INTRODUCTION TO COST ALLOCATION AND RATE DESIGN

Hydro One Networks Inc. has prepared its cost allocation and rate design evidence in accordance with Chapter 2 of the Board's Filing Requirements for Electricity Distribution Rate Applications issued on July 14, 2016, and has followed the cost allocation policies outlined in the Board's reports and letters, including: (i) OEB Report - Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219), issued on March 31, 2011; (ii) OEB Report - Review of the Board's Cost Allocation Policy for Unmetered Loads (EB-2012-0383), issued on December 19, 2013; and (iii) OEB Letter – New Cost Allocation Policy for Street Lighting Rate Class (EB-2012-0383), issued on June 12, 2015.

In accordance with the Board's policy – A New Distribution Rate Design for Residential Electricity Customers (EB-2012-0410), Hydro One continues the move to all-fixed residential distribution rates, including seasonal customers, over the five years of the custom IR application. The Board views the move to all-fixed rates as the initial step to eliminate Hydro One's seasonal customer class. In November 2016, the Board initiated a proceeding (EB-2016-0315) to consider the remaining steps for the elimination of Hydro One's seasonal customer class. Given that the outcome of this proceeding is pending, Hydro One has not assumed the elimination of the seasonal customer class in this Application.

Hydro One proposes to make a number of changes related to the rate classification of its Acquired Utilities' customers in this Application, as described in Exhibit G1, Tab 2, Schedule 1. The changes include the addition of new residential and general service rate classes for the acquired customers from Norfolk Power Distribution Inc. ("Norfolk Power"), Haldimand County Hydro Inc. ("Haldimand County Hydro") and Woodstock Hydro Services Inc. ("Woodstock Hydro"), together the Acquired Utilities, when the rates for the acquired customers are harmonized in 2021. Acquired customers in the Street Lights, Sentinel Lights, Unmetered Scattered Load and Large User classes will be merged into Hydro One's existing rate classes in 2021.

As described in Exhibit G1, Tab 3, Schedule 1, Hydro One has prepared two cost allocation models, for test years 2018 and 2021. The 2018 cost allocation model applies to all Hydro One customers, excluding those of the three Acquired Utilities. The three Acquired Utilities are integrated into the 2021 cost allocation model, which is used to allocate costs to the existing and newly-added acquired customer classes.

During the other years of the Custom IR period (i.e. 2019, 2020 and 2022), the revenue requirement to be collected by rate class will not be determined by the cost allocation model. Instead, it will be determined in a manner consistent with the Custom IR approach described in Exhibit A, Tab 3, Schedule 2.

As described in rate design Exhibit H1, Tab 1, Schedule 1, Hydro One proposes to make necessary revenue-to-cost ("R/C") adjustments to maintain R/C ratios for all rate classes within the Board's approved range specified in the Board's Filing Requirements for Electricity Distribution Rate Applications issued on July 14, 2016. For the new acquired residential and general service customer classes to be created in 2021, if required, Hydro One proposes to phase in their R/C ratios to within the Board-approved range in a manner that limits total bill impacts. For Street Lights, Sentinel Lights, Unmetered Scattered Load and Large User customers from the three acquired utilities, if required, Hydro One proposes to mitigate their total bill impact by providing bill credits to be tracked in its existing Bill Impact Mitigation Variance Account for future disposition. Details of the proposed changes to R/C ratios, rate design (including Retail Transmission Service Rates) and bill impact mitigation are provided in Exhibit H1, Tab 1, Schedule 1 and Exhibit H1, Tab 4, Schedule 1.

The determination of rate riders for regulatory asset recovery is discussed in Exhibit H1, Tab 3, Schedule 1.

CUSTOMER CLASSIFICATION

1. RATE CLASS REVIEW

In accordance with the Board Decision on Hydro One’s rate application EB-2013-0416, Hydro One has reviewed its customer rate classification to ensure that all customers are classified in accordance with the Company’s currently approved density-based rate classes.

This rate class review used the same methodology as described in Hydro One’s last distribution rate application, EB-2013-0416, to define density zones.

The rate class review continued to leverage Hydro One’s Geographic Information System (“GIS”) to identify clusters of customers and the circuit-kilometers (“cct-km”) of distribution line required to serve those customers to verify that the density zone criteria for Hydro One’s density-based rate classes are being satisfied. Hydro One’s residential and general service rate classes are tied to the identification of the following density zones:

- High (Urban) Density Zone: >= 3000 customers and >= 60 cust/cct-km
- Medium Density Zone: >=100 customers and >= 15 cust/cct-km
- Low Density Zone: Areas that are not Medium or High Density

As shown in Table 1, the most recent rate class review resulted in less than 1.0% of Hydro One customers being reclassified. The customer reclassifications identified by the rate class review have been incorporated into the customer load forecast included with this Application for the 2018-2022 Custom IR period, for implementation as of January 1, 2018.

Table 1: Summary of Rate Class Review Results

Reclassification	# of Customers
R1 to UR	8,250
R2 to UR	46
R2 to R1	3,887
GSe to UGe	227
GSd to UGd	22

In its Decision on Hydro One's last distribution rate application (EB-2013-0416), the Board agreed that a five-year cycle of review and reclassification may be appropriate for the company in the future. As such, Hydro One proposes to update the rate class review on a province-wide basis every five years to coincide with the resetting of rates as part of a rates application. Individual density zones will be updated in the interim period between rates applications in response to customer inquiries or if material changes within or adjacent to a density zone would impact the rate classification of affected customers.

2. REVIEW OF SEASONAL RATE CLASS

In its Decision dated March 12, 2015 in proceeding EB-2013-0146, the Board directed Hydro One to bring forward a plan for elimination of the Seasonal rate class. Hydro One prepared a "Report on Elimination of the Seasonal Class", which was filed with the Board on August 4, 2015. The report assessed the impact of eliminating the Seasonal class and included consideration of the Board's policy to move residential classes to all-fixed rates starting in 2016, which was issued after the March 12, 2015, Decision. On September 30, 2015, the Board issued an Order requiring Hydro One to apply the OEB's policy on distribution rate design (i.e., move to all-fixed rates) for residential customers to its Seasonal class. In the Board's view, such a change constituted the initial step in the execution of the Board's direction to eliminate the Seasonal class.

On November 10, 2016, the Board issued Procedural Order No.1 in a new proceeding, EB-2016-0315, initiated by the Board to consider the next steps for the elimination of the Seasonal Class, ordering Hydro One to update the report that it had initially filed with the Board on August 4, 2015. Accordingly, Hydro One filed an updated "Report on Elimination of the Seasonal Class" on December 1, 2016.

Until such time as the Board issues a Decision in the EB-2016-0315 proceeding, Hydro One will not implement any changes to the Seasonal class except the continued move to all-fixed distribution rates as previously directed by the Board. The elimination of the Seasonal class has not been incorporated into the customer load forecast included with this application for the 2018-2022 Custom IR period.

3. INTEGRATION OF ACQUIRED DISTRIBUTORS

Hydro One is proposing a balanced approach to integrating the acquired customers into Hydro One rate classes. In EB-2013-0187, EB-2014-0244 and EB-2014-0213, the Board approved the acquisition of Norfolk Power, Haldimand County Hydro and Woodstock Hydro (together the "Acquired Utilities") by Hydro One. In these three decisions, the Board stated that it expected that future rates for acquired customers would be reflective of the costs to serve these acquired customers. Implementing the Board's direction requires moving acquired customers to new "acquired" rate classes, increasing the number of rate classes. Conversely, in its distribution rate application (EB-2006-0501), Hydro One proposed, and received approval from the Board, to reduce the number of rate classes that existed at the time. Given that Hydro One already has thirteen existing rate classes, it needs to keep the total number of rate classes manageable.

With this balanced approach in mind, Hydro One proposes that acquired residential and general service customers be assigned to new acquired rate classes. For a small number of customers (i.e., USL, Street Lights, Sentinel Lights and Large Users), Hydro One proposes that they be merged into existing Hydro One rate classes to achieve cost and administrative efficiency and simplicity, and to keep the total number of rate classes manageable. The proposed acquired classes would also be used to harmonize the rates of any future acquired utilities. The integration of the Acquired Utilities into Hydro One's rate classes in 2021 is summarized in Table 2. Sections 5.1 and 5.2 further discuss the process and rationale.

Table 2: Hydro One Rate Classes 2018 to 2022

Hydro One Rate Classes	2018 to 2020	2021 to 2022
R1	H1	H1
R2	H1	H1
UR	H1	H1
Seasonal	H1	H1
GSe	H1	H1
GSd	H1	H1
UGe	H1	H1
UGd	H1	H1
ST	H1	H1 + (Norfolk + Haldimand + Woodstock) GS*
Street Lights	H1	H1 + (Norfolk + Haldimand + Woodstock) St. Lights
Sentinel Lights	H1	H1 + (Norfolk + Haldimand) Sent. Lights
USL	H1	H1 + (Norfolk + Haldimand + Woodstock) USL
DGen	H1	H1
MicroFIT	H1	H1 + (Norfolk + Haldimand + Woodstock) MicroFIT
AR	N/A	(Norfolk + Haldimand) Res
AGSe	N/A	(Norfolk + Haldimand) GS < 50 kW
AGSd	N/A	(Norfolk + Haldimand) GS > 50 kW
AUR	N/A	Woodstock Res
AUGe	N/A	Woodstock GS < 50 kW
AUGd	N/A	Woodstock GS > 50 kW

Norfolk Existing Classes	2018 to 2020	2021 to 2022
Res	Norfolk	N/A
GS < 50 kW	Norfolk	N/A
GS > 50 kW	Norfolk	N/A
Street Lights	Norfolk	N/A
Sentinel Lights	Norfolk	N/A
USL	Norfolk	N/A
Embedded Distributor	Norfolk	N/A
MicroFIT	Norfolk	N/A

Haldimand Existing Classes	2018 to 2020	2021 to 2022
Res	Haldimand	N/A
GS < 50 kW	Haldimand	N/A
GS > 50 kW	Haldimand	N/A
Street Lights	Haldimand	N/A
Sentinel Lights	Haldimand	N/A
USL	Haldimand	N/A
Embedded Distributor	Haldimand	N/A
MicroFIT	Haldimand	N/A

Woodstock Existing Classes	2018 to 2020	2021 to 2022
Res	Woodstock	N/A
GS < 50 kW	Woodstock	N/A
GS 50 to 999 kW	Woodstock	N/A
GS > 1,000 kW	Woodstock	N/A
Street Lights	Woodstock	N/A
USL	Woodstock	N/A
MicroFIT	Woodstock	N/A

H1 = Hydro One Existing, Norfolk = Norfolk Power Existing, Haldimand = Haldimand County Hydro Existing, Woodstock = Woodstock Hydro Existing
* (Norfolk + Haldimand + Woodstock) GS = Acquired GS and Large User customers that meet Hydro One ST requirements

3.1 New Acquired Residential and General Service Rate Classes

Hydro One proposes adding six new rate classes for residential and general service customers formerly served by Haldimand County Hydro, Norfolk Power and Woodstock Hydro for 2021 cost allocation and rate setting:

<u>Acquired Urban</u>

- Acquired Urban Residential (AUR)
- Acquired Urban General Service Energy (AUGe)
- Acquired Urban General Service Demand (AUGd)

<u>Acquired Mixed Density</u>

- Acquired Residential (AR)
- Acquired General Service Energy (AGSe)
- Acquired General Service Demand (AGSd)

The Board directed Hydro One in its decisions on the acquisition of Norfolk Power, Haldimand County Hydro and Woodstock Hydro (EB 2013-0187, EB-2014-0244 and EB-2014-0213) that future rates for acquired customers need to be reflective of the costs to serve these acquired customers. As such, these new rate classes are required to appropriately reflect Hydro One's costs to serve these acquired customers in the cost allocation model. This would not be possible if these customers were merged into existing Hydro One rate classes.

The decision to create two new sets of acquired rate classes is based on the fact that the majority of former Woodstock Hydro customers are located in urban areas, with an average customer density of 63 customers/cct-km, while customers from former Norfolk Power and Haldimand Hydro have a mixed density (i.e., customers are found in urban, low density and medium density areas), with an average customer density of 16 customers/cct-km. Hydro One proposes to assign former Woodstock Hydro customers to the Acquired Urban classes; and to assign former Norfolk Power and Haldimand County Hydro customers to the Acquired Mixed Density classes. This approach keeps the number of customer rate classes manageable but at the same time allows differentiation of the costs to serve acquired customers at "urban" and "mixed" density levels. Hydro One proposes to use these six new acquired rate classes for rate harmonization of potential future acquired utilities' customers.

The six new rate classes have been created in the 2021 Cost Allocation Model ("CAM"), which has been populated with all required inputs specific to these new classes. The CAM results for these six rate classes are included in cost allocation Exhibit G1, Tab 3, Schedule 1. The proposed Total Loss Factors ("TLF") for these new rate classes are discussed in Exhibit H1, Tab 5, Schedule 1.

3.2 Existing Hydro One Rate Classes

In this application, Hydro One proposes no changes to existing Hydro One rate classes. Hydro One also proposes that acquired customers currently in the Unmetered Scattered Load Service Class ("USL"), Street Lighting Service Class ("Street Lights"), Sentinel Lighting Service Class ("Sent. Lights"), MicroFIT Service ("MicroFIT") and those users meeting the requirements of Hydro One's existing Sub Transmission Class be merged into the equivalent Hydro One rate classes in 2021, as shown in Table 2. The number of acquired customers in these classes represents only a small portion of the existing Hydro One customers in these classes, as shown in Table 3.

Table 3: Merging Acquired Customers into Existing Hydro One Rate Classes

	Number of Customers (in 2021)		
	Acquired Utilities	Hydro One Existing	TOTAL
USL	244	5,700	5,944
Street Lights	7	5,438	5,445
Sent. Lights	218	23,501	23,719
Large Users to ST	7	818	825

The current Board-approved volumetric charges for Hydro One Sentinel Lighting Service and Street Lighting Service customers are based on kWh consumption. For the Acquired Utilities, the current Board-approved volumetric charges for Sentinel Lighting Service and Street Lighting Service are based on kW demand. As shown in Table 3, the number of customers from the Acquired Utilities is small compared to the number of existing Hydro One customers within these rate classes. As such, Hydro One proposes that acquired customers from the Acquired Utilities adopt the Hydro One charge determinants in 2021 when they are merged into the corresponding Hydro One rate classes. The existing kWh consumption from these acquired Street Lighting Service and Sentinel Lighting Service customers will be used as the billing quantities. Hydro One also proposes that the Total Loss Factors ("TLF") of the existing Hydro One rate classes remain unchanged from the current Board-approved values, given the relatively small number of acquired customers that will be migrating to these classes. Loss factors are further discussed in Exhibit H1, Tab 5, Schedule 1.

COST ALLOCATION

1. INTRODUCTION

Hydro One Networks Inc.'s total annual revenue requirement for the period 2018 to 2022 is described in Exhibit A, Tab 3, Schedule 2. Hydro One has populated two cost allocation models for test years 2018 and 2021, in accordance with the cost allocation policies outlined in the Board's reports and letters, including: (i) OEB Report - Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219), issued on March 31, 2011; (ii) OEB Report - Review of the Board's Cost Allocation Policy for Unmetered Loads (EB-2012-0383), issued on December 19, 2013; and (iii) OEB Letter – New Cost Allocation Policy for Street Lighting Rate Class (EB-2012-0383), issued on June 12, 2015. The cost allocation model used is consistent with the Board's 2017 Cost Allocation Model ("CAM"), modified as discussed in Hydro One's last distribution rate application (EB-2013-0416) in order to accommodate the Company's specific circumstances, including the breakout of bulk system assets and incorporation of density-based rate classes.

Unless otherwise noted in this Exhibit, the changes made to the Board's CAM are the same changes previously approved in the 2017 CAM used by Hydro One in proceedings EB-2013-0416/EB-2016-0081. Hydro One has not incorporated the elimination of the seasonal class in the 2018 and 2021 CAMs.

The 2018 revenue requirement has been allocated to all existing Hydro One rate classes using the 2018 CAM. Attachment 1 to this schedule provides the input and output sheets from the 2018 CAM, as specified in the Board's filing requirements. The full excel model for the 2018 CAM has also been filed electronically as Attachment 3.

The 2021 revenue requirement has been allocated to all existing Hydro One and new acquired rate classes using the 2021 CAM, which includes all customers from the three Acquired Utilities (Norfolk Power, Woodstock Hydro and Haldimand County Hydro). Attachment 2 to this Exhibit provides the input and output sheets from the 2021 CAM, as specified in the Board's filing requirements. The full excel model for the 2021 CAM has also been filed electronically as Attachment 4.

Consistent with the approach described in Exhibit A, Tab 3, Schedule 2, no CAM was used for rate years 2019, 2020 and 2022. A description of how the revenue requirement by rate class is determined in these years is provided in Exhibit H1, Tab 1, Schedule 1.

2. COST ALLOCATION MODEL

2.1 Introduction

The OEB's CAM is designed based on the principle that costs should be allocated to those customer classes causing them. Cost allocation is generally performed in three steps: functionalization, categorization and allocation.

In the functionalization step, costs are aggregated into homogenous groups as defined by functions within the utility. Functionalization is achieved by allocating utility costs to the various USofA accounts, with further refinement in some categories for bulk and primary-related costs and station costs.

In the categorization step, each of the USofA accounts determined in the functionalization step is categorized as demand-related (related to the peak demands on the system), customer-related (related to the number of customers or connections of the utility), or jointly demand and customer-related (related to both demand on the system and number of customers). Where costs are categorized as jointly demand and customer-related, the proportions of each are determined using a minimum system approach. This approach determines the customer-related proportion by estimating the minimum system that would be needed to serve the minimum load requirements of all distribution customers. The remainder of the cost is considered to be demand-related. Hydro One uses a minimum system split specific to its system as determined by the minimum system study reviewed and approved by the Board as part of Hydro One's 2008 and 2015 – 2019 Rates applications (EB-2007-0681 and EB-2013-0416).

The final step of the cost allocation process is the allocation of the demand and customer-related costs based on various allocators.

2.2 2018 and 2021 Cost Allocation Models – Excel Model and Input Data

The 2018 and 2021 CAMs used in this application are based on the Board-approved 2017 CAM, used in Hydro One's 2017 Distribution Rate Order (EB-2016-0081). The 2018 and 2021 CAMs have been populated with Hydro One's 2018 and 2021 proposed revenue requirement, charge determinants and updated load profiles, which reflect the latest hourly metered data results from existing Hydro One customers and acquired customers. All input data has been reviewed and updated as required. Hydro One has also reviewed all allocators and weighting factors in the 2017 model and has determined that it is appropriate to continue using the same values in the 2018 and 2021 CAMs with the following exceptions:

2.2.1 Weighting Factors

Services, Billing and Collecting weighting factors (CAM sheet I5.2) for the six new acquired rate classes have been established by adopting values from similar existing

Hydro One rate classes. These factors for all Hydro One existing rate classes remain unchanged from the factors used in the 2017 model.

Table 1: Services, Billing and Collecting Weighting Factors in 2021 CAM (Sheet I5.2)

	UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	USL	DGen	ST	AUR	AUGe	AUGd	AR	AGSe	AGSd
Weighting Factor for Services	0.50	0.75	1.50	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00	0.75	0.00	0.00
Weighting Factor for Billing and Collecting	1.00	1.00	1.00	1.00	2.00	7.00	2.00	7.00	2.00	0.02	2.00	15.00	15.00	1.00	2.00	7.00	1.00	2.00	7.00

Meter Capital and Meter Reading Weighted factors for all rate classes have been updated to reflect the forecast number of meters and manually read meters in 2018 and 2021.

Table 2: Meter Capital Weighted Average Costs in 2018 and 2021 CAMs (Sheet I7.1)

Meter Capital Weighted Average Costs

2018 CAM		from I7.1																	
UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	USL	DGen	ST							TOTAL
15.3%	30.1%	22.2%	10.1%	10.7%	1.7%	2.2%	0.6%	0.0%	0.0%	0.0%	0.4%	6.7%							100.0%
2021 CAM		from I7.1																	
UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	USL	DGen	ST	Acq_UR	Acq_UGe	Acq_UGd	Acq_Res	Acq_GSe	Acq_GSd	TOTAL
14.9%	29.0%	21.2%	9.5%	10.1%	1.7%	2.1%	0.5%	0.0%	0.0%	0.0%	0.5%	6.3%	0.8%	0.3%	0.0%	2.3%	0.7%	0.1%	100.0%

Table 3: Meter Reading Weighted Average Costs in 2018 and 2021 CAMs (Sheet I7.2)

Meter Reading Weighted Average Costs

2018 CAM From I7.2																			
UR	R1	R2	Seasonal	GSe	GSd	UGe	Ugd	St Lgt	Sen Lgt	USL	DGEN	ST							TOTAL
0.5%	3.9%	53.0%	13.2%	13.0%	12.0%	1.4%	3.1%	0.0%	0.0%	0.0%	0.0%	0.0%							100.0%
2021 CAM From I7.2																			
UR	R1	R2	Seasonal	GSe	GSd	UGe	Ugd	St Lgt	Sen Lgt	USL	DGEN	ST	Acq_UR	Acq_UGe	Acq_UGd	Acq_Res	Acq_GSe	Acq_GSd	TOTAL
0.5%	3.8%	52.6%	13.1%	12.9%	11.9%	1.3%	3.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%	0.1%	0.0%	100.0%

2.2.2 Density Factors (CAM Sheet E2)

No density adjustment is required for the six new acquired rate classes, as these classes are not distinguished based on density. The value "1" has been input in the 2021 CAM sheet E2 for the six acquired rate classes. These factors for all Hydro One existing rate classes remain unchanged from the factors used in the 2017 model.

Table 4: Density Factors in 2021 CAM (CAM Sheet E2)

UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	USL	DGen	ST	Acq_UR	Acq_UGe	Acq_UGd	Acq_Res	Acq_GSe	Acq_GSd
1.000	1.900	4.800	3.600	2.400	2.200	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000

2.2.3 New Acquired Rate Class Allocator Adjustments

All costs associated with serving the customers of the Acquired Utilities in 2021 have been added to the 2021 CAM. Six new rate classes have also been added to the 2021 CAM to accommodate the rate harmonization of the acquired utilities in 2021. All inputs to the 2021 CAM have been reviewed to ensure that the model is appropriately assigning costs to the Hydro One existing and the new acquired rate classes. In addition, three adjustment factors were developed and included in the 2021 CAM to ensure that the costs allocated to the six new acquired rate classes appropriately reflect the cost of serving the customers in these rate classes. These adjustment factors are described below.

Fixed Assets Adjustment

An adjustment factor has been applied to the amount of gross fixed assets ("GFA") in USofA accounts 1830 to 1860 to align the costs allocated by the CAM to these USofA accounts with the amount of GFA specifically required to serve the new acquired rate classes. The amount of GFA that should appropriately be allocated to the new acquired rate classes is estimated from the GFA in these USofA accounts for the acquired utilities prior to acquisition plus the in-service additions to these accounts up to 2021. The total GFA that should appropriately be assigned to the new acquired rate classes also takes into consideration that a portion of Hydro One's bulk distribution assets associated with serving customers in each of the new acquired rate classes should also be allocated to these classes. The amount of bulk distribution assets assigned to the new acquired classes was determined using the same proportion of bulk assets assigned to Hydro One's other customer classes not directly served by the bulk system.

Assets in all other USofA fixed asset accounts (e.g. distribution station assets, land, buildings, general plant, etc.) are considered to be commonly shared among all classes served by Hydro One. The amount of these common assets normally allocated to all rate classes using the cost allocation principles underlying the CAM are not adjusted.

The GFA adjustment factors are shown in Table 5. The adjustment factors are applied to the GFA in USofAs 1830 to 1860 as shown in rows 437-507 of the 2021 CAM's "E2 Allocators" tab. Hydro One proposes to apply these same factors in future runs of the CAM.

Table 5: GFA Adjustment Factor

GFA (USofA 1830-1860)	Acq_URes	Acq_UGSe	Acq_UGSd	Acq_Res	Acq_GSe	Acq_GSd
Adjustment Factor	0.515	0.381	0.197	0.670	0.701	0.383

The amount of GFA not assigned to the new acquired rate classes as a result of applying the adjustment factors shown above is subsequently redistributed to all other rate classes in proportion to the amounts already assigned to those classes.

Given the Board's CAM methodology, the appropriate allocation of GFA to the new acquired rate classes is critical for driving the allocation of the majority of distribution O&M costs, other than customer-related costs (e.g. billing, collections, meter-related expenses). The allocation of O&M costs, in turn, is a key driver of most administration and general costs.

Net Fixed Asset ("NFA") Allocator Adjustment

The NFA and NFA ECC allocators in the CAM's "E2 Allocator" tab are also adjusted to reflect the GFA adjustment for USofA's 1830-1860 as described above. GFA values assigned to the new acquired rate classes are translated to NFA values based on the relationship between total GFA and NFA determined from rows 112 to 116 in the CAM's "O6 Source Data for E2" tab. The NFA adjustment factors that have been applied are shown in Table 6 below.

Table 6: NFA and NFA ECC Adjustment Factor

NFA and NFA ECC	Acq_URes	Acq_UGSe	Acq_UGSd	Acq_Res	Acq_GSe	Acq_GSd
Adjustment Factor	0.549	0.461	0.354	0.697	0.740	0.498

The amount of NFA and NFA ECC not assigned to the new acquired rate classes as a result of applying the adjustment factors shown above is subsequently redistributed to all other rate classes in proportion to the amounts already assigned to those classes.

Depreciation Cost Adjustment

A depreciation adjustment factor is applied to the depreciation assigned by the CAM to USofA accounts 1830 to 1860 for the new acquired rate classes. The depreciation amounts assigned to the new acquired rate classes as shown in "Sheet 7 Amortization" of the CAM are reduced by the same GFA adjustment factors discussed above in order to reduce the depreciation amount assigned to the new acquired rate classes consistent with the reduction in the GFA for those USofA accounts.

The depreciation amount not assigned to the new acquired rate classes as a result of applying the adjustment factors shown above is subsequently redistributed to all other rate classes in proportion to the amounts already assigned to those classes.

Table 7 shows the unadjusted depreciation amounts compared to the adjusted amounts for each rate class shown in row 2016 of the "O4 Summary by Class & Accounts" tab of the CAM.

Table 7: Adjusted Depreciation Amounts to Reflect New Acquired Rate Classes

Deprecation USofA 5705	UR	R1	R2	Seas	GSe	GSd	UGe	UGd	St.L	Sen.L	USL	Dgen	ST	AUR	AUGSe	AUGSd	AR	AGSd	AGSe
Unadjusted	22.1	74.5	138.3	27.1	40.5	45.4	6.0	9.6	3.3	1.5	0.6	1.0	14.8	2.5	0.9	1.8	7.0	1.7	3.1
Adjusted	22.4	75.5	140.3	27.5	41.1	46.0	6.1	9.8	3.4	1.6	0.6	1.0	15.0	1.6	0.5	0.9	5.3	1.4	1.8

2018 Cost Allocation Model

EB-2017-0049

Sheet I6.1 Revenue Worksheet -

Total kWhs from Load Forecast	33,957,468,361
Total kWs from Load Forecast	41,020,926
Deficiency/sufficiency (RRWF 8. cell F51)	73,508,196
Miscellaneous Revenue (RRWF 5. cell F48)	53,630,485

			1	2	3	4	5	6	7	8	9	10	11	12	13
	ID	**Total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**UGe**	**UGd**	**St Lgt**	**Sen Lgt**	**USL**	**DGen**	**ST**
Billing Data															
Forecast kWh	**CEN**	33,957,468,361	2,047,262,889	4,924,068,303	4,539,367,306	631,921,216	2,104,034,980	2,341,979,038	598,366,765	1,057,526,028	121,367,848	20,385,578	24,437,190	18,368,070	15,528,383,151
Forecast kW	**CDEM**	41,020,926	-	-	-	-	-	8,025,918	-	2,832,322				184,739	29,977,946
Forecast kW, included in CDEM, of customers receiving line transformer allowance		1,172,237	-	-	-	-	-	692,372	-	326,958				152,907	-
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**	23,305,622,359	2,047,262,889	4,924,068,303	4,539,367,306	631,921,216	2,104,034,980	2,341,979,038	598,366,765	1,057,526,028	121,367,848	20,385,578	24,437,190	18,368,070	4,876,537,149
Existing Monthly Charge			$24.78	$33.77	$80.33	$36.28	$27.87	$89.48	$23.30	$93.97	$4.25	$2.71	$35.18	$149.34	$1,054.04
Existing Distribution kWh Rate			$0.0094	$0.0230	$0.0374	$0.0635	$0.0560		$0.0262		$0.0924	$0.1178	$0.0285		
Existing Distribution kW Rate								$15.9121		$9.0851				$6.9518	$1.3365
Existing TFOA Rate															
Additional Charges															
Distribution Revenue from Rates		$1,372,743,246	$86,431,034	$294,031,748	$486,346,781	$105,206,634	$147,418,514	$133,513,581	$20,730,664	$27,698,803	11,485,873	$3,181,473	$3,059,399	$3,349,603	$50,289,137
Transformer Ownership Allowance		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Class Revenue	**CREV**	$1,372,743,246	$86,431,034	$294,031,748	$486,346,781	$105,206,634	$147,418,514	$133,513,581	$20,730,664	$27,698,803	$11,485,873	$3,181,473	$3,059,399	$3,349,603	$50,289,137

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Sheet I6.2 Customer Data Worksheet -

Billing Data

	ID	Total	1 UR	2 R1	3 R2	4 Seasonal	5 GSe	6 GSd	7 UGe	8 UGd	9 St Lgt	10 Sen Lgt	11 USL	12 DGen	13 ST
Bad Debt 3 Year Historical Average	BDHA	$26,649,115	$3,787,028	$9,290,923	$7,667,706	$86,130	$2,744,091	$1,883,540	$635,575	$363,264	4,145	1,880	1,129	$40,510	143,193
Late Payment 3 Year Historical Average	LPHA	$15,954,115	1,930,081	5,482,880	4,660,562	577,022	1,594,108	716,650	360,326	182,474	21,154	19,725	5,827	45,217	358,087
Number of Bills	CNB	14,410,320	2,711,330	5,353,218	3,940,924	597,939	1,061,807	64,868	216,886	20,931	63,879	287,842	67,167	13,830	9,699
Number of Devices											168,101				
Number of Connections (Unmetered)	CCON	37,191	-	-	-	-	-	-	-	-	19,600	11,993	5,597	-	-
Total Number of Customers	CCA	1,302,800	225,944	446,102	328,410	149,485	88,484	5,406	18,074	1,744	19,600	11,993	5,597	1,152	808
Bulk Customer Base	CCB	1,302,800	225,944	446,102	328,410	149,485	88,484	5,406	18,074	1,744	19,600	11,993	5,597	1,152	808
Primary Customer Base	CCP	1,301,912	225,944	446,102	328,410	149,485	88,484	5,406	18,074	1,744	19,600	11,993	5,597	996	77
Line Transformer Customer Base	CCLT	1,301,836	225,944	446,102	328,410	149,485	88,484	5,406	18,074	1,744	19,600	11,993	5,597	996	-
Secondary Customer Base	CCS	1,293,690	225,944	446,102	328,410	149,485	88,484	-	18,074	-	19,600	11,993	5,597	-	-
Weighted - Services	CWCS	1,089,648	112,972	334,576	492,616	149,485	-	-	-	-	-	-	-	-	-
Weighted Meter Capital	CWMC	500,650,982	76,414,324	150,871,532	111,068,381	50,555,708	53,614,165	8,597,145	10,951,322	2,774,034	-	-	-	2,176,256	33,628,116
Weighted Meter Reading	CWMR	354,865	1,946	13,693	187,913	46,923	46,074	42,456	4,821	11,040	-	-	-	-	-
Weighted Bills	CWNB	16,382,168	2,711,330	5,353,218	3,940,924	597,939	2,123,614	454,075	433,773	146,516	127,757	5,757	134,334	207,447	145,484

Bad Debt Data

		Total	UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	USL	DGen	ST
Historic Year:	2013	10,487,600	1,487,599	3,553,261	3,191,171	243,548	438,286	953,470	114,354	108,807	10,244	5,641	196	12,637	368,387
Historic Year:	2014	28,551,765	4,443,855	10,366,830	8,007,945	10,850	2,938,576	1,486,800	894,417	229,876	436	-	3,091	108,084	61,006
Historic Year:	2015	40,907,980	5,429,631	13,952,678	11,804,003	3,993	4,855,411	3,210,350	897,955	751,110	1,754	-	99	810	186
Three-year average		**26,649,115**	**3,787,028**	**9,290,923**	**7,667,706**	**86,130**	**2,744,091**	**1,883,540**	**635,575**	**363,264**	**4,145**	**1,880**	**1,129**	**40,510**	**143,193**

Street Lighting Adjustment Factors

NCP Test Results	4 NCP

	Primary Asset Data		Line Transformer Asset Data	
Class	**Customers/ Devices**	4 NCP	**Customers/ Devices**	4 NCP
UR	225,944	1,887,604	225,944	1,887,604
R1	446,102	4,280,532	446,102	4,280,532
R2	328,410	4,017,982	328,410	4,017,982
Seasonal	149,485	600,609	149,485	600,609
Street Light	168,101	183,857	168,101	183,857

Street Lighting Adjustment Factors	
Primary	8.58
Line Transformer	8.58

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Sheet I8 Demand Data Worksheet -

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	4	5	6	7	8	9	10	11	12	13
Customer Classes		Total	UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	USL	DGen	ST
CO-INCIDENT PEAK															
1 CP															
Transformation CP	TCP1	6,169,450	438,064	1,183,717	1,140,397	151,778	361,635	299,913	100,278	127,115	25,918	4,514	3,016	5,117	2,327,990
Bulk Delivery CP	BCP1	6,146,625	423,973	1,146,314	1,105,308	147,103	350,416	290,302	97,082	122,999	199,408	4,374	2,922	4,949	2,251,476
Total Sytem CP	DCP1	6,349,348	438,064	1,183,717	1,140,397	151,778	361,635	299,913	100,278	127,115	205,816	4,514	3,016	5,117	2,327,990
4 CP															
Transformation CP	TCP4	23,782,078	1,790,856	4,370,784	4,019,379	501,708	1,390,370	1,257,731	389,040	574,459	80,946	13,849	12,123	13,622	9,367,211
Bulk Delivery CP	BCP4	23,021,158	1,733,251	4,232,674	3,895,705	486,257	1,347,238	1,217,427	376,643	555,858	78,426	13,418	11,745	13,175	9,059,341
Total Sytem CP	DCP4	23,782,078	1,790,856	4,370,784	4,019,379	501,708	1,390,370	1,257,731	389,040	574,459	80,946	13,849	12,123	13,622	9,367,211
12 CP															
Transformation CP	TCP12	64,815,453	4,881,659	11,399,446	10,344,462	1,230,846	3,748,113	3,604,565	1,050,474	1,680,571	205,816	35,024	36,660	34,758	26,563,060
Bulk Delivery CP	BCP12	62,739,528	4,724,633	11,039,240	10,026,171	1,192,939	3,631,840	3,489,056	1,017,001	1,626,153	199,408	33,933	35,518	33,618	25,690,018
Total Sytem CP	DCP12	64,815,453	4,881,659	11,399,446	10,344,462	1,230,846	3,748,113	3,604,565	1,050,474	1,680,571	205,816	35,024	36,660	34,758	26,563,060
NON CO_INCIDENT PEAK															
1 NCP															
Classification NCP from Load Data Provider	DNCP1	6,826,560	535,589	1,200,545	1,145,055	162,341	423,621	430,608	123,848	194,300	54,890	8,761	3,200	6,295	2,537,507
Primary NCP	PNCP1	4,127,396	513,064	1,140,557	1,075,573	152,549	399,323	405,851	118,118	185,048	51,824	8,271	3,022		73,588
Line Transformer NCP	LTNCP1	3,996,932	513,064	1,140,557	1,075,573	152,549	399,323	370,840	118,118	163,686	51,824	8,271	3,022		
Secondary NCP	SNCP1	3,369,557	506,707	1,115,748	1,036,249	147,048	386,515		116,071		50,266	8,023	2,931		
4 NCP							-								
Classification NCP from Load Data Provider	DNCP4	25,822,274	1,970,477	4,505,667	4,277,544	639,159	1,644,380	1,678,049	484,829	739,174	194,735	32,180	12,506	24,207	9,619,366
Primary NCP	PNCP4	15,592,084	1,887,604	4,280,532	4,017,982	600,609	1,550,065	1,581,573	462,400	703,975	183,857	30,382	11,808	2,335	278,962
Line Transformer NCP	LTNCP4	15,093,486	1,887,604	4,280,532	4,017,982	600,609	1,550,065	1,445,135	462,400	- 622,709	183,857	30,382	11,808	-	-
Secondary NCP	SNCP4	12,675,651	1,864,217	4,187,423	3,871,081	578,949	1,500,347		454,385		178,328	29,469	11,453		
12 NCP							-						402		
Classification NCP from Load Data Provider	DNCP12	69,461,456	5,101,617	11,646,974	10,618,963	1,669,886	4,439,550	4,708,623	1,337,831	2,099,943	450,092	75,116	36,778	62,871	27,213,214
Primary NCP	PNCP12	40,720,387	4,887,056	11,065,008	9,974,601	1,569,169	4,184,915	4,437,911	1,275,939	1,999,945	424,949	70,920	34,723	6,064	789,185
Line Transformer NCP	LTNCP12	39,312,466	4,887,056	11,065,008	9,974,601	1,569,169	4,184,915	4,055,065	1,275,939	- 1,769,075	424,949	70,920	34,723	- 1,045	-
Secondary NCP	SNCP12	32,592,477	4,826,506	10,824,326	9,609,921	1,512,577	4,050,684		1,253,825		412,172	68,787	33,679		

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Sheet O1 Revenue to Cost Summary Worksheet

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 UR	2 R1	3 R2	4 Seasonal	5 GSe	6 GSd	7 UGe	8 UGd	9 St Lgt	10 Sen Lgt	11 USL	12 DGen	13 ST
crev	Distribution Revenue at Existing Rates	$1,372,743,246	$86,431,034	$294,031,748	$486,346,781	$105,206,634	$147,418,514	$133,513,581	$20,730,664	$27,698,803	$11,485,873	$3,181,473	$3,059,399	$3,349,603	$50,289,137
mi	Miscellaneous Revenue (mi)	$53,630,485	$5,113,873	$13,762,853	$16,978,792	$3,251,750	$5,143,910	$2,799,207	$884,648	$630,884	$400,910	$3,095,690	$128,914	$175,550	$1,263,504
		Miscellaneous Revenue Input equals Output													
	Total Revenue at Existing Rates	$1,426,373,731	**$91,544,907**	**$307,794,601**	**$503,325,573**	**$108,458,384**	**$152,562,424**	**$136,312,787**	**$21,615,312**	**$28,329,688**	**$11,886,784**	**$6,277,163**	**$3,188,313**	**$3,525,152**	**$51,552,642**
	Factor required to recover deficiency (1 + D)	1.0535													
	Distribution Revenue at Status Quo Rates	$1,446,251,442	$91,059,278	$309,776,676	$512,389,870	$110,840,280	$155,312,539	$140,663,018	$21,840,758	$29,182,030	$12,100,924	$3,351,836	$3,223,225	$3,528,969	$52,982,040
	Miscellaneous Revenue (mi)	$53,630,485	$5,113,873	$13,762,853	$16,978,792	$3,251,750	$5,143,910	$2,799,207	$884,648	$630,884	$400,910	$3,095,690	$128,914	$175,550	$1,263,504
	Total Revenue at Status Quo Rates	$1,499,881,927	**$96,173,150**	**$323,539,529**	**$529,368,662**	**$114,092,030**	**$160,456,449**	**$143,462,225**	**$22,725,406**	**$29,812,914**	**$12,501,834**	**$6,447,526**	**$3,352,139**	**$3,704,518**	**$54,245,544**
	Expenses														
di	Distribution Costs (di)	$296,043,624	$13,880,251	$56,811,229	$123,632,500	$22,442,750	$30,566,173	$24,066,976	$3,639,014	$4,913,696	$3,249,036	$1,276,804	$623,713	$129,298	$10,812,183
cu	Customer Related Costs (cu)	$112,914,202	$17,342,130	$35,880,922	$29,884,640	$7,396,371	$11,750,651	$3,669,940	$2,389,657	$942,101	$782,311	$307,921	$453,381	$615,006	$1,499,170
ad	General and Administration (ad)	$165,812,442	$12,272,123	$36,787,914	$61,635,070	$11,930,641	$17,016,378	$12,062,489	$2,418,638	$2,587,786	$1,606,652	$629,519	$422,161	$994,016	$5,449,055
dep	Depreciation and Amortization (dep)	$392,554,546	$22,041,757	$74,859,159	$143,680,290	$27,159,381	$42,143,309	$45,932,205	$6,051,795	$9,735,237	$3,175,609	$1,565,488	$563,812	$780,121	$14,866,382
INPUT	PILs (INPUT)	$61,450,658	$3,089,741	$11,412,410	$23,389,292	$4,208,265	$6,660,515	$7,053,841	$914,232	$1,461,570	$539,992	$198,348	$98,756	$67,904	$2,355,792
INT	Interest	$191,624,551	$9,634,887	$35,587,869	$72,935,958	$13,122,835	$20,769,805	$21,996,332	$2,850,895	$4,557,684	$1,683,882	$618,519	$307,955	$211,749	$7,346,179
	Total Expenses	$1,220,400,023	**$78,260,888**	**$251,339,504**	**$455,157,751**	**$86,260,243**	**$128,906,830**	**$114,781,782**	**$18,264,233**	**$24,198,075**	**$11,037,483**	**$4,596,599**	**$2,469,778**	**$2,798,095**	**$42,328,762**
	Direct Allocation	$10,056,427	**$0**	**$0**	**$0**	**$0**	**$0**	**$2,433,638**	**$0**	**$742,547**	**$0**	**$792,388**	**$0**	**$3,349,392**	**$2,738,463**
NI	Allocated Net Income (NI)	$269,425,477	$13,546,720	$50,036,797	$102,548,474	$18,450,799	$29,202,493	$30,926,999	$4,008,379	$6,408,136	$2,367,551	$869,642	$432,987	$297,721	$10,328,780
	Revenue Requirement (includes NI)	$1,499,881,927	$91,807,608	$301,376,300	$557,706,225	$104,711,041	$158,109,324	$148,142,418	$22,272,612	$31,348,758	$13,405,033	$6,258,629	$2,902,765	$6,445,207	$55,396,005
		Revenue Requirement Input equals Output													
	Rate Base Calculation														
	Net Assets														
dp	Distribution Plant - Gross	$11,237,405,954	$579,713,089	$2,115,962,140	$4,283,058,771	$786,930,558	$1,189,677,239	$1,268,742,598	$163,522,270	$263,447,311	$96,412,087	$35,454,190	$17,636,787	$13,324,945	$423,523,969
gp	General Plant - Gross	$1,177,857,488	$58,457,160	$216,512,174	$443,684,292	$80,762,598	$124,689,466	$133,196,119	$17,071,972	$27,610,485	$10,197,283	$18,812,133	$1,876,989	$1,370,755	$43,616,062
accum dep	Accumulated Depreciation	($4,334,809,525)	($232,298,166)	($829,215,397)	($1,646,212,508)	($306,952,885)	($448,639,165)	($477,148,904)	($62,062,368)	($99,356,301)	($35,808,932)	($21,144,024)	($6,481,711)	($5,178,453)	($164,310,710)
co	Capital Contribution	($896,478,209)	($44,988,122)	($170,042,045)	($348,174,064)	($68,750,362)	($88,309,790)	($101,001,376)	($11,839,720)	($21,006,039)	($7,736,768)	($3,528,163)	($1,493,867)	($1,551,257)	($28,056,636)
	Total Net Plant	$7,183,975,709	**$360,883,961**	**$1,333,216,872**	**$2,732,356,490**	**$491,989,910**	**$777,417,750**	**$823,788,436**	**$106,692,154**	**$170,695,456**	**$63,063,671**	**$29,594,135**	**$11,538,199**	**$7,965,990**	**$274,772,685**
	Directly Allocated Net Fixed Assets	$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	$3,578,426,392	$314,343,871	$756,058,590	$696,990,259	$97,027,383	$323,060,856	$359,595,615	$91,875,316	$162,376,228	$18,635,242	$3,130,073	$3,752,171	$2,820,297	$748,760,491
	OM&A Expenses	$574,770,268	$43,494,504	$129,480,065	$215,152,211	$41,769,762	$59,333,201	$39,799,404	$8,447,310	$8,443,584	$5,637,999	$2,214,244	$1,499,256	$1,738,320	$17,760,409
	Directly Allocated Expenses	$10,056,427	$0	$0	$0	$0	$0	$2,433,638	$0	$742,547	$0	$792,388	$0	$3,349,392	$2,738,463
	Subtotal	$4,163,253,087	**$357,838,375**	**$885,538,655**	**$912,142,470**	**$138,797,145**	**$382,394,057**	**$401,828,657**	**$100,322,626**	**$171,562,359**	**$24,273,241**	**$6,136,704**	**$5,251,427**	**$7,908,009**	**$769,259,363**
	Working Capital	$325,326,021	**$27,962,301**	**$69,197,995**	**$71,276,877**	**$10,845,923**	**$29,881,137**	**$31,399,801**	**$7,839,437**	**$13,406,271**	**$1,896,766**	**$479,536**	**$410,358**	**$617,950**	**$60,111,668**
	Total Rate Base	$7,509,301,730	**$388,846,261**	**$1,402,414,867**	**$2,803,633,368**	**$502,835,833**	**$807,298,888**	**$855,188,237**	**$114,531,591**	**$184,101,727**	**$64,960,437**	**$30,073,671**	**$11,948,558**	**$8,583,940**	**$334,884,353**
		Rate Base Input Does Not Equal Output													
	Equity Component of Rate Base	$3,003,720,692	**$155,538,504**	**$560,965,947**	**$1,121,453,347**	**$201,134,333**	**$322,919,555**	**$342,075,295**	**$45,812,636**	**$73,640,691**	**$25,984,175**	**$12,029,469**	**$4,779,423**	**$3,433,576**	**$133,953,741**
	Net Income on Allocated Assets	$269,425,477	**$17,912,262**	**$72,200,025**	**$74,210,911**	**$27,831,788**	**$31,549,618**	**$26,246,806**	**$4,461,173**	**$4,872,292**	**$1,464,351**	**$1,058,539**	**$882,360**	**($2,442,968)**	**$9,178,319**
	Net Income on Direct Allocation Assets	$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	Net Income	$269,425,477	**$17,912,262**	**$72,200,025**	**$74,210,911**	**$27,831,788**	**$31,549,618**	**$26,246,806**	**$4,461,173**	**$4,872,292**	**$1,464,351**	**$1,058,539**	**$882,360**	**($2,442,968)**	**$9,178,319**
	RATIOS ANALYSIS														
	REVENUE TO EXPENSES STATUS QUO%	100.00%	**1.05**	**1.07**	**0.95**	**1.09**	**1.01**	**0.97**	**1.02**	**0.95**	**0.93**	**1.03**	**1.15**	**0.57**	**0.98**
	EXISTING REVENUE MINUS ALLOCATED COSTS	($73,508,196)	($262,700)	$6,418,301	($54,380,652)	$3,747,343	($5,546,900)	($11,829,631)	($657,300)	($3,019,071)	($1,518,250)	$18,534	$285,548	($2,920,055)	($3,843,363)
		Deficiency Input equals Output													
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	$4,365,543	$22,163,229	($28,337,563)	$9,380,989	$2,347,125	($4,680,193)	$452,794	($1,535,844)	($903,200)	$188,896	$449,373	($2,740,689)	($1,150,461)
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.97%	11.52%	12.87%	6.62%	13.84%	9.77%	7.67%	9.74%	6.62%	5.64%	8.80%	18.46%	-71.15%	6.85%

2018 Cost Allocation Model

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	4	5	6	7	8	9	10	11	12	13
	UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	USL	DGen	ST
Customer Unit Cost per month - Avoided Cost	$7.73	$7.50	$8.08	$7.06	$13.15	$78.18	$12.69	$78.07	$3.09	$2.01	$6.11	$101.99	$335.84
Customer Unit Cost per month - Directly Related	$10.02	$9.83	$10.72	$9.00	$17.12	$96.95	$16.52	$96.19	$4.35	$2.85	$8.53	$159.39	$419.75
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$20.42	$27.74	$50.45	$52.30	$22.80	$106.14	$14.09	$105.72	$22.11	$15.47	$38.79	$196.16	$462.03
Existing Approved Fixed Charge	$24.78	$33.77	$80.33	$36.28	$27.87	$89.48	$23.30	$93.97	$4.25	$2.71	$35.18	$149.34	$1,054.04

2021 Cost Allocation Model

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Sheet I6.1 Revenue Worksheet -

Total kWhs from Load Forecast	34,267,266,492

Total kWs from Load Forecast	41,396,206

Deficiency/sufficiency (RRWF 8. cell F51)	42,314,799

Miscellaneous Revenue (RRWF 5. cell F48)	55,882,454

			1	2	3	4	5	6	7	8	9
	ID	**Total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**UGe**	**UGd**	**St Lgt**
Billing Data											
Forecast kWh	**CEN**	34,267,266,492	2,075,368,926	4,971,183,532	4,425,991,400	605,493,061	2,017,505,440	2,301,725,939	589,001,013	1,043,858,333	132,827,621
Forecast kW	**CDEM**	41,396,206	-	-	-	-	-	7,887,971	-	2,771,740	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		1,639,901	-	-	-	-	-	680,472	-	319,965	
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**	23,750,320,874	2,075,368,926	4,971,183,532	4,425,991,400	605,493,061	2,017,505,440	2,301,725,939	589,001,013	1,043,858,333	132,827,621
Existing Monthly Charge			$35.85	$47.06	$107.71	$50.05	$30.88	$106.19	$25.10	$105.02	$4.33
Existing Distribution kWh Rate			$0.0000	$0.0160	$0.0269	$0.0439	$0.0633		$0.0299		$0.1043
Existing Distribution kW Rate								$17.8594		$10.2289	
Existing TFOA Rate											
Additional Charges											
Distribution Revenue from Rates		$1,582,235,723	$100,704,642	$337,959,393	$550,079,444	$116,938,615	$160,478,744	$147,963,022	$23,147,088	$30,585,303	14,136,825
Transformer Ownership Allowance		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Class Revenue	**CREV**	$1,582,235,723	$100,704,642	$337,959,393	$550,079,444	$116,938,615	$160,478,744	$147,963,022	$23,147,088	$30,585,303	$14,136,825

	10	11	12	13	14	15	16	17	18	19
	Sen Lgt	**USL**	**DGen**	**ST**	**AUR**	**AUGe**	**AUGd**	**AR**	**AGSe**	**AGSd**
Billing Data										
Forecast kWh	20,598,751	26,193,559	20,331,530	15,132,132,885	92,804,245	43,284,079	142,271,592	287,240,419	103,513,037	235,941,130
Forecast kW			204,487	29,457,615	-	-	410,749	-	-	663,644
Forecast kW, included in CDEM, of customers receiving line transformer allowance			169,252	-	-	-	202,593	-	-	267,619
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	20,598,751	26,193,559	20,331,530	4,615,187,267	92,804,245	43,284,079	142,271,592	287,240,419	103,513,037	235,941,130
Existing Monthly Charge	$3.57	$36.66	$196.16	$1,073.56	$29.98	$25.19	$139.96	$36.18	$37.64	$160.10
Existing Distribution kWh Rate	$0.1354	$0.0298			$0.0000	$0.0145		$0.0000	$0.0173	
Existing Distribution kW Rate			$10.5803	$1.5383			$2.5777			$3.9470
Existing TFOA Rate										
Additional Charges										
Distribution Revenue from Rates	$3,805,212	$3,395,663	$5,712,491	$55,937,606	$5,508,610	$1,032,227	$1,383,942	$16,399,355	$3,747,248	$3,320,293
Transformer Ownership Allowance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Class Revenue	$3,805,212	$3,395,663	$5,712,491	$55,937,606	$5,508,610	$1,032,227	$1,383,942	$16,399,355	$3,747,248	$3,320,293

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Sheet I6.2 Customer Data Worksheet -

	ID	Total	1 UR	2 R1	3 R2	4 Seasonal	5 GSe	6 GSd	7 UGe	8 UGd	9 St Lgt
Billing Data											
Bad Debt 3 Year Historical Average	BDHA	$26,940,875	$3,787,028	$9,290,923	$7,667,706	$86,130	$2,744,091	$1,883,540	$635,575	$363,264	$4,145
Late Payment 3 Year Historical Average	LPHA	$16,121,285	1,930,081	5,482,880	4,660,562	577,022	1,594,108	716,650	360,326	182,474	21,219
Number of Bills	CNB	15,434,700	2,809,056	5,491,297	4,001,674	601,781	1,061,226	66,754	220,556	21,267	65,336
Number of Devices											183,962
Number of Connections (Unmetered)	CCON	39,498	-	-	-	-	-	-	-	-	21,693
Total Number of Customers	CCA	1,390,911	234,088	457,608	333,473	150,445	88,435	5,563	18,380	1,772	21,693
Bulk Customer Base	CCB	1,390,911	234,088	457,608	333,473	150,445	88,435	5,563	18,380	1,772	21,693
Primary Customer Base	CCP	1,389,960	234,088	457,608	333,473	150,445	88,435	5,563	18,380	1,772	21,693
Line Transformer Customer Base	CCLT	1,389,882	234,088	457,608	333,473	150,445	88,435	5,563	18,380	1,772	21,693
Secondary Customer Base	CCS	1,380,685	234,088	457,608	333,473	150,445	88,435	-	18,380	-	21,693
Weighted - Services	CWCS	1,146,887	117,044	343,206	500,209	150,445	-	-	-	-	-
Weighted Meter Capital	CWMC	532,974,659	79,168,549	154,763,066	112,780,504	50,880,613	53,584,823	8,847,103	11,136,611	2,818,573	-
Weighted Meter Reading	CWMR	304,047	1,656	11,655	159,938	39,937	39,215	36,135	4,103	9,396	-
Weighted Bills	CWNB	17,602,501	2,809,056	5,491,297	4,001,674	601,781	2,122,451	467,277	441,112	148,868	130,672

	10 Sen Lgt	11 USL	12 DGen	13 ST	14 AUR	15 AUGe	16 AUGd	17 AR	18 AGSe	19 AGSd
Billing Data										
Bad Debt 3 Year Historical Average	$1,880	$1,129	$40,510	$143,193	$66,967	$2,975	$0	$180,496	$19,213	$22,109
Late Payment 3 Year Historical Average	19,725	5,843	45,217	358,087	39,742	4,296	6,203	90,722	21,130	4,997
Number of Bills	284,633	71,334	18,092	9,896	183,743	16,062	2,323	453,226	52,066	4,378
Number of Devices										
Number of Connections (Unmetered)	11,860	5,944	-	-						
Total Number of Customers	11,860	5,944	1,508	825	15,312	1,339	194	37,769	4,339	365
Bulk Customer Base	11,860	5,944	1,508	825	15,312	1,339	194	37,769	4,339	365
Primary Customer Base	11,860	5,944	1,303	78	15,312	1,339	194	37,769	4,339	365
Line Transformer Customer Base	11,860	5,944	1,303	-	15,312	1,339	194	37,769	4,339	365
Secondary Customer Base	11,860	5,944	-	-	15,312	1,339	-	37,769	4,339	-
Weighted - Services	-	-	-	-	7,656	-	-	28,327	-	-
Weighted Meter Capital	-	-	2,846,982	33,810,846	4,269,571	1,541,331	222,934	12,096,609	3,852,170	354,373
Weighted Meter Reading	-	-	-	-	-	-	36	1,530	400	45
Weighted Bills	5,693	142,667	271,382	148,438	183,743	32,124	16,262	453,226	104,132	30,644

Bad Debt Data

		Total	1 UR	2 R1	3 R2	4 Seasonal	5 GSe	6 GSd	7 UGe	8 UGd	9 St Lgt
Historic Year:	2013	10,756,467	1,487,599	3,553,261	3,191,171	243,548	438,286	953,470	114,354	108,807	10,244
Historic Year:	2014	28,890,581	4,443,855	10,366,830	8,007,945	10,850	2,938,576	1,486,800	894,417	229,876	436
Historic Year:	2015	41,175,578	5,429,631	13,952,678	11,804,003	3,993	4,855,411	3,210,350	897,955	751,110	1,754
Three-year average		**26,940,875**	**3,787,028**	**9,290,923**	**7,667,706**	**86,130**	**2,744,091**	**1,883,540**	**635,575**	**363,264**	**4,145**

		10 Sen Lgt	11 USL	12 DGen	13 ST	14 AUR	15 AUGe	16 AUGd	17 AR	18 AGSe	19 AGSd
Historic Year:	2013	5,641	196	12,637	368,387	68,114	7,367	-	170,363	19,722	3,302
Historic Year:	2014	-	3,091	108,084	61,006	71,000	1,135	-	198,226	25,616	42,838
Historic Year:	2015	-	99	810	186	61,788	423	-	172,898	12,301	20,187
Three-year average		**1,880**	**1,129**	**40,510**	**143,193**	**66,967**	**2,975**	**-**	**180,496**	**19,213**	**22,109**

Street Lighting Adjustment Factors

NCP Test Results	4 NCP

	Primary Asset Data		Line Transformer Asset Data	
Class	**Customers/ Devices**	4 NCP	**Customers/ Devices**	4 NCP
UR	234,088	1,913,450	234,088	1,913,450
R1	457,608	4,306,523	457,608	4,306,523
R2	333,473	3,944,571	333,473	3,944,571
Seasonal	150,445	575,793	150,445	575,793
AUR	15,312	94,046	15,312	94,046
AR	37,769	265,480	37,769	265,480
Street Light	183,962	198,190	183,962	198,190

Street Lighting Adjustment Factors	
Primary	8.48
Line Transformer	8.48

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Sheet I8 Demand Data Worksheet

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	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Customer Classes		Total	UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	USL	DGen	ST	AUR	AUGe	AUGd	AR	AGSe	AGSd
CO-INCIDENT PEAK																					
1 CP																					
Transformation CP	TCP1	6,138,279	472,253	1,195,213	1,115,823	127,540	338,985	274,398	88,801	121,417	28,870	4,568	3,219	4,876	2,222,286	20,035	5,805	13,869	58,669	14,944	26,709
Bulk Delivery CP	BCP1	6,099,983	457,062	1,157,446	1,081,490	123,612	328,470	265,605	85,971	117,485	185,793	4,426	3,119	4,716	2,149,246	19,390	5,619	13,418	56,799	14,467	25,849
Total Sytem CP	DCP1	6,301,173	472,253	1,195,213	1,115,823	127,540	338,985	274,398	88,801	121,417	191,763	4,568	3,219	4,876	2,222,286	20,035	5,805	13,869	58,669	14,944	26,709
4 CP																					
Transformation CP	TCP4	23,955,907	1,948,629	4,332,605	3,700,263	447,370	1,357,681	1,265,549	383,450	575,463	65,108	9,794	13,034	13,489	9,201,841	89,707	27,689	70,795	266,755	63,300	123,382
Bulk Delivery CP	BCP4	23,188,982	1,885,949	4,195,701	3,586,409	433,593	1,315,563	1,224,994	371,231	556,829	63,081	9,489	12,629	13,047	8,899,406	86,822	26,799	68,495	258,253	61,282	119,410
Total Sytem CP	DCP4	23,955,907	1,948,629	4,332,605	3,700,263	447,370	1,357,681	1,265,549	383,450	575,463	65,108	9,794	13,034	13,489	9,201,841	89,707	27,689	70,795	266,755	63,300	123,382
12 CP																					
Transformation CP	TCP12	65,149,745	4,867,598	11,258,782	9,924,230	1,164,168	3,649,977	3,611,748	1,050,138	1,680,576	191,763	29,781	39,260	39,255	25,953,932	214,670	74,295	216,307	657,958	171,672	353,633
Bulk Delivery CP	BCP12	63,062,768	4,711,025	10,903,022	9,618,869	1,128,315	3,536,748	3,496,008	1,016,675	1,626,157	185,793	28,854	38,037	37,968	25,100,911	207,765	71,905	209,280	636,985	166,200	342,250
Total Sytem CP	DCP12	65,149,745	4,867,598	11,258,782	9,924,230	1,164,168	3,649,977	3,611,748	1,050,138	1,680,576	191,763	29,781	39,260	39,255	25,953,932	214,670	74,295	216,307	657,958	171,672	353,633
NON CO_INCIDENT PEAK																					
1 NCP																					
Classification NCP from Load Data Provider	DNCP1	7,011,172	539,268	1,211,304	1,115,823	155,549	405,976	423,266	121,901	191,726	59,065	8,813	3,432	6,912	2,560,893	28,845	9,968	25,257	82,664	19,478	41,031
Primary NCP	PNCP1	4,281,225	516,587	1,150,779	1,048,114	146,167	382,691	398,931	116,262	182,597	55,766	8,321	3,240		74,266	27,575	9,529	24,134	78,303	18,450	38,845
Line Transformer NCP	LTNCP1	4,123,346	516,587	1,150,779	1,048,114	146,167	382,691	364,517	116,262	161,518	55,766	8,321	3,240			27,575	9,529	12,231	78,303	18,450	23,180
Secondary NCP	SNCP1	3,469,066	510,187	1,125,748	1,009,794	140,896	370,416		114,247		54,089	8,071	3,142			27,289	9,430		77,497	18,260	
4 NCP																					
Classification NCP from Load Data Provider	DNCP4	26,463,996	1,997,458	4,533,026	4,199,392	612,750	1,592,935	- 1,633,919	478,267	727,312	209,916	32,413	13,403	667 115 26,429	9,657,032	98,375	36,667	100,058	280,267	72,923	161,456
Primary NCP	PNCP4	16,166,876	1,913,450	4,306,523	3,944,571	575,793	1,501,570	1,539,980	456,141	692,678	198,190	30,603	12,654	2,549	- 280,055	94,046	35,054	95,610	265,480	69,075	152,853
Line Transformer NCP	LTNCP4	15,563,103	1,913,450	4,306,523	3,944,571	575,793	1,501,570	1,407,131	456,141	- 612,717	198,190	30,603	12,654	-	-	94,045.73	35,053.75	- 48,452.57	265,479.68	69,075.30	- 91,214.05
Secondary NCP	SNCP4	13,052,672	1,889,742	4,212,849	3,800,354	555,027	1,453,408		448,236		192,231	29,683	12,273			93,069	34,690		262,747	68,364	
12 NCP																					
Classification NCP from Load Data Provider	DNCP12	70,991,719	5,149,960	11,730,403	10,373,481	1,612,604	4,286,906	- 4,639,941	1,313,833	2,075,755	491,110	75,868	39,421	439 69,540	27,158,871	240,134	100,474	280,817	691,506	199,957	461,137
Primary NCP	PNCP12	42,222,948	4,933,367	11,144,268	9,744,015	1,515,342	4,041,026	4,373,177	1,253,052	1,976,910	463,676	71,630	37,219	6,708	- 787,609	229,567	96,053	268,336	655,020	189,407	436,567
Line Transformer NCP	LTNCP12	40,515,915	4,933,367	11,144,268	9,744,015	1,515,342	4,041,026	3,995,916	1,253,052	- 1,748,699	463,676	71,630	37,219	- 1,156	-	229,567	96,053	- 135,985	655,020	189,407	- 260,518
Secondary NCP	SNCP12	33,478,587	4,872,242	10,901,862	9,387,765	1,460,692	3,911,410		1,231,333		449,735	69,476	36,100			227,181	95,055		648,278	187,457	

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Sheet O1 Revenue to Cost Summary Worksheet -

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

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets			1	2	3	4	5	6	7	8	9
		Total	UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt
crev	Distribution Revenue at Existing Rates	$1,582,235,723	$100,704,642	$337,959,393	$550,079,444	$116,938,615	$160,478,744	$147,963,022	$23,147,088	$30,585,303	$14,136,825
mi	Miscellaneous Revenue (mi)	$55,882,454	$5,217,768	$14,118,714	$17,483,633	$3,321,143	$5,215,891	$2,943,302	$903,087	$662,277	$439,395
		Miscellaneous Revenue Input equals Output									
	Total Revenue at Existing Rates	**$1,638,118,177**	**$105,922,410**	**$352,078,108**	**$567,563,076**	**$120,259,758**	**$165,694,635**	**$150,906,324**	**$24,050,175**	**$31,247,580**	**$14,576,220**
	Factor required to recover deficiency (1 + D)	1.0267									
	Distribution Revenue at Status Quo Rates	$1,624,550,523	$103,397,854	$346,997,670	$564,790,590	$120,065,983	$164,770,536	$151,920,097	$23,766,126	$31,403,266	$14,514,896
	Miscellaneous Revenue (mi)	$55,882,454	$5,217,768	$14,118,714	$17,483,633	$3,321,143	$5,215,891	$2,943,302	$903,087	$662,277	$439,395
	Total Revenue at Status Quo Rates	**$1,680,432,976**	**$108,615,622**	**$361,116,384**	**$582,274,223**	**$123,387,127**	**$169,986,426**	**$154,863,399**	**$24,669,213**	**$32,065,543**	**$14,954,290**
	Expenses										
di	Distribution Costs (di)	$324,101,078	$15,053,892	$61,179,465	$130,488,781	$23,585,001	$32,074,426	$25,883,646	$3,918,267	$5,324,420	$3,696,759
cu	Customer Related Costs (cu)	$118,872,405	$17,820,370	$36,521,560	$30,135,148	$7,490,787	$11,660,183	$3,673,881	$2,401,599	$939,489	$850,466
ad	General and Administration (ad)	$167,217,070	$11,992,182	$36,042,300	$59,990,903	$11,546,361	$16,379,845	$12,021,026	$2,362,587	$2,586,455	$1,686,402
dep	Depreciation and Amortization (dep)	$446,076,294	$24,353,691	$82,956,649	$156,265,232	$29,303,793	$45,978,369	$51,993,454	$6,784,324	$11,062,036	$3,782,369
INPUT	PILs (INPUT)	$72,364,565	$3,470,748	$13,038,166	$26,443,719	$4,681,652	$7,550,888	$8,351,647	$1,061,988	$1,735,893	$669,358
INT	Interest	$224,695,067	$10,776,821	$40,484,063	$82,108,878	$14,536,729	$23,445,829	$25,932,222	$3,297,519	$5,390,021	$2,078,385
	Total Expenses	**$1,353,326,478**	**$83,467,704**	**$270,222,203**	**$485,432,662**	**$91,144,323**	**$137,089,540**	**$127,855,875**	**$19,826,285**	**$27,038,314**	**$12,763,738**
	Direct Allocation	**$11,174,701**	**$0**	**$0**	**$0**	**$0**	**$0**	**$2,413,988**	**$0**	**$736,552**	**$0**
NI	Allocated Net Income (NI)	$315,931,797	$15,152,716	$56,922,491	$115,448,931	$20,439,323	$32,965,934	$36,461,920	$4,636,466	$7,578,622	$2,922,307
	Revenue Requirement (includes NI)	$1,680,432,976	$98,620,419	$327,144,694	$600,881,593	$111,583,646	$170,055,474	$166,731,784	$24,462,751	$35,353,487	$15,686,045
		Revenue Requirement Input equals Output									
	Rate Base Calculation										
	Net Assets										
dp	Distribution Plant - Gross	$13,156,156,067	$655,190,527	$2,387,593,637	$4,723,483,078	$864,593,067	$1,321,080,445	$1,464,966,614	$187,237,154	$306,051,482	$115,855,816
gp	General Plant - Gross	$1,496,735,388	$71,364,188	$268,037,410	$542,607,441	$97,244,658	$153,132,864	$170,463,787	$21,507,069	$35,453,862	$13,667,007
accum dep	Accumulated Depreciation	($5,174,483,179)	($276,451,157)	($965,082,956)	($1,843,792,212)	($348,502,550)	($508,383,683)	($560,292,307)	($73,096,236)	($117,893,056)	($43,323,168)
co	Capital Contribution	($896,478,209)	($44,023,442)	($165,093,747)	($328,845,344)	($65,155,016)	($83,286,264)	($98,531,984)	($11,536,426)	($20,614,517)	($7,925,678)
	Total Net Plant	**$8,581,930,067**	**$406,080,117**	**$1,525,454,345**	**$3,093,452,963**	**$548,180,159**	**$882,543,361**	**$976,606,109**	**$124,111,562**	**$202,997,770**	**$78,273,977**
	Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	$4,279,279,726	$373,935,334	$895,696,737	$797,465,237	$109,096,386	$363,509,620	$414,719,835	$106,124,886	$188,080,061	$23,932,584
	OM&A Expenses	$610,190,552	$44,866,444	$133,743,326	$220,614,833	$42,622,149	$60,114,454	$41,578,552	$8,682,454	$8,850,365	$6,233,626
	Directly Allocated Expenses	$11,174,701	$0	$0	$0	$0	$0	$2,413,988	$0	$736,552	$0
	Subtotal	**$4,900,644,979**	**$418,801,778**	**$1,029,440,062**	**$1,018,080,070**	**$151,718,536**	**$423,624,074**	**$458,712,375**	**$114,807,340**	**$197,666,977**	**$30,166,210**
	Working Capital	**$384,364,096**	**$32,847,180**	**$80,740,352**	**$79,849,372**	**$11,899,486**	**$33,225,399**	**$35,977,421**	**$9,004,492**	**$15,503,284**	**$2,365,976**
	Total Rate Base	**$8,966,294,163**	**$438,927,296**	**$1,606,194,696**	**$3,173,302,335**	**$560,079,645**	**$915,768,760**	**$1,012,583,530**	**$133,116,054**	**$218,501,054**	**$80,639,952**
		Rate Base Input Does Not Equal Output									
	Equity Component of Rate Base	**$3,586,517,665**	**$175,570,919**	**$642,477,878**	**$1,269,320,934**	**$224,031,858**	**$366,307,504**	**$405,033,412**	**$53,246,422**	**$87,400,421**	**$32,255,981**
	Net Income on Allocated Assets	**$315,931,797**	**$25,147,918**	**$90,894,181**	**$96,841,561**	**$32,242,804**	**$32,896,887**	**$24,593,535**	**$4,842,928**	**$4,290,678**	**$2,190,552**
	Net Income on Direct Allocation Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	Net Income	**$315,931,797**	**$25,147,918**	**$90,894,181**	**$96,841,561**	**$32,242,804**	**$32,896,887**	**$24,593,535**	**$4,842,928**	**$4,290,678**	**$2,190,552**
	RATIOS ANALYSIS										
	REVENUE TO EXPENSES STATUS QUO%	100.00%	**1.10**	**1.10**	**0.97**	**1.11**	**1.00**	**0.93**	**1.01**	**0.91**	**0.95**
	EXISTING REVENUE MINUS ALLOCATED COSTS	($42,314,799)	$7,301,990	$24,933,414	($33,318,516)	$8,676,112	($4,360,839)	($15,825,460)	($412,576)	($4,105,907)	($1,109,825)
		Deficiency Input equals Output									
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	$9,995,203	$33,971,690	($18,607,370)	$11,803,481	($69,048)	($11,868,385)	$206,462	($3,287,944)	($731,755)
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.81%	14.32%	14.15%	7.63%	14.39%	8.98%	6.07%	9.10%	4.91%	6.79%

Rate Base Assets		10	11	12	13	14	15	16	17	18	19
		Sen Lgt	USL	DGen	ST	AUR	AUGe	AUGd	AR	AGSe	AGSd
crev	Distribution Revenue at Existing Rates	$3,805,212	$3,395,663	$5,712,491	$55,937,606	$5,508,610	$1,032,227	$1,383,942	$16,399,355	$3,747,248	$3,320,293
mi	Miscellaneous Revenue (mi)	$2,458,770	$133,838	$198,832	$1,350,618	$279,947	$49,187	$60,633	$777,117	$157,976	$110,324
	Total Revenue at Existing Rates	**$6,263,983**	**$3,529,501**	**$5,911,323**	**$57,288,224**	**$5,788,557**	**$1,081,414**	**$1,444,576**	**$17,176,472**	**$3,905,224**	**$3,430,617**
	Distribution Revenue at Status Quo Rates	$3,906,978	$3,486,476	$5,865,264	$57,433,583	$5,655,931	$1,059,832	$1,420,954	$16,837,934	$3,847,464	$3,409,090
	Miscellaneous Revenue (mi)	$2,458,770	$133,838	$198,832	$1,350,618	$279,947	$49,187	$60,633	$777,117	$157,976	$110,324
	Total Revenue at Status Quo Rates	**$6,365,748**	**$3,620,313**	**$6,064,096**	**$58,784,202**	**$5,935,878**	**$1,109,019**	**$1,481,587**	**$17,615,051**	**$4,005,439**	**$3,519,414**
di	Distribution Costs (di)	$1,309,943	$692,729	$169,805	$11,894,518	$1,316,074	$330,536	$585,750	$4,405,843	$988,669	$1,202,552
cu	Customer Related Costs (cu)	$312,972	$479,549	$781,380	$1,483,830	$990,150	$155,982	$49,672	$2,529,476	$486,762	$109,147
ad	General and Administration (ad)	$599,487	$427,084	$1,044,693	$5,557,477	$840,398	$180,662	$328,352	$2,547,391	$547,559	$535,906
dep	Depreciation and Amortization (dep)	$1,651,600	$655,953	$1,011,681	$17,421,359	$1,721,831	$601,020	$1,053,300	$5,789,180	$1,532,039	$2,158,415
INPUT	PILs (INPUT)	$221,893	$120,162	$78,585	$3,154,947	$237,506	$73,411	$119,395	$849,903	$220,669	$284,035
INT	Interest	$688,987	$373,107	$244,008	$9,796,244	$737,467	$227,945	$370,728	$2,638,985	$685,187	$881,941
	Total Expenses	**$4,784,882**	**$2,748,585**	**$3,330,152**	**$49,308,375**	**$5,843,428**	**$1,569,557**	**$2,507,198**	**$18,760,777**	**$4,460,885**	**$5,171,995**
	Direct Allocation	**$898,092**	**$0**	**$3,735,618**	**$2,748,938**	**$0**	**$0**	**$456,187**	**$0**	**$0**	**$185,326**
NI	Allocated Net Income (NI)	$968,748	$524,606	$343,087	$13,773,979	$1,036,914	$320,501	$521,261	$3,710,536	$963,405	$1,240,050
	Revenue Requirement (includes NI)	$6,651,722	$3,273,192	$7,408,857	$65,831,291	$6,880,341	$1,890,058	$3,484,646	$22,471,314	$5,424,290	$6,597,372
dp	Distribution Plant - Gross	$38,447,389	$20,778,044	$17,930,046	$502,301,942	$79,757,736	$28,645,613	$60,356,495	$226,150,961	$53,822,926	$101,913,096
gp	General Plant - Gross	$19,704,501	$2,465,373	$1,756,721	$62,788,227	$4,881,942	$1,488,821	$2,428,091	$17,498,294	$4,465,578	$5,779,553
accum dep	Accumulated Depreciation	($23,667,314)	($7,693,979)	($8,606,890)	($196,840,735)	($29,107,127)	($10,098,788)	($20,504,091)	($85,477,009)	($20,166,143)	($35,503,778)
co	Capital Contribution	($3,292,273)	($1,492,729)	($1,824,699)	($27,780,291)	($5,567,618)	($1,788,214)	($3,901,869)	($15,919,363)	($3,265,831)	($6,632,903)
	Total Net Plant	**$31,192,303**	**$14,056,710**	**$9,255,178**	**$340,469,142**	**$49,964,933**	**$18,247,432**	**$38,378,625**	**$142,252,884**	**$34,856,530**	**$65,555,968**
	Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	$3,711,437	$4,719,497	$3,663,290	$831,554,126	$16,721,261	$7,798,829	$25,634,178	$51,754,337	$18,650,748	$42,511,345
	OM&A Expenses	$2,222,402	$1,599,363	$1,995,878	$18,935,825	$3,146,623	$667,181	$963,775	$9,482,709	$2,022,991	$1,847,604
	Directly Allocated Expenses	$898,092	$0	$3,735,618	$2,748,938	$0	$0	$456,187	$0	$0	$185,326
	Subtotal	**$6,831,931**	**$6,318,860**	**$9,394,786**	**$853,238,888**	**$19,867,884**	**$8,466,009**	**$27,054,139**	**$61,237,046**	**$20,673,738**	**$44,544,276**
	Working Capital	**$535,837**	**$495,597**	**$736,846**	**$66,920,659**	**$1,558,265**	**$664,000**	**$2,121,892**	**$4,802,903**	**$1,621,469**	**$3,493,667**
	Total Rate Base	**$31,728,140**	**$14,552,306**	**$9,992,023**	**$407,389,802**	**$51,523,198**	**$18,911,433**	**$40,500,517**	**$147,055,786**	**$36,477,999**	**$69,049,635**
	Equity Component of Rate Base	**$12,691,256**	**$5,820,922**	**$3,996,809**	**$162,955,921**	**$20,609,279**	**$7,564,573**	**$16,200,207**	**$58,822,315**	**$14,591,200**	**$27,619,854**
	Net Income on Allocated Assets	**$682,774**	**$871,728**	**($1,001,674)**	**$6,726,889**	**$92,450**	**($460,537)**	**($1,481,798)**	**($1,145,726)**	**($455,446)**	**($1,837,907)**
	Net Income on Direct Allocation Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	Net Income	**$682,774**	**$871,728**	**($1,001,674)**	**$6,726,889**	**$92,450**	**($460,537)**	**($1,481,798)**	**($1,145,726)**	**($455,446)**	**($1,837,907)**
	REVENUE TO EXPENSES STATUS QUO%	**0.96**	**1.11**	**0.82**	**0.89**	0.86	0.59	0.43	0.78	0.74	0.53
	EXISTING REVENUE MINUS ALLOCATED COSTS	($387,740)	$256,309	($1,497,534)	($8,543,067)	($1,091,784)	($808,644)	($2,040,070)	($5,294,842)	($1,519,066)	($3,166,754)
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($285,974)	$347,122	($1,344,761)	($7,047,090)	($944,463)	($781,039)	($2,003,058)	($4,856,263)	($1,418,851)	($3,077,957)
	RETURN ON EQUITY COMPONENT OF RATE BASE	5.38%	14.98%	-25.06%	4.13%	0.45%	-6.09%	-9.15%	-1.95%	-3.12%	-6.65%

2021 Cost Allocation Model

EB-2017-0049

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Output sheet showing minimum and maximum level for Monthly Fixed Charge

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Summary	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**UGe**	**UGd**	**St Lgt**	**Sen Lgt**	**USL**	**DGen**	**ST**	**AUR**	**AUGe**	**AUGd**	**AR**	**AGSe**	**AGSd**
Customer Unit Cost per month - Avoided Cost	$7.52	$7.29	$7.85	$6.87	$12.68	$72.37	$12.23	$72.34	$3.05	$2.06	$6.10	$95.78	$326.64	$6.83	$17.50	$46.85	$7.47	$15.64	$44.38
Customer Unit Cost per month - Directly Related	$9.60	$9.40	$10.24	$8.63	$16.27	$88.59	$15.68	$88.00	$4.21	$2.87	$8.35	$141.84	$400.48	$8.68	$21.18	$57.70	$9.46	$19.24	$53.09
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$20.26	$27.87	$52.38	$55.11	$20.60	$89.36	$10.20	$93.74	$22.68	$22.04	$40.90	$177.06	$444.38	$22.29	$11.32	$52.59	$26.32	$24.81	$48.73
Existing Approved Fixed Charge	$35.85	$47.06	$107.71	$50.05	$30.88	$106.19	$25.10	$105.02	$4.33	$3.57	$36.66	$196.16	$1,073.56	$29.98	$25.19	$139.96	$36.18	$37.64	$160.10

2018 COST ALLOCATION MODEL

This exhibit has been filed separately in MS Excel.

2021 COST ALLOCATION MODEL

This exhibit has been filed separately in MS Excel.