Hydro One for the 2006 CAIF were used for all classes except the LU (1) and LU (2) classes. Elenchus provided updated load profiles for these classes using actual 2012 data. Using actual data to inform the load profile for these customer classes provides a stronger indication of how these two classes attract costs and as such provides a better approach for determining their rates for the 2015 – 2019 term. This methodology is based on current information and provides a more accurate output from the Cost Allocation model.

Elenchus advised that the hourly load profiles provided by Hydro One for all other classes, exclusive of the LU (1) and LU (2) customer classes, for the 2006 CA model were considered appropriate for use in the 2015-2019 CA Models for the reasons identified in Section 2.3 of the CA Report.

Costs and Revenues

In preparing the 2015 – 2019 CA Models, Horizon Utilities has provided financial information for the forecast years at the level of detail embedded within the Board's 3.1 CA Model.

[2] Consistent with common practice in the Ontario electricity distribution sector Horizon Utilities has previously used the term connection to refer to the number of devices that the customer is billed on. Within the OEB cost allocation model, the term connection has been used in recent years to refer to either to a single device or as a group of daisy chained devices. In order to provide more transparency, and to align with the terminology currently used in the Board's Cost Allocation model, Horizon Utilities has clarified its language using devices to refer to the number of lights the customer is billed on, and connection to refer to a group of daisy chained lights as well as lights that are connected at a one to one ratio.

Load Profiles

The Horizon Utilities hourly load shapes derived by Hydro One for the 2006 CAIF were used without any revision for all rate classes with the exception of LU (1) and LU (2). Elenchus revised the demand allocators derived by Hydro One for the 2006 CAIF to incorporate changes in the relative loads for the classes from 2004 to 2015-2019. The adjustments to relative loads are discussed in Secion 3.1.1 of the CA Report.

For the LU (1) and LU (2) customer classes, 2012 actual interval hourly data was used.

The load profiles for the Street Light customer class remain unchanged from the previous cost allocation study.

Demand Allocators

Elenchus provided demand allocators for the 2015-2019 CA models which were derived using the same methodology Hydro One used for the 2006 CAIF, but updated for the forecast 2015-2019 hourly load profiles resulting from the preceding step. Demand Allocators are discussed in section 3.1.2 of the CA Report.

New and Updated Allocators

New allocators were required in order to accommodate the direct allocation of assets and expenses to Horizon Utilities' LU (2) class[3]. All new allocators were created on sheet "E2 – Allocators".

Through an examination of the assets required by the LU (2) class, Elenchus determined the following, as discussed in section 3.1.6 in the CA Report:

- 100% of the customers in this rate class were served: i) exclusively by dedicated conductors, and ii) almost exclusively by dedicated conduit;

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[3] Modeled after the PNCP1, PNCP4, and PNCP12 allocators, new allocators PNCP1exSU, PNCP4exSU, PNCP12exSU were created. New allocators CENexSU and CCPexSU were also created based on CEN and CCP respectively. Finally, a new allocator NFAexDA was created in order to overcome a double allocation of: financing costs; Deemed Interest expense; PILs; and Net Income.

- under current design practices, if the conductors and conduit were to be replaced, these assets would be fully dedicated to the LU (2) class; and
- if a new customer qualified for the LU (2), that customer would also be served from dedicated assets.

The "I9 – Direct Allocation" worksheet already calculates amounts for "Approved Total PILs", "Approved Total Return on Debt", and "Approved Total Return on Equity" in rows 149-151; and these amounts are already assigned on worksheet O1, row 36. Consequently, no further assignment of PILs, Interest, or Net Income to each rate class would be appropriate.

Weighting Factors

The Services weighting factors were developed based on Horizon Utilities conducting an evaluation of the costs of providing services to the customer classes.

The Billing and Collecting weighting factors used in Horizon Utilities' cost allocation models were updated according to Horizon Utilities' information on such for each customer class.

The Meter Reading weighting factors have been updated to incorporate the costs per meter type.

Host Distributor

Horizon Utilities is not a host distributor to any distributor within its service territory.

CLASS REVENUE REQUIREMENTS AND REVENUE TO COST RATIOS

The results of a cost allocation study are typically presented in the form of revenue-to-cost ratios. This is shown by rate classification and is the ratio of distribution revenue collected by rate classification compared to the costs allocated to the classification. A ratio lower than the Board's floor for that rate class indicates the rate classification is under-contributing and is being subsidized by other classes of customers. A ratio greater than the Board's ceiling indicates the rate classification is over-contributing and is subsidizing other classes of customers.

In its Cost Allocation Review, the Board established appropriate ranges of revenue-to-cost ratios as summarized in Table C of OEB Appendix 2-P. In addition, Table C - Revenue-to-Cost Ratios provides: Horizon Utilities' revenue-to-cost ratios from its last Cost of Service Application (EB-2010-0131); the updated 2014 cost allocation study; and the proposed 2014 ratios.

Horizon Utilities is proposing to re-align its revenue-to-cost ratios by adjusting the revenue-to-cost ratios for those Rate Classes that are outside of the Board's Policy Range to the upper or lower end of the range as applicable, and allocating the associated revenue shortfall to the remaining Rate Classes, with the exclusion of the Standby Class. While the Board's consultation on developing a standby rate policy (EB-2013-0004) is still ongoing, Horizon Utilities proposes that it is appropriate to set a standby charge that is equal to the variable charged proposed for the GS > 50 kW class (where most users of standby generation reside). Horizon Utilities believes this treatment is appropriate as it is allows for further promotion of Standby generation in the scope of Green Energy initiatives, without causing a rate disincentive to the customer. In addition, in lieu of a formal Standby rate policy, the Board has approved Standby charges equal to the rate class variable distribution charge (ex. EB-2012-0143) for the rate class in which the customer is assigned for standard distribution services. The proposed revenue to cost ratios for the Standby class are consistent with the Status Quo ratios for the 2015 – 2019 Test Years. Tables 7-3 through 7-22 provide details on the revenue to cost ratios for all classes, including the Standby Class.

In addition to setting the existing standby rate equal to the variable rate for the GS > 50 kW class, Horizon Utilities is requesting standby power rates for both the LU (1) and LU (2) rate classes. Approved standby rates for the all three customer classes would mitigate Horizon

Utilities' risk of the lost distribution revenue from the displaced load as a result of generation and would also provide these customers a clear indication of their future standby costs. Horizon Utilities is proposing that the standby rates be set equal to the distribution volumetric charge for each rate class. Using this standby rate holds the distributor revenue neutral from any future load displacement projects that would reduce the load assumed in the load forecast. It also provides the customer with a consistent distribution rate should their generation operate for a partial month. Horizon Utilities is also applying for the creation of a new deferral and variance account to track incremental revenues when the customer's load that is charged the standard distribution rates plus the load that is charged standby rate in the LU (1) and LU (2) classes exceeds the proposed load assumed in the load forecast. The request for this account is discussed in greater detail in Exhibit 9, Tab 1, Schedule 6. Any excess revenues will be returned to these customers following Board approval of a request for disposition of the account balance.

Tables 7-4, 7-8, 7-12, 7-16, and 7-20 provide information on calculated class revenues. The resulting 2014 proposed base revenue amounts are used in Exhibit 8 to design the proposed distribution charges in this Application.

As required in the Chapter 2 Filing Requirements, copies of input sheets I-6, I-8, output O-1 and O-2 are included as Appendices 7-2 – 7-6. In addition, a live excel version of the 2015 – 2019 CA models have been filed with this Application.

Table 7-3: Chapter 2 Filing Requirement Appendix 2P (A) - Allocated Costs - 2015[4]

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$ 57,738,673	56.41%	$ 70,466,605	59.50%
GS < 50 kW	$ 11,823,974	11.55%	$ 16,204,091	13.68%
GS > 50 kW	$ 19,773,789	19.32%	$ 23,895,432	20.18%
Large Use (1)	$ 2,257,890	2.21%	$ 1,993,594	1.68%
Large Use (2)	$ 6,577,075	6.43%	$ 432,222	0.36%
Street Lighting	$ 2,963,902	2.90%	$ 3,433,447	2.90%
Sentinel Lighting	$ 57,144	0.06%	$ 52,068	0.04%
Unmetered Scattered Load (USL)	$ 533,639	0.52%	$ 452,069	0.38%
Standby	$ 620,650	0.61%	$ 1,504,414	1.27%
Total	$ 102,346,736	100.00%	$ 118,433,942	100.00%

Table 7-4: Chapter 2 Filing Requirement Appendix 2P (B) – Calculated Class Revenues - 2015

Classes (same as previous table)	Column 7B	Column 7C	Column 7D	Column 7E
	Load Forecast (LF) X current approved rates	L.F. X current approved rates X (1 + d)	LF X proposed rates	Miscellaneous Revenue
Residential	$ 63,270,290	$ 69,461,355	$ 69,461,355	$ 3,279,512
GS < 50 kW	$ 12,383,472	$ 13,595,208	$ 15,412,682	$ 708,085
GS > 50 kW	$ 17,191,673	$ 18,873,896	$ 21,400,734	$ 1,093,262
Large Use (1)	$ 2,827,619	$ 3,104,305	$ 2,157,451	$ 135,182
Large Use (2)	$ 3,721,203	$ 4,085,327	$ 480,086	$ 16,969
Street Lighting	$ 2,202,026	$ 2,417,497	$ 2,740,679	$ 137,417
Sentinel Lighting	$ 37,542	$ 41,215	$ 46,725	$ 2,372
Unmetered Scattered Load (USL)	$ 509,223	$ 559,051	$ 517,021	$ 25,462
Standby	$ 745,248	$ 818,171	$ 739,292	$ 79,654
Total	$ 102,888,297	$ 112,956,026	$ 112,956,026	$ 5,477,916

[4] Costs Allocated from previous study have been restated to break out the LU (2) proposed class for comparative purposes

Table 7-5: Chapter 2 Filing Requirement Appendix 2P (C) – Rebalancing Revenue-to-Cost (R/C) Ratios - 2015

Class	Previously Approved Ratios Most Recent Year: 2011	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	111.76%	103.23	103.23	85 - 115
GS < 50 kW	104.52%	88.27	99.49	80 - 120
GS > 50 kW	85.35%	83.56	94.14	80 - 120
Large Use (1)	93.73%	162.49	115.00	85 - 115
Large Use (2)	45.74%	949.12	115.00	85 - 115
Street Lighting	75.01%	74.41	83.83	70 - 120
Sentinel Lighting	61.98%	83.71	94.29	80 - 120
Unmetered Scattered Load (USL)	131.61%	129.30	120.00	80 - 120
Standby	79.83%	59.68	54.44	Undefined

Table 7-6: Chapter 2 Filing Requirement Appendix 2P (D) – Proposed Revenue-to-Cost Ratios - 2015

Class	Proposed Revenue-to-Cost Ratios					Policy Range
	2015	2016	2017	2018	2019	
	%	%	%	%	%	%
Residential	103.23	104.03	103.77	104.96	103.86	85 - 115
GS < 50 kW	99.49	98.99	99.12	100.95	98.71	80 - 120
GS > 50 kW	94.14	93.34	94.23	90.11	94.34	80 - 120
Large Use (1)	115.00	112.17	111.03	109.45	108.05	85 - 115
Large Use (2)	115.00	85.00	85.00	91.39	96.86	85 - 115
Street Lighting	83.83	82.74	83.56	83.48	83.34	70 - 120
Sen inel Ligh ing	94.29	96.55	95.19	94.80	93.98	80 - 120
Unmetered Scattered Load (USL)	120.00	119.90	119.30	120.00	120.00	80 - 120
Standby	54.44	53.43	52.64	52.29	51.92	Undefined

Table 7-7: Chapter 2 Filing Requirement Appendix 2P (A) - Allocated Costs - 2016

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$ 57,738,673	56.41%	$ 73,556,314	59.25%
GS < 50 kW	$ 11,823,974	11.55%	$ 16,974,807	13.67%
GS > 50 kW	$ 19,773,789	19.32%	$ 25,069,638	20.19%
Large Use (1)	$ 2,257,890	2.21%	$ 2,130,702	1.72%
Large Use (2)	$ 6,577,075	6.43%	$ 702,654	0.57%
Street Lighting	$ 2,963,902	2.90%	$ 3,586,432	2.89%
Sentinel Lighting	$ 57,144	0.06%	$ 53,182	0.04%
Unmetered Scattered Load (USL)	$ 533,639	0.52%	$ 465,464	0.37%
Standby	$ 620,650	0.61%	$ 1,605,816	1.29%
Total	$ 102,346,736	100.00%	$ 124,145,010	100.00%

Table 7-8: Chapter 2 Filing Requirement Appendix 2P (B) – Calculated Class Revenues - 2016

Classes (same as previous table)	Column 7B	Column 7C	Column 7D	Column 7E
	Load Forecast (LF) X current approved rates	L.F. X current approved rates X (1 + d)	LF X proposed rates	Miscellaneous Revenue
Residential	$ 69,700,443	$ 72,959,832	$ 72,903,466	$ 3,616,832
GS < 50 kW	$ 15,438,593	$ 16,160,545	$ 16,160,545	$ 642,881
GS > 50 kW	$ 21,473,366	$ 22,477,521	$ 22,482,464	$ 916,481
Large Use (1)	$ 2,170,258	$ 2,271,745	$ 2,269,990	$ 120,073
Large Use (2)	$ 486,538	$ 509,290	$ 580,573	$ 16,683
Street Lighting	$ 2,739,202	$ 2,867,294	$ 2,867,294	$ 100,277
Sentinel Lighting	$ 45,463	$ 47,588	$ 47,588	$ 3,760
Unmetered Scattered Load (USL)	$ 512,499	$ 536,465	$ 522,521	$ 35,584
Standby	$ 762,559	$ 798,219	$ 794,058	$ 63,938
Total	$ 113,328,920	$ 118,628,501	$ 118,628,501	$ 5,516,509

Table 7-9: Chapter 2 Filing Requirement Appendix 2P (C) – Rebalancing Revenue-to-Cost (R/C) Ratios - 2016

Class	Previously Approved Ratios Most Recent Year: 2011	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	111.76%	104.11	104.03	85 - 115
GS < 50 kW	104.52%	98.99	98.99	80 - 120
GS > 50 kW	85.35%	93.32	93.34	80 - 120
Large Use (1)	93.73%	112.25	112.17	85 - 115
Large Use (2)	45.74%	74.86	85.00	85 - 115
Street Lighting	75.01%	82.74	82.74	70 - 120
Sentinel Lighting	61.98%	96.55	96.55	80 - 120
Unmetered Scattered Load (USL)	131.61%	122.90	119.90	80 - 120
Standby	79.83%	53.69	53.43	Undefined

Table 7-10: Chapter 2 Filing Requirement Appendix 2P (D) – Proposed Revenue-to-Cost Ratios – 2016

Class	Proposed Revenue-to-Cost Ratios					Policy Range
	2015	2016	2017	2018	2019	
	%	%	%	%	%	%
Residential	103.23	104.03	103.77	104.96	103.86	85 - 115
GS < 50 kW	99.49	98.99	99.12	100.95	98.71	80 - 120
GS > 50 kW	94.14	93.34	94.23	90.11	94.34	80 - 120
Large Use (1)	115.00	112.17	111.03	109.45	108.05	85 - 115
Large Use (2)	115.00	85.00	85.00	91.39	96.86	85 - 115
Street Lighting	83.83	82.74	83.56	83.48	83.34	70 - 120
Sen inel Ligh ing	94.29	96.55	95.19	94.80	93.98	80 - 120
Unmetered Scattered Load (USL)	120.00	119.90	119.30	120.00	120.00	80 - 120
Standby	54.44	53.43	52.64	52.29	51.92	Undefined

Table 7-11: Chapter 2 Filing Requirement Appendix 2P (A) - Allocated Costs - 2017

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$ 57,738,673	56.41%	$ 75,390,124	59.22%
GS < 50 kW	$ 11,823,974	11.55%	$ 17,348,930	13.63%
GS > 50 kW	$ 19,773,789	19.32%	$ 25,534,659	20.06%
Large Use (1)	$ 2,257,890	2.21%	$ 2,210,392	1.74%
Large Use (2)	$ 6,577,075	6.43%	$ 940,741	0.74%
Street Lighting	$ 2,963,902	2.90%	$ 3,630,428	2.85%
Sentinel Lighting	$ 57,144	0.06%	$ 53,735	0.04%
Unmetered Scattered Load (USL)	$ 533,639	0.52%	$ 473,174	0.37%
Standby	$ 620,650	0.61%	$ 1,717,198	1.35%
Total	$ 102,346,736	100.00%	$ 127,299,380	100.00%

Table 7-12: Chapter 2 Filing Requirement Appendix 2P (B) – Calculated Class Revenues - 2017

Classes (same as previous table)	Column 7B	Column 7C	Column 7D	Column 7E
	Load Forecast (LF) X current approved rates	L.F. X current approved rates X (1 + d)	LF X proposed rates	Miscellaneous Revenue
Residential	$ 73,079,964	$ 74,803,727	$ 74,595,365	$ 3,640,355
GS < 50 kW	$ 16,168,612	$ 16,549,987	$ 16,549,987	$ 646,606
GS > 50 kW	$ 22,567,744	$ 23,100,057	$ 23,137,026	$ 923,050
Large Use (1)	$ 2,284,168	$ 2,338,046	$ 2,331,533	$ 122,616
Large Use (2)	$ 588,816	$ 602,704	$ 782,837	$ 16,792
Street Lighting	$ 2,865,772	$ 2,933,368	$ 2,933,368	$ 100,222
Sentinel Lighting	$ 46,352	$ 47,446	$ 47,446	$ 3,706
Unmetered Scattered Load (USL)	$ 518,301	$ 530,526	$ 529,049	$ 35,448
Standby	$ 818,281	$ 837,582	$ 836,832	$ 67,143
Total	$ 118,938,011	$ 121,743,444	$ 121,743,444	$ 5,555,937

Table 7-13: Chapter 2 Filing Requirement Appendix 2P (C) – Rebalancing Revenue-to-Cost (R/C) Ratios - 2017

Class	Previously Approved Ratios	Status Quo Ratios	Proposed Ratios	Policy Range
	Most Recent Year: 2011	(7C + 7E) / (7A)	(7D + 7E) / (7A)	
	%	%	%	%
Residential	111.76%	104.05	103.77	85 - 115
GS < 50 kW	104.52%	99.12	99.12	80 - 120
GS > 50 kW	85.35%	94.08	94.23	80 - 120
Large Use (1)	93.73%	111.32	111.03	85 - 115
Large Use (2)	45.74%	65.85	85.00	85 - 115
Street Lighting	75.01%	83.56	83.56	70 - 120
Sentinel Lighting	61.98%	95.19	95.19	80 - 120
Unmetered Scattered Load (USL)	131.61%	119.61	119.30	80 - 120
Standby	79.83%	52.69	52.64	Undefined

Table 7-14: Chapter 2 Filing Requirement Appendix 2P (D) – Proposed Revenue-to-Cost Ratios - 2017

Class	Proposed Revenue-to-Cost Ratios					Policy Range
	2015	2016	2017	2018	2019	
	%	%	%	%	%	%
Residential	103.23	104.03	103.77	104.96	103.86	85 - 115
GS < 50 kW	99.49	98.99	99.12	100.95	98.71	80 - 120
GS > 50 kW	94.14	93.34	94.23	90.11	94.34	80 - 120
Large Use (1)	115.00	112.17	111.03	109.45	108.05	85 - 115
Large Use (2)	115.00	85.00	85.00	91.39	96.86	85 - 115
Street Lighting	83.83	82.74	83.56	83.48	83.34	70 - 120
Sen inel Ligh ing	94.29	96.55	95.19	94.80	93.98	80 - 120
Unmetered Scattered Load (USL)	120.00	119.90	119.30	120.00	120.00	80 - 120
Standby	54.44	53.43	52.64	52.29	51.92	Undefined

Table 7-15: Chapter 2 Filing Requirement Appendix 2P (A) - Allocated Costs - 2018

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$ 57,738,673	56.41%	$ 75,876,331	58.55%
GS < 50 kW	$ 11,823,974	11.55%	$ 17,320,549	13.37%
GS > 50 kW	$ 19,773,789	19.32%	$ 27,184,710	20.98%
Large Use (1)	$ 2,257,890	2.21%	$ 2,288,572	1.77%
Large Use (2)	$ 6,577,075	6.43%	$ 899,524	0.69%
Street Lighting	$ 2,963,902	2.90%	$ 3,687,336	2.85%
Sentinel Lighting	$ 57,144	0.06%	$ 53,260	0.04%
Unmetered Scattered Load (USL)	$ 533,639	0.52%	$ 471,359	0.36%
Standby	$ 620,650	0.61%	$ 1,804,875	1.39%
Total	$ 102,346,736	100.00%	$ 129,586,516	100.00%

Table 7-16: Chapter 2 Filing Requirement Appendix 2P (B) – Calculated Class Revenues - 2018

Classes (same as previous table)	Column 7B Load Forecast (LF) X current	Column 7C L.F. X current approved rates X	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 74,874,323	$ 75,944,135	$ 75,944,135	$ 3,695,041
GS < 50 kW	$ 16,592,024	$ 16,829,093	$ 16,829,093	$ 656,757
GS > 50 kW	$ 23,206,536	$ 23,538,113	$ 23,538,584	$ 958,012
Large Use (1)	$ 2,344,804	$ 2,378,306	$ 2,378,306	$ 126,476
Large Use (2)	$ 792,967	$ 804,297	$ 804,863	$ 17,221
Street Lighting	$ 2,931,775	$ 2,973,664	$ 2,975,756	$ 102,454
Sentinel Lighting	$ 46,136	$ 46,795	$ 46,828	$ 3,665
Unmetered Scattered Load (USL)	$ 524,482	$ 531,975	$ 530,200	$ 35,431
Standby	$ 861,626	$ 873,937	$ 872,552	$ 71,142
Total	$ 122,174,673	$ 123,920,317	$ 123,920,317	$ 5,666,198

Table 7-17: Chapter 2 Filing Requirement Appendix 2P (C) – Rebalancing Revenue-to-Cost (R/C) Ratios - 2018

Class	Previously Approved Ratios	Status Quo Ratios	Proposed Ratios	Policy Range
	Most Recent Year: 2011	(7C + 7E) / (7A)	(7D + 7E) / (7A)	
	%	%	%	%
Residential	111.76%	104.96	104.96	85 - 115
GS < 50 kW	104.52%	100.95	100.95	80 - 120
GS > 50 kW	85.35%	90.11	90.11	80 - 120
Large Use (1)	93.73%	109.45	109.45	85 - 115
Large Use (2)	45.74%	91.33	91.39	85 - 115
Street Lighting	75.01%	83.42	83.48	70 - 120
Sentinel Lighting	61.98%	94.74	94.80	80 - 120
Unmetered Scattered Load (USL)	131.61%	120.38	120.00	80 - 120
Standby	79.83%	52.36	52.29	Undefined

Table 7-18: Chapter 2 Filing Requirement Appendix 2P (D) – Proposed Revenue-to-Cost Ratios - 2018

Class	Proposed Revenue-to-Cost Ratios					Policy Range
	2015	2016	2017	2018	2019	
	%	%	%	%	%	%
Residential	103.23	104.03	103.77	104.96	103.86	85 - 115
GS < 50 kW	99.49	98.99	99.12	100.95	98.71	80 - 120
GS > 50 kW	94.14	93.34	94.23	90.11	94.34	80 - 120
Large Use (1)	115.00	112.17	111.03	109.45	108.05	85 - 115
Large Use (2)	115.00	85.00	85.00	91.39	96.86	85 - 115
Street Lighting	83.83	82.74	83.56	83.48	83.34	70 - 120
Sen inel Ligh ing	94.29	96.55	95.19	94.80	93.98	80 - 120
Unmetered Scattered Load (USL)	120.00	119.90	119.30	120.00	120.00	80 - 120
Standby	54.44	53.43	52.64	52.29	51.92	Undefined

Table 7-19: Chapter 2 Filing Requirement Appendix 2P (A) - Allocated Costs - 2019

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$ 57,738,673	56.41%	$ 79,069,634	59.17%
GS < 50 kW	$ 11,823,974	11.55%	$ 18,257,837	13.66%
GS > 50 kW	$ 19,773,789	19.32%	$ 26,778,744	20.04%
Large Use (1)	$ 2,257,890	2.21%	$ 2,397,891	1.79%
Large Use (2)	$ 6,577,075	6.43%	$ 883,632	0.66%
Street Lighting	$ 2,963,902	2.90%	$ 3,796,229	2.84%
Sentinel Lighting	$ 57,144	0.06%	$ 53,660	0.04%
Unmetered Scattered Load (USL)	$ 533,639	0.52%	$ 480,234	0.36%
Standby	$ 620,650	0.61%	$ 1,917,936	1.44%
Total	$ 102,346,736	100.00%	$ 133,635,798	100.00%

Table 7-20: Chapter 2 Filing Requirement Appendix 2P (B) – Calculated Class Revenues - 2019

Classes (same as previous table)	Column 7B Load Forecast (LF) X current	Column 7C L.F. X current approved rates X	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 76,178,855	$ 78,365,794	$ 78,365,794	$ 3,752,045
GS < 50 kW	$ 16,867,483	$ 17,351,714	$ 17,351,714	$ 671,083
GS > 50 kW	$ 23,616,451	$ 24,294,431	$ 24,297,713	$ 964,332
Large Use (1)	$ 2,391,904	$ 2,460,571	$ 2,460,571	$ 130,375
Large Use (2)	$ 815,054	$ 838,452	$ 838,452	$ 17,451
Street Lighting	$ 2,974,161	$ 3,059,543	$ 3,059,543	$ 104,314
Sentinel Lighting	$ 45,499	$ 46,806	$ 46,806	$ 3,622
Unmetered Scattered Load (USL)	$ 526,065	$ 541,167	$ 540,863	$ 35,419
Standby	$ 897,651	$ 923,421	$ 920,444	$ 75,258
Total	$ 124,313,123	$ 127,881,899	$ 127,881,899	$ 5,753,899

Table 7-21: Chapter 2 Filing Requirement Appendix 2P (C) – Rebalancing Revenue-to-Cost (R/C) Ratios - 2019

Class	Previously Approved Ratios Most Recent Year: 2011	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	111.76%	103.86	103.86	85 - 115
GS < 50 kW	104.52%	98.71	98.71	80 - 120
GS > 50 kW	85.35%	94.32	94.34	80 - 120
Large Use (1)	93.73%	108.05	108.05	85 - 115
Large Use (2)	45.74%	96.86	96.86	85 - 115
Street Lighting	75.01%	83.34	83.34	70 - 120
Sentinel Lighting	61.98%	93.98	93.98	80 - 120
Unmetered Scattered Load (USL)	131.61%	120.06	120.00	80 - 120
Standby	79.83%	52.07	51.92	Undefined

Table 7-22: Chapter 2 Filing Requirement Appendix 2P (D) – Proposed Revenue-to-Cost Ratios - 2019

Class	Proposed Revenue-to-Cost Ratios					Policy Range
	2015	2016	2017	2018	2019	
	%	%	%	%	%	%
Residential	103.23	104.03	103.77	104.96	103.86	85 - 115
GS < 50 kW	99.49	98.99	99.12	100.95	98.71	80 - 120
GS > 50 kW	94.14	93.34	94.23	90.11	94.34	80 - 120
Large Use (1)	115.00	112.17	111.03	109.45	108.05	85 - 115
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Street Lighting	83.83	82.74	83.56	83.48	83.34	70 - 120
Sen inel Ligh ing	94.29	96.55	95.19	94.80	93.98	80 - 120
Unmetered Scattered Load (USL)	120.00	119.90	119.30	120.00	120.00	80 - 120
Standby	54.44	53.43	52.64	52.29	51.92	Undefined

APPENDIX 7-1: HORIZON UTILITIES 2015 – 2019 COST ALLOCATION AND RATE DESIGN STUDY

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Horizon Utilities
2015-2019 Cost Allocation

A Report Prepared by
Elenchus Research Associates Inc.

On Behalf of
Horizon Utilities

April 11, 2014

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1 INTRODUCTION

Horizon Utilities ("Horizon") has prepared its 2015-2019 Custom IR Application as a cost of service rate application based on a forward test year. The relevant filing requirements for this Application are set out in Chapter 2 of the July 17, 2013 update to the document entitled *Ontario Energy Board, Filing Requirements for Electricity Distribution Rate Applications* ("Filing Requirements").

Section 2.10 of the Filing Requirements sets out the expectations of the Board with respect to Exhibit 7: Cost Allocation. The Filing Requirements state:

> *A completed cost allocation study using the Board approved methodology or a comparable model must be filed. This filing must reflect future loads and costs and be supported by appropriate explanations and live Excel spreadsheets. The most current update of the model (version 3.1) will be available on the Board's web site.*[1]

Section 2.11 of the Filing Requirements sets out the Board's expectations with respect to Exhibit 8: Rate Design.

Horizon asked Elenchus Research Associates Inc. ("Elenchus")[2] to assist it with preparing an appropriate cost allocation and rate design for its 2015-2019 Custom IR rate application. This work included assisted Horizon to satisfy a commitment to its largest volume customers to review its methodology to determine whether there are modifications that would result in an allocation of costs that would better reflect the principle of cost causality.

In addressing the cost allocation issues, Elenchus was guided by the Filing Requirements, the November 28, 2007 *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667) ("CA Application Report") which "sets out the Board's policies in relation to specific cost allocation matters for electricity distributors"[3] and the March 31, 2011 *Report of the Board, Review of Electricity Distribution Cost Allocation Policy* (EB-2010-0219) ("CA Review Report") in which the Board narrowed some ranges, and committed to further consultations on unmetered and standby loads, as well as the Board's decisions in various electricity distributor cost of service proceedings that addressed relevant issues, as cited in this report.

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1 *Ontario Energy Board, Filing Requirements for Electricity Distribution Rate Applications (July 17, 2013), p. 39.*

2 John Todd, President of Elenchus Research Associates, was the lead consultant for the development and implementation of the methodology used by Horizon and documented in this report. John Todd's curriculum vitae is available at www.elenchus.ca.

3 Ontario Energy Board, *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667), November 28, 2007, page 1.

1.1 SUMMARY OF RECOMMENDATIONS

With respect to Horizon's customer classes, Elenchus recommends the division of the previous Large User class into two separate classes designated Large User (1) and Large User (2). The customers qualifying for the Large User (2) class would be customers with demand of 15 MW or greater that are served with dedicated feeders.

With respect to Horizon's cost allocation model, Elenchus recommends disaggregating USoA accounts that are classified as primary into more granular accounts based on Horizon's internal accounting system. This disaggregation will allow primary and secondary assets to be more accurately identified since it was discovered that some USoA asset account that are classified as primary actually include a substantial amount of secondary assets. The model has been modified to reflect this improved identification of primary and secondary assets.

With respect to Horizon's rate design, Elenchus recommends setting the rates for Standby, which would be below the Board-approved revenue to cost ratio in the absence of rate rebalancing, so that the variable rate is at the same level as the GS > 50 variable rate, with no fixed charge. In addition, Elenchus recommends reducing the pre-rebalancing rates for the three customer classes that would have revenue to cost ratios above the Board approved range (i.e., Large Use (1), Large Use (2) and Unmetered Scattered Load) so that their ratios are at the top end of their ranges. Finally, Elenchus recommends increasing the rates of the remaining classes for purposes of rebalancing only for those classes with revenue to cost ratios that are below 100%.

1.2 MANDATE OF ELENCHUS

The mandate of Elenchus with respect to Horizon's 2015-2019 Customer IR Application was set out in a proposal and work plan dated June 20, 2012. The proposed work plan included three phases:

Phase 1 - Review of Customer Classification

Phase 2 - Cost Allocation

Phase 3 - Rate Design

Each phase was approached as a collaborative effort to ensure that the final evidence and recommendations of Elenchus recognized the operational configuration of Horizon's assets and the details of Horizon's historic and current accounting procedures as a basis for determining how best to allocate Horizon's costs so as to properly reflect the principle of cost causality.

Elenchus conducted its work in accordance the Ontario Energy Board Rules of Practice and Procedure (“Rule”). In particular, Elenchus notes that its mandate included the preparation of expert evidence and Elenchus conducted its work in accordance with section 13A.02 of the Rules which was implemented effective January 9, 2012 and states: “An expert shall assist the Board impartially by giving evidence that is fair and objective.”

1.3 PURPOSE OF THE COST ALLOCATION STUDY

In the context of a cost of service rate application based on 2015-2019 forward test years, the primary purpose of the cost allocation study (“CA Study”) is to determine the proportions of a distributor’s total revenue requirement that are the “responsibility” of each rate class.

In addition, cost allocation studies provide revenue to cost ratios for each customer class that can be examined to ensure that they generally fall within the Board-specified ranges (or move toward those ranges where appropriate to mitigate rate impacts) and generally are not moving away from 100%.

Conceptually, Horizon’s prospective year CA Study for the 2015-2019 test years is based on an allocation of the 2015-2019 test year costs (i.e., the 2015-2019 forecast revenue requirement) to the various customer classes using allocators that are based on the forecast class loads (kW and kWh) by class, customer counts, etc. By definition, this approach will result in a total revenue to cost ratio at proposed rates of 100%. Given a revenue deficiency for the test year, the total revenue to cost ratio at current rates will be somewhat below 100%.

1.4 HORIZON’S 2011 COST ALLOCATION

The last cost allocation study filed by Horizon was in 2010 in Proceeding EB-2010-0131 (“2011 CA Study”) was based on the 2006 Informational Filing adjusted for the loss of some customers. The 2015-2019 models were performed in accordance with the internal documentation in the v 3.1 Cost Allocation Model (CA Model).

Horizon‘s 2011 CA Study relied on the Board’s 2006 Cost Allocation Model (“CA Model”) and was prepared in accordance with the September 29, 2006 Board report entitled *Cost Allocation: Board Directions on Cost Allocation Methodology for Electricity Distributors* ("the Directions"), the subsequent (November 15, 2006) *Cost Allocation Informational Filing Guidelines for Electricity Distributors* ("the Guidelines"), and the *Cost Allocation Review: User Instruction for the Cost Allocation Model for Electricity Distributors* (“the Instructions").

Horizon's largest volume customers took issue with the fairness of the rates which resulted from the 2011 CA Study. As a result, Horizon committed to review in detail its cost allocation and ensure that cost causation was appropriately reflected. A full review of cost allocation, including fairness to all customer classes was undertaken with the assistance of Elenchus. This review included an examination of the sub-accounts that are rolled up into the USoA accounts used in the OEB's CA Model. This analysis determined that some sub-accounts that consisted exclusively of secondary assets were being allocated as primary assets in the 2011 model. As a result, the split between Primary and Secondary assets has been updated for the 2015-2019 models.

1.5 STRUCTURE OF THE REPORT

The remainder of this report is divided into three additional sections. Section 2 provides an overview of the Horizon 2015-2019 CA Study, explaining the model runs included in the study, as well as the load and cost information used for the run. Section 3 explains the methodology used to develop the 2015-2019 Horizon models by documenting each step taken in completing the model. Section 4 summarizes the results of the Horizon CA Study, showing the class revenue requirements and revenue to cost ratios generated by the CA models.

2 Overview of the Horizon 2015-2019 CA Studies

2.1 Model Run Included in the Horizon Cost Allocation Study

Section 2.10.3 of the updated Filing Requirements specifies that the third table in Appendix 2-P, "...includes the following information for each class" that should be provided based on:

- *The previously approved ratios most recently implemented by the distributor;*
- *The ratios that would result from the most recent approved distribution rates and the distributor's forecast of billing quantities in the test year, prorated upwards or downwards (as applicable) to match the revenue requirement, expressed as a ratio with the class revenue requirements derived in the updated cost allocation model; and*
- *The ratios that are proposed for the Test Year, which are the proposed class revenues, together with the updated cost allocation model.*

For clarity, the following designations are used.

- Horizon-2011: The Horizon 2011 revenue to cost ratios.
- Horizon-2011 Restated: The Horizon 2011 revenue to cost ratios restated with the addition of the proposed new customer class.
- Horizon-2015: The version 3.1 CA Model with 2015 loads, costs, and revenues.
- Horizon-2016: The version 3.1 CA Model with 2016 loads, costs, and revenues.
- Horizon-2017: The version 3.1 CA Model with 2017 loads, costs, and revenues.
- Horizon-2018: The version 3.1 CA Model with 2018 loads, costs, and revenues.
- Horizon-2019: The version 3.1 CA Model with 2019 loads, costs, and revenues.

2.2 Customer Classification: Proposed New Customer Class

In order to appropriately reflect cost causation, and the uniqueness of its largest volume customers, Elenchus recommended to Horizon that a new "Large Use (2)" customer class be created. This class would consist of customers with demand over 15 MW. Because these particularly high demand Large Use customers are served by dedicated feeders, they are not served using Horizon's pooled assets and hence should not be responsible for the associated costs which they do not cause. They are, however, allocated 100% of the cost of the dedicated primary feeders that they use.

Presently, all customers which qualify for the Large Use (2) rate class have demands over 20 MW, while the largest of the remaining Large Use (1) customers demand is less than 10 MW. It is expected that customers under the 15 MW threshold are unlikely to cross over unless they undertake a significant expansion of their production facilities, and those above the 15 MW threshold are unlikely to cross under in the absence of a significant reduction in their operations. Further, if there were a new customer with a demand over 15MW, that customer would be connected with dedicated assets to accommodate the incremental load. The remaining Large Use (1) customers by contrast are served by means of the pooled assets.

It is further noted that Horizon has advised Elenchus that there is a credible risk that some or all of the Large Use (2) customers could directly connect to Hydro One, leaving Horizon with stranded assets, and significantly less volume throughput. Retention of these customers will reduce the risk of an increased burden on Horizon's remaining customers.

2.3 LOAD AND CUSTOMER INFORMATION

The updated Filing Requirements specify that "This filing must reflect future loads and costs..." and "[f]or any customer class for which updated load profiles are not available, the load profiles provided by Hydro One for use in the Informational Filing may be used, scaled to match the load forecast as it relates to the respective rate classes", (Section 2.10.1, p. 39)

The Horizon 2015-2019 models have been prepared using the following load and load profile information:

- Annual Loads (kW and kWh, as appropriate) and customer counts: The 2015-2019 load forecast and customer counts by class being used by Horizon in its application were also used for the 2015-2019 CA models.
- Hourly load profile: The hourly load profiles prepared by Hydro One for the 2006 CAIF was used for all classes except the Large Use (1) and Large Use (2) classes. Updating of the hourly load profiles for these classes was necessary because of the small number of customers in these classes. Furthermore, actual 2012 hourly load data are available for these classes (all customers have interval meters) and the hourly load data does not require weather adjustment, making it a straightforward task to determine the updated hourly load shape of these classes in a manner that is consistent with the Hydro One methodology.

The hourly load profiles provided by Hydro One for all of the classes for the 2006 model were considered to be appropriate for use in the 2015-2019 models for the following reasons.

1. Elenchus has previously explored alternatives for updating the hourly load profiles by rate class comparable to the estimated load profiles that Hydro One prepared for the LDCs for their 2006 CA Models. Hydro One advised that they no longer have the capacity to produce a significant number of LDC-specific hourly load profiles. As far as Elenchus is aware, no other entity has the necessary information and models to produce comparable quality hourly load profiles for Ontario LDCs. It therefore was not practical for distributors to update their hourly load profiles by class except in exceptional circumstances.
2. It is Elenchus' opinion that there would be little point in investing in updated load profiles without also investing in updated saturation surveys for the residential class in each service area. These are expensive and time consuming to undertake as they involve a survey of a statistically significant sample of customers.
3. With the widespread rollout of smart meters and the collection of smart meter data, Ontario distributors will have better hourly load profile by class data than the Hydro One estimates. Unless there is evidence of a significant change in circumstances, investing in new hourly load profile by class estimates would be a questionable use of ratepayer funds when superior hourly load profile information may be available in the future at minimal cost.
4. Both time-of-use commodity pricing and changes to the design of distribution rates are influencing the hourly load profiles of the affected classes; however, it will not be practical to use smart meter data to update the load profiles of the weather sensitive classes until a sufficient number of years of data have been collected to determine demand on a weather normalized basis.

2.4 COST INFORMATION

As noted earlier, the Filing Requirements mandate that the cost allocation models be prepared on the basis of prospective test year information. In the case of Horizon, the financial information for the forecast years has been prepared at the USoA level in most case; however, more granular rate base information was used in the case of USoA accounts that included a mix of primary and secondary assets.

3 Horizon Cost Allocation Study Methodology

This section documents Elenchus' methodology for the Horizon Cost Allocation Study, the 2015-2019 CA Models.

3.1 2015-2019 Horizon CA Models

3.1.1 Hourly Load Profile (HONI File)

For the Horizon 2006 CAIF, HONI provided data files with three worksheets that were to be used as inputs:

- Data Summary: actual and weather normalized monthly kWh by class, disaggregated by weather sensitive and non-weather sensitive load for relevant classes.
- Hourly Load Shape by Class: GWh by class for each hour in 2004.
- Input to Cost Allocation Model: The 1CP, 4CP, 12CP, 1NCP, 4NCP, 12NCP allocators are derived from the hourly load profiles.

The Horizon hourly load shapes derived by Hydro One for the 2006 CAIF were not updated. However, the demand allocators derived by Hydro One for the 2006 CAIF were revised to reflect changes in the relative loads for the classes from 2004 to 2015-2019. This was done by scaling the hourly load profiles of each class on the Hourly Load Shape by Class worksheet of the HONI file to levels consistent with the 2015-2019 load forecasts while maintaining the hourly load shapes.

For the Large Use (1) and Large Use (2) customer classes, 2012 actual interval hourly data were used.

3.1.2 Demand Allocators (HONI File)

The demand allocators used in the Horizon 2015-2019 CA models were derived using the same methodology as Hydro One used for the 2006 file; however, they were re-determined using the forecast 2015-2019 hourly load profiles resulting from the preceding step. Using the 2015-2019 hourly load profiles by class, the 12 monthly coincident and non-coincident peaks for the rate classes were determined on the Hourly Load Shape by Rate Class worksheet. The allocators were then derived as follows.

- The 1, 4 and 12 NCP values for each class were calculated by selecting the peak in the year (1 NCP), summing the four highest monthly peaks (4 NCP) and summing the 12 monthly peaks for each class (12 NCP), respectively.

- The total 1, 4 and 12 NCP values are the totals of the corresponding class NCP values.
- The 1, 4 and 12 CP values for each class were derived by identifying the hour in each month when the coincident peak occurred and then selecting the peak in the year (1 CP), adding the demands during the four highest coincident peak hours (4 CP) and summing the demand for each class during the 12 monthly coincident peak hours (12 CP), respectively.
- The total 1, 4 and 12 CP values are the totals of the corresponding class CP values, which are the values used to identify the relevant coincident peak hours.

3.1.3 2015-2019 Demand Data (Horizon-2015-2019 Models)

The demand allocators derived in the updated Hydro One file as described in the preceding section were input at the appropriate cells at sheet I8 Demand Data of the 2015-2019 Horizon CA Models. However, the Line Transformer and Secondary 1NCP, 4NCP and 12NCP values (rows 57-58, 63-64, 69-70) for GS > 50, Large Use (1), Large Use (2), and Backup/Standby customer classes are not equal to the full class NCP values since not all customers in these customer classes use these facilities. The Line Transformer and Secondary 1NCP, 4NCP and 12NCP values were therefore determined from the full load data NCP values using the ratio of values in the 2006 CA Model.

3.1.4 Review of Primary and Secondary Assets

Horizon’s internal accounting system tracks assets in accounts at a more granular level than is required under the USoA. Horizon then uses a method of aggregating several of their accounts into each of the USoA accounts. In preparing 2015-2019 Cost Allocation models, Elenchus asked Horizon to review the asset accounts within its own accounting system (i.e., sub-accounts from the perspective of the USoA) with the collaboration of Accounting and Engineering staff to determine which of those accounts contained primary assets, and which contained secondary assets. The results of this investigation is a more accurate apportionment of the USoA accounts into Primary and Secondary in the Cost Allocation model as seen on sheet “I4 BO Assets”.

3.1.5 Review of the Street Lighting Daisy Chaining Ratio

Horizon’s 2011 Cost Allocation model relied on an understanding that daisy chaining existed in the Horizon service territory and was a best estimate of the extent of that daisy chaining at 2 streetlight devices per streetlight connection.

Since then, Horizon has undertaken to study the actual extent of daisy chaining in their service territory, and has concluded that the actual extent of daisy chaining at 1.3141 streetlight devices per streetlight connection. This updated factor is used in the calculation of the number of connections on “I6.2 Customer Data”.

It is noted that the current OEB CA Model includes the count of “devices” as well as connections for unmetered customer classes, including Street Lighting. To be consistent with this terminology, elenchus recommends that the term “connections” as used in Horizon’s rate design model and tariff sheets no longer be used to refer to devices.

3.1.6 NEW AND UPDATED ALLOCATORS

In order to accommodate the direct allocation of assets and expenses to Horizon’s Large Use (2) class, new allocators were required. Modeled after the PNCP1, PNCP4, and PNCP12 allocators, new allocators PNCP1exLU2, PNCP4exLU2, PNCP12exLU2 were created. Also, new allocator CENexLU2 and CCPexLU2 were created based on CEN and CCP respectively. All new allocators were created on sheet “E2 Allocators”. In each of these cases, the Large Use (2) class was assigned an allocation of 0.00% leaving the other rate classes to absorb the costs. One additional allocator was created, NFAexDA, which is an allocator of Net Fixed Assets, excluding directly allocated assets.

All allocators now include the allocation factors for both Large Use (1) and Large Use (2), which in cases other than those noted above have no effect on the allocators for other classes since the sum of the Large Use (1) and Large Use (2) equals the factor that would have been applicable to the combined Large Use class.

Through examination of the assets required by the Large Use (2) class, it was determined that 100% of the customers in this rate class were served exclusively by dedicated conductors, and nearly exclusively by dedicated conduit. Furthermore, it was established that under current design practices, if the conductors and conduit were to be replaced, these assets would be fully dedicated to the Large Use (2) class, and if a new customer qualified for the Large Use (2), that customer would also be served from dedicated assets. As such, the Large Use (2) customers do not participate in use of the pooled assets in accounts 1830, 1835, 1840, and 1845. To remove cost responsibility from the Large Use (2) class, the new PNCP4exLU2 and CCPexLU2 allocators were used in place of the PNCP4 and CCP allocators respectively for these accounts. The cable and conduit assets required to serve the Large Use (2) class were directly allocated on sheet “I9 Direct Allocation”.

In addition, Horizon’s Distribution Station Equipment is used to step down to primary voltages lower than that used by any Large Use (2) customer, or any customer who would conceivably qualify for the Large Use (2) rate class. All Large Use (2) customers and any customer that could conceivably qualify for the Large Use (2) rate class are served at a voltage supplied by Hydro One. Since the Large Use (2) class does not, and would not use the Distribution Station Equipment, the PNCP4 and CEN allocators have been replaced by PNCP4exLU2 and CENexLU2 respectively.

The “I9 Direct Allocation” worksheet calculates an amount for “Approved Total PILs”, “Approved Total Return on Debt” and “Approved Total Return on Equity” in rows 149-151, and this amount is assigned on worksheet O1, row 36. Because of this, no further assignment of PILs, Interest, or Net Income is appropriate. In order to appropriately allocate these amounts, the NFAexDA allocator was selected for accounts 3046 Balance Transferred from Income, 6005 Interest on Long Term Debt, and 6110 Income Taxes. The original definition of NFA and its related allocator NFA ECC, both of which include directly allocated assets are still used in all other cases where they were formerly used – including the allocation of all General Plant assets.

4 REQUIRED RATE REBALANCING

As seen in Table 7, below in Section 5, Summary of Revenue to Cost Ratios, Horizon would have 4 rate classes, outside the Board approved ranges in the absence of rebalancing: Large Use (1), Large Use (2), Standby, and Unmetered Scattered Load.

With respect to the Standby class, the current methodology is presently being reviewed under EB-2013-0004 "Development of a Standby Rate Policy for Load Displacement Generation". For purposes of the current application, Elenchus is of the view that it would be reasonable to set the Standby variable rate at the same level as the GS > 50 variable rate, with no fixed charge. While this approach results in a fixed charge that is below the minimum of the Board Approved range, Elenchus is of the view that this rate design is more consistent with cost causation than the results of the current cost allocation model for this customer class. Horizon's Standby customers are also GS > 50 customers and this approach will result in a distribution bill that is equal to the amount that would be charged for the same total load under the standard GS > 50 rate. In the short run (i.e., pending direction from the Board with respect to standby rates) it is inherently no more expensive to serve any additional standby load than it is to serve the base GS > 50 load.

The remaining three rate classes outside the Board approved ranges; Large Use (1), Large Use (2), and Unmetered Scattered Load all have revenue to cost ratios above the range. All of these rate classes were brought down to the top of the range in 2015. The shortfall was made up with a uniform rate increase applied to all rate classes below 100% Revenue-to-Cost, GS < 50, GS > 50, Sentinel Lights, and Street Lighting.

The Board's Decision in Horizon's 2011 Cost of Service included the following direction to Horizon:

> *The Board is of the view that updating the pre-existing cost allocation model with test year data is an insufficient "improvement" for the purpose of supporting the movement within class ranges, as the Board recognizes that the results will vary somewhat due to data limitations and volatility.*
>
> *For those customer classes with starting revenue-to-cost ratios greater or less than the upper or lower end of the range provided by the Board in EB-2007-0667, Horizon is directed to move the customer class ratio to the upper or lower boundary, as appropriate, and to adjust the other class ratios only as required to reconcile with the overall approved revenue requirement*[4]

[4] Ontario Energy Board, Decision and Order, Application by Horizon Utilities Corporation (EB-2010-0131), July 7 2011, page 43.

The rebalancing recommended by Elenchus is consistent with the Board's direction in that decision. Specifically, the proposed rates rebalance only those rate classes that are outside the range to the limit of the range, and move other rate classes sufficiently to reconcile with the overall approved revenue requirement.

The rebalancing recommended for the remaining rate classes takes into account the need for mitigation of excessive rate impacts as directed in the EB-2010-0219 Report of the Board, Review of Electricity Distribution Cost Allocation Policy, dated March 31, 2011, section 2.9.4 which states:

> *To the extent that the application of the Board's cost allocation policies results in a significant shift in the rate burden amongst classes relative to the status quo, distributors should be prepared to address potential mitigation measures.* [5]

The proposal is also guided by the Board's Decision and Order in EB-2012-0033, dated December 13, 2012 setting rates for Enersource Hydro Mississauga ("Enersource") effective January 1, 2013 and January 1 2014. In that application, Enersource proposed to move the revenue to cost ratios of several classes that were within the Board approved ranges closer to unity. In its acceptance of Enersource's position, the Board reasoned "the Board's policy sets out that distributors should endeavour to move their revenue-to-cost ratios closer to one if that is supported by improved cost allocations." [6]

In the Enersource case, the Board was also cognisant of the potential for a need for mitigation and supported its approval of the Enersource methodology by stating "The Board notes that these changes can be made without triggering the need for mitigation."[7]

Again on the need for impact mitigation in Hydro One Brampton Networks Inc. in EB-2010-0132 the Board expressed its concern and ordered a mitigation strategy where none had been proposed by Brampton:

> *The Board is concerned that the proposed revenue-to-cost ratios for the Street Lighting class will result in a significant bill impacts. The Board agrees with the proposal to move the revenue-to-cost ratio for Street Lighting class to 41.2% in 2011 with a further increase to 70% in 2012*[8]

[5] Ontario Energy Board, *Report of the Board, Review of Electricity Distribution Cost Allocation Policy* (EB-2010-0218), March 31 2011, page 35.

[6] Ontario Energy Board, *Decision and Order, Application by Enersource Hydro Mississauga* (EB-2012-0033), December 13 2012, page 46.

[7] Ibid.

[8] Ontario Energy Board, *Decision and Order, Application by Hydro One Brampton Networks Inc. (EB-2010-0132), April 4 2011, page 37.*

In a similar vein, in Toronto Hydro's 2011 Cost of Service (EB-2010-0142) the Board decision stated:

> *The Board has reviewed the comments of parties on this matter and finds that Toronto Hydro should allocate the $300,000 amount to the customer classes in accordance with the Board's cost allocation policy, outlined in EB-2007-0667 Report of the Board: Application of Cost Allocation for Electricity Distributors of November 28, 2007, as updated in the EB-2010-0219 Report of the Board Review of Electricity Distribution Cost Allocation Policy of March 31, 2011. The Board finds that in accordance with this policy, this amount should be allocated on a pro-rata basis to all customer classes, other than the Large User class, in accordance with the approach used in the Board's cost allocation model.* [9]

Given Horizon's more detailed cost allocation modelling, and the more recent direction given to Enersource around moving toward unity where justified, Elenchus is of the view that it would be appropriate to increase rates for purposes of rebalancing only for those classes with revenue to cost ratios that are below unity. Increasing rates only for the rate classes where doing so brings them closer to unity is consistent with the past direction to use pro-rata increases, to avoid increases that move the class ratios away from unity and to minimize the need for mitigation.

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[9] Ontario Energy Board, *Decision on Draft Rate Order, Application by Toronto Hydro-Electric System Limited (EB-2010-0142), July 21 2011, page 37.*

5 SUMMARY OF REVENUE TO COST RATIOS

The class revenue-to-cost ratios as determined in the Horizon cost allocation models are shown in Table 7, below.

Table 7: Revenue to Cost Ratios

Customer Class	Horizon-2011	Horizon-2011 Restated	Horizon-2015 Status Quo Rates	Horizon-2016 Status Quo Rates	Horizon-2017 Status Quo Rates	Horizon-2018 Status Quo Rates	Horizon-2019 Status Quo Rates	Board Target Range
Residential	111.21	111.76	103.23	104.11	104.05	104.96	103.86	85-115
GS < 50 kW	103.46	104.52	88.27	98.99	99.12	100.95	98.71	80-120
GS > 50 kW	84.01	85.35	83.56	93.32	94.08	90.11	94.32	80-120
Large Use (1)	63.25	93.73	162.49	112.25	111.32	109.45	108.05	85-115
Large Use (2)	-	45.74	949.12	74.86	65.85	91.33	96.86	85-115
Street Lighting	75.01	75.01	74.41	82.74	83.56	83.43	83.34	70-120
Sentinel Light	61.98	61.98	83.71	96.55	95.19	94.74	93.98	80-120
USL	131.43	131.61	129.30	122.90	119.61	120.38	120.06	80-120
Backup / Standby	77.55	79.83	59.68	53.69	52.69	52.36	52.07	80-120
Total	100.00	100.00	100.00	100.00	100.00	100.00	100.00	

The Horizon-2015 to 2019 ratios (at current rates) reflect the impact of changes in throughput by class as well as changes in costs from 2006 through the 2015-2019 forecast test years.

Table 8 presents the revenue responsibility (i.e., allocation of the total revenue requirement to the rate classes) in each of the models. This revenue responsibility is presented in both dollar and percentage terms.

Table 8: Revenue Responsibility by Rate Class

Customer Class	Horizon-2011		Horizon-2011 Restated		Horizon-2015		Horizon-2016	
	$	%	$	%	$	%	$	%
Residential	58,034,239	56.70	57,738,673	56.41	70,466,605	59.50	73,556,314	59.25
GS < 50 kW	11,949,011	11.68	11,823,974	11.55	16,204,091	13.68	16,974,807	13.67
GS > 50 kW	20,101,816	19.64	19,773,789	19.32	23,895,432	20.18	25,069,638	20.19
Large Use (1)	8,066,771	7.88	2,257,890	2.21	1,993,594	1.68	2,130,702	1.72
Large Use (2)	-	-	6,577,075	6.43	432,222	0.36	702,654	0.57
Street Lighting	2,963,843	2.90	2,963,902	2.90	3,433,447	2.90	3,586,432	2.89
Sentinel Light	57,144	0.06	57,144	0.06	52,068	0.04	53,182	0.04
USL	534,372	0.52	533,639	0.52	452,069	0.38	465,464	0.37
Backup / Standby	639,542	0.62	620,650	0.61	1,504,414	1.27	1,605,816	1.29
Total	102,346,763	100.00	102,346,736	100.0	118,433,942	100.00	124,145,010	100.00

Note: Table continued on the next page (years 2017 – 2019)

Customer Class	Horizon-2017		Horizon-2018		Horizon-2019	
	$	%	$	%	$	%
Residential	75,390,124	59.22	75,876,331	58.55	79,069,634	59.17
GS < 50 kW	17,348,930	13.63	17,320,549	13.37	18,257,837	13.66
GS > 50 kW	25,534,659	20.06	27,184,710	20.98	26,778,744	20.04
Large Use (1)	2,210,392	1.74	2,288,572	1.77	2,397,891	1.79
Large Use (2)	940,741	0.74	899,524	0.69	883,632	0.66
Street Lighting	3,630,428	2.85	3,687,336	2.85	3,796,229	2.84
Sentinel Light	53,735	0.04	53,260	0.04	53,660	0.04
USL	473,174	0.37	471,359	0.36	480,234	0.36
Backup / Standby	1,717,198	1.35	1,804,875	1.39	1,917,936	1.44
Total	127,299,380	100.00	129,586,516	100.00	133,635,798	100.00

6 Fixed Charge Rates

The Horizon cost allocation model produced the following customer unit cost per month values:

Table 9: 2015 Customer Unit Cost per Month

Customer Class	Avoided Cost	Directly Related	Minimum System with PLCC[10] Adjustment
Residential	2.94	3.92	13.69
GS < 50 kW	6.23	8.31	19.28
GS > 50 kW	45.60	61.48	88.24
Large Use (1)	476.05	774.33	1,229.24
Large Use (2)	946.84	1,264.07	2,299.20
Street Lighting	0.14	0.21	7.01
Sentinel Light	0.12	0.22	10.48
USL	-0.04	0.06	7.56
Backup / Standby	-	-	-

[10] PLCC: ‘Peak Load Carrying Capacity’

Table 10: 2016 Customer Unit Cost per Month

Customer Class	Avoided Cost	Directly Related	Minimum System with PLCC Adjustment
Residential	2.97	3.95	14.43
GS < 50 kW	6.30	8.36	20.67
GS > 50 kW	46.21	61.92	100.57
Large Use (1)	480.73	775.93	1,546.90
Large Use (2)	862.02	1,169.45	2,397.90
Street Lighting	0.14	0.22	7.42
Sentinel Light	0.13	0.23	11.04
USL	-0.03	0.07	7.95
Backup / Standby	-	-	-

Table 11: 2017 Customer Unit Cost per Month

Customer Class	Avoided Cost	Directly Related	Minimum System with PLCC Adjustment
Residential	2.95	3.87	14.69
GS < 50 kW	6.23	8.18	20.93
GS > 50 kW	45.79	60.53	100.92
Large Use (1)	467.08	744.07	1,554.31
Large Use (2)	856.79	1,149.44	2,444.74
Street Lighting	0.15	0.23	7.51
Sentinel Light	0.13	0.23	11.33
USL	-0.03	0.08	8.13
Backup / Standby	-	-	-

Table 12: 2018 Customer Unit Cost per Month

Customer Class	Avoided Cost	Directly Related	Minimum System with PLCC Adjustment
Residential	2.92	3.80	14.80
GS < 50 kW	6.16	8.00	20.97
GS > 50 kW	44.96	58.87	98.99
Large Use (1)	449.82	711.09	1,513.72
Large Use (2)	863.22	1,141.94	2,419.00
Street Lighting	0.16	0.24	7.63
Sentinel Light	0.14	0.24	11.40
USL	-0.02	0.09	8.18
Backup / Standby	-	-	-

Table 13: 2019 Customer Unit Cost per Month

Customer Class	Avoided Cost	Directly Related	Minimum System with PLCC Adjustment
Residential	2.91	3.77	14.94
GS < 50 kW	6.11	7.91	21.13
GS > 50 kW	44.91	58.50	99.01
Large Use (1)	437.86	693.18	1,504.94
Large Use (2)	872.37	1,146.75	2,432.71
Street Lighting	0.16	0.25	7.87
Sentinel Light	0.14	0.25	11.67
USL	-0.01	0.10	8.21
Backup / Standby	-	-	-

In accordance with Board policy,[11] the following boundary values would apply for the fixed monthly service charge:

Table 14: 2015 Fixed Charge Boundary Values

Customer Class	Cost Allocation		Existing Rate	Boundary Values	
	Low	High		Minimum	Maximum
Residential	2.94	13.69	15.70	2.94	15.70
GS < 50 kW	6.23	19.28	35.23	6.23	35.23
GS > 50 kW	45.60	88.24	321.20	45.60	321.20
Large Use (1)	476.05	1,229.24	24,859.64	476.05	24,859.64
Large Use (2)	946.84	2,299.20	24,859.64	946.84	24,859.64
Street Lighting	0.14	7.01	2.53	0.14	7.01
Sentinel Light	0.12	10.48	4.85	0.12	10.48
USL	-0.04	7.56	9.87	-0.04	9.87
Backup / Standby	-	-	-	-	-

[11] Ontario Energy Board, *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667), November 28, 2007, pages 12-13

Table 15: 2016 Fixed Charge Boundary Values

Customer Class	Cost Allocation		Existing Rate	Boundary Values	
	Low	High		Minimum	Maximum
Residential	2.97	14.43	16.37	2.97	16.37
GS < 50 kW	6.30	20.67	41.24	6.30	41.24
GS > 50 kW	46.21	100.57	377.34	46.21	377.34
Large Use (1)	480.73	1,546.90	17,826.97	480.73	17,826.97
Large Use (2)	862.02	2,397.90	3,015.01	862.02	3,015.01
Street Lighting	0.14	7.42	2.97	0.14	7.42
Sentinel Light	0.13	11.04	5.68	0.13	11.04
USL	-0.03	7.95	9.54	-0.03	9.54
Backup / Standby	-	-	-	-	-

Table 16: 2017 Fixed Charge Boundary Values

Customer Class	Cost Allocation		Existing Rate	Boundary Values	
	Low	High		Minimum	Maximum
Residential	2.95	14.69	17.12	2.95	17.12
GS < 50 kW	6.23	20.93	43.16	6.23	43.16
GS > 50 kW	45.79	100.92	394.98	45.79	394.98
Large Use (1)	467.08	1,554.31	18,642.82	467.08	18,642.82
Large Use (2)	856.79	2,444.74	3,595.44	856.79	3,595.44
Street Lighting	0.15	7.51	3.11	0.15	7.51
Sentinel Light	0.13	11.33	5.94	0.13	11.33
USL	-0.03	8.13	9.73	-0.03	9.73
Backup / Standby	-	-	-	-	-

Table 17: 2018 Fixed Charge Boundary Values

Customer Class	Cost Allocation		Existing Rate	Boundary Values	
	Low	High		Minimum	Maximum
Residential	2.92	14.80	17.47	2.92	17.47
GS < 50 kW	6.16	20.97	44.16	6.16	44.16
GS > 50 kW	44.96	98.99	404.14	44.96	404.14
Large Use (1)	449.82	1,513.72	19,029.34	449.82	19,029.34
Large Use (2)	863.22	2,419.00	4,777.64	863.22	4,777.64
Street Lighting	0.16	7.63	3.18	0.16	7.63
Sentinel Light	0.14	11.40	6.08	0.14	11.40
USL	-0.02	8.18	9.93	-0.02	9.93
Backup / Standby	-	-	-	-	-

Table 18: 2019 Fixed Charge Boundary Values

Customer Class	Cost Allocation		Existing Rate	Boundary Values	
	Low	High		Minimum	Maximum
Residential	2.91	14.94	17.70	2.91	17.70
GS < 50 kW	6.11	21.13	44.73	6.11	44.73
GS > 50 kW	44.91	99.01	409.44	44.91	409.44
Large Use (1)	437.86	1,504.94	19,276.42	437.86	19,276.42
Large Use (2)	872.37	2,432.71	4,840.07	872.37	4,840.07
Street Lighting	0.16	7.87	3.22	0.16	7.87
Sentinel Light	0.14	11.67	6.16	0.14	11.67
USL	-0.01	8.21	10.01	-0.01	10.01
Backup / Standby	-	-	-	-	-

APPENDIX 7-2: 2015 UPDATED COST ALLOCATION STUDY

EB-2014-0002

Sheet I6.1 Revenue Worksheet - 2015 Cost Allocation

Total kWhs from Load Forecast	4,712,295,573
Total kWs from Load Forecast	8,027,466
Deficiency/sufficiency (RRWF 8. cell F51)	- 10,067,729
Miscellaneous Revenue (RRWF 5. cell F48)	5,477,916

			1	2	3	5	6	7	8	9	11
	ID	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Large Use (1)**	**Large Use (2)**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Back-up/Standby Power**
Billing Data											
Forecast kWh	**CEN**	4,712,295,573	1,617,715,605	586,002,830	1,857,864,416	269,877,849	329,305,006	39,694,810	437,397	11,397,660	-
Forecast kW	**CDEM**	8,027,466	-	-	5,114,245	626,465	1,884,533	110,006	1,241	-	290,976
Forecast kW, included in CDEM, of customers receiving line transformer allowance		2,101,227			2,101,227	-	-				
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-									
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	4 712 295 573	1 617 715 605	586 002 830	1 857 864 416	269 877 849	329 305 006	39 694 810	437 397	11 397 660	-
Existing Monthly Charge			14 92	33.21	302.77	23,376.17	23,376.17	2 39	4.57	9.40	$0 00
Existing Distribution kWh Rate			$0.0147	$0.0086						0.01	
Existing Distribution kW Rate					2.10	1.38	1 38	6 36	12.53		2 56
Existing TOA Rate					0.73						
Additional Charges											
Distribution Revenue from Rates		$104,422,193	$63,270,290	$12,383,472	$18,725,569	$2,827,619	$3,721,203	$2,202,026	$37,542	$509,223	$745,248
Transformer Ownership Allowance		$1,533,896	$0	$0	$1,533,896	$0	$0	$0	$0	$0	$0
Net Class Revenue	**CREV**	$102 888 297	$63 270 290	$12 383 472	$17 191 673	$2 827 619	$3 721 203	$2 202 026	$37 542	$509 223	$745 248

2014 Cost Allocation Model

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Sheet I6.2 Customer Data Worksheet - 2015 Cost Allocation

	ID	Total	1 Residential	2 GS <50	3 GS>50-Regular	5 Large Use (1)	6 Large Use (2)	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	11 Back-up/Standby Power
Billing Data											
Bad Debt 3 Year Historical Average	BDHA	$1,486,970	$1,330,229	$130,751	$25,990	$0	$0	$0	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$894,324	$645,686	$112,163	$94,783	$35,167		$109	$80	$6,336	$0
Number of Bills	CNB	1,550,455	1,349,855	132,680	26,374	84	48	48	4,812	36,470	84
Number of Devices								52,384			
Number of Connections (Unmetered)	CCON	43,303						39,863	401	3,039	
Total Number of Customers	CCA	243,310	220,565	18,428	2,198	7	4	4	248	1,857	
Bulk Customer Base	CCB	-									
Primary Customer Base	CCP	241,201	220,565	18,428	2,198	7	4				
Line Transformer Customer Base	CCLT	240,935	220,565	18,428	1,943	-	-				
Secondary Customer Base	CCS	239,915	220,565	18,428	923	-	-				
Weighted - Services	CWCS	248,836	220,565	26,536	1,735	-	-	-	-	-	-
Weighted Meter -Capital	CWMC	45,391,594	32,864,113	6,118,031	5,749,451	345,000	225,000	-	-	-	90,000
Weighted Meter Reading	CWMR	3,065,682	1,349,855	132,680	1,570,286	5,001	2,858	-	-	-	5,001
Weighted Bills	CWNB	1,640,294	1,349,855	140,641	112,879	8,098	8,098	81	2,406	18,235	-

Bad Debt Data

		Total	Residential	GS <50	GS>50-Regular	Large Use (1)	Large Use (2)	Street Light	Sentinel	Unmetered Scattered Load	Back-up/Standby Power
Historic Year	2011	1,536,562	1,374,593	135,112	26,857						
Historic Year	2012	1,549,348	1,386,031	136,236	27,080						
Historic Year	2013	1,375,000	1,230,061	120,905	24,033						
Three-year average		**1,486,970**	**1,330,229**	**130,751**	**25,990**	**-**	**-**	**-**	**-**	**-**	**-**

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Sheet I8 Demand Data Worksheet - 2015 Cost Allocation

This is an input sheet for demand allocators.

CP TEST RESULTS
NCP TEST RESULTS

Co-incident Peak
1 CP
4 CP
12 CP

Non-co-incident Peak
1 NCP
4 NCP
12 NCP

Customer Classes	1 Residential	2 GS <50	3 GS>50-Regular	4 GS> 50-TOU	5 Large Use (1)	6 Large Use (2)	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor	11 Back-up/Standby Power
CO-INCIDENT PEAK											
1 CP											
Transformation CP	391,339	118,593	277,104		31,342	128,289	-	-	1,082		10,022
Bulk Delivery CP	391,339	118,593	277,104		31,342	128,289	-	-	1,082		10,022
Total Sytem CP	391,339	118,593	277,104		31,342	128,289	-	-	1,082		10,022
4 CP											
Transformation CP	1 394 143	390 069	1 128 193		129 553	565 812	7 933	64	4 466		35 771
Bulk Delivery CP	1 394 143	390 069	1 128 193		129 553	565 812	7 933	64	4 466		35 771
Total Sytem CP	1 394 143	390 069	1 128 193		129 553	565 812	7 933	64	4 466		35 771
12 CP											
Transformation CP	3,378,871	1 097 717	3,141,099		415,122	1 654 061	62,085	568	15,717		102 709
Bulk Delivery CP	3,378,871	1,097,717	3,141,099		415,122	1,654,061	62,085	568	15,717		102,709
Total Sytem CP	3,378,871	1,097,717	3,141,099		415,122	1,654,061	62,085	568	15,717		102,709
NON CO INCIDENT PEAK											
1 NCP											
Classification NCP from Load Data Provider	391,339	137,161	324,959		40,167	167,297	9,526	141	1,947		38,281
Primary NCP	391,339	137,161	324,959		40,167	167,297	9,526	141	1,947		38,281
Line Transformer NCP	391,339	137,161	191,447		-	-	9,526	141	1,947		-
Secondary NCP	391,339	137,161	136,483		-	-	9,526	141	1,947		-
4 NCP											
Classification NCP from Load Data Provider	1 461 089	512 529	1 239 075		159 122	656 503	37 881	533	7 346		132 894
Primary NCP	1 461 089	512 529	1 239 075		159 122	656 503	37 881	533	7 346		132 894
Line Transformer NCP	1,461,089	512 529	729,991		-	-	37,881	533	7,346		-
Secondary NCP	1,461,089	512 529	520,411		-	-	37,881	533	7,346		-
12 NCP											
Classification NCP from Load Data Provider	3,731,042	1,347,249	3,463,326		471,779	1,871,544	110,006	1,241	20,082		290,976
Primary NCP	3,731,042	1,347,249	3,463,326		471,779	1,871,544	110,006	1,241	20,082		290,976
Line Transformer NCP	3,731,042	1,347,249	2,040,391		-	-	110,006	1,241	20,082		-
Secondary NCP	3,731,042	1,347,249	1,454,597		-	-	110,006	1,241	20,082		-

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Sheet O1 Revenue to Cost Summary Worksheet - 2015 Cost Allocation

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	5	6	7	8	9	11
Rate Base Assets		**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Large Use (1)**	**Large Use (2)**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Back-up/Standby Power**
crev	Distribution Revenue at Existing Rates	$102,888,297	$63,270,290	$12,383,472	$17,191,673	$2,827,619	$3,721,203	$2,202,026	$37,542	$509,223	$745,248
mi	Miscellaneous Revenue (mi)	$5,477,916	$3,279,512	$708,085	$1,093,262	$135,182	$16,969	$137,417	$2,372	$25,462	$79,654
		Miscellaneous Revenue Input equals Output									
	Total Revenue at Existing Rates	$108,366,213	$66,549,802	$13,091,558	$18,284,935	$2,962,801	$3,738,172	$2,339,443	$39,914	$534,686	$824,902
	Factor required to recover deficiency (1 + D)	1.0979									
	Distribution Revenue at Status Quo Rates	$112,956,026	$69,461,355	$13,595,208	$18,873,896	$3,104,305	$4,085,327	$2,417,497	$41,215	$559,051	$818,171
	Miscellaneous Revenue (mi)	$5,477,916	$3,279,512	$708,085	$1,093,262	$135,182	$16,969	$137,417	$2,372	$25,462	$79,654
	Total Revenue at Status Quo Rates	$118,433,942	$72,740,867	$14,303,294	$19,967,158	$3,239,486	$4,102,296	$2,554,914	$43,588	$584,514	$897,825
	Expenses										
di	Distribution Costs (di)	$28,914,649	$15,066,443	$4,249,185	$7,181,151	$647,342	$165,019	$986,636	$9,996	$95,176	$513,701
cu	Customer Related Costs (cu)	$15,622,045	$12,433,118	$1,575,374	$1,251,849	$80,193	$66,917	$89,796	$13,387	$101,461	$9,950
ad	General and Administration (ad)	$18,095,985	$11,148,012	$2,371,915	$3,441,018	$296,972	$92,460	$442,331	$9,425	$79,372	$214,481
dep	Depreciation and Amortization (dep)	$24,970,618	$14,544,157	$3,614,616	$5,190,674	$372,104	$47,118	$830,850	$8,358	$76,340	$286,401
INPUT	PILs (INPUT)	$2,911,933	$1,633,357	$415,363	$645,853	$56,445	$2,604	$102,478	$1,031	$9,429	$45,373
INT	Interest	$9,798,680	$5,496,261	$1,397,699	$2,173,302	$189,939	$8,763	$344,838	$3,469	$31,728	$152,681
	Total Expenses	$100,313,909	$60,321,347	$13,624,152	$19,883,847	$1,642,995	$382,881	$2,796,929	$45,665	$393,505	$1,222,588
	Direct Allocation	$33,167	$0	$0	$0	$0	$33,167	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$18,086,866	$10,145,257	$2,579,939	$4,011,584	$350,599	$16,174	$636,518	$6,403	$58,564	$281,827
	Revenue Requirement (includes NI)	$118,433,942	$70,466,605	$16,204,091	$23,895,432	$1,993,594	$432,222	$3,433,447	$52,068	$452,069	$1,504,414
		Revenue Requirement Input equals Output									
	Rate Base Calculation										
	Net Assets										
dp	Distribution Plant - Gross	$438,510,313	$248,070,287	$62,783,745	$95,896,873	$8,035,283	$460,839	$15,294,008	$153,847	$1,406,199	$6,409,231
gp	General Plant - Gross	$72,899,540	$40,793,877	$10,394,353	$16,181,977	$1,412,315	$139,956	$2,577,655	$25,930	$237,098	$1,136,381
accum dep	Accumulated Depreciation	($87,703,594)	($51,695,623)	($12,687,418)	($17,849,486)	($1,229,162)	($191,142)	($2,832,450)	($28,491)	($260,151)	($929,670)
co	Capital Contribution	($14,506,035)	($7,697,188)	($2,124,142)	($3,462,907)	($286,893)	$0	($631,422)	($6,352)	($57,559)	($239,572)
	Total Net Plant	$409,200,224	$229,471,353	$58,366,539	$90,766,456	$7,931,543	$409,653	$14,407,791	$144,934	$1,325,587	$6,376,369
	$0										
	Directly Allocated Net Fixed Assets	$394,345	$0	$0	$0	$0	$394,345	$0	$0	$0	$0
COP	Cost of Power (COP)	$520,162,944	$179,538,651	$64,553,600	$204,209,364	$29,662,890	$36,194,664	$4,675,946	$51,224	$1,276,606	$0
	OM&A Expenses	$62,632,679	$38,647,573	$8,196,474	$11,874,018	$1,024,507	$324,396	$1,518,763	$32,808	$276,008	$738,132
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$582,795,623*	*$218,186,223*	*$72,750,074*	*$216,083,382*	*$30,687,397*	*$36,519,060*	*$6,194,709*	*$84,032*	*$1,552,614*	*$738,132*
	Working Capital	$74,015,044	$27,709,650	$9,239,259	$27,442,590	$3,897,299	$4,637,921	$786,728	$10,672	$197,182	$93,743
	Total Rate Base	$483,609,614	$257,181,003	$67,605,798	$118,209,046	$11,828,842	$5,441,919	$15,194,519	$155,606	$1,522,769	$6,470,112
		Rate Base Input equals Output									
	Equity Component of Rate Base	$193,443,846	$102,872,401	$27,042,319	$47,283,618	$4,731,537	$2,176,768	$6,077,808	$62,243	$609,108	$2,588,045
	Net Income on Allocated Assets	$18,086,866	$12,419,520	$679,142	$83,311	$1,596,491	$3,686,249	($242,015)	($2,077)	$191,009	($324,762)
	Net Income on Direct Allocation Assets	$19,478	$0	$0	$0	$0	$19,478	$0	$0	$0	$0
	Net Income	$18,106,344	$12,419,520	$679,142	$83,311	$1,596,491	$3,705,727	($242,015)	($2,077)	$191,009	($324,762)
	RATIOS ANALYSIS										
	REVENUE TO EXPENSES STATUS QUO%	100.00%	103.23%	88.27%	83.56%	162.49%	949.12%	74.41%	83.71%	129.30%	59.68%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($10,067,729)	($3,916,803)	($3,112,533)	($5,610,497)	$969,207	$3,305,951	($1,094,003)	($12,154)	$82,616	($679,512)
		Deficiency Input equals Output									
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	$0	$2,274,262	($1,900,798)	($3,928,273)	$1,245,892	$3,670,074	($878,533)	($8,480)	$132,444	($606,589)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.36%	12.07%	2.51%	0.18%	33.74%	170.24%	-3.98%	-3.34%	31.36%	-12.55%

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - 2015 Cost Allocation

Output sheet showing minimum and maximum level for Monthly Fixed Charge

	1	2	3	5	6	7	8	9	11
Summary	**Residential**	**GS <50**	**GS>50-Regular**	**Large Use (1)**	**Large Use (2)**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Back-up/Standby Power**
Customer Unit Cost per month - Avoided Cost	$2.94	$6.23	$45.60	$476.05	$946.84	$0.14	$0.12	-$0.04	0
Customer Unit Cost per month - Directly Related	$3.92	$8.31	$61.48	$774.33	$1,264.07	$0.21	$0.22	$0.06	0
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$13.69	$19 28	$88.24	$1,229.24	$2,299.20	$7.01	$10.48	$7.56	0
Existing Approved Fixed Charge	$14.92	$33 21	$302.77	$23,376.17	$23,376.17	$2.39	$4.57	$9.40	$0.00

APPENDIX 7-3: 2016 UPDATED COST ALLOCATION STUDY

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Sheet I6.1 Revenue Worksheet - 2016 Cost Allocation

Total kWhs from Load Forecast	4,716,078,768
Total kWs from Load Forecast	8,056,840
Deficiency/sufficiency (RRWF 8. cell F51)	- 5,299,581
Miscellaneous Revenue (RRWF 5. cell F48)	5,516,509

			1	2	3	5	6	7	8	9	11
	ID	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Large Use 5-14.9 MW**	**Super Use >15MW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Back-up/Standby Power**
Billing Data											
Forecast kWh	**CEN**	4,716,078,768	1,615,569,770	585,648,636	1,852,830,462	275,125,662	335,708,389	39,602,538	418,980	11,174,331	-
Forecast kW	**CDEM**	8,056,840	-	-	5,085,745	638,647	1,921,178	109,948	1,185	-	300,137
Forecast kW, included in CDEM, of customers receiving line transformer allowance		2,101,227			2,101,227						
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-									
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	4 716 078 768	1 615 569 770	585 648 636	1 852 830 462	275 125 662	335 708 389	39 602 538	418 980	11 174 331	-
Existing Monthly Charge			16 38	41.33	376.90	17,835.83	3,015 85	2 97	5.69	9.54	$0 00
Existing Distribution kWh Rate			0 02	0.01						0.01	
Existing Distribution kW Rate					2.54	1.05	0.18	7 92	15.60		2 54
Existing TOA Rate					0.73						
Additional Charges											
Distribution Revenue from Rates		$114,862,816	$69,700,443	$15,438,593	$23,007,262	$2,170,258	$486,538	$2,739,202	$45,463	$512,499	$762,559
Transformer Ownership Allowance		$1,533,896	$0	$0	$1,533,896	$0	$0	$0	$0	$0	$0
Net Class Revenue	**CREV**	$113 328 920	$69 700 443	$15 438 593	$21 473 366	$2 170 258	$486 538	$2 739 202	$45 463	$512 499	$762 559

2014 Cost Allocation Model

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Sheet I6.2 Customer Data Worksheet - 2016 Cost Allocation

			1	2	3	5	6	7	8	9	11
	ID	Total	Residential	GS <50	GS>50-Regular	Large Use 5-14.9 MW	Super Use >15MW	Street Light	Sentinel	Unmetered Scattered Load	Back-up/Standby Power
Billing Data											
Bad Debt 3 Year Historical Average	BDHA	$1,486,970	$1,330,554	$130,243	$26,174	$0	$0	$0	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$894,324	$645,686	$112,163	$94,783	$35,167		$109	$80	$6,336	$0
Number of Bills	CNB	1,561,594	1,360,304	133,155	26,759	84	48	48	4,742	36,371	84
Number of Devices								52,356			
Number of Connections (Unmetered)	CCON	43,268						39,842	395	3,031	
Total Number of Customers	CCA	245,116	222,272	18,494	2,230	7	4	4	248	1,857	
Bulk Customer Base	CCB	-									
Primary Customer Base	CCP	243,007	222,272	18,494	2,230	7	4				
Line Transformer Customer Base	CCLT	242,741	222,272	18,494	1,975	-	-				
Secondary Customer Base	CCS	241,702	222,271 92	18,493.73	937	-	-				
Weighted - Services	CWCS	250,664	222,272	26,631	1,761	-	-	-	-	-	-
Weighted Meter -Capital	CWMC	45,661,861	33,118,517	6,139,920	5,833,425	345,000	225,000	-	-	-	-
Weighted Meter Reading	CWMR	3,099,540	1,360,304	133,155	1,593,221	5,001	2,858	-	-	-	5,001
Weighted Bills	CWNB	1,652,810	1,360,304	141,144	114,528	8,098	8,098	81	2,371	18,185	-

Bad Debt Data

Historic Year	2010	1,536,562	1,374,929	134,586	27,047						
Historic Year	2011	1,549,348	1,386,370	135,706	27,272						
Historic Year	2012	1,375,000	1,230,362	120,435	24,203						
Three-year average		**1,486,970**	**1,330,554**	**130,243**	**26,174**	**-**	**-**	**-**	**-**	**-**	**-**

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Sheet I8 Demand Data Worksheet - 2016 Cost Allocation

This is an input sheet for demand allocators.

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

			1	2	3	5	6	7	8	9	11
Customer Classes		Total	Residential	GS <50	GS>50-Regular	Large Use 5-14.9 MW	Super Use >15MW	Street Light	Sentinel	Unmetered Scattered Load	Back-up/Standby Power
CO-INCIDENT PEAK											
1 CP											
Transformation CP	TCP1	959,828	390,820	118,521	276,353	31,952	130,783	-	-	1,061	10,338
Bulk Delivery CP	BCP1	959,828	390,820	118,521	276,353	31,952	130,783	-	-	1,061	10,338
Total Sytem CP	DCP1	959,828	390,820	118,521	276,353	31,952	130,783	-	-	1,061	10,338
4 CP											
Transformation CP	TCP4	3 665 416	1 392 294	389 833	1 125 137	132 072	576 815	7 928	61	4 379	36 897
Bulk Delivery CP	BCP4	3 665 416	1 392 294	389 833	1 125 137	132 072	576 815	7 928	61	4 379	36 897
Total Sytem CP	DCP4	3 665 416	1 392 294	389 833	1 125 137	132 072	576 815	7 928	61	4 379	36 897
12 CP											
Transformation CP	TCP12	9,897,396	3,374,389	1 097 053	3,132,588	423,195	1 686 224	62,052	542	15,409	105 943
Bulk Delivery CP	BCP12	9,897,396	3,374,389	1,097,053	3,132,588	423,195	1,686,224	62,052	542	15,409	105,943
Total Sytem CP	DCP12	9,897,396	3,374,389	1,097,053	3,132,588	423,195	1,686,224	62,052	542	15,409	105,943
NON CO INCIDENT PEAK											
1 NCP											
Classification NCP from Load Data Provider	DNCP1	1,114,525	390,820	137,078	324,078	40,949	170,550	9,521	134	1,908	39,486
Primary NCP	PNCP1	1,114,525	390,820	137,078	324,078	40,949	170,550	9,521	134	1,908	39,486
Line Transformer NCP	LTNCP1	729,644	390,820	137,078	190,182	-	-	9,521	134	1,908	-
Secondary NCP	SNCP1	675,575	390,820	137,078	136,113	-	-	9,521	134	1,908	-
4 NCP											
Classification NCP from Load Data Provider	DNCP4	4 221 222	1 459 151	512 219	1 235 717	162 216	669 269	37 861	509	7 202	137 078
Primary NCP	PNCP4	4 221 222	1 459 151	512 219	1 235 717	162 216	669 269	37 861	509	7 202	137 078
Line Transformer NCP	LTNCP4	2,742,110	1,459,151	512 219	725,168	-	-	37,861	509	7,202	-
Secondary NCP	SNCP4	2,535,943	1,459,151	512 219	519,001	-	-	37,861	509	7,202	-
12 NCP											
Classification NCP from Load Data Provider	DNCP12	11,346,318	3,726,093	1,346,435	3,453,942	480,952	1,907,936	109,948	1,185	19,688	300,137
Primary NCP	PNCP12	11,346,318	3,726,093	1,346,435	3,453,942	480,952	1,907,936	109,948	1,185	19,688	300,137
Line Transformer NCP	LTNCP12	7,230,260	3,726,093	1,346,435	2,026,910	-	-	109,948	1,185	19,688	-
Secondary NCP	SNCP12	6,654,005	3,726,093	1,346,435	1,450,656	-	-	109,948	1,185	19,688	-

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Sheet O1 Revenue to Cost Summary Worksheet - 2016 Cost Allocation

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	5	6	7	8	9	11
Rate Base Assets		Total	Residential	GS <50	GS>50 Regular	Large Use 5 14.9 MW	Super Use >15MW	Street Light	Sentinel	Unmetered Scattered Load	Back up/Standby Power
crev	Distr bution Revenue at Existing Rates	$113,328,920	$69,700,443	$15,438,593	$21,473,366	$2,170,258	$486,538	$2,739,202	$45,463	$512,499	$762,559
mi	Miscellaneous Revenue (mi)	$5,516,509	$3,616,832	$642,881	$916,481	$120,073	$16,683	$100,277	$3,760	$35,584	$63,938
		Miscellaneous Revenue Input equals Output									
	Total Revenue at Existing Rates	**$118,845,429**	**$73,317,275**	**$16,081,474**	**$22,389,847**	**$2,290,331**	**$503,221**	**$2,839,479**	**$49,222**	**$548,084**	**$826,497**
	Factor required to recover deficiency (1 + D)	**1.0468**									
	Distr bution Revenue at Status Quo Rates	$118,628,501	$72,959,832	$16,160,545	$22,477,521	$2,271,745	$509,290	$2,867,294	$47,588	$536,465	$798,219
	Miscellaneous Revenue (mi)	$5,516,509	$3,616,832	$642,881	$916,481	$120,073	$16,683	$100,277	$3,760	$35,584	$63,938
	Total Revenue at Status Quo Rates	**$124,145,010**	**$76,576,665**	**$16,803,426**	**$23,394,002**	**$2,391,819**	**$525,973**	**$2,967,572**	**$51,348**	**$572,049**	**$862,156**
	Expenses										
di	Distr bution Costs (di)	$29,648,588	$15,417,279	$4,365,266	$7,371,219	$679,229	$170,396	$994,298	$9,934	$95,170	$545,798
cu	Customer Related Costs (cu)	$16,053,226	$12,779,158	$1,615,311	$1,299,557	$82,039	$68,376	$92,324	$13,432	$103,029	$0
ad	General and Administration (ad)	$18,692,317	$11,505,989	$2,451,315	$3,560,805	$312,774	$96,709	$449,629	$9,483	$80,553	$225,059
dep	Depreciation and Amortization (dep)	$26,487,624	$15,361,195	$3,831,824	$5,511,889	$402,513	$97,622	$886,293	$8,790	$80,647	$306,851
INPUT	PILs (INPUT)	$4,257,804	$2,384,547	$607,474	$944,676	$84,349	$3,418	$150,078	$1,488	$13,677	$68,097
INT	Interest	$10,106,799	$5,660,228	$1,441,967	$2,242,388	$200,221	$8,113	$356,242	$3,533	$32,464	$161,643
	Total Expenses	**$105,246,358**	**$63,108,397**	**$14,313,156**	**$20,930,533**	**$1,761,125**	**$444,634**	**$2,928,864**	**$46,661**	**$405,539**	**$1,307,449**
	Direct Allocation	**$243,045**	**$0**	**$0**	**$0**	**$0**	**$243,045**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	$18,655,607	$10,447,917	$2,661,651	$4,139,105	$369,577	$14,975	$657,568	$6,522	$59,924	$298,367
	Revenue Requirement (includes NI)	$124,145,010	$73,556,314	$16,974,807	$25,069,638	$2,130,702	$702,654	$3,586,432	$53,182	$465,464	$1,605,816
		Revenue Requirement Input equals Output									
	Rate Base Calculation										
	Net Assets										
dp	Distr bution Plant - Gross	$467,458,722	$264,623,085	$66,977,653	$101,943,447	$8,660,940	$468,866	$16,247,434	$161,137	$1,479,762	$6,896,398
gp	General Plant - Gross	$80,263,958	$44,584,148	$11,376,636	$17,707,772	$1,579,092	$633,062	$2,822,079	$27,989	$257,121	$1,276,059
accum dep	Accumulated Depreciation	($110,984,932)	($65,230,064)	($16,024,402)	($22,571,028)	($1,590,868)	($467,892)	($3,562,806)	($35,333)	($324,279)	($1,178,259)
co	Capital Contribution	($14,506,035)	($7,700,297)	($2,127,683)	($3,452,031)	($290,230)	$0	($627,648)	($6,225)	($56,699)	($245,222)
	Total Net Plant	**$422,231,713**	**$236,276,872**	**$60,202,203**	**$93,628,160**	**$8,358,934**	**$634,036**	**$14,879,059**	**$147,568**	**$1,355,905**	**$6,748,976**
	Directly Allocated Net Fixed Assets	**$2,780,762**	**$0**	**$0**	**$0**	**$0**	**$2,780,762**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	$541,395,015	$186,448,485	$67,097,648	$211,823,577	$31,452,455	$38,378,292	$4,842,140	$51,020	$1,301,398	$0
	OM&A Expenses	$64,394,131	$39,702,426	$8,431,892	$12,231,580	$1,074,042	$335,482	$1,536,251	$32,849	$278,751	$770,858
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	***$605,789,145***	***$226,150,912***	***$75,529,540***	***$224,055,157***	***$32,526,496***	***$38,713,773***	***$6,378,390***	***$83,869***	***$1,580,150***	***$770,858***
	Working Capital	**$76,935,221**	**$28,721,166**	**$9,592,252**	**$28,455,005**	**$4,130,865**	**$4,916,649**	**$810,056**	**$10,651**	**$200,679**	**$97,899**
	Total Rate Base	**$501,947,696**	**$264,998,037**	**$69,794,455**	**$122,083,165**	**$12,489,799**	**$8,331,447**	**$15,689,115**	**$158,219**	**$1,556,584**	**$6,846,875**
		Rate Base Input equals Output									
	Equity Component of Rate Base	**$200,779,078**	**$105,999,215**	**$27,917,782**	**$48,833,266**	**$4,995,920**	**$3,332,579**	**$6,275,646**	**$63,288**	**$622,633**	**$2,738,750**
	Net Income on Allocated Assets	**$18,655,607**	**$13,468,268**	**$2,490,269**	**$2,463,470**	**$630,694**	**($161,706)**	**$38,708**	**$4,688**	**$166,510**	**($445,292)**
	Net Income on Direct Allocation Assets	**$137,314**	**$0**	**$0**	**$0**	**$0**	**$137,314**	**$0**	**$0**	**$0**	**$0**
	Net Income	**$18,792,922**	**$13,468,268**	**$2,490,269**	**$2,463,470**	**$630,694**	**($24,392)**	**$38,708**	**$4,688**	**$166,510**	**($445,292)**
	RATIOS ANALYSIS										
	REVENUE TO EXPENSES STATUS QUO%	**100.00%**	**104.11%**	**98.99%**	**93.32%**	**112.25%**	**74.86%**	**82.74%**	**96.55%**	**122.90%**	53.69%
	EXISTING REVENUE MINUS ALLOCATED COSTS	**($5,299,581)**	($239,039)	($893,334)	($2,679,791)	$159,629	($199,433)	($746,953)	($3,960)	$82,620	($779,319)
		Deficiency Input equals Output									
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	**($0)**	$3,020,351	($171,382)	($1,675,636)	$261,116	($176,681)	($618,860)	($1,834)	$106,586	($743,660)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.36%	12.71%	8.92%	5.04%	12.62%	-0.73%	0.62%	7.41%	26.74%	-16.26%

2014 Cost Allocation Model

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - 2016 Cost Allocation

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	5	6	7	8	9	11
	Residential	**GS <50**	**GS>50-Regular**	**Large Use 5-14.9 MW**	**Super Use >15MW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Back-up/Standby Power**
Customer Unit Cost per month - Avoided Cost	$2.97	$6.30	$46.21	$480.73	$862.02	$0.14	$0.13	-$0.03	0
Customer Unit Cost per month - Directly Related	$3.95	$8.36	$61.92	$775.93	$1,169.45	$0.22	$0.23	$0.07	0
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$14.43	$20 67	$100.57	$1,546.90	$2,397.90	$7.42	$11.04	$7.95	0
Existing Approved Fixed Charge	$16.38	$41 33	$376.90	$17,835 83	$3,015.85	$2.97	$5.69	$9.54	$0.00

APPENDIX 7-4: 2017 UPDATED COST ALLOCATION STUDY

2014 Cost Allocation Model

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Sheet I6.1 Revenue Worksheet - 2017 Cost Allocation

Total kWhs from Load Forecast	4,706,567,248
Total kWs from Load Forecast	8,099,828
Deficiency/sufficiency (RRWF 8. cell F51)	- 2,805,433
Miscellaneous Revenue (RRWF 5. cell F48)	5,555,937

			1	2	3	5	6	7	8	9	11
	ID	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Large Use (1)**	**Large Use (2)**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Back-up/Standby Power**
Billing Data											
Forecast kWh	**CEN**	4,706,567,248	1,608,117,860	583,142,939	1,841,172,846	280,664,097	342,466,388	39,651,553	400,564	10,951,001	-
Forecast kW	**CDEM**	8,099,828	-	-	5,068,149	651,503	1,959,852	109,890	1,135	-	309,299
Forecast kW, included in CDEM, of customers receiving line transformer allowance		2,101,227			2,101,227						
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-									
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	4 706 567 248	1 608 117 860	583 142 939	1 841 172 846	280 664 097	342 466 388	39 651 553	400 564	10 951 001	-
Existing Monthly Charge			17.13	43.26	394.61	18,655.46	3,598.73	3.11	5.95	9.73	$0 00
Existing Distribution kWh Rate			0 02	0.01						0.02	
Existing Distribution kW Rate					2.65	1.10	0 21	8 29	16.33		2 65
Existing TOA Rate					0.73						
Additional Charges											
Distribution Revenue from Rates		$120,471,907	$73,079,964	$16,168,612	$24,101,640	$2,284,168	$588,816	$2,865,772	$46,352	$518,301	$818,281
Transformer Ownership Allowance		$1,533,896	$0	$0	$1,533,896	$0	$0	$0	$0	$0	$0
Net Class Revenue	**CREV**	$118 938 011	$73 079 964	$16 168 612	$22 567 744	$2 284 168	$588 816	$2 865 772	$46 352	$518 301	$818 281

2014 Cost Allocation Model

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Sheet I6.2 Customer Data Worksheet - 2017 Cost Allocation

			1	2	3	5	6	7	8	9	11
	ID	Total	Residential	GS <50	GS>50-Regular	Large Use (1)	Large Use (2)	Street Light	Sentinel	Unmetered Scattered Load	Back-up/Standby Power
Billing Data											
Bad Debt 3 Year Historical Average	BDHA	$1,486,970	$1,330,953	$129,723	$26,294	$0	$0	$0	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$894,324	$645,686	$112,163	$94,783	$35,167		$109	$80	$6,336	$0
Number of Bills	CNB	1,573,388	1,371,420	133,667	27,093	84	48	48	4,672	36,272	84
Number of Devices								52,328			
Number of Connections (Unmetered)	CCON	43,233						39,821	389	3,023	
Total Number of Customers	CCA	247,031	224,088	18,565	2,258	7	4	4	248	1,857	
Bulk Customer Base	CCB	-									
Primary Customer Base	CCP	244,922	224,088	18,565	2,258	7	4				
Line Transformer Customer Base	CCLT	244,656	224,088	18,565	2,003	-	-				
Secondary Customer Base	CCS	243,601	224,088 27	18,564 90	948	-	-				
Weighted - Services	CWCS	252,604	224,088	26,733	1,783	-	-	-	-	-	-
Weighted Meter -Capital	CWMC	46,119,055	33,389,152	6,163,547	5,906,356	345,000	225,000	-	-	-	90,000
Weighted Meter Reading	CWMR	3,131,088	1,371,420	133,667	1,613,140	5,001	2,858	-	-	-	5,001
Weighted Bills	CWNB	1,665,816	1,371,420	141,687	115,960	8,098	8,098	81	2,336	18,136	-

Bad Debt Data

Historic Year	2010	1,536,562	1,375,342	134,050	27,171						
Historic Year	2011	1,549,348	1,386,786	135,165	27,397						
Historic Year	2012	1,375,000	1,230,731	119,955	24,314						
Three-year average		**1,486,970**	**1,330,953**	**129,723**	**26,294**	**-**	**-**	**-**	**-**	**-**	**-**

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Sheet I8 Demand Data Worksheet - 2017 Cost Allocation

This is an input sheet for demand allocators.

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

			1	2	3	5	6	7	8	9	11
Customer Classes		Total	Residential	GS <50	GS>50-Regular	Large Use (1)	Large Use (2)	Street Light	Sentinel	Unmetered Scattered Load	Back-up/Standby Power
CO-INCIDENT PEAK											
1 CP											
Transformation CP	TCP1	959,350	389,018	118,014	274,614	32,595	133,416	-	-	1,040	10,653
Bulk Delivery CP	BCP1	959,350	389,018	118,014	274,614	32,595	133,416	-	-	1,040	10,653
Total Sytem CP	DCP1	959,350	389,018	118,014	274,614	32,595	133,416	-	-	1,040	10,653
4 CP											
Transformation CP	TCP4	3 665 549	1 385 872	388 165	1 118 057	134 731	588 426	7 924	58	4 291	38 024
Bulk Delivery CP	BCP4	3 665 549	1 385 872	388 165	1 118 057	134 731	588 426	7 924	58	4 291	38 024
Total Sytem CP	DCP4	3 665 549	1 385 872	388 165	1 118 057	134 731	588 426	7 924	58	4 291	38 024
12 CP											
Transformation CP	TCP12	9,902,762	3,358,824	1 092 359	3,112,879	431,714	1 720 169	62,019	519	15,101	109 177
Bulk Delivery CP	BCP12	9,902,762	3,358,824	1,092,359	3,112,879	431,714	1,720,169	62,019	519	15,101	109,177
Total Sytem CP	DCP12	9,902,762	3,358,824	1,092,359	3,112,879	431,714	1,720,169	62,019	519	15,101	109,177
NON CO INCIDENT PEAK											
1 NCP											
Classification NCP from Load Data Provider	DNCP1	1,115,511	389,018	136,492	322,039	41,773	173,983	9,516	129	1,870	40,691
Primary NCP	PNCP1	1,115,511	389,018	136,492	322,039	41,773	173,983	9,516	129	1,870	40,691
Line Transformer NCP	LTNCP1	725,548	389,018	136,492	188,523	-	-	9,516	129	1,870	-
Secondary NCP	SNCP1	672,281	389,018	136,492	135,256	-	-	9,516	129	1,870	-
4 NCP											
Classification NCP from Load Data Provider	DNCP4	4 225 262	1 452 420	510 027	1 227 943	165 482	682 741	37 841	487	7 058	141 262
Primary NCP	PNCP4	4 225 262	1 452 420	510 027	1 227 943	165 482	682 741	37 841	487	7 058	141 262
Line Transformer NCP	LTNCP4	2,726,678	1,452,420	510 027	718,844	-	-	37,841	487	7,058	-
Secondary NCP	SNCP4	2,523,570	1,452,420	510 027	515,736	-	-	37,841	487	7,058	-
12 NCP											
Classification NCP from Load Data Provider	DNCP12	11,358,388	3,708,906	1,340,674	3,432,210	490,634	1,946,344	109,890	1,135	19,295	309,299
Primary NCP	PNCP12	11,358,388	3,708,906	1,340,674	3,432,210	490,634	1,946,344	109,890	1,135	19,295	309,299
Line Transformer NCP	LTNCP12	7,189,135	3,708,906	1,340,674	2,009,234	-	-	109,890	1,135	19,295	-
Secondary NCP	SNCP12	6,621,429	3,708,906	1,340,674	1,441,528	-	-	109,890	1,135	19,295	-

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Sheet O1 Revenue to Cost Summary Worksheet - 2017 Cost Allocation

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS>50 Regular	5 Large Use (1)	6 Large Use (2)	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	11 Back up/Standby Power
crev	Distr bution Revenue at Existing Rates	$118,938,011	$73,079,964	$16,168,612	$22,567,744	$2,284,168	$588,816	$2,865,772	$46,352	$518,301	$818,281
mi	Miscellaneous Revenue (mi)	$5,555,937	$3,640,355	$646,606	$923,050	$122,616	$16,792	$100,222	$3,706	$35,448	$67,143
		Miscellaneous Revenue Input equals Output									
	Total Revenue at Existing Rates	**$124,493,948**	**$76,720,319**	**$16,815,218**	**$23,490,794**	**$2,406,784**	**$605,608**	**$2,965,994**	**$50,058**	**$553,749**	**$885,424**
	Factor required to recover deficiency (1 + D)	1.0236									
	Distr bution Revenue at Status Quo Rates	$121,743,444	$74,803,727	$16,549,987	$23,100,057	$2,338,046	$602,704	$2,933,368	$47,446	$530,526	$837,582
	Miscellaneous Revenue (mi)	$5,555,937	$3,640,355	$646,606	$923,050	$122,616	$16,792	$100,222	$3,706	$35,448	$67,143
	Total Revenue at Status Quo Rates	**$127,299,380**	**$78,444,082**	**$17,196,593**	**$24,023,107**	**$2,460,661**	**$619,497**	**$3,033,590**	**$51,151**	**$565,974**	**$904,725**
	Expenses										
di	Distr bution Costs (di)	$30,340,607	$15,779,484	$4,474,946	$7,521,217	$707,859	$176,497	$1,000,813	$9,861	$95,055	$574,875
cu	Customer Related Costs (cu)	$16,767,576	$13,350,750	$1,674,328	$1,359,237	$84,930	$71,051	$94,934	$13,914	$108,030	$10,402
ad	General and Administration (ad)	$19,147,644	$11,812,069	$2,504,734	$3,624,337	$323,793	$100,380	$450,844	$9,589	$82,022	$239,876
dep	Depreciation and Amortization (dep)	$26,379,676	$15,300,863	$3,814,866	$5,451,537	$399,403	$130,157	$877,948	$8,583	$79,173	$317,147
INPUT	PILs (INPUT)	$4,416,544	$2,470,772	$629,735	$977,927	$89,608	$3,131	$155,611	$1,521	$14,052	$74,186
INT	Interest	$10,474,541	$5,859,831	$1,493,517	$2,319,310	$212,520	$7,427	$369,057	$3,608	$33,327	$175,945
	Total Expenses	**$107,526,588**	**$64,573,770**	**$14,592,125**	**$21,253,566**	**$1,818,113**	**$488,643**	**$2,949,206**	**$47,075**	**$411,658**	**$1,392,431**
	Direct Allocation	**$438,390**	**$0**	**$0**	**$0**	**$0**	**$438,390**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	$19,334,403	$10,816,354	$2,756,805	$4,281,093	$392,279	$13,708	$681,222	$6,660	$61,516	$324,767
	Revenue Requirement (includes NI)	$127,299,380	$75,390,124	$17,348,930	$25,534,659	$2,210,392	$940,741	$3,630,428	$53,735	$473,174	$1,717,198
		Revenue Requirement Input equals Output									
	Rate Base Calculation										
	Net Assets										
dp	Distr bution Plant - Gross	$501,510,699	$284,047,662	$71,846,360	$108,905,270	$9,428,311	$474,562	$17,353,128	$169,642	$1,566,246	$7,719,518
gp	General Plant - Gross	$85,710,943	$47,321,306	$12,076,856	$18,766,932	$1,717,712	$1,112,400	$2,993,404	$29,264	$270,267	$1,422,803
accum dep	Accumulated Depreciation	($134,451,262)	($78,775,447)	($19,367,985)	($27,284,314)	($1,968,584)	($795,687)	($4,293,456)	($41,970)	($387,370)	($1,536,448)
co	Capital Contribution	($14,506,035)	($7,700,008)	($2,131,037)	($3,442,472)	($295,140)	$0	($623,526)	($6,096)	($55,843)	($251,913)
	Total Net Plant	**$438,264,345**	**$244,893,513**	**$62,424,194**	**$96,945,415**	**$8,882,300**	**$791,274**	**$15,429,549**	**$150,840**	**$1,393,301**	**$7,353,960**
	Directly Allocated Net Fixed Assets	**$5,047,352**	**$0**	**$0**	**$0**	**$0**	**$5,047,352**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	$561,407,753	$192,815,853	$69,424,156	$218,738,898	$33,342,905	$40,685,020	$5,025,384	$50,664	$1,324,873	$0
	OM&A Expenses	$66,255,827	$40,942,304	$8,654,008	$12,504,792	$1,116,582	$347,928	$1,546,591	$33,364	$285,107	$825,153
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	***$627,663,580***	***$233,758,157***	***$78,078,164***	***$231,243,690***	***$34,459,487***	***$41,032,947***	***$6,571,974***	***$84,028***	***$1,609,980***	***$825,153***
	Working Capital	**$79,713,275**	**$29,687,286**	**$9,915,927**	**$29,367,949**	**$4,376,355**	**$5,211,184**	**$834,641**	**$10,672**	**$204,467**	**$104,794**
	Total Rate Base	**$523,024,972**	**$274,580,798**	**$72,340,120**	**$126,313,363**	**$13,258,654**	**$11,049,811**	**$16,264,190**	**$161,512**	**$1,597,768**	**$7,458,755**
		Rate Base Input equals Output									
	Equity Component of Rate Base	**$209,209,989**	**$109,832,319**	**$28,936,048**	**$50,525,345**	**$5,303,462**	**$4,419,924**	**$6,505,676**	**$64,605**	**$639,107**	**$2,983,502**
	Net Income on Allocated Assets	**$19,334,403**	**$13,870,312**	**$2,604,467**	**$2,769,541**	**$642,549**	**($307,536)**	**$84,384**	**$4,076**	**$154,316**	**($487,706)**
	Net Income on Direct Allocation Assets	**$247,652**	**$0**	**$0**	**$0**	**$0**	**$247,652**	**$0**	**$0**	**$0**	**$0**
	Net Income	**$19,582,055**	**$13,870,312**	**$2,604,467**	**$2,769,541**	**$642,549**	**($59,884)**	**$84,384**	**$4,076**	**$154,316**	**($487,706)**
	RATIOS ANALYSIS										
	REVENUE TO EXPENSES STATUS QUO%	**100.00%**	**104.05%**	**99.12%**	**94.08%**	**111.32%**	**65.85%**	**83.56%**	**95.19%**	**119.61%**	52.69%
	EXISTING REVENUE MINUS ALLOCATED COSTS	**($2,805,433)**	$1,330,195	($533,712)	($2,043,865)	$196,392	($335,133)	($664,434)	($3,677)	$80,575	($831,774)
		Deficiency Input equals Output									
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	**($0)**	$3,053,958	($152,337)	($1,511,551)	$250,269	($321,244)	($596,838)	($2,584)	$92,800	($812,473)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.36%	12.63%	9.00%	5.48%	12.12%	-1.35%	1.30%	6.31%	24.15%	-16.35%

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - 2017 Cost Allocation

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	5	6	7	8	9	11
	Residential	**GS <50**	**GS>50-Regular**	**Large Use (1)**	**Large Use (2)**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Back-up/Standby Power**
Customer Unit Cost per month - Avoided Cost	$2.95	$6.23	$45.79	$467.08	$856.79	$0.15	$0.13	-$0.03	0
Customer Unit Cost per month - Directly Related	$3.87	$8.18	$60.53	$744.07	$1,149.44	$0.23	$0.23	$0.08	0
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$14.69	$20 93	$100.92	$1,554.31	$2,444.74	$7.51	$11.33	$8.13	0
Existing Approved Fixed Charge	$17.13	$43 26	$394.61	$18,655.46	$3,598.73	$3.11	$5.95	$9.73	$0.00

APPENDIX 7-5: 2018 UPDATED COST ALLOCATION STUDY

EB-2014-0002

Sheet I6.1 Revenue Worksheet - 2018 Cost Allocation

Total kWhs from Load Forecast	4,703,656,447
Total kWs from Load Forecast	8,130,739
Deficiency/sufficiency (RRWF 8. cell F51)	- 1,745,644
Miscellaneous Revenue (RRWF 5. cell F48)	5,666,198

			1	2	3	5	6	7	8	9	11
	ID	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Large Use (1)**	**Large Use (2)**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Back-up/Standby Power**
Billing Data											
Forecast kWh	**CEN**	4,703,656,447	1,604,991,612	581,558,617	1,831,925,238	285,758,686	348,682,806	39,629,670	382,147	10,727,671	-
Forecast kW	**CDEM**	8,130,739	-	-	5,042,608	663,329	1,995,427	109,831	1,083	-	318,460
Forecast kW, included in CDEM, of customers receiving line transformer allowance		2,101,227			2,101,227						
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-									
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	4 703 656 447	1 604 991 612	581 558 617	1 831 925 238	285 758 686	348 682 806	39 629 670	382 147	10 727 671	-
Existing Monthly Charge			17.49	44.28	404.56	19,042.30	4,784 55	3.19	6.09	9.93	$0 00
Existing Distribution kWh Rate			0 02	0.01						0.02	
Existing Distribution kW Rate					2.71	1.12	0 28	8.48	16.71		2.71
Existing TOA Rate					0.73						
Additional Charges											
Distribution Revenue from Rates		$123,708,569	$74,874,323	$16,592,024	$24,740,432	$2,344,804	$792,967	$2,931,775	$46,136	$524,482	$861,626
Transformer Ownership Allowance		$1,533,896	$0	$0	$1,533,896	$0	$0	$0	$0	$0	$0
Net Class Revenue	**CREV**	$122 174 673	$74 874 323	$16 592 024	$23 206 536	$2 344 804	$792 967	$2 931 775	$46 136	$524 482	$861 626

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Sheet I6.2 Customer Data Worksheet - 2018 Cost Allocation

			1	2	3	5	6	7	8	9	11
	ID	Total	Residential	GS <50	GS>50-Regular	Large Use (1)	Large Use (2)	Street Light	Sentinel	Unmetered Scattered Load	Back-up/Standby Power
Billing Data											
Bad Debt 3 Year Historical Average	BDHA	$1,486,970	$1,331,367	$129,191	$26,412	$0	$0	$0	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$894,324	$645,686	$112,163	$94,783	$35,167		$109	$80	$6,336	$0
Number of Bills	CNB	1,585,682	1,383,006	134,202	27,436	84	48	48	4,601	36,172	84
Number of Devices								52,300			
Number of Connections (Unmetered)	CCON	43,197						39,799	383	3,014	
Total Number of Customers	CCA	249,027	225,981	18,639	2,286	7	4	4	248	1,857	
Bulk Customer Base	CCB	-									
Primary Customer Base	CCP	246,918	225,981	18,639	2,286	7	4				
Line Transformer Customer Base	CCLT	246,652	225,981	18,639	2,031	-	-				
Secondary Customer Base	CCS	245,581	225,981 35	18,639.15	960	-	-				
Weighted - Services	CWCS	254,627	225,981	26,840	1,805	-	-	-	-	-	-
Weighted Meter -Capital	CWMC	46,500,556	33,671,222	6,188,199	5,981,136	345,000	225,000	-	-	-	90,000
Weighted Meter Reading	CWMR	1,550,636	1,383,006	18,639	136,130	5,001	2,858	-	-	-	5,001
Weighted Bills	CWNB	1,679,352	1,383,006	142,254	117,428	8,098	8,098	81	2,301	18,086	-

Bad Debt Data

Historic Year	2010	1,536,562	1,375,770	133,500	27,293						
Historic Year	2011	1,549,348	1,387,217	134,611	27,520						
Historic Year	2012	1,375,000	1,231,114	119,463	24,423						
Three-year average		**1,486,970**	**1,331,367**	**129,191**	**26,412**	**-**	**-**	**-**	**-**	**-**	**-**

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Sheet I8 Demand Data Worksheet - 2018 Cost Allocation

This is an input sheet for demand allocators.

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

			1	2	3	5	6	7	8	9	11
Customer Classes		Total	Residential	GS <50	GS>50-Regular	Large Use (1)	Large Use (2)	Street Light	Sentinel	Unmetered Scattered Load	Back-up/Standby Power
CO-INCIDENT PEAK											
1 CP											
Transformation CP	TCP1	960,201	388,261	117,693	273,235	33,187	135,838	-	-	1,018	10,969
Bulk Delivery CP	BCP1	960,201	388,261	117,693	273,235	33,187	135,838	-	-	1,018	10,969
Total Sytem CP	DCP1	960,201	388,261	117,693	273,235	33,187	135,838	-	-	1,018	10,969
4 CP											
Transformation CP	TCP4	3 670 343	1 383 177	387 110	1 112 442	137 177	599 107	7 920	55	4 204	39 150
Bulk Delivery CP	BCP4	3 670 343	1 383 177	387 110	1 112 442	137 177	599 107	7 920	55	4 204	39 150
Total Sytem CP	DCP4	3 670 343	1 383 177	387 110	1 112 442	137 177	599 107	7 920	55	4 204	39 150
12 CP											
Transformation CP	TCP12	9,919,559	3,352,295	1 089 392	3,097,244	439,550	1 751 393	61,986	495	14,793	112 410
Bulk Delivery CP	BCP12	9,919,559	3,352,295	1,089,392	3,097,244	439,550	1,751,393	61,986	495	14,793	112,410
Total Sytem CP	DCP12	9,919,559	3,352,295	1,089,392	3,097,244	439,550	1,751,393	61,986	495	14,793	112,410
NON CO INCIDENT PEAK											
1 NCP											
Classification NCP from Load Data Provider	DNCP1	1,117,839	388,261	136,121	320,422	42,531	177,141	9,511	123	1,832	41,897
Primary NCP	PNCP1	1,117,839	388,261	136,121	320,422	42,531	177,141	9,511	123	1,832	41,897
Line Transformer NCP	LTNCP1	820,533	388,261	136,121	284,685	-	-	9,511	123	1,832	-
Secondary NCP	SNCP1	670,425	388,261	136,121	134,577	-	-	9,511	123	1,832	-
4 NCP											
Classification NCP from Load Data Provider	DNCP4	4 234 279	1 449 597	508 642	1 221 775	168 485	695 134	37 820	465	6 914	145 447
Primary NCP	PNCP4	4 234 279	1 449 597	508 642	1 221 775	168 485	695 134	37 820	465	6 914	145 447
Line Transformer NCP	LTNCP4	3,088,948	1,449,597	508 642	1,085,510	-	-	37,820	465	6,914	-
Secondary NCP	SNCP4	2,516,583	1,449,597	508 642	513,146	-	-	37,820	465	6,914	-
12 NCP											
Classification NCP from Load Data Provider	DNCP12	11,383,189	3,701,696	1,337,032	3,414,971	499,540	1,981,674	109,831	1,083	18,901	318,460
Primary NCP	PNCP12	11,383,189	3,701,696	1,337,032	3,414,971	499,540	1,981,674	109,831	1,083	18,901	318,460
Line Transformer NCP	LTNCP12	8,202,640	3,701,696	1,337,032	3,034,097	-	-	109,831	1,083	18,901	-
Secondary NCP	SNCP12	6,602,831	3,701,696	1,337,032	1,434,288	-	-	109,831	1,083	18,901	-

2014 Cost Allocation Model

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Sheet O1 Revenue to Cost Summary Worksheet - 2018 Cost Allocation

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS>50 Regular	5 Large Use (1)	6 Large Use (2)	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	11 Back up/Standby Power
crev	Distr bution Revenue at Existing Rates	$122,174,673	$74,874,323	$16,592,024	$23,206,536	$2,344,804	$792,967	$2,931,775	$46,136	$524,482	$861,626
mi	Miscellaneous Revenue (mi)	$5,666,198	$3,695,041	$656,757	$958,012	$126,476	$17,221	$102,454	$3,665	$35,431	$71,142
		Miscellaneous Revenue Input equals Output									
	Total Revenue at Existing Rates	**$127,840,872**	**$78,569,364**	**$17,248,781**	**$24,164,548**	**$2,471,280**	**$810,189**	**$3,034,229**	**$49,801**	**$559,913**	**$932,768**
	Factor required to recover deficiency (1 + D)	1.0143									
	Distr bution Revenue at Status Quo Rates	$123,920,317	$75,944,135	$16,829,093	$23,538,113	$2,378,306	$804,297	$2,973,664	$46,795	$531,975	$873,937
	Miscellaneous Revenue (mi)	$5,666,198	$3,695,041	$656,757	$958,012	$126,476	$17,221	$102,454	$3,665	$35,431	$71,142
	Total Revenue at Status Quo Rates	**$129,586,516**	**$79,639,176**	**$17,485,849**	**$24,496,125**	**$2,504,783**	**$821,519**	**$3,076,119**	**$50,460**	**$567,406**	**$945,079**
	Expenses										
di	Distr bution Costs (di)	$31,149,243	$15,986,215	$4,500,420	$8,017,279	$738,180	$182,254	$1,013,543	$9,841	$94,914	$606,596
cu	Customer Related Costs (cu)	$16,897,132	$13,447,484	$1,685,168	$1,380,414	$85,028	$70,878	$97,599	$13,537	$106,418	$10,606
ad	General and Administration (ad)	$19,662,283	$12,016,398	$2,536,325	$3,861,425	$338,545	$103,158	$460,335	$9,498	$81,898	$254,701
dep	Depreciation and Amortization (dep)	$25,824,486	$14,726,377	$3,614,125	$5,740,745	$386,898	$101,275	$859,437	$8,280	$76,179	$311,170
INPUT	PILs (INPUT)	$3,906,664	$2,159,788	$546,476	$897,343	$81,121	$2,416	$137,747	$1,327	$12,273	$68,171
INT	Interest	$11,470,346	$6,341,350	$1,604,506	$2,634,688	$238,179	$7,094	$404,440	$3,896	$36,036	$200,157
	Total Expenses	**$108,910,153**	**$64,677,612**	**$14,487,019**	**$22,531,895**	**$1,867,952**	**$467,075**	**$2,973,101**	**$46,379**	**$407,720**	**$1,451,400**
	Direct Allocation	**$419,920**	**$0**	**$0**	**$0**	**$0**	**$419,920**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	$20,256,442	$11,198,719	$2,833,531	$4,652,816	$420,621	$12,528	$714,234	$6,881	$63,639	$353,474
	Revenue Requirement (includes NI)	$129,586,516	$75,876,331	$17,320,549	$27,184,710	$2,288,572	$899,524	$3,687,336	$53,260	$471,359	$1,804,875
		Revenue Requirement Input equals Output									
	Rate Base Calculation										
	Net Assets										
dp	Distr bution Plant - Gross	$540,938,305	$302,469,135	$75,699,059	$122,906,529	$10,319,065	$479,817	$18,659,029	$179,761	$1,660,151	$8,565,758
gp	General Plant - Gross	$91,429,843	$49,938,383	$12,647,228	$20,783,669	$1,876,817	$1,095,598	$3,195,011	$30,781	$284,644	$1,577,711
accum dep	Accumulated Depreciation	($157,863,150)	($90,781,551)	($21,985,336)	($34,494,703)	($2,353,233)	($861,327)	($5,027,517)	($48,432)	($446,024)	($1,865,027)
co	Capital Contribution	($14,506,035)	($7,568,320)	($2,073,759)	($3,625,628)	($299,845)	$0	($619,031)	($5,964)	($54,675)	($258,812)
	Total Net Plant	**$459,998,962**	**$254,057,648**	**$64,287,193**	**$105,569,867**	**$9,542,804**	**$714,088**	**$16,207,492**	**$156,146**	**$1,444,095**	**$8,019,630**
	Directly Allocated Net Fixed Assets	**$4,917,414**	**$0**	**$0**	**$0**	**$0**	**$4,917,414**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	$581,873,212	$199,388,505	$71,830,077	$225,885,781	$35,234,524	$42,993,174	$5,148,883	$49,648	$1,342,620	$0
	OM&A Expenses	$67,708,658	$41,450,097	$8,721,913	$13,259,118	$1,161,753	$356,290	$1,571,476	$32,876	$283,231	$871,903
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	***$649,581,870***	***$240,838,603***	***$80,551,989***	***$239,144,899***	***$36,396,278***	***$43,349,464***	***$6,720,360***	***$82,524***	***$1,625,851***	***$871,903***
	Working Capital	**$82,496,897**	**$30,586,503**	**$10,230,103**	**$30,371,402**	**$4,622,327**	**$5,505,382**	**$853,486**	**$10,481**	**$206,483**	**$110,732**
	Total Rate Base	**$547,413,274**	**$284,644,150**	**$74,517,296**	**$135,941,269**	**$14,165,131**	**$11,136,884**	**$17,060,978**	**$166,626**	**$1,650,578**	**$8,130,361**
		Rate Base Input equals Output									
	Equity Component of Rate Base	**$218,965,310**	**$113,857,660**	**$29,806,918**	**$54,376,508**	**$5,666,053**	**$4,454,754**	**$6,824,391**	**$66,650**	**$660,231**	**$3,252,145**
	Net Income on Allocated Assets	**$20,256,442**	**$14,961,564**	**$2,998,831**	**$1,964,230**	**$636,831**	**($65,477)**	**$103,017**	**$4,081**	**$159,687**	**($506,322)**
	Net Income on Direct Allocation Assets	**$238,711**	**$0**	**$0**	**$0**	**$0**	**$238,711**	**$0**	**$0**	**$0**	**$0**
	Net Income	**$20,495,153**	**$14,961,564**	**$2,998,831**	**$1,964,230**	**$636,831**	**$173,234**	**$103,017**	**$4,081**	**$159,687**	**($506,322)**
	RATIOS ANALYSIS										
	REVENUE TO EXPENSES STATUS QUO%	**100.00%**	**104.96%**	**100.95%**	**90.11%**	**109.45%**	**91.33%**	**83.42%**	**94.74%**	**120.38%**	52.36%
	EXISTING REVENUE MINUS ALLOCATED COSTS	**($1,745,644)**	$2,693,034	($71,769)	($3,020,163)	$182,708	($89,335)	($653,107)	($3,460)	$88,554	($872,107)
		Deficiency Input equals Output									
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	**($0)**	$3,762,846	$165,300	($2,688,585)	$216,210	($78,005)	($611,217)	($2,800)	$96,048	($859,796)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.36%	13.14%	10.06%	3.61%	11.24%	3.89%	1.51%	6.12%	24.19%	-15.57%

2014 Cost Allocation Model

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - 2018 Cost Allocation

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	5	6	7	8	9	11
	Residential	**GS <50**	**GS>50-Regular**	**Large Use (1)**	**Large Use (2)**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Back-up/Standby Power**
Customer Unit Cost per month - Avoided Cost	$2.92	$6.16	$44.96	$449.82	$863.22	$0.16	$0.14	-$0.02	0
Customer Unit Cost per month - Directly Related	$3.80	$8.00	$58.87	$711.09	$1,141.94	$0.24	$0.24	$0.09	0
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$14.80	$20 97	$98.99	$1,513.72	$2,419.00	$7.63	$11.40	$8.18	0
Existing Approved Fixed Charge	$17.49	$44 28	$404.56	$19,042 30	$4,784.55	$3.19	$6.09	$9.93	$0.00

APPENDIX 7-6: 2019 UPDATED COST ALLOCATION STUDY

2014 Cost Allocation Model

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Sheet I6.1 Revenue Worksheet - 2019 Cost Allocation

Total kWhs from Load Forecast	4,699,541,403
Total kWs from Load Forecast	8,161,782
Deficiency/sufficiency (RRWF 8. cell F51)	- 3,568,776
Miscellaneous Revenue (RRWF 5. cell F48)	5,753,899

			1	2	3	5	6	7	8	9	11
	ID	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Large Use (1)**	**Large Use (2)**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Back-up/Standby Power**
Billing Data											
Forecast kWh	**CEN**	4,699,541,403	1,600,739,130	579,899,038	1,822,597,172	290,887,091	354,940,487	39,610,413	363,731	10,504,342	-
Forecast kW	**CDEM**	8,161,782	-	-	5,016,885	675,234	2,031,238	109,773	1,030	-	327,622
Forecast kW, included in CDEM, of customers receiving line transformer allowance		2,101,227			2,101,227						
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-									
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	4 699 541 403	1 600 739 130	579 899 038	1 822 597 172	290 887 091	354 940 487	39 610 413	363 731	10 504 342	-
Existing Monthly Charge			17.74	44.91	410.35	19,314.38	4,856 33	3 23	6.19	10.04	$0 00
Existing Distribution kWh Rate			0 02	0.01						0.02	
Existing Distribution kW Rate					2.74	1.14	0 29	8 61	16.96		2.74
Existing TOA Rate					0.73						
Additional Charges											
Distribution Revenue from Rates		$125,847,018	$76,178,855	$16,867,483	$25,150,347	$2,391,904	$815,054	$2,974,161	$45,499	$526,065	$897,651
Transformer Ownership Allowance		$1,533,896	$0	$0	$1,533,896	$0	$0	$0	$0	$0	$0
Net Class Revenue	**CREV**	$124 313 123	$76 178 855	$16 867 483	$23 616 451	$2 391 904	$815 054	$2 974 161	$45 499	$526 065	$897 651

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Sheet I6.2 Customer Data Worksheet - 2019 Cost Allocation

Billing Data

	ID	Total	1 Residential	2 GS <50	3 GS>50-Regular	5 Large Use (1)	6 Large Use (2)	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	11 Back-up/Standby Power
Bad Debt 3 Year Historical Average	BDHA	$1,486,970	$1,331,718	$128,695	$26,557	$0	$0	$0	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$894,324	$645,686	$112,163	$94,783	$35,167		$109	$80	$6,336	$0
Number of Bills	CNB	1,597,277	1,393,906	134,705	27,797	84	48	48	4,531	36,073	84
Number of Devices								52,273			
Number of Connections (Unmetered)	CCON	43,162						39,778	378	3,006	
Total Number of Customers	CCA	250,908	227,762	18,709	2,316	7	4	4	248	1,857	
Bulk Customer Base	CCB	-									
Primary Customer Base	CCP	248,799	227,762	18,709	2,316	7	4				
Line Transformer Customer Base	CCLT	248,533	227,762	18,709	2,061	-	-				
Secondary Customer Base	CCS	247,444	227,762.44	18,709 02	973	-	-				
Weighted - Services	CWCS	256,532	227,762	26,941	1,829	-	-	-	-	-	-
Weighted Meter -Capital	CWMC	46,867,791	33,936,603	6,211,394	6,059,794	345,000	225,000	-	-	-	90,000
Weighted Meter Reading	CWMR	1,563,396	1,393,906	18,709	137,921	5,001	2,858	-	-	-	5,001
Weighted Bills	CWNB	1,692,231	1,393,906	142,787	118,972	8,098	8,084	81	2,266	18,037	-

Bad Debt Data

Historic Year	2010	1,536,562	1,376,132	132,987	27,443						
Historic Year	2011	1,549,348	1,387,583	134,094	27,671						
Historic Year	2012	1,375,000	1,231,438	119,004	24,557						
Three-year average		**1,486,970**	**1,331,718**	**128,695**	**26,557**	**-**	**-**	**-**	**-**	**-**	**-**

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Sheet I8 Demand Data Worksheet - 2019 Cost Allocation

This is an input sheet for demand allocators.

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes		Total	1 Residential	2 GS <50	3 GS>50-Regular	5 Large Use (1)	6 Large Use (2)	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	11 Back-up/Standby Power
CO-INCIDENT PEAK											
1 CP											
Transformation CP	TCP1	960,773	387,233	117,358	271,844	33,782	138,275	-	-	997	11,284
Bulk Delivery CP	BCP1	960,773	387,233	117,358	271,844	33,782	138,275	-	-	997	11,284
Total Sytem CP	DCP1	960,773	387,233	117,358	271,844	33,782	138,275	-	-	997	11,284
4 CP											
Transformation CP	TCP4	3 674 155	1 379 513	386 006	1 106 777	139 639	609 859	7 916	53	4 116	40 276
Bulk Delivery CP	BCP4	3 674 155	1 379 513	386 006	1 106 777	139 639	609 859	7 916	53	4 116	40 276
Total Sytem CP	DCP4	3 674 155	1 379 513	386 006	1 106 777	139 639	609 859	7 916	53	4 116	40 276
12 CP											
Transformation CP	TCP12	9,933,986	3,343,413	1 086 283	3,081,473	447,439	1 782 825	61,953	471	14,485	115 644
Bulk Delivery CP	BCP12	9,933,986	3,343,413	1,086,283	3,081,473	447,439	1,782,825	61,953	471	14,485	115,644
Total Sytem CP	DCP12	9,933,986	3,343,413	1,086,283	3,081,473	447,439	1,782,825	61,953	471	14,485	115,644
NON CO INCIDENT PEAK											
1 NCP											
Classification NCP from Load Data Provider	DNCP1	1,119,889	387,233	135,732	318,790	43,294	180,320	9,506	117	1,794	43,102
Primary NCP	PNCP1	1,119,889	387,233	135,732	318,790	43,294	180,320	9,506	117	1,794	43,102
Line Transformer NCP	LTNCP1	719,653	387,233	135,732	185,271	-	-	9,506	117	1,794	-
Secondary NCP	SNCP1	668,274	387,233	135,732	133,892	-	-	9,506	117	1,794	-
4 NCP											
Classification NCP from Load Data Provider	DNCP4	4 242 262	1 445 756	507 190	1 215 554	171 509	707 610	37 800	442	6 770	149 631
Primary NCP	PNCP4	4 242 262	1 445 756	507 190	1 215 554	171 509	707 610	37 800	442	6 770	149 631
Line Transformer NCP	LTNCP4	2,704,401	1,445,756	507 190	706,442	-	-	37,800	442	6,770	-
Secondary NCP	SNCP4	2,508,491	1,445,756	507 190	510,533	-	-	37,800	442	6,770	-
12 NCP											
Classification NCP from Load Data Provider	DNCP12	11,405,363	3,691,888	1,333,216	3,397,583	508,505	2,017,238	109,773	1,030	18,508	327,622
Primary NCP	PNCP12	11,405,363	3,691,888	1,333,216	3,397,583	508,505	2,017,238	109,773	1,030	18,508	327,622
Line Transformer NCP	LTNCP12	7,128,985	3,691,888	1,333,216	1,974,570	-	-	109,773	1,030	18,508	-
Secondary NCP	SNCP12	6,581,400	3,691,888	1,333,216	1,426,985	-	-	109,773	1,030	18,508	-

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Sheet O1 Revenue to Cost Summary Worksheet - 2019 Cost Allocation

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS>50 Regular	5 Large Use (1)	6 Large Use (2)	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	11 Back up/Standby Power
crev	Distr bution Revenue at Existing Rates	$124,313,123	$76,178,855	$16,867,483	$23,616,451	$2,391,904	$815,054	$2,974,161	$45,499	$526,065	$897,651
mi	Miscellaneous Revenue (mi)	$5,753,899	$3,752,045	$671,083	$964,332	$130,375	$17,451	$104,314	$3,622	$35,419	$75,258
			Miscellaneous Revenue Input equals Output								
	Total Revenue at Existing Rates	$130,067,021	$79,930,900	$17,538,565	$24,580,784	$2,522,279	$832,505	$3,078,475	$49,121	$561,483	$972,909
	Factor required to recover deficiency (1 + D)	1.0287									
	Distr bution Revenue at Status Quo Rates	$127,881,899	$78,365,794	$17,351,714	$24,294,431	$2,460,571	$838,452	$3,059,543	$46,806	$541,167	$923,421
	Miscellaneous Revenue (mi)	$5,753,899	$3,752,045	$671,083	$964,332	$130,375	$17,451	$104,314	$3,622	$35,419	$75,258
	Total Revenue at Status Quo Rates	$133,635,798	$82,117,839	$18,022,796	$25,258,764	$2,590,946	$855,903	$3,163,857	$50,427	$576,586	$998,678
	Expenses										
di	Distr bution Costs (di)	$31,753,980	$16,529,373	$4,694,752	$7,816,701	$764,649	$188,119	$1,020,405	$9,759	$95,014	$635,208
cu	Customer Related Costs (cu)	$17,194,604	$13,683,847	$1,708,857	$1,413,089	$85,888	$71,466	$100,250	$13,442	$107,015	$10,750
ad	General and Administration (ad)	$20,191,905	$12,434,379	$2,646,871	$3,822,315	$352,654	$106,460	$468,102	$9,505	$82,859	$268,759
dep	Depreciation and Amortization (dep)	$26,490,670	$15,438,099	$3,850,053	$5,427,001	$396,108	$89,224	$881,151	$8,364	$77,917	$322,754
INPUT	PILs (INPUT)	$3,924,270	$2,190,271	$559,187	$866,304	$83,356	$2,117	$138,439	$1,314	$12,257	$71,026
INT	Interest	$12,436,685	$6,941,343	$1,772,160	$2,745,464	$264,169	$6,709	$438,738	$4,165	$38,845	$225,093
	Total Expenses	$111,992,114	$67,217,312	$15,231,880	$22,090,873	$1,946,823	$464,095	$3,047,085	$46,549	$413,907	$1,533,590
	Direct Allocation	$408,083	$0	$0	$0	$0	$408,083	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$21,235,601	$11,852,322	$3,025,957	$4,687,871	$451,067	$11,455	$749,144	$7,111	$66,327	$384,346
	Revenue Requirement (includes NI)	$133,635,798	$79,069,634	$18,257,837	$26,778,744	$2,397,891	$883,632	$3,796,229	$53,660	$480,234	$1,917,936
			Revenue Requirement Input equals Output								
	Rate Base Calculation										
	Net Assets										
dp	Distr bution Plant - Gross	$581,744,419	$329,748,220	$83,356,252	$125,461,043	$11,258,820	$485,015	$20,007,517	$189,910	$1,770,874	$9,466,768
gp	General Plant - Gross	$96,903,243	$53,495,202	$13,666,033	$21,177,241	$2,036,447	$1,073,090	$3,387,638	$32,156	$299,913	$1,735,524
accum dep	Accumulated Depreciation	($180,591,646)	($105,881,968)	($26,038,391)	($36,555,322)	($2,728,152)	($900,192)	($5,733,738)	($54,421)	($507,487)	($2,191,975)
co	Capital Contribution	($14,506,035)	($7,704,951)	($2,135,956)	($3,420,242)	($304,494)	$0	($614,881)	($5,837)	($54,054)	($265,620)
	Total Net Plant	$483,549,981	$269,656,501	$68,847,938	$106,662,721	$10,262,620	$657,913	$17,046,536	$161,808	$1,509,246	$8,744,697
	Directly Allocated Net Fixed Assets	$4,787,476	$0	$0	$0	$0	$4,787,476	$0	$0	$0	$0
COP	Cost of Power (COP)	$600,222,979	$204,445,567	$74,064,403	$232,781,161	$37,151,948	$45,332,814	$5,059,021	$46,455	$1,341,609	$0
	OM&A Expenses	$69,140,489	$42,647,599	$9,050,480	$13,052,105	$1,203,191	$366,045	$1,588,757	$32,706	$284,889	$914,717
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$669,363,467*	*$247,093,167*	*$83,114,883*	*$245,833,266*	*$38,355,138*	*$45,698,859*	*$6,647,778*	*$79,162*	*$1,626,498*	*$914,717*
	Working Capital	$85,009,160	$31,380,832	$10,555,590	$31,220,825	$4,871,103	$5,803,755	$844,268	$10,054	$206,565	$116,169
	Total Rate Base	$573,346,618	$301,037,334	$79,403,528	$137,883,546	$15,133,723	$11,249,145	$17,890,804	$171,862	$1,715,812	$8,860,866
			Rate Base Input equals Output								
	Equity Component of Rate Base	$229,338,647	$120,414,933	$31,761,411	$55,153,418	$6,053,489	$4,499,658	$7,156,321	$68,745	$686,325	$3,544,347
	Net Income on Allocated Assets	$21,235,601	$14,900,528	$2,790,916	$3,167,891	$644,123	($16,274)	$116,772	$3,878	$162,678	($534,911)
	Net Income on Direct Allocation Assets	$230,497	$0	$0	$0	$0	$230,497	$0	$0	$0	$0
	Net Income	$21,466,097	$14,900,528	$2,790,916	$3,167,891	$644,123	$214,222	$116,772	$3,878	$162,678	($534,911)
	RATIOS ANALYSIS										
	REVENUE TO EXPENSES STATUS QUO%	100.00%	103.86%	98.71%	94.32%	108.05%	96.86%	83.34%	93.98%	120.06%	52.07%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($3,568,776)	$861,266	($719,272)	($2,197,961)	$124,389	($51,128)	($717,754)	($4,539)	$81,249	($945,027)
			Deficiency Input equals Output								
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	$3,048,206	($235,041)	($1,519,981)	$193,055	($27,729)	($632,372)	($3,233)	$96,351	($919,257)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.36%	12.37%	8.79%	5.74%	10.64%	4.76%	1.63%	5.64%	23.70%	-15.09%

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - 2019 Cost Allocation

Output sheet showing minimum and maximum level for Monthly Fixed Charge

	1	2	3	5	6	7	8	9	11
Summary	**Residential**	**GS <50**	**GS>50-Regular**	**Large Use (1)**	**Large Use (2)**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Back-up/Standby Power**
Customer Unit Cost per month - Avoided Cost	$2.91	$6.11	$44.91	$437.86	$872.37	$0.16	$0.14	-$0.01	0
Customer Unit Cost per month - Directly Related	$3.77	$7.91	$58.50	$693.18	$1,146.75	$0.25	$0.25	$0.10	0
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$14.94	$21.13	$99.01	$1,504.94	$2,432.71	$7.87	$11.67	$8.21	0
Existing Approved Fixed Charge	$17.74	$44 91	$410.35	$19,314 38	$4,856.33	$3.23	$6.19	$10.04	$0.00