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APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

Direct Testimony and Exhibits

of

JEFFRY POLLOCK

On Behalf of

Freeport-McMoRan, Inc.

October 22, 2021

J. POLLOCK
INCORPORATED

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GLOSSARY OF ACRONYMS

Term	Definition
1CP	Annual System Coincident Peak
4CP	Four Coincident Peak
12CP	Twelve Coincident Peak
AD	Average Demand
AED	Average and Excess
ASLF	Annual System Load Factor
CCOSS	Class Cost-of-Service Study
ED	Excess Demand
EPE	El Paso Electric Company
ETI	Entergy Texas, Inc.
FMI	Freeport-McMoRan, Inc.
NARUC CAM	National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual
O&M	Operation and Maintenance
SPS	Southwestern Public Service Company
SWEPCO	Southwestern Electric Power Company
TIEC	Texas Industrial Energy Consumers

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AFFIDAVIT OF JEFFRY POLLOCK

State of Missouri)
) **SS**
County of St. Louis)

Jeffry Pollock, being first duly sworn, on his oath states:

1. My name is Jeffry Pollock. I am President of J. Pollock, Incorporated, 12647 Olive Blvd., Suite 585, St. Louis, Missouri 63141. We have been retained by Freeport-McMoRan, Inc. to testify in this proceeding on its behalf;

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony, Exhibits and Appendices A, B and C, which have been prepared in written form for introduction into evidence in SOAH Docket No. 473-21-2606 and Public Utility Commission of Texas Docket No. 52195; and,

3. I hereby swear and affirm that my answers contained in the testimony are true and correct.

Jeffry Pollock
Digitally signed by: Jeffry Pollock
DN: CN = Jeffry Pollock email = jcp@jpollockinc.com C = AD O = J. Pollock, Inc.
Date: 2021.10.22 10:22:11 -05'00'

Jeffry Pollock

Subscribed and sworn to before me this 22nd day of October 2021.

KITTY TURNER
Notary Public - Notary Seal
State of Missouri
Commissioned for Lincoln County
My Commission Expires: April 25, 2023
Commission Number: 15390610

Kitty Turner, Notary Public
Commission #: 15390610

My Commission expires on April 25, 2023.

Direct Testimony of Jeffry Pollock

1. INTRODUCTION, QUALIFICATIONS AND SUMMARY

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock; 12647 Olive Blvd., Suite 585, St. Louis, MO 63141.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and President of J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Arts degree in electrical engineering and a Master's in Business Administration from Washington University. Since graduation, I have been engaged in a variety of consulting assignments, including energy procurement and regulatory matters in both the United States and several Canadian provinces. I have participated in numerous regulatory proceedings before the Public Utility Commission of Texas, including rate cases and rulemaking cases. My qualifications are documented in **Appendix A**. A list of my appearances is provided in **Appendix B** to this testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of Freeport-McMoRan, Inc. (FMI). FMI purchases electricity from El Paso Electric Company (EPE) under Rates 15 and 38.

Q WHAT ISSUES ARE YOU ADDRESSING?

A I address:

- EPE's Class Cost-of-Service Study (CCOSS);
- Class revenue allocation; and
- The design of Rate 15.

Q ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A Yes. I am sponsoring **Exhibit JP-1** through **JP-9**.

Q THROUGHOUT YOUR TESTIMONY, YOU REFERENCE EPE'S CLAIMED REVENUE REQUIREMENT. DOES THIS CONSTITUTE AN ENDORSEMENT OF EPE'S PROPOSED BASE RATE INCREASE?

A No.

<u>Summary</u>

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A My findings and recommendations are as follows:

<u>Class Cost-of-Service Study</u>

- EPE has proposed substantial changes in the methodologies used to classify and allocate costs in its CCOSS. Most of these changes would shift costs from lower load factor to higher load factor rate classes.

- One such change is that EPE has misapplied the Average and Excess Four Coincident Peak (AED-4CP) method because the load-factor weighting was based on the average *adjusted* load factor during the *four* summer month system peaks rather than the *actual* Annual (*i.e.,* 1CP) System Load Factor (ASLF).

- The Commission has previously determined that the load-factor weighting should be based on the actual (unadjusted) ASLF.

- EPE's Loss Study is flawed because, for deliveries at the substation and transmission voltages, the energy loss factor is higher than the (peak) demand loss factor. This result defies the laws of physics because losses are a function of power demand; that is, losses are highest during the system peak hour. Standard industry practice is that energy losses are lower than demand loss factors.

- In reality, EPE's Loss Study merely *estimates* the energy losses in each hour by extrapolating the peak losses for each of eight one-hour power flows. However, there are many more hours between the four Winter power flows than between the Summer power flows. As a result of this process, undue weight is given to the losses in the Winter power flows.

- EPE should be ordered to prepare an updated loss study that actually measures energy losses over an annual period.
- For this case, the energy loss factors for the substation and transmission levels should be set at 90% of the corresponding substation and transmission demand loss factors. The 90% is consistent with the relationship between the energy and demand loss factors applicable to the primary and secondary levels.
- EPE is proposing to allocate load dispatching expense to retail customer classes using the twelve coincident peak (12CP) method, despite the fact that EPE uses the 4CP method to allocate the corresponding production and transmission capital and related costs. This is contrary to how other (ERCOT and non-ERCOT) utilities allocate their load dispatching expense.
- EPE asserts that load dispatching is a year-round activity. The reality is that load dispatching reflects EPE's management of its production and transmission assets. Accordingly, this expense should be allocated in the same manner as the corresponding production and transmission assets.
- The Commission should reject EPE's proposed 12CP allocation. However, if the Commission accepts EPE's rationale (*i.e.,* that load dispatching expense is a year-round activity), it should require that these expenses be allocated using the AED-4CP method because AED-4CP allocates costs, in part, based on average demand, which occurs year-round.
- There is no requirement or necessity for including fuel factor revenues and eligible fuel expenses in a CCOSS.
- EPE is proposing to allocate other production plant, which consists of peaking units, using the 4CP method. This is a change from prior CCOSSs, and it is also contrary to past Commission practice.
- EPE operates its generation fleet on an integrated basis. Further, the AED-4CP method already recognizes that EPE serves load from a mix of different types of generating units. Accordingly, the same method – AED-4CP – should be used to allocate all production plant.

- Another major change is in how EPE is classifying certain production operation and maintenance (O&M) expenses. Specifically, EPE is proposing to reclassify the expenses in FERC Account Nos. 512, 513 and 514 from a demand/energy split to all energy. Further, accounts that were previously classified entirely to demand (FERC Account Nos. 519, 520 and 523) would be classified entirely to energy.

- EPE asserts that the proposed reclassifications are consistent with the guidance provided in the January 1992 Electric Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners (NARUC CAM). However, the NARUC manual contains several recommendations, and EPE has failed to demonstrate why several of the above-listed accounts should be classified entirely to energy.

- For example, the NARUC recommends that labor-related expenses should be classified to demand. Accordingly, the labor-related expenses in FERC Account Nos. 502 and 505 should be classified to demand. All of the expenses in FERC Account Nos. 519, 520, and 523 should be classified to demand, consistent with EPE's past proposals.

<u>Class Revenue Allocation</u>

- EPE is not proposing to move all rates to cost; that is, each rate class would not achieve the same rate of return. EPE's rate moderation proposal is contrary to long-standing Commission practice, which sets all rates to produce the same rate of return unless it would violate the principle of gradualism.

- EPE cites the COVID-19 pandemic for targeting certain classes for more favorable treatment; that is, the targeted classes (*i.e.,* Residential, Off Peak Water Heating, Small General Service, General Service, and City/County rate groups) would receive below-system average base rate increases, and their rates would be set below their allocated costs. The non-targeted classes (including Rate 15) would be forced to subsidize the below-cost rates proposed for the targeted classes.

- EPE asserts that its rate moderation proposal is necessary due to shifting usage patterns. However, EPE has provided no evidence that shifting usage patterns has altered or compromised the results of its CCOSS.

- In fact, despite the pandemic, EPE experienced a 2% increase in energy sales and a 7% increase in base revenues. For the most part, those rate classes that experienced increases in energy usage also provided additional base revenues, and vice versa. Thus, the shifting usage patterns cited by EPE during the test year will have no discernable impact on the CCOSS results. Accordingly, this is not a legitimate reason for moderating the proposed base rate increases.

- Gradualism should be applied to the Off Peak Water Heating rate class. Consistent with recent pronouncements, this class should not receive a base rate increase exceeding 43%.

Rate 15 Design

- Although EPE is not proposing any major structural changes, it is proposing to realign specific charges in Rate 15. For example, the Monthly Customer charge would be substantially reduced, the On-Peak Energy charge would decrease, and the Non-Summer Demand charge would be increased by approximately 23% more than the Summer Demand charge.

- With the exception of the Monthly Customer charge, the proposed realignments would not send the proper price signals.

  - First, EPE is a summer peaking utility.

  - Second, the On-Peak Energy charge applies during on-peak hours, which occur during the summer months, June through September, between the hours of 12 noon and 6 p.m.

  - Third, EPE is projecting tighter reserve margins due to planned generation retirements and significant year-over-year growth in customer load.

- Accordingly, to ensure that Rate 15 provides the proper price signals, the current On-Peak Energy charge should be retained and the Summer Demand charge should be increased by approximately 20% more than the increase in the Non-Summer Demand charge.

- The minimum contract demand should be reduced from 7,500 kW to 5,000 kW to provide an incentive for FMI to expand its on-site generation, thereby providing needed additional capacity to EPE.

2. CLASS COST-OF-SERVICE STUDY

Background

Q WHAT IS A CLASS COST-OF-SERVICE STUDY (CCOSS)?

A A CCOSS is an analysis used to determine each class's responsibility for the utility's costs. Thus, it determines whether the revenues a class generates cover the class's cost of service. A CCOSS separates the utility's total costs into portions incurred by the various customer groups. Most of a utility's costs are incurred to jointly serve many customers. For rate design and revenue allocation purposes, customers are grouped into homogeneous classes according to their usage patterns and service characteristics. A more in-depth discussion of the procedures and key principles underlying CCOSSs is provided in **Appendix C**.

Q HAS EPE FILED A CLASS COST-OF-SERVICE STUDY IN THIS PROCEEDING?

A Yes.

Q HAVE THE METHODOLOGIES USED BY EPE IN ITS CLASS COST-OF-SERVICE STUDY CHANGED IN RECENT TIMES?

A Yes. Over the past several rate cases, EPE has made significant changes in the cost classification and allocation methodologies used in its CCOSS; this case is no exception. EPE's proposed changes are summarized in Table 1. For the most part, these proposed changes would shift costs from lower load factor to higher load factor rate classes.

Table 1 EPE's Proposed Changes to its CCOSS Methodology			
FERC Account	**Description**	**Past Cases**	**Proposed**
Various	Peaking Generation	AED-4CP	4CP
506	Misc. Steam Power Expense	AED-4CP/Energy	AED-4CP
510	Steam Maint. Supervision	AED-4CP	Labor
512	Steam Maint. Boiler Plant	AED-4CP/Energy	Energy
513	Steam Maint. Electric Plant	AED-4CP/Energy	Energy
514	Steam Maint. Misc. Steam Plant	AED-4CP/Energy	Energy
519	Nuclear - Coolants and Water	AED-4CP	Energy
520	Nuclear - Steam Expenses	AED-4CP	Energy
523	Nuclear - Electric Expenses	AED-4CP	Energy
546 - 555	Other Pwr. Gen Expense	AED-4CP	4CP
551	Other Pwr. Gen. Maint. Supervision	AED-4CP	4CP
552	Other Pwr. Gen. Maint. Structures	AED-4CP	4CP
553	Other Pwr. Gen. Maint. Gen. & Elec.	AED-4CP	4CP
554	Other Pwr. Gen. Misc. Other Power	AED-4CP	4CP
556	System Control & Load Dispatch	AED-4CP	12CP
561	Load Dispatching	4CP	12CP

Not evident in Table 1 is that EPE is proposing to change how it applies the AED-4CP method. This and the other proposed changes are discussed below.

Application of the AED-4CP Method

Q WHAT IS THE AED-4CP METHOD?

A AED-4CP is a variation of the Average and Excess method. Average and Excess is one of several methodologies recognized in the NARUC CAM that explicitly considers energy usage in developing allocation factors. The AED allocation factors are derived as follows:

$$AED = (AD\% \times ASLF\%) + [ED\% \times (1\text{-}ASLF\%)]$$

Where:

AD% = A class's share of Average Demand (or energy usage);

ED% = A class's share of Excess Demand, which is the difference between a class's Peak Demand and its Average Demand; and

ASLF% = Annual System Load Factor.[1]

Thus, the ASLF determines the weighting between Average Demand and Excess Demand.

Q WHAT IS AVERAGE DEMAND (AD)?

A The AD component of the AED allocation factors is the product of each class's percent of average demand (*i.e.,* energy consumption) and the ASLF%. This measures the amount of capacity costs that would be incurred if the utility served the same size load at a constant 100% load factor.[2]

Q WHAT IS EXCESS DEMAND (ED)?

A The ED component of AED measures the relative variability of each class's load. The greater a class's load variability, the greater the amount of load-following resources (*e.g.,* simple-cycle and combined-cycle gas turbines) needed to provide service.

Under AED-4CP, ED is the higher of (1) the difference between a class's 4CP demand and its corresponding AD, or (2) zero. Thus, a class operating at a 100% load factor, or a class that is entirely off-peak, such as lighting, would have little or no ED. Thus, ED recognizes two important cost drivers:

[1] NARUC CAM at 49-50.

[2] *Id.*

- Off-peak loads do not contribute to a utility's capacity needs to the same degree as comparable on-peak loads.
- Very high load factor loads are relatively flat, and for this reason they have much less variability than do low load factor loads.

Q HOW IS ANNUAL SYSTEM LOAD FACTOR DEFINED?

A ASLF is defined as the ratio of the average load over a designated period to the peak demand occurring in that period.[3]

Q HAS THE AED-4CP METHOD BEEN USED IN PRIOR RATE CASES BEFORE THIS COMMISSION?

A Yes. AED-4CP has been widely used and accepted by the Commission in most electric investor-owned utility rate cases since the early 1990s. All of the major non-ERCOT utilities — including Southwestern Public Service Company (SPS), Southwestern Electric Power Company (SWEPCO) and Entergy Texas, Inc. (ETI) — use AED-4CP to allocate production plant-related costs.

Q HOW IS EPE PROPOSING TO APPLY THE AED-4CP METHOD?

A Despite recognizing past Commission precedent, EPE is proposing to use 4CP, not 1CP, to measure ALSF.[4] As discussed later, this is not a proper definition of ALSF.

Q HAS THE COMMISSION DETERMINED THE PROPER LOAD FACTOR IN APPLYING AED-4CP?

A Yes. In a prior SWEPCO rate case, the Commission adopted Texas Industrial Energy Consumers' (TIEC's) recommendation to use a system-wide, rather than Texas retail, load factor. In adopting TIEC's proposal the Commission stated:

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[3] *Id.* at 81.

[4] Direct Testimony of George Novela at 7-9.

> 283. Because SWEPCO's generation is built to meet system needs based on analysis of the system loads, it is reasonable to allocate costs using the system load factor. ***The appropriate load factor for use in the AED-4CP methodology is the system load factor***.[5] (emphasis added)

Q DID THE COMMISSION AFFIRM AND FURTHER CLARIFY THIS PRECEDENT IN SUBSEQUENT RATE CASES?

A Yes. The ASLF metric was contested in a subsequent SPS rate case (Docket No. 43695). The Commission determined that the Annual System (*i.e.,* 1CP) Load Factor should be used in conjunction with applying AED-4CP.[6]

The issue was also litigated in a more recent SWEPCO rate case (Docket No. 46449) and the Commission cited the aforementioned SPS case in its Order requiring SWEPCO to use the annual coincident peak in deriving the ASLF. Specifically, the Commission found:

> 278. In SPS Docket No. 43695, the only Commission docket in which this issue has been litigated, the Commission determined that the system load factor should be calculated by ***using the single annual coincident peak***, rather than the average of four coincident peaks.
>
> 279. ***SWEPCO used the single coincident peak in calculating its system load factor for Schedule O-1.6***.
>
> 280. ***The use of the annual coincident peak in calculating system load factor is consistent with the definition of load factor in the Commission's rules***.
>
> 281. The use of the annual coincident peak for calculating system load factor is consistent with SWEPCO's generation and transmission planning.

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[5] *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 40443, Order at 43. (Oct. 13, 2013)

[6] *Application of Southwestern Public Service Company for Authority to Change Rates*, Docket No. 43695, Order at Finding of Fact Nos. 246A – 251A (Dec. 18, 2015). *See also*, *Order on Rehearing* Finding of Fact Nos. 246A-251A (Feb. 23, 2016).

> 282. ***The use of the annual coincident peak for calculating system load factor is consistent with the National Association of Regulatory Commissioners (NARUC) manual***.
>
> 283. The use of the annual coincident peak for calculating system load factor is consistent with SPP planning.
>
> 284. In using the A&E-4CP methodology, ***SWEPCO should calculate its system load factor using the single annual coincident peak***.[7] (emphasis added)

Q WHY IS IT APPROPRIATE TO USE THE ASLF TO WEIGHT AVERAGE AND EXCESS DEMAND?

A ASLF is defined as the ratio of the average load over a designated period to the peak demand occurring in that period.[8] AD is measured over a year. Thus, it follows that the ASLF should also be measured using the annual system coincident peak (*i.e.,* 1CP). Further, the NARUC CAM explicitly states that in applying the AED method the ASLF should be derived from the utility's annual system peak (*i.e.,* 1CP).[9]

Q WHY ELSE SHOULD THE ASLF BE USED IN APPLYING THE AED-4CP METHOD?

A The 1CP load factor is clearly consistent with the fact that EPE's planning reserve margin is based on the amount of available capacity and load coincident occurring with the annual system peak. Specifically, EPE has adopted a 15% planning reserve

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[7] *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 46449, Order at 45 (Jan. 11, 2018). See also, *Order on Rehearing* at 45-46 (Mar. 19, 2018).

[8] NARUC CAM at 81.

[9] *Id.* at 82.

margin in determining the adequacy of its generating resources. The 15% margin is applied to EPE's projected annual (1CP) system peak demands.[10]

Q SHOULD THE 4CP LOAD FACTORS PROPOSED BY EPE BE ADOPTED?

A No. EPE's application of AED-4CP is not consistent with accepted practice, system planning and the decisions in prior SWEPCO and SPS rate cases.

Q WHAT DO YOU RECOMMEND?

A The Commission should approve the actual (unadjusted) system 1CP load factor in applying the AED-4CP method.

Q HAVE YOU CALCULATED EPE'S UNADJUSTED 1CP SYSTEM LOAD FACTOR?

A Yes. **Exhibit JP-1** is a calculation of EPE's unadjusted 1CP ASLF. This calculation is based on the information provided in Schedule O-1.6. As can be seen, EPE's unadjusted 1CP System Load Factor is 45.44% (line 1).

Q HAVE YOU DEVELOPED REVISED AED-4CP DEMAND ALLOCATION FACTORS USING THE ACTUAL 1CP SYSTEM LOAD FACTOR?

A Yes. **Exhibit JP-2** shows the derivation of revised AED-4CP demand allocation factors using the actual 1CP ASLF to weight the AD portion of the method. As previously explained, this is consistent with the proper application of AED-4CP.

[10] NMPRC Case No. 18-00293-UT, *In the Matter of El Paso Electric Company's 2018 Integrated Resource Plan for New Mexico,* Amended 2018 Integrated Resource Plan at 24 (Jan. 3, 2019).

Loss Study

Q WHAT IS A LOSS STUDY?

A. A loss study determines the fixed and variable losses that occur when an electric utility generates and delivers electricity to retail customers. As explained in **Appendix C**, not all customers take service at the same delivery voltage. A utility incurs more losses to serve customers at lower delivery voltages. Thus, in order to allocate costs equitably to the various classes of service on an electric power system, all of the customer sales volumes, both peak (demand) and annual energy measured at the meter, must be adjusted to one common voltage level; normally the generation level. In that way, customers that take power and energy at various voltage levels are only responsible for the losses that they cause the system to incur. For example, if demand and energy allocation factors of all classes of service are adjusted to a common level, customers that take power at the transmission levels are not allocated costs associated with losses that are incurred on the primary or secondary distribution levels. The output of a loss study consists of the peak (demand) and energy loss factors.

Q HAVE YOU REVIEWED THE LOSS STUDY USED BY EPE IN ITS CLASS COST-OF-SERVICE STUDY?

A Yes. A summary of EPE's Loss Study is provided in Table 2 below.

Table 2
Summary of EPE's Loss Study Results

Voltage	Energy Loss Factor	Demand Loss Factor
Secondary	7.850%	8.212%
Primary	5.123%	6.265%
Substation	3.467%	3.158%
Transmission 69 kV	2.916%	2.790%
Transmission 115 kV	2.669%	2.412%

The Loss Study was provided in Schedule O-6.3. A working version of the study was provided in discovery.[11]

Q DO YOU HAVE ANY CONCERNS WITH THE LOSS STUDY?

A Yes. There appears to be a fundamental problem with the loss factors used by EPE in its CCOSS. Losses are a function of electrical current, and current is highest during peak periods. Accordingly, the peak demand losses *should* be higher than energy losses. Despite the physics behind the variable losses incurred by electric utilities, the energy loss factors used by EPE in this proceeding (which measure the average losses incurred over all 8,760 hours) are higher than the corresponding peak demand loss factors at the substation and transmission levels.

For example, referring to Table 2, the demand loss percentage for transmission and substation level classes are 2.412%, 2.790%, and 3.158% for 115 kV, 69 kV, and substation levels, respectively. The corresponding annual energy loss factors are higher: 2.669%, 2.916%, and 3.467%, respectively. In other words, the losses incurred on the system during the summer peak period are less than losses incurred over the annual period, which includes times of high and low stress on the power grid.

Q ARE THE ENERGY LOSSES HIGHER THAN THE DEMAND LOSSES FOR DISTRIBUTION-LEVEL LOADS?

A No. For example, the corresponding demand and energy loss factors at primary voltage are 6.265% and 5.123%. The latter is 82% of the former. Similarly, for secondary voltage, the demand and energy loss factors are 8.212% and 7.85% (or 96% of the demand loss factor), respectively. Thus, EPE's Loss Study concludes that

[11] EPE Response to FMI 1-1 (Confidential).

the distribution system losses incurred at the time of the system peak are more (not less) than the annual energy losses. This is more consistent with the expected result and makes EPE's anomalous analysis with regard to transmission loss factors appear all the more puzzling.

Q HOW ARE LOSSES CALCULATED?

A The large majority of the demand and energy losses on a power system are the result of the square of the current (I) passing through electrical devices and the resistance (R) in those devices, or I^2R. The Loss Study states:

> Electrical losses result from the transmission of energy over various electrical equipment. The largest component of total losses during peaking conditions is power dissipation as a result of varying loading conditions and are oftentimes called load losses which are mostly related to the square of the current (I^2R). These peak hour losses can be as high as 65% to 80% of all technical losses during peak loading conditions. The remaining losses are called no-load and represent essentially fixed (constant) energy losses throughout the year. These no-load losses represent energy required to energize various electrical equipment regardless of their loading levels over the entire year. The major portion of these no-load losses consist of core or magnetizing energy related to installed transformers throughout the power system and generates the major component of annual losses on any distribution system.[12]

Q DOES IT MAKE SENSE TO HAVE LOWER PEAK (DEMAND) LOSS FACTORS THAN THE CORRESPONDING ENERGY LOSS FACTORS?

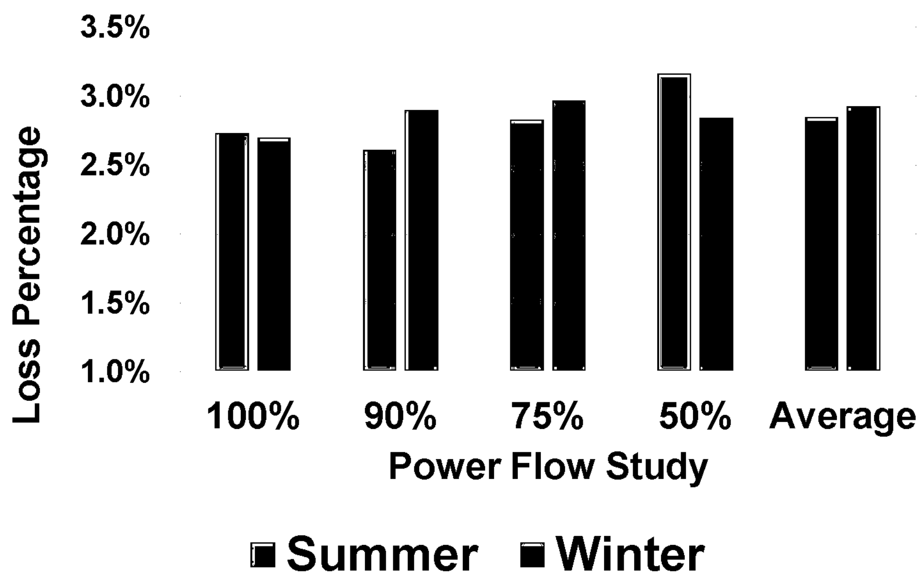
A No. At the time of peak demand on the power grid, the overall current passing through the system is at its highest level during the year. Since power loss varies exponentially with the current, the percentage loss at the time of the highest demand on the system should be significantly greater than the average energy percentage loss experienced throughout the year.

[12] EPE Rate Filing Package, Schedule O-6.3 at 11.

Q IS THERE A REASON WHY EPE'S LOSS STUDY RESULTED IN THE ENERGY LOSS FACTORS BEING HIGHER THAN THE DEMAND LOSS FACTORS FOR THE TRANSMISSION AND SUBSTATION LEVELS?

A Yes. The transmission energy loss factors were developed from eight separate one-hour power flows – four based on summer conditions (*i.e.,* June-September) and four based on winter conditions (*i.e.,* October through May). Each power flow is based on a percentage of the summer and winter peak demand: 100%, 90%, 75%, and 50%. The resulting losses for each power flow are summarized in Figure 1 below.

Figure 1
Losses By Power Flow Study



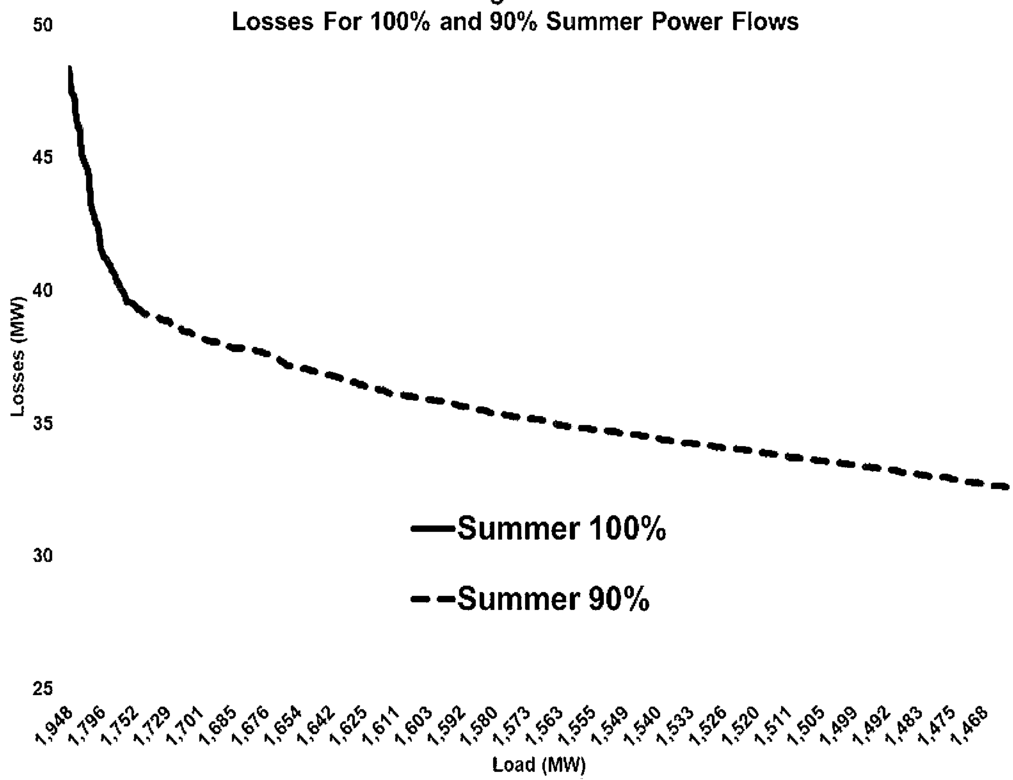
Applying the laws of physics, the highest losses should occur during the peak period (*i.e.*, at 100%), and the losses should decline with load. However, as demonstrated in Figure 1, the highest summer losses occurred when the load was only 50% of the summer peak, while the highest winter losses occurred when the load was 75% of the winter peak.

Q HOW WERE THE DEMAND AND ENERGY LOSS FACTORS SHOWN IN TABLE 2 DERIVED?

A The demand loss factors reflect the peak losses derived in each of the eight power flows. The energy losses were derived by summing the *estimated* energy losses in each hour within each power flow. The *estimated* energy losses within each power flow were calculated from the corresponding peak losses. Specifically, the losses in each hour are assumed to vary directly with the hourly load within each power flow.

For example, if the peak losses in the Summer 90% power flow are 10 MW and the system load in a particular hour within the power flow was 80% of the peak load, the corresponding hourly losses would be 8 MW. The process is illustrated in Figure 2 for the Summer 100% and 90% power flows. As can be seen, losses are assumed to vary proportionately with load.

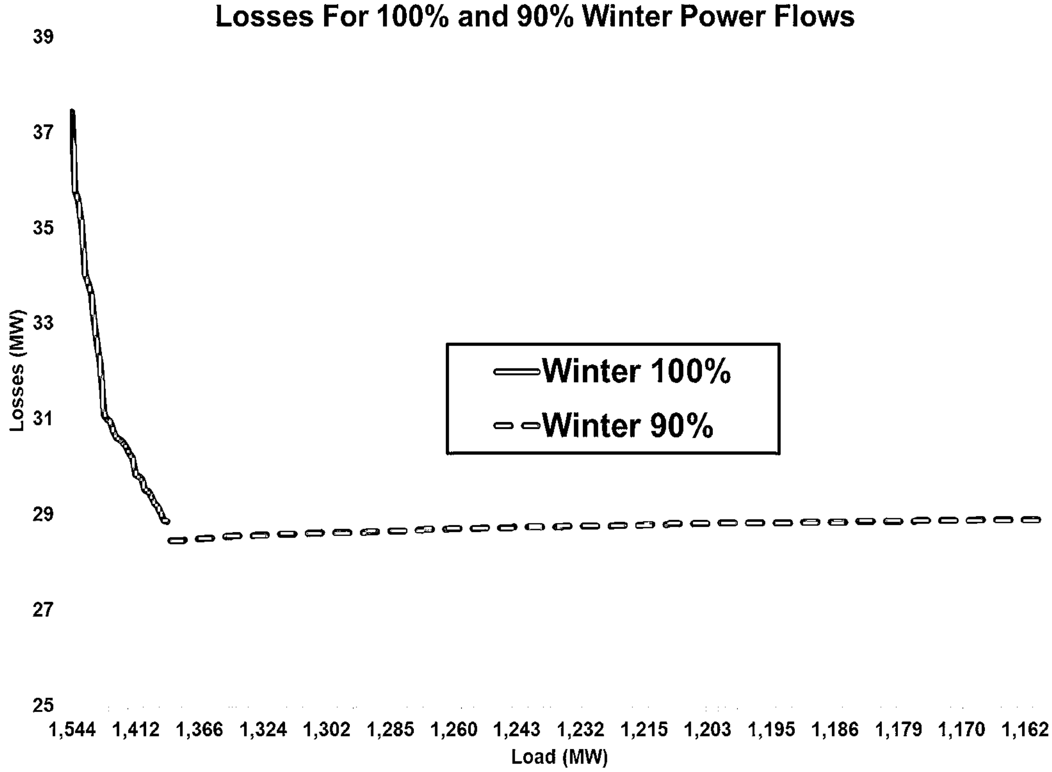
Figure 2
Losses For 100% and 90% Summer Power Flows



Q WAS THERE A SIMILAR PATTERN WITH THE LOSSES DERIVED FROM THE WINTER POWER FLOWS?

A No. Figure 3 shows the losses derived in the Winter 100% and 90% power flows. As can be seen, the losses in the Winter 90% power flow are not proportional with load. Clearly, EPE's Loss Study is flawed.

Figure 3
Losses For 100% and 90% Winter Power Flows



Q DO YOU HAVE ANY OTHER CONCERNS WITH EPE'S LOSS STUDY?

A Yes. Another flaw is with how EPE aggregated the *estimated* hourly losses in each of the eight power flows. Specifically, within each power flow, the estimated hourly losses were summed, and the result was divided by the total energy output. This procedure has the effect of placing more weight on the losses derived from the Winter 75% and 50% power flows, which span the most hours. For example, the estimated energy loss factor derived from the Winter 75% power flow is 2.97%. However, the Winter 75% power flow determined 41% (3,581 ÷ 8,760) of the average (energy) losses.[13] Thus, the losses derived from one power flow analysis for the winter months had a disproportionate impact on the derived energy losses. This explains why EPE's Loss Study concludes that energy losses are higher than the peak demand losses.

Finally, EPE has not shown that the eight power flows used in the Loss Study are "representative" of the losses incurred over all 8,760 hours. There is no evidence that EPE incurs 2.97% energy losses in each of the 3,581 hours represented by the Winter 75% power flow. Yet, the losses in just this one power flow had the most influence in determining the energy loss factors. At the very least, there must be a showing that the selected power flow studies are representative of the losses that actually occur during peak hours as well as in all 8,760 hours. In my opinion, this invalidates EPE's energy loss factors.

Q IS THERE GENERAL ACCEPTANCE THAT ENERGY LOSS FACTORS MUST BE LOWER THAN THE CORRESPONDING DEMAND LOSS FACTORS?

A Yes. There is an industry standard relationship between peak (or demand) losses and average (or energy) losses, which is known as the Hoebel Coefficient. The Hoebel Coefficient is discussed in EPE's Loss Study.[14] In essence, average losses are a function of the product of (1) peak losses, (2) load factor, and (3) the Hoebel Coefficient. The relationship is as follows:

[13] EPE Response to FMI 1-1 (Confidential). Specifically, the summation of losses in the Winter 75% Power Flow encompasses 3,581 hours, as shown in the worksheet "Data Win."

[14] EPE Rate Filing Package, Schedule O-6.3, Appendix C.

$$A_{LS} \approx P_{LS} \times [H \times F_{LD}^2 + (1\text{-}H) \times F_{LD}]$$

Where: A_{LS} = Average Losses
P_{LS} = Peak Losses
H = Hoebel Coefficient
F_{LD} = Load Factor

For example, assuming peak losses of 3%, a Hoebel Coefficient of 0.8, and a 70% load factor, average losses should be 1.6% (3% x [0.8 x 0.49 + 0.2 x 0.7]). Thus, based on this relationship, the average (*i.e.,* energy) losses are, by definition, always lower than the corresponding peak (*i.e.,* demand) losses.

Q WHAT DO YOU RECOMMEND?

A The Commission should reject EPE's energy loss factors for the substation and transmission voltage services. At a minimum, the energy loss factors for these services should not exceed 90% of the corresponding demand loss factors. This would approximate the relationships between the energy and demand loss factors for primary and secondary services. It would also be consistent with industry standard practice. This would result in the following revised energy loss factors.

Table 3
Revised Energy Loss Factors

Voltage	Energy Loss Factor
Secondary	7.850%
Primary	5.123%
Substation	2.842%
Transmission 69 kV	2.511%
Transmission 115 kV	2.171%

Q HAVE YOU REVISED EPE'S ENERGY ALLOCATION FACTORS TO REFLECT YOUR RECOMMENDED ENERGY LOSS FACTORS?

A Yes. **Exhibit JP-3** shows the derivation of EPE's Energy1 allocation factors using the revised energy loss factors shown in Table 3.

Q SHOULD THE REVISED ENERGY1 LOSS FACTOR BE USED TO ALLOCATE ALL COSTS THAT ARE CLASSIFIED TO ENERGY?

A Yes.

Q DOES EPE USE A SECOND ENERGY ALLOCATOR TO ALLOCATE CERTAIN COSTS?

A Yes. EPE also uses a second energy allocator (Energy2) to allocate fuel and purchased power expense and certain rate base items. As discussed later, Fuel Factor revenues and eligible fuel expenses should be removed from the CCOSS. The difference between the Energy1 and Energy2 allocators is the latter includes both firm and interruptible service.

Q SHOULD THE ENERGY2 ALLOCATOR BE USED?

A No. The CCOSS determines the firm cost to serve. The non-firm rates are not included in the CCOSS, which is appropriate. Thus, non-firm energy sales are irrelevant in determining the cost to serve firm loads. Accordingly, the Commission should reject EPE's Energy2 allocator.

Q WOULD REVISING THE ENERGY LOSS FACTORS ALSO AFFECT THE AED-4CP ALLOCATION FACTORS?

A Yes. **Exhibit JP-4** shows the derivation of the AED-4CP allocation factors using both the actual system 1CP load factor and the revised energy loss factors shown in Table 3.

Load Dispatching Expense

Q WHAT IS LOAD DISPATCHING EXPENSE?

A Load dispatching expense is incurred by EPE in its production and transmission functions. Production load dispatching expenses are booked to FERC Account No. 556 (System load control), which is defined as follows:

> This account shall include the cost of labor and expenses incurred in load dispatching activities for system control. Utilities having an interconnected electric system or operating under a central authority which controls the production and dispatching of electricity may apportion these costs to this account and transmission expense Accounts 561.1 through 561.4, and Account 581, Load Dispatching-Distribution.[15]

Transmission load dispatching expenses are booked in FERC Account No. 561 (load dispatch), which is defined as follows:

> **561.1 Load Dispatch—Reliability.**
>
> This account shall include the cost of labor, materials used and expenses incurred by a regional transmission service provider or other transmission provider to manage the reliability coordination function as specified by the North American Electric Reliability Council (NERC) and individual reliability organizations. These activities shall include performing current and next day reliability analysis. This account shall include the costs incurred to calculate load forecasts, and performing contingency analysis.
>
> **561.2 Load Dispatch—Monitor and Operate Transmission System.**
>
> This account shall include the costs of labor, materials used and expenses incurred by a regional transmission service provider or other transmission provider to monitor, assess and operate the power system and individual transmission facilities in real-time to maintain safe and reliable operation of the transmission system. This account shall also include the expense incurred to manage transmission facilities to maintain system reliability and to monitor the

[15] 18 C.F.R. Chapter 1, Part 101 - Uniform System of Accounts.

> real-time flows and direct actions according to regional plans and tariffs as necessary.
>
> **561.3 Load Dispatch—Transmission Service and Scheduling.**
>
> This account shall include the costs of labor, materials used and expenses incurred by a regional transmission service provider or other transmission provider to process hourly, daily, weekly and monthly transmission service requests using an automated system such as an Open Access Same-Time Information System (OASIS). It shall also include the expenses incurred to operate the automated transmission service request system and to monitor the status of all scheduled energy transactions.[16]

Q HOW IS EPE PROPOSING TO ALLOCATE LOAD DISPATCHING EXPENSE?

A EPE witness Adrian Hernandez is proposing to allocate load dispatching expense using the 12CP method.[17] The 12CP method measures each rate class's demand coincident with each of the twelve monthly system peaks.

Q DO OTHER TEXAS UTILITIES ALLOCATE LOAD DISPATCHING EXPENSES IN THE MANNER PROPOSED BY MR. HERNANDEZ?

A No. ETI[18] and SWEPCO[19] use the same methods to allocate load dispatching expenses as the method used to allocate the corresponding asset. Further, within ERCOT, AEP Texas, Inc., CenterPoint Energy Houston Electric, LLC, Oncor Electric

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[16] *Id.*

[17] Hernandez Direct at 14.

[18] *Entergy Texas, Inc.'s Statement of Intent and Application for Authority to Change Rates*, Docket No. 48371, Cost Allocation/Rate Design Rebuttal Testimony of Richard E. Lain at 8-9; *Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 39896 Revised Schedules for Entergy Texas Reflecting Changes Based on Number Running, Comm Number Run 39896 ETI COS 8.28.12 SENT - Redacted.xlsx, Tab "ATT-Com-2 Sch P-1,2,3" at row 724 (showing Acct. 556 allocated on a production demand basis) and rows 742-743 (showing Acct. 561 allocated on transmission demand basis) (Aug. 28, 2012). See also, *Order on Rehearing* at Ordering Paragraph 2 (granting ETI's application except as modified by the Order) (Nov. 2, 2012).

[19] *Application of Southwestern Electric Power Company for Authority to Change Rates*; Docket No. 51415, Schedule P-1 (Oct. 14, 2020).

Delivery Company, and Texas-New Mexico Power Company allocate transmission load dispatching expense (FERC Account No. 561) using the 4CP method. The 4CP method is also used to allocate transmission plant in accordance with 16 T.A.C. § 25.192. Thus, Mr. Hernandez's proposal is inconsistent with how other utilities in Texas allocate load dispatching expenses.

Q IS 12CP AN APPROPRIATE METHOD FOR ALLOCATING LOAD DISPATCHING EXPENSE?

A No. As discussed in Mr. Hernandez's testimony,[20] EPE is a predominantly summer-peaking utility, so an allocation method where two-thirds of the costs are allocated to the non-summer months is inappropriate. The 12CP method shifts more costs away from those rate classes that peak during the summer months and onto the rate classes that exhibit steady demands throughout the year.

Q DOES THE FACT THAT LOAD DISPATCHING IS A YEAR-ROUND ACTIVITY SUPPORT ALLOCATING THESE EXPENSES DIFFERENTLY THAN PRODUCTION AND TRANSMISSION PLANT COSTS?

A No. Whether an expense is a year-round activity or not is irrelevant to determining cost causation. Load dispatching expenses reflect EPE's management of its production and transmission assets. Accordingly, it would be more consistent with cost-causation principles to allocate load dispatching expenses in the same manner as the corresponding production and transmission assets.

[20] Hernandez Direct at 9.

Q WHAT DO YOU RECOMMEND?

A The Commission has generally approved allocating load dispatching expenses in a manner consistent with how the underlying asset was allocated. Accordingly, the Commission should allocate Account No. 556 expense using the AED-4CP method and Account No. 561 expense using the 4CP method. This would comport with the practices of other Texas utilities. If, however, the Commission believes that Account No. 561 expenses should be allocated in a manner that recognize the year-round nature of this activity, then it should approve AED-4CP.

Inclusion of Fuel Factor Revenues and Eligible Fuel Expenses

Q EPE IS PROPOSING TO INCLUDE THE REVENUES RECOVERED UNDER THE FUEL FACTOR AND ASSOCIATED ELIGIBLE FUEL EXPENSES IN ITS CLASS COST-OF-SERVICE STUDY. IS EPE'S FUEL FACTOR AT ISSUE IN THIS CASE?

A No. The sole issue in this case is to determine EPE's base (or non-fuel) revenue requirement. As EPE witness Hernandez states:

> Fuel and purchased power expenses do not have a base-rate impact since they are recovered (off-set) by fuel-related revenues.[21]

Further, EPE is not proposing to reconcile eligible fuel expenses in this case.

Q WHY THEN DOES EPE INCLUDE FUEL FACTOR REVENUES AND ELIGIBLE FUEL EXPENSES IN ITS CLASS COST-OF-SERVICE STUDY?

A EPE cites the instructions in the rate filing package for the proposition that fuel factor revenues and eligible fuel expenses must be included in a CCOSS. However, those instructions were published in September 1992. This was prior to the adoption of the

[21] Hernandez Direct at 31.

fuel reconciliation provisions of the Commission's Fuel Rule, which became effective in April 2001.[22] Further, none of the other non-ERCOT utilities (*i.e.*, ETI, SWEPCO, and SPS) include fuel factor revenues and eligible fuel expenses in their respective CCOSSs.

Q HAS EPE RECENTLY FILED A PROPOSAL TO REVISE THE FUEL FACTOR?

A Yes.[23]

Q WHAT DO YOU RECOMMEND?

A All fuel factor revenues and eligible fuel expenses should be removed from the CCOSS. This is consistent with the practices of other non-ERCOT utilities and recognizes that fuel and purchased power expenses are not at issue in this proceeding.

Allocation of Other Production Plant

Q YOU PREVIOUSLY STATED THAT EPE IS NOT USING AED-4CP TO ALLOCATE ALL PRODUCTION PLANT. WHAT OTHER METHOD DOES EPE USE TO ALLOCATE PRODUCTION PLANT?

A EPE is proposing to allocate the costs associated with its peaking units using the 4CP method. EPE defines peaking units as those that were primarily designed to be ramped up and down as needed to meet load fluctuations, especially during peak summer hours; they are not designed to run for extended periods of time.[24]

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[22] 16 T.A.C. § 25.236.

[23] *Petition of El Paso Electric Company to Revise its Fixed Fuel Factor*, Docket No. 52723 (Oct. 15, 2021) (pending).

[24] Hernandez Direct at 10.

Q WHAT ARE EPE'S PEAKING UNITS?

A EPE identifies its peaking units to include the following:

- Montana Power Station Units 1 through 4;
- Rio Grande Generating Station Unit 9; and
- Copper Generating Station.[25]

Q DID EPE ALLOCATE THE COSTS OF ITS PEAKING UNITS USING 4CP IN ITS LAST RATE CASE?

A No. In EPE's 2017 rate case (Docket No. 46831), EPE used AED-4CP to allocate all generation plant-related costs, including the costs of the peaking units.[26]

Q HAS THE COMMISSION EVER APPROVED ALLOCATING PEAKING UNITS USING A DIFFERENT METHODOLOGY THAN THE ALLOCATION OF A UTILITY'S OTHER THERMAL GENERATION RESOURCES?

A No. The Commission has consistently adopted AED-4CP to allocate all production plant, regardless of the type of plant.

Q SHOULD DIFFERENT METHODS BE USED TO ALLOCATE DIFFERENT TYPES OF PRODUCTION PLANT?

A No. EPE operates its system on an integrated basis.[27] The peaking units obviously play a role in providing the necessary ramping and load-following capability required to maintain a safe and reliable system.

[25] *Id.* at 11.

[26] *Id.* at 10.

[27] EPE Response to FMI 2-19.

Further, as previously explained, the AED-4CP method already recognizes the different types of generating units. Specifically, average demand recognizes those units designed to operate year round, while excess demand recognizes the units designed to provide load following. This includes both peaking units and demand response.

Accordingly, there is no reason to use different allocation methods for peaking and non-peaking base rate costs.

Q WHAT DO YOU RECOMMEND?

A All production capital costs and related expenses should be allocated to customer classes using the AED-4CP method. This is consistent with past Commission practice, as previously discussed.

Classification of Production O&M Expense

Q IS EPE PROPOSING TO CHANGE CERTAIN ASPECTS OF THE CLASSIFICATION OF PRODUCTION O&M EXPENSE?

A Yes. EPE is proposing to reclassify a significant portion of its production O&M expense from demand to energy.[28] For example, expenses that were partially classified between demand and energy (FERC Account Nos. 512, 513 and 514) would be classified entirely to energy. Further, accounts that were classified entirely to demand (FERC Account Nos. 519, 520 and 523) would be classified entirely to energy.

[28] *See* Table 1 supra.

Q WHAT IS THE BASIS FOR RECLASSIFYING THESE EXPENSES FROM DEMAND TO ENERGY?

A Mr. Hernandez states that EPE generally follows the NARUC CAM to determine how production O&M expenses should be classified between demand and energy.[29]

Q DID EPE FOLLOW THE GUIDANCE PROVIDED IN THE NARUC CAM?

A No. According to the NARUC CAM, only a portion of the production O&M expenses in FERC Account Nos. 502, 505, 519, 520 and 523 would be considered energy related. Specifically, these expenses should be:

> …classified between demand and energy on the basis of labor expenses and material expenses. Labor expenses are considered demand-related, while material expenses are considered energy-related.[30]

Q IS THIS THE ONLY METHOD OF CLASSIFYING PRODUCTION O&M EXPENSES DESCRIBED IN THE NARUC CAM?

A No. The NARUC CAM also recognizes another common method is to classify each account according to its predominant character.[31] In other words, if the majority of expenses are labor-related, then the entire account would be classified as demand-related. Conversely, if the majority of the expense is material-related, then the entire account would be classified as energy-related.

Q WHAT DO YOU RECOMMEND?

A I recommend that the labor-related expenses in FERC Account Nos. 502 and 505 be classified to demand. All of the expenses in FERC Account Nos. 519, 520, and 523

[29] Hernandez Direct at 14.

[30] NARUC CAM at 36, 38.

[31] *Id.* at 66.

should be classified to demand, consistent with EPE's past proposals, because the proportions of labor and materials expenses are not defined and EPE has provided no support for classifying the entirety of these accounts to energy.

Revised Class Cost-of-Service Study

Q HAVE YOU PREPARED A REVISED CLASS COST-OF-SERVICE STUDY?

A Yes. My revised CCOSS is presented in **Exhibit JP-5**. In this revised study:

- The load-factor weighting in the AED-4CP method was based on the actual system 1CP load factor.
- AED-4CP was applied to all production plant.
- The energy allocation factor and average demand component of AED-4CP were revised to reflect my recommended energy loss factors for the rate classes taking service at the substation and transmission voltages.
- All costs allocated by EPE using the Energy2 allocator were allocated using the Energy1 allocator.
- Production and transmission load dispatching expenses were allocated using the AED-4CP and 4CP methods, respectively, which are the same allocation methods used for the related production and transmission plant.
- Fuel revenues and eligible fuel expenses were removed.
- The labor-related portion of the production O&M expenses charged to Account Nos. 502, 505, were classified to demand, while the production O&M expenses charged to Account Nos. 519, 520, and 523 were classified entirely to demand.

Q SHOULD YOUR REVISED CLASS COST-OF-SERVICE STUDY BE USED TO DETERMINE THE SPREAD OF ANY BASE REVENUE CHANGE THAT THE COMMISSION MAY AUTHORIZE IN THIS PROCEEDING?

A Yes. This is discussed in the following section of my testimony.

3. CLASS REVENUE ALLOCATION

Q WHAT IS CLASS REVENUE ALLOCATION?

A Class revenue allocation is the process of determining how any base revenue change approved by the Commission should be spread to each customer class served by the utility.

Q HOW IS EPE PROPOSING TO SPREAD THE BASE RATE INCREASE AMONG THE VARIOUS RATE CLASSES?

A EPE is proposing a $41.5 million firm base revenue increase. Of this amount, the proposed COVID-19 surcharge would be $2.2 million. Thus, firm base rates would increase by $39.3 million (7.4%).

Exhibit JP-6 shows how EPE is proposing to spread the $39.3 million firm base revenue increase by rate class. As can be seen, the proposed base rate changes would range from a 22.6% *decrease* (Street Lighting) to a 36.6% *increase* (Cotton Gin).

Q WOULD EPE'S PROPOSED CLASS REVENUE ALLOCATION MOVE ALL RATES TO COST?

A No. **Exhibit JP-7**, page 1 is a comparison between EPE's proposed firm base revenue allocation to the base rate increases required to move each class to cost under its proposed CCOSS. As can be seen, the proposed base rate increases would range from 20% to 470% of the increases required to achieve cost-based rates.

A similar comparison with FMI's revised CCOSS is provided in **Exhibit JP-7**, page 2. As can be seen, EPE is proposing to increase, rather than decrease, base rates for some classes (*i.e.,* Municipal Pumping TOU, Traffic Signals, Large Power).

For the other rate classes, the proposed changes would range from 20% to 268% of the required cost-based increases.

Q WHY IS EPE NOT PROPOSING TO MOVE ALL RATES TO COST IN THIS PROCEEDING?

A Citing the COVID-19 pandemic:

> EPE is proposing to modify the cost-based revenue requirements for the Residential, Water Heating, Small General Service, General Service, and City/County rate groups.[32]

Specifically:

> EPE initially caps the allocated revenue requirement increase to the Residential and Water Heating classes at 1.5 times the system average increase of 7.79% and limits the revenue requirement reductions for the other three classes at 50% of the cost-based reduction. The resulting revenue deficiency is then redistributed to all rate groups, including the moderated groups.[33]

Q WHY DOES EPE BELIEVE THAT THE COVID-19 PANDEMIC JUSTIFIES MODERATING THE COST-BASED RATE INCREASES TO CERTAIN TARGETED RATE GROUPS?

A EPE's rate moderation proposal is based on an observation that:

> ***The COVID-19 pandemic resulted in a shift in usage patterns during the test year due to business and government office closures and employees working from home as opposed to the office.*** This phenomena drove significant increased usage from residential customers and a significant reduction in usage from the commercial and city/county customers.[34] (emphasis added)

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[32] Schichtl Direct at 38.

[33] *Id.* at 39.

[34] Novela Direct at 10.

Q DOES THE COVID-19 PANDEMIC REVEAL A SHIFT IN USAGE PATTERNS THAT WOULD AFFECT THE CLASS COST-OF-SERVICE STUDY RESULTS?

A No. **Exhibit JP-8** provides a comparison of energy sales and base revenues between this case and EPE's last rate case. First, I would note that compared to the rates approved in the settlement of EPE's last rate case, EPE has experienced a 2% increase in energy sales and a 7% increase in base revenues (line 18).

Second, for the most part, those rate classes experiencing increases in energy usage also provided additional base revenues. For example, the Residential class experienced a 17% increase in energy sales, but this increase resulted in an 18% increase in base revenues (line 1). This explains why the Residential class's share of base revenues and energy sales increased since EPE's last rate case. By contrast, several rate classes experienced reductions in both energy sales and base revenues. This includes Electrolytic Refining (Rate 15), Large Power (Rate 25), Petroleum (Rate 26), and City/County (Rate 41). In these instances, however, both the energy sales and base revenues declined by a similar magnitude (Large Power and Petroleum) or base revenues declined by less than the decline in energy sales (Electrolytic Refining, City/County). All but six of the rate classes shown in **Exhibit JP-7** have experienced larger changes in base revenues than the corresponding energy sales.

Q WHAT CONCLUSIONS DO YOU DRAW FROM EXHIBIT JP-8?

A These statistics demonstrate that, in general, the changes in usage patterns were matched by corresponding changes in base revenues. It also demonstrates that some of the non-targeted rate classes (*i.e.*, Rate 15, Rate 25, and Rate 26) were also affected by the COVID-19 pandemic. Despite this, EPE's proposal would force these classes to subsidize the targeted rate classes.

3. Class Revenue Allocation

In summary, the shift in usage pattern cited by EPE during the test year will have no discernable impact on the CCOSS results. Accordingly, shifting usage patterns is not a reason to moderate the proposed base rate increases.

Q IS THERE ANOTHER REASON WHY EPE'S RATE MODERATION PROPOSAL SHOULD BE REJECTED?

A Moderating the cost-based revenue requirement is, effectively, price-based costing rather than cost-based pricing. The Commission has had a long-standing policy of cost-based pricing; that is, all rate classes should produce equal rates of return using an accepted CCOSS. The notable exception is in the case where achieving equal rates of return would violate the principle of gradualism; that is, no class should receive an increase that would result in rate shock. However, in recent cases, the Commission has applied gradualism by limiting a base rate increase to 43%.[35]

Q WOULD ANY RATE CLASS REQUIRE AN INCREASE EXCEEDING 43% IN ORDER TO ACHIEVE COST-BASED RATES?

A Yes. Under EPE's CCOSS, the Off Peak Water Heating rate class would require a base rate increase in excess of 60%. Consistent with the Commission's recent pronouncements on applying the principle of gradualism, the increase should not exceed 43%.

Q WHAT DO YOU RECOMMEND?

A EPE's rate moderation proposal should be rejected. There is no indication that shifting usage patterns have affected the integrity of EPE's CCOSS. It would also be contrary to this Commission's long-standing practice.

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[35] Docket No. 46449, *Commission Number Run Memorandum* from William Abbott (Dec. 20, 2017) and *Order* at Finding of Fact Nos. 311-314 (Jan. 11, 2018).

Q HAVE YOU DEVELOPED AN ALTERNATIVE CLASS REVENUE ALLOCATION BASED ON YOUR REVISED CLASS COST-OF-SERVICE STUDY?

A Yes. My alternative class revenue allocation is shown in **Exhibit JP-9**. Under this proposal, all rates would move to cost with the exception of Off Peak Water Heating. Applying gradualism, the increase in Off Peak Water Heating rates should not exceed 43%. The revenue shortfall would be spread to those classes receiving below-system average base rate increases.

4. RATE 15 DESIGN

Q IS EPE PROPOSING ANY MAJOR CHANGES IN THE DESIGN OF RATE 15?

A No. The structure of Rate 15 would be retained. However, EPE is proposing to realign specific charges. A comparison between EPE's present and proposed Rate 15 charges is provided in Table 4.

Table 4
Rate 15 Design

Charge	Present Rates	Proposed Rates	Percent Increase
On-Peak Energy Rate ($/kWh)	$0.16219	$0.14961	-7.8%
Base Energy Rate ($/kWh)	$0.00479	$0.00530	10.6%
Demand Rate ($/kW) - Summer	$15.97	$21.34	33.6%
Demand Rate ($/kW) - Non-Summer	$11.84	$16.72	41.2%
Monthly Customer Charge	$400.00	$22.07	-94.5%

As can be seen, EPE is proposing to significantly reduce the Monthly Customer charge. EPE is proposing a lower On-Peak Energy charge. The Non-Summer Demand charge would be increased by approximately 23% more than the Summer Demand charge.

Q DO YOU AGREE WITH THE PROPOSED CHANGES IN THE SUMMER DEMAND CHARGE AND ON-PEAK ENERGY CHARGE?

A No. EPE is a summer peaking utility. The On-Peak Energy charge applies during on-peak hours, which occur during the summer months, June through September, between the hours of 12 noon and 6 p.m. Further, EPE is projecting tighter reserve margins due to planned generation retirements and significant year-over-year growth in customer load.[36] This, coupled with its proposal to lower the current 15% planning reserve margin,[37] explains why EPE is now proposing to expand the current Interruptible program (Rate 38). In addition to expanding demand response options, EPE should also be providing stronger price signals to encourage firm customers to minimize their power demands during the summer on-peak period. EPE's proposed Rate 15 design would have the opposite effect.

Q ARE THERE SPECIFIC TERMS AND CONDITIONS IN RATE 15 THAT SHOULD ALSO BE ADDRESSED?

A Yes. Rate 15 currently has a 7,500 kW minimum contract capacity. This provision is inconsistent with EPE's proposal to expand its interruptible program. FMI may have the capability to expand its on-site generation and/or its curtailable load to provide precisely the additional demand response EPE desires to acquire, but the 7,500 kW minimum contract capacity effectively precludes FMI from being able to offer this functionality to EPE. A reduction in the minimum contract demand to 5,000 kW would enable FMI to work with EPE after the conclusion of this rate case to determine if there is an economically efficient solution available that would benefit both FMI and the EPE system.

Q WHAT DO YOU RECOMMEND?

A First, the current On-Peak Energy charge should be retained. Second, the Summer

[36] Direct Testimony of James Schichtl at 35.

[37] EPE's Integrated Resource Plan for the Period 2021-2040 which states at 75: "The resulting PCAP PRM through 2029 will be 10% for a 2 in 10 LOLE [Loss of Load Expectation]." (Sept. 16, 2021).

Demand charge should be increased by approximately 20% more than the increase in the Non-Summer Demand charge. Third, the minimum contract capacity provision of Rate 15 should be reduced to 5,000 kW.

5. CONCLUSION

Q BASED ON YOUR DIRECT TESTIMONY, WHAT FINDINGS SHOULD THE COMMISSION MAKE?

A The Commission should make the following findings:

- Reject EPE's class cost-of-service study.
- Adopt FMI's revised class cost-of-service study under which:
  - The load-factor weighting used in applying the AED-4CP method is based on the actual system annual coincident peak (*i.e.,* 1CP) demand.
  - AED-4CP is used to allocate all production plant.
  - The energy loss factor for transmission and substation voltages are set to 90% of the corresponding demand loss factor.
  - The Energy2 allocator is replaced by the Energy1 allocator for all costs that are classified to energy.
  - Load dispatching expenses booked to FERC Account Nos. 556 and 561 are allocated using the same methodology as is used to allocate production and transmission plant, respectively.
  - Fuel Factor revenues and eligible expenses are removed.
  - Labor-related O&M expenses in FERC Account Nos. 502 and 505 and all expenses in FERC Account Nos. 519, 520, and 523 were classified to demand.
- Reject EPE's Loss Study and require EPE to file a new study that measures the *actual* energy losses over a calendar year.
- Reject EPE's proposed rate moderation plan.
- Adopt FMI's recommended class revenue allocation, which moves all rate classes to cost, except that the increase to the Off Peak Water Heating rate class should be capped at 43%, consistent with the principle of gradualism.
- Reject EPE's proposed Rate 15 design.
- Adopt FMI's recommended Rate 15 design under which:
  - The On-Peak Energy rate is unchanged.
  - The Summer Demand charge is increased approximately 20% more than the increase in the Non-Summer Demand charge.
  - The minimum contract capacity is reduced to 5,000 kW

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

APPENDIX A

Qualifications of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock. My business mailing address is 12647 Olive Blvd., Suite 585, St. Louis, Missouri 63141.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and President of J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Master's Degree in Business Administration from Washington University. I have also completed a Utility Finance and Accounting course.

Upon graduation in June 1975, I joined Drazen-Brubaker & Associates, Inc. (DBA). DBA was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. From April 1995 to November 2004, I was a managing principal at Brubaker & Associates (BAI).

During my career, I have been engaged in a wide range of consulting assignments including energy and regulatory matters in both the United States and several Canadian provinces. This includes preparing financial and economic studies of investor-owned, cooperative and municipal utilities on revenue requirements, cost of service and rate design, tariff review and analysis, conducting site evaluations, advising clients on electric restructuring issues, assisting clients to procure and manage electricity in both competitive and regulated markets, developing and issuing requests for proposals (RFPs), evaluating RFP responses and contract negotiation and developing and presenting seminars on electricity issues.

I have worked on various projects in 28 states and several Canadian provinces, and have testified before the Federal Energy Regulatory Commission, the Ontario Energy Board, and the state regulatory commissions of Alabama, Arizona, Arkansas, Colorado, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, Ohio, Pennsylvania, South Carolina, Texas, Virginia, Washington, and Wyoming. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Board of Directors of the South Carolina Public Service Authority (a.k.a. Santee Cooper), the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court.

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A J. Pollock assists clients to procure and manage energy in both regulated and competitive markets. The J. Pollock team also advises clients on energy and regulatory issues. Our clients include commercial, industrial and institutional energy consumers. J. Pollock is a registered broker and Class I aggregator in the State of Texas.

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Cross Rebuttal	TX	Cost Allocation; Production Tax Credits; Radial Lines; Load Dispatching Expenses; Uncollectible Expense; Class Revenue Allocation; LGS-T Rate Design	9/14/2021
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	43838	Direct	GA	Vogtle Unit 3 Rate Increase	9/9/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	21-00172-UT	Direct	NM	RPS Financial Incentive	9/3/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; LGS-T Rate Design	8/13/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Direct	TX	Schedule 11 Expenses; Jurisdictional Cost Allocation; Abandoned Generation Assets	8/13/2021
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51997	Direct	TX	Storm Restoration Cost Allocation and Rate Design	8/6/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Surrebuttal	PA	Class Cost-of-Service Study; Revenue Allocation	8/5/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Rebuttal	PA	Class Cost-of-Service Study; Revenue Allocation; Universal Service Costs	7/22/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Rebuttal	NM	Settlement Support of Class Cost-of-Service Study; Rate Desgin; Revenue Requirement.	7/1/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Direct	PA	Class Cost-of-Service Study; Revenue Allocation	6/28/2021
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20940	Rebuttal	MI	Allocation of Uncollectible Expense	6/23/2021
FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	20210015-EI	Direct	FL	Four-Year Rate Plan; Reserve Surplus; Solar Base Rate Adjustments; Class Cost-of-Service Study; Class Revenue Allocation; CILC/CDR Credits	6/21/2021
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	20-067-U	Surrebuttal	AR	Certificate of Environmental Compatibility and Public Need	6/17/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Rebuttal	NM	Rate Design	6/9/2021
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20940	Direct	MI	Class Cost-of-Service Study; Rate Design	6/3/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	51415	Supplemental Direct	TX	Retail Behind-The-Meter-Generation; Class Cost of Service Study; Class Revenue Allocation; LGS-T Rate Design; Time-of-Use Fuel Rate	5/17/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Direct	NM	Class Cost-of-Service Study; Class Revenue Allocation, LGS-T Rate Design, TOU Fuel Charge	5/17/2021

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ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	20-067-U	Direct	AR	Certificate of Environmental Compatibility and Public Need	5/6/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51625	Direct	TX	Fuel Factor Formula; Time Differentiated Costs; Time-of-Use Fuel Factor	4/5/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	51415	Direct	TX	ATC Tracker, Behind-The-Meter Generation; Class Cost-of-Service Study; Class Revenue Allocation; Large Lighting and Power Rate Design; Synchronous Self-Generation Load Charge	3/31/2021
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51215	Direct	TX	Certificate of Convenience and Necessity for the Liberty County Solar Facility	3/5/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	50997	Cross Rebuttal	TX	Rate Case Expenses	1/28/2021
PPL ELECTRIC UTILITIES CORPORATION	PPL Industrial Customer Alliance	M-2020-3020824	Supplemental	PA	Energy Efficiency and Conservation Plan	1/27/2021
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	20-E-0428 / 20-G-0429	Rebuttal	NY	Distribution cost classification; revised Electric Embedded Cost-of-Service Study; revised Distribution Mains Study	1/22/2020
MIDAMERICAN ENERGY COMPANY	Tech Customers	EPB-2020-0156	Reply	IA	Emissions Plan	1/21/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	50997	Direct	TX	Disallowance of Unreasonable Mine Development Costs; Amortization of Mine Closure Costs; Imputed Capacity	1/7/2021
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	20-E-0428 / 20-G-0429	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Revenue Decoupling Mechanism	12/22/2020
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	20-E-0380 / 20-G-0381	Rebuttal	NY	AMI Cost Allocation Framework	12/16/2020
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51381	Direct	TX	Generation Cost Recovery Rider	12/8/2020
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	20-E-0380 / 20-G-0381	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Earnings Adjustment Mechanism; Advanced Metering Infrastructure Cost Allocation	11/25/2020
LUBBOCK POWER & LIGHT	Texas Industrial Energy Consumers	51100	Direct	TX	Test Year; Wholesale Transmission Cost of Service and Rate Design	11/6/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20889	Direct	MI	Scheduled Lives, Cost Allocation and Rate Design of Securitization Bonds	10/30/2020
CHEYENNE LIGHT, FUEL AND POWER COMPANY	HollyFrontier Cheyenne Refining LLC	20003-194-EM-20	Cross-Answer	WY	PCA Tariff	10/16/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00143	Direct	NM	RPS Incentives; Reassignment of non-jurisdictional PPAs	9/11/2020

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ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-578-ER-20	Cross	WY	Time-of-Use period definitions; ECAM Tracking of Large Customer Pilot Programs	9/11/2020
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-578-ER-20	Direct	WY	Class Cost-of-Service Study; Time-of-Use period definitions; Interruptible Service and Real-Time Day Ahead Pricing pilot programs	8/7/2020
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	50790	Direct	TX	Hardin Facility Acquisition	7/27/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Surrebuttal	PA	Interruptible transportation tariff; Allocation of Distribution Mains; Universal Service and Energy Conservations; Gradualism	7/24/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20697	Rebuttal	MI	Energy Weighting, Treatment of Interruptible Load; Allocation of Distribution Capacity Costs; Allocation of CVR Costs	7/14/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Rebuttal	PA	Distribution Main Allocation; Design Day Demand; Class Revenue Allocation; Balancing Provisions	7/13/2020
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2020-3019290	Rebuttal	PA	Network Integration Transmission Service Costs	7/9/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20697	Direct	MI	Class Cost-of-Service Study;Financial Compensation Method; General Interruptible Service Credit	6/24/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	6/15/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20650	Rebuttal	MI	Distribution Mains Classification and Allocation	5/5/2020
GEORGIA POWER COMPANY	Georgia Association of Manufacturers and Georgia Industrial Group	43011	Direct	GA	Fuel Cost Recovery Natural Gas Price Assumptions	5/1/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20650	Direct	MI	Class Cost-of-Service Study; Transportation Rate Design; Gas Demand Response Pilot Program; Industry Association Dues	4/14/2020
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	90000-144-XI-19	Direct	WY	Coal Retirement Studies and IRP Scenarios	4/1/2020
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20642	Direct	MI	Class Cost-of-Service Study; Class Revenue Allocation; Infrastructure Recovery Mechanism; Industry Association Dues	3/24/2020

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SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Cross	TX	Radial Transmission Lines; Allocation of Transmission Costs; SPP Administrative Fees; Load Dispatching Expenses; Uncollectible Expense	3/10/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00315-UT	Direct	NM	Time-Differentiated Fuel Factor	3/6/2020
SOUTHERN PIONEER ELECTRIC COMPANY	Western Kansas Industrial Electric Consumers	20-SPEE-169-RTS	Direct	KS	Class Revenue Allocation	3/2/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Direct	TX	Schedule 11 Expenses; Depreciation Expense (Rev. Req. Phase Testimony)	2/10/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Direct	TX	Class-Cost-of-Service Study; Class Revenue Allocation; Rate Design (Rate Design Phase Testimony)	2/10/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00134-UT	Direct	NM	Renewable Portfolio Standard Rider	2/5/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00170-UT	Settlement	NM	Settlement Support of Rate Design, Cost Allocation and Revenue Requirement	1/20/2020
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	49737	Direct	TX	Certificate of Convenience and Necessity	1/14/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00170-UT	Rebuttal	NM	Class Cost-of-Service Study; Class Revenue Allocation	12/20/2019
ALABAMA POWER COMPANY	Alabama Industrial Energy Consumers	32953	Direct	AL	Certificate of Convenience and Necessity	12/4/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00170-UT	Direct	NM	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	11/22/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49616	Cross	TX	Contest proposed changes in the Fuel Factor Formula	10/17/2019
GEORGIA POWER COMPANY	Georgia Association of Manufacturers and Georgia Industrial Group	42516	Direct	GA	Return on Equity; Capital Structure; Coal Combustion Residuals Recovery; Class Revenue Allocation; Rate Design	10/17/2019
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	19-E-0378 / 19-G-0379 19-E-0380 / 19-G-0381	Rebuttal	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design	10/15/2019
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	19-E-0378 / 19-G-0379 19-E-0380 / 19-G-0381	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Amortization of Regulatory Liabilties; AMI Cost Allocation	9/20/2019
AEP TEXAS INC.	Texas Industrial Energy Consumers	49494	Cross-Rebuttal	TX	ERCOT 4CPs; Class Revenue Allocation; Customer Support Costs	8/13/2019

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AEP TEXAS INC.	Texas Industrial Energy Consumers	49494	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Transmission Line Extensions	7/25/2019
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	49421	Cross-Rebuttal	TX	Class Cost-of-Service Study	6/19/2019
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	49421	Direct	TX	Class Cost-of-Service Study; Rate Design; Transmission Service Facilities Extensions	6/6/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	48973	Direct	TX	Prudence of Solar PPAs, Imputed Capacity, treatment of margins from Off-System Sales	5/21/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20322	Rebuttal	MI	Classification of Distribution Mains; Allocation of Working Gas in Storage and Storage	4/29/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20322	Direct	MI	Class Cost-of-Service Study; Transportation Rate Design	4/5/2019
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	49042	Cross-Rebuttal	TX	Transmsision Cost Recovery Factor	3/21/2019
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	49057	Direct	TX	Transmsision Cost Recovery Factor	3/18/2019
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2018-318-E	Direct	SC	Class Cost-of-Service Study, Class Revenue Allocation, LGS Rate Design, Depreciation Expense	3/4/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Settlement	AR	Testimony in Support of Settlement	3/1/2019
ENERGY+ INC.	Toyota Motor Manufacturing Canada	EB-2018-0028	Updated Evidence	ON	Class Cost-of-Service Study, Distribution and Standby Distribution Rate Design	2/15/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Surrebuttal	AR	Solar Energy Purchase Option Tariff	2/14/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	48847	Direct	TX	Fuel Factor Formulas	1/11/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Direct	AR	Solar Energy Purchase Option Tariff	1/10/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20165	Direct	MI	Integrated Resources Plan; Projected Rate Impact, Risk Assessment; Early Retirement of Coal Units; Financial Compensation Mechanism	10/15/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20134	Rebuttal	MI	Class Cost-of-Service Study; Average Historical Profile; Distribution Cost Classification and Allocation; Rate Design	10/1/2018
ENERGY+ INC.	Toyota Motor Manufacturing Canada	EB-2018-0028	Initial Evidence	ON	Class Cost-of-Service Study, Distribution and Standby Distribution Rate Design	9/27/2018

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CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20134	Direct	MI	Investment Recovery Mechanism, Litigation surcharge, Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	9/10/2018
KANSAS GAS AND ELECTRIC COMPANY	Occidental Chemical Corporation	18-KG&E-303-CON	Rebuttal	KS	Benefits of the Interruptible Load Provided in the Special Contract	8/29/2018
TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	48401	Cross-Rebuttal	TX	4CP Moderation Adjustment	8/28/2018
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	48371	Cross-Rebuttal	TX	Class Cost-of-Service Study; Schedule FERC	8/16/2018
TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	48401	Direct	TX	Tax Cuts and Jobs Act; Rider TCRF; 4CP Moderation Adjustment	8/13/2018
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2018-3000164	Surrebuttal	PA	Post Test-Year Adjustment; Tax Cuts and Jobs Act; Class Cost-of-Service Study; Distribution System Improvement Charge	8/8/2018
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	48371	Direct	TX	Revenue Requirements; Tax Cuts and Jobs Act; Riders	8/1/2018
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	48371	Direct	TX	Class Cost-of-Service Study; Firm, Interruptible and Standby Rate Design	8/1/2018
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2018-3000164	Rebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation	7/24/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	48233	Cross-Rebuttal	TX	Allocation of TCJA reduction	7/19/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	48233	Direct	TX	Allocation of TCJA reduction	7/5/2018
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2018-3000164	Direct	PA	Post Test-Year Adjustment; Tax Cuts and Jobs Act; Class Cost-of-Service Study; Class Revenue Allocation	6/26/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	47527	Cross-Rebuttal	TX	Class Cost-of-Service Study; Revenue Allocation	5/22/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	17-00255-UT	Rebuttal	NM	Class Cost-of-Service Study; Revenue Allocation	5/2/2018
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	17-041	Stipulation	AR	Support of Stipulation	4/27/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	47527	Direct	TX	Present Base Revenues Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	4/25/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	47527	Direct	TX	Tax Cuts and Jobs Act; SPP Transmission and Wheeling Costs; Depreciation Rate; LLPPAs; Imputed Capacity; Off-System Sales Margins	4/25/2018

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SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	17-00255-UT	Direct	NM	Class Cost-of-Service Study; Revenue Requirements; Revenue Allocation	4/13/2018
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	17-041	Surrebuttal	AR	Certificate of Convenience and Necessity	4/6/2018
METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY, PENNSYLVANIA POWER COMPANY AND WEST PENN POWER COMPANY	MEIUG, PICA and WPPII	2017-2637855 2017-2637857 2017-2637858 2017-2637866	Rebuttal	PA	Recovery of NITS Charges	3/22/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	46936	2nd Supplemental Direct	TX	Support of Stipulation	3/2/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-18424	Direct	MI	Class Cost of Service	2/28/2018
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	17-041	Direct	AR	Certificate of Convenience and Necessity	2/23/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	47553	Direct	TX	Off-System Sales Margins; Renewable Energy Credits	2/20/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	47461	2nd Supplemental Direct	TX	Certificate of Convenience and Necessity	2/7/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	47461	Supplemental Direct	TX	Certificate of Convenience and Necessity	1/4/2018
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	17-E-0459/G-0460	Rebuttal	NY	Electric and Gas Embedded Class Cost of Service; Class Revenue Allocation; Gas Rate Design; Revenue Decoupling Mechanism	12/18/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	17-00044-UT	Supplemental Direct	NM	Support of Unanimous Comprehensive Stipulation	12/11/2017
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	47461	Direct	TX	Certificate of Convenience and Necessity	12/4/2017
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	17-E-0459/G-0460	Direct	NY	Electric and Gas Embedded Class Cost of Service; Class Revenue Allocation; Customer Charges; Revenue Decoupling Mechanism; Carbon Program and EAM	11/21/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	17-00044-UT	Direct	NM	Certificate of Convenience and Necessity	10/24/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	46936	Cross-Rebuttal	TX	Certificate of Convenience and Necessity	10/23/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	46936	Supplemental Direct	TX	Certificate of Convenience and Necessity	10/6/2017
KENTUCKY POWER COMPANY	Kentucky League of Cities	2017-00179	Direct	KY	Class Cost-of-Service Study; Class Revenue Allocation	10/3/2017

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SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	46936	Direct	TX	Certificate of Convenience and Necessity	10/2/2017
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	17-E-0238 / 17-G-0239	Rebuttal	NY	Electric/Gas Embedded Class Cost of Service; Class Revenue Allocation; Electric/Gas Rate Design	9/15/2017
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-18322	Rebuttal	MI	Class Cost-of-Service Study, Rate Design	9/7/2017
PENNSYLVANIA-AMERICAN WATER COMPANY	Pennsylvania-American Water Large Users Group	R-2017-2595853	Rebuttal	PA	Rate Design	8/31/2017
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	17-E-0238 / 17-G-0239	Direct	NY	Electric/Gas Embedded Class Cost of Service; Class Revenue Allocation; Electric/Gas Rate Design, Electric/Gas Rate Modifiers, AMI Cost Allocation	8/25/2017
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-18322	Direct	MI	Revenue Requirement, Class Cost-of-Service Study, Rate Design	8/10/2017
FLORIDA POWER & LIGHT COMPANY, DUKE ENERGY FLORIDA, LLC, AND TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	170057	Direct	FL	Fuel Hedging Practices	8/10/2017
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	46449	Cross-Rebuttal	TX	Class Revenue Allocation and Rate Design	5/19/2017
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	46449	Direct	TX	Revenue Requirement, Class Cost-of-Service Study, Class Revenue Allocation and Rate Design	4/25/2017
KENTUCKY UTILITIES COMPANY	Kentucky League of Cities	2016-00370	Supplemental Direct	KY	Class Cost-of-Service Study; Class Revenue Allocation	4/14/2017
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	46416	Direct	TX	Certificate of Convenience and Necessity - Montgomery County Power Station	3/31/2017
SHARYLAND UTILITIES, L.P.	Texas Industrial Energy Consumers	45414	Cross-Rebuttal	TX	Cost Allocation Issues; Class Revenue Allocation	3/16/2017
ENTERGY LOUISIANA, LLC	Occidental Chemical Corporation	U-34283	Direct*	LA	Approval to Construct Lake Charles Power Station	3/13/2017
LOUISVILLE GAS AND ELECTRIC COMPANY	Louisville/Jefferson Metro Government	2016-00371	Direct	KY	Revenue Requirement Issues; Class Cost-of-Service Study Electric/Gas; Class Revenue Allocation Electric/Gas	3/3/2017
KENTUCKY UTILITIES COMPANY	Kentucky League of Cities	2016-00370	Direct	KY	Revenue Requirement Issues; Class Cost-of-Service Study; Class Revenue Allocation	3/3/2017
SHARYLAND UTILITIES, L.P.	Texas Industrial Energy Consumers	45414	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; TCRF Allocation Factors; McAllen Division Deferrals	2/28/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	46025	Direct	TX	Long-Term Purchased Power Agreements	12/12/2016

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NORTHERN STATES POWER COMPANY	Xcel Large Industrials	15-826	Surrebuttal	MN	Settlement, Cost-of-Service Study, Class Revenue Allocation, Interruptible Rates, Renew-A-Source	10/18/2016
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	15-826	Rebuttal	MN	Class Cost-of-Service Study, Class Revenue Allocation	9/23/2016
VICTORY ELECTRIC COOPERATION ASSOCIATION, INC.	Western Kansas Industrial Electric Consumers	16-VICE-494-TAR	Surrebuttal	KS	Formula-Based Rate Plan	9/22/2016
NATIONAL FUEL GAS DISTRIBUTION CORPORATION	Multiple Intervenors	16-G-0257	Rebuttal	NY	Embedded Class Cost of Service; Class Revenue Allocation; Rate Design	9/16/2016
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	45524	Cross-Rebuttal	TX	Class Cost-of-Service Study;	9/7/2016
METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPII	2016-2537349 2016-2537352 2016-2537359	Surrebuttal	PA	Post-Test Year Sales Adjustment; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	8/31/2016
VICTORY ELECTRIC COOPERATION ASSOCIATION, INC.	Western Kansas Industrial Electric Consumers	16-VICE-494-TAR	Direct	KS	Formula-Based Rate Plan	8/30/2016
WESTERN COOPERATIVE ELECTRIC ASSOCIATION, INC.	Western Kansas Industrial Electric Consumers	16-WSTE-496-TAR	Direct	KS	Formula-Based Rate Plan and Debt Service Payments	8/30/2016
NATIONAL FUEL GAS DISTRIBUTION CORPORATION	Multiple Intervenors	16-G-0257	Direct	NY	Embedded Class Cost of Service; Class Revenue Allocation; Rate Design	8/26/2016
METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPII	2016-2537349 2016-2537352 2016-2537359	Rebuttal	PA	Class Cost-of-Service; Class Revenue Allocation	8/17/2016
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	45524	Direct	TX	Revenue Requirement; Class Cost-of-Service; Revenue Allocation; Rate Design	8/16/2016
METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPII	2016-2537349 2016-2537352 2016-2537359	Direct	PA	Post-Test Year Sales Adjustment; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	7/22/2016
FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	160021	DIrect	FL	Multi-Year Rate Plan, Construction Work in Progress; Cost of Capital; Class Revenue Allocation; Class Cost-of-Service Study; Rate Design	7/7/2016
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Supplemental	AR	Support for Settlement Stipulation	7/1/2016
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2016-0001	Direct	IA	Application of Advanced Ratemaking Principles to Wind XI	6/21/2016
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	15-826	Direct	MN	Class Cost-of-Service Study, Class Revenue Allocation, Multi-Year Rate Plan, Rate Design	6/14/2016
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Surrebuttal	AR	Incentive Compensation, Class Cost-of-Service Study, Class Revenue Allocation, LCS-1 Rate Design	6/7/2016

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SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	15-00296-UT	Direct	NM	Support of Stipulation	5/13/2016
CHEYENNE LIGHT, FUEL AND POWER COMPANY	Dyno Nobel, Inc. and HollyFrontier Cheyenne Refining LLC	20003-146-ET-15	Cross	WY	Large Power Contract Service Tariff	4/15/2016
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Direct	AR	Incentive Compensation, Class Cost-of-Service Study, Class Revenue Allocation, Act 725, Formula Rate Plan	4/14/2016
CHEYENNE LIGHT, FUEL AND POWER COMPANY	Dyno Nobel, Inc. and HollyFrontier Cheyenne Refining LLC	20003-146-ET-15	Direct	WY	Large Power Contract Service Tariff	3/18/2016
ENTERGY LOUISIANA, LLC, ENTERGY GULF STATES LOUISIANA, L.L.C., AND ENTERGY LOUISIANA POWER, LLC	Occidental Chemical Corporation	U-33770	Cross-Answering	LA	Approval to Construct St. Charles Power Station	2/26/2016
NORTHERN INDIANA PUBLIC SERVICE COMPANY	NLMK-Indiana	44688	Cross-Answering	IN	Cost-of-Service Study, Rider 775	2/16/2016
ENTERGY LOUISIANA, LLC, ENTERGY GULF STATES LOUISIANA, L.L.C., AND ENTERGY LOUISIANA POWER, LLC	Occidental Chemical Corporation	U-33770	Direct	LA	Approval to Construct St. Charles Power Station	1/21/2016
EL PASO ELECTRIC COMPANY	Freeport-McMoRan Copper & Gold, Inc.	44941	Cross-Rebuttal	TX	Class Cost-of-Service Study, Class Revenue Allocation; Rate Design	1/15/2016
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-015	Supplemental	AR	Support for Settlement Stipulation	12/31/2015
EL PASO ELECTRIC COMPANY	Freeport-McMoRan Copper & Gold, Inc.	44941	Direct	TX	Class Cost-of-Service Study, Class Revenue Allocation; Rate Design	12/11/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-015	Surrebuttal	AR	Post-Test-Year Additions; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Riders; Formula Rate Plan	11/24/2015
MID-KANSAS ELECTRIC COMPANY, LLC, PRAIRIE LAND ELECTRIC COOPERATIVE, INC., SOUTHERN PIONEER ELECTRIC COMPANY, THE VICTORY ELECTRIC COOPERATIVE ASSOCIATION, INC., AND WESTERN COOPERATIVE ELECTRIC ASSOCIATION, INC.	Western Kansas Industrial Electric Consumers	16-MKEE-023	Direct	KS	Formula Rate Plan for Distribution Utility	11/17/2015
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	45084	Direct	TX	Transmission Cost Recovery Factor Revenue Increase.	11/17/2015
GEORGIA POWER COMPANY	Georgia Industrial Group and Georgia Association of Manufacturers	39638	Direct	GA	Natural Gas Price Assumptions, IFR Mechanism, Seasonal FCR-24 Rates, Imputed Capacity	11/4/2015
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	15-E-0283 15-G-0284 15-E-0285 15-G-0286	Rebuttal	NY	Electric and Gas Embedded Class Cost-of-Service Studies, Class Revenue Allocation	10/13/2015

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ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-015	Direct	AR	Post-Test-Year Additions; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Riders; Formula Rate Plan	9/29/2015
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	15-E-0283 15-G-0284 15-E-0285 15-G-0286	Direct	NY	Electric and Gas Embedded Class Cost-of-Service Studies, Class Revenue Allocation, Electric Rate Design	9/15/2015
SHARYLAND UTILITIES	Texas Industrial Energy Consumers	44620	Cross-Rebuttal	TX	Transmission Cost Recovery Factor Class Allocation Factors.	9/8/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	14-118	Surrebuttal	AR	Proposed Acquisition of Union Power Station Power Block 2 and Cost Recovery	8/21/2015
SHARYLAND UTILITIES	Texas Industrial Energy Consumers	44620	Direct	TX	Transmission Cost Recovery Factor Class Allocation Factors	8/7/2015
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2015-2468981	Surrebuttal	PA	Class Cost-of-Service, Capacity Reservation Rider	8/4/2015
WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	15-WSEE-115-RTS	Cross-Answering	KS	Class Cost-of-Service Study, Revenue Allocation	7/22/2015
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2015-2468981	Rebuttal	PA	Class Cost-of-Service, Class Revenue Allocation, Rate Design, Capacity Reservation Rider, Revenue Deoupling	7/21/2015
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	15-00083	Direct	NM	Long-Term Purchased Power Agreements	7/10/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-014	Surrebuttal	AR	Solar Power Purchase Agreement	7/10/2015
WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	15-WSEE-115-RTS	Direct	KS	Class Cost-of-Service and Electric Distrbution Grid Resiliency Program	7/9/2015
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	43958	Supplemental DIrect	TX	Certificiate of Need for Union Power Station Power Block 1	7/7/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	14-118	Direct	AR	Proposed Acquisition of Union Power Station Power Block 2 and Cost Recovery	7/2/2015
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2015-2468981	Direct	PA	Class Cost-of-Service, Class Revenue Allocation, Rate Design, Capacity Reservation Rider	6/23/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-014-U	Direct	AR	Solar Power Purchase Agreement	6/19/2015
FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	150075	Direct	FL	Cedar Bay Power Purchase Agreement	6/8/2015

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SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	43695	Cross-Rebuttal	TX	Class Cost of Service Study; Class Revenue Allocation	6/8/2015
FLORIDA POWER AND LIGHT COMPANY, DUKE ENERGY FLORIDA, GULF POWER COMPANY, TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	140226	Surrebuttal	FL	Opt-Out Provision	5/20/2015
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	43695	Direct	TX	Post-Test Year Adjustments; Weather Normalization	5/15/2015
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	43695	Direct	TX	Class Cost of Service Study; Class Revenue Allocation	5/15/2015
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	43958	Direct	TX	Certificiate of Need for Union Power Station Power Block 1	4/29/2015
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	42370	Cross-Rebuttal	TX	Allocation and recovery of Municipal Rate Case Expenses and the proposed Rate-Case-Expense Surcharge Tariff.	1/27/2015
WEST PENN POWER COMPANY	West Penn Power Industrial Intervenors	2014-2428742	Surrebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	1/6/2015
PENNSYLVANIA ELECTRIC COMPANY	Penelec Industrial Customer Alliance	2014-2428743	Surrebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	1/6/2015
METROPOLITAN EDISON COMPANY	Med-Ed Industrial Users Group	2014-2428745	Surrebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	1/6/2015
WEST PENN POWER COMPANY	West Penn Power Industrial Intervenors	2014-2428742	Rebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	12/18/2014
PENNSYLVANIA ELECTRIC COMPANY	Penelec Industrial Customer Alliance	2014-2428743	Rebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	12/18/2014
METROPOLITAN EDISON COMPANY	Med-Ed Industrial Users Group	2014-2428745	Rebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	12/18/2014
PUBLIC SERVICE COMPANY OF COLORADO	Colorado Healthcare Electric Coordinating Council	14AL-0660E	Cross	CO	Clean Air Clean Jobs Act Rider; Transmission Cost Adjustment	12/17/2014

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WEST PENN POWER COMPANY	West Penn Power Industrial Intervenors	2014-2428742	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation, Rate Design, Partial Services Rider; Storm Damage Rider	11/24/2014
PENNSYLVANIA ELECTRIC COMPANY	Penelec Industrial Customer Alliance	2014-2428743	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation, Rate Design, Partial Services Rider; Storm Damage Rider	11/24/2014
METROPOLITAN EDISON COMPANY	Med-Ed Industrial Users Group	2014-2428745	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation, Rate Design, Partial Services Rider; Storm Damage Rider	11/24/2014
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	14-E-0318 / 14-G-0319	Direct	NY	Class Cost-of-Service Study; Class Revenue Allocation (Electric)	11/21/2014
PUBLIC SERVICE COMPANY OF COLORADO	Colorado Healthcare Electric Coordinating Council	14AL-0660E	Direct	CO	Clean Air Clean Jobs Act Rider; Electric Commodity Adjustment Incentive Mechanism	11/7/2014
FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	140001-E	Direct	FL	Cost-Effectiveness and Policy Issues Surrounding the Investment in Working Gas Production Facilities	9/22/2014
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-446-ER14	Surrebuttal	WY	Class Cost-of-Service, Rule 12 (Line Extension Policy)	9/19/2014
INDIANA MICHIGAN POWER COMPANY	I&M Industrial Group	44511	Direct	IN	Clean Energy Solar Pilot Project, Solar Power Rider and Green Power Rider	9/17/2014
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-446-ER14	Cross	WY	Class Cost-of-Service Study; Rule 12 Line Extension	9/5/2014
VARIOUS UTILITIES	Florida Industrial Power Users Group	140002-EI	Direct	FL	Energy Efficiency Cost Recovery Opt-Out Provision	9/5/2014
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E-002/GR-13-868	Surrebuttal	MN	Nuclear Depreciation Expense, Monticello EPU/LCM Project, Class Cost-of-Service Study, Class Revenue Allocation, Fuel Clause Rider Reform, Rate Design	8/4/2014
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-446-ER14	Direct	WY	Class Cost-of-Service Study, Rule 12 Line Extension	7/25/2014
DUKE ENERGY FLORIDA	NRG Florida, LP	140111 and 140110	Direct	FL	Cost-Effectiveness of Proposed Self Build Generating Projects	7/14/2014
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E-002/GR-13-868	Rebuttal	MN	Class Cost-of-Service Study, Class Revenue Allocation	7/7/2014
PPL ELECTRIC UTILITIES CORPORATION	PP&L Industrial Customer Alliance	2013-2398440	Rebuttal	PA	Energy Efficiency Cost Recovery	7/1/2014

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NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E-002/GR-13-868	Direct	MN	Revenue Requirements, Fuel Clause Rider, Class Cost-of-Service Study, Rate Design and Revenue Allocation	6/5/2014
PPL ELECTRIC UTILITIES CORPORATION	PP&L Industrial Customer Alliance	2013-2398440	Direct	PA	Energy Efficiency Cost Recovery	5/23/2014
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	42042	Direct	TX	Transmission Cost Recovery Factor	4/24/2014
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	41791	Cross	TX	Class Cost-of-Service Study and Rate Design	1/31/2014
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	41791	Direct	TX	Revenue Requirements, Fuel Reconciliation; Cost Allocation Issues; Rate Design Issues	1/10/2014
DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Supplemental Surrebuttal	PA	Class Cost-of-Sevice Study	12/13/2013
DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Surrebuttal	PA	Class Cost-of-Service Study; Cash Working Capital; Miscellaneous General Expense; Uncollectable Expense; Class Revenue Allocation	12/9/2013
DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Rebuttal	PA	Rate L Transmission Service; Class Revenue Allocation	11/26/2013
ENTERGY TEXAS, INC. ITC HOLDINGS CORP.	Texas Industrial Energy Consumers	41850	Direct	TX	Rate Mitigation Plan; Conditions re Transfer of Control of Ownership	11/6/2013
SHARYLAND UTILITIES	Texas Industrial Energy Consumers and Atlas Pipeline Mid-Continent WestTex, LLC	41474	Cross-Rebuttal	TX	Customer Class Definitions; Class Revenue Allocation; Allocation of TTC costs	11/4/2013
MIDAMERICAN ENERGY COMPANY	Deere & Company	RPU-2013-0004	Surrebuttal	IA	Class Cost-of-Service Study; Class Revenue Allocation; Depreciation Surplus	11/4/2013
DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Direct	PA	Class Cost-of-Service, Class Revenue Allocations	11/1/2013
PUBLIC SERVICE ENERGY AND GAS	New Jersey Large Energy Users Coalition	EO13020155 and GO13020156	Direct	NJ	Energy Strong	10/28/2013
GEORGIA POWER COMPANY	Georgia Industrial Group and Georgia Association of Manufacturers	36989	Direct	GA	Depreciation Expense, Alternate Rate Plan, Return on Equity, Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	10/18/2013
SHARYLAND UTILITIES	Texas Industrial Energy Consumers and Atlas Pipeline Mid-Continent WestTex, LLC	41474	Direct	TX	Regulatory Asset Cost Recovery; Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	10/18/2013
MIDAMERICAN ENERGY COMPANY	Deere & Company	RPU-2013-0004	Rebuttal	IA	Class Cost-of-Service Study	10/1/2013

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FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	130007	Direct	FL	Environmental Cost Recovery Clause	9/13/2013
MIDAMERICAN ENERGY COMPANY	Deere & Company	RPU-2013-0004	Direct	IA	Class Cost-of-Service Study, Class Revenue Allocation, Depreciation, Cost Recovery Clauses, Revenue Sharing, Revenue True-up	9/10/2013
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	12-00350-UT	Rebuttal	NM	RPS Cost Rider	9/9/2013
WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	13-WSEE-629-RTS	Cross-Answering	KS	Cost Allocation Methodology	9/5/2013
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	12-00350-UT	Direct	NM	Class Cost-of-Service Study	8/22/2013
WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	13-WSEE-629-RTS	Direct	KS	Class Revenue Allocation.	8/21/2013
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	41437	Direct	TX	Avoided Cost; Standby Rate Design	8/14/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-699	Direct	KS	Class Revenue Allocation	8/12/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Supplemental	KS	Testimony in Support of Settlement	8/9/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Supplemental	KS	Modification Agreement	7/24/2013
TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	130040	Direct	FL	GSD-IS Consolidation, GSD and IS Rate Design, Class Cost-of-Service Study, Planned Outage Expense, Storm Damage Expense	7/15/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Supplemental	KS	Testimony in Support of Nonunanimous Settlement	6/28/2013
JERSEY CENTRAL POWER & LIGHT COMPANY	Gerdau Ameristeel Sayreville, Inc.	ER12111052	Direct	NJ	Cost of Service Study for GT-230 KV Customers; AREP Rider	6/14/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Direct	KS	Wholesale Requirements Agreement; Process for Excemption From Regulation; Conditions Required for Public Interest Finding on CCN spin-down	5/14/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Cross	KS	Formula Rate Plan for Distribution Utility	5/10/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Direct	KS	Formula Rate Plan for Distribution Utility	5/3/2013
ENTERGY TEXAS, INC. ITC HOLDINGS CORP.	Texas Industrial Energy Consumers	41223	Direct	TX	Public Interest of Proposed Divestiture of ETI's Transmission Business to an ITC Holdings Subsidiary	4/30/2013
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Surrebuttal	MN	Depreciation; Used and Useful; Cost Allocation; Revenue Allocation	4/12/2013

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NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Rebuttal	MN	Class Revenue Allocation.	3/25/2013
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Direct	MN	Depreciation; Used and Useful; Property Tax; Cost Allocation; Revenue Allocation; Competitive Rate & Property Tax Riders	2/28/2013
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Second Supplemental Rebuttal	TX	Competitive Generation Service Tariff	2/1/2013
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Second Supplemental Direct	TX	Competitive Generation Service Tariff	1/11/2013
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	40443	Cross Rebuttal	TX	Cost Allocation and Rate Design	1/10/2013
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	40443	Direct	TX	Application of the Turk Plant Cost-Cap; Revenue Requirements; Class Cost-of-Service Study; Class Revenue Allocation; Industrial Rate Design	12/10/2012
FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Corrected Supplemental Rebuttal	FL	Support for Non-Unanimous Settlement	11/13/2012
FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Corrected Supplemental Direct	FL	Support for Non-Unanimous Settlement	11/13/2012
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	12-E-0201/12-G-0202	Rebuttal	NY	Electric and Gas Class Cost-of-Service Studies.	9/25/2012
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	12-E-0201/12-G-0202	Direct	NY	Electric and Gas Class Cost-of-Service Study; Revenue Allocation; Rate Design; Historic Demand	8/31/2012
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	12-MKEE-650-TAR	Direct	KS	Transmission Formula Rate Plan	7/31/2012
WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	12-WSEE-651-TAR	Direct	KS	TDC Tariff	7/30/2012
FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Direct	FL	Class Cost-of-Service Study, Revenue Allocation, and Rate Design	7/2/2012
LONE STAR TRANSMISSION, LLC	Texas Industrial Energy Consumers	40020	Direct	TX	Revenue Requirement, Rider AVT	6/21/2012
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39896	Cross	TX	Class Cost-of-Service Study, Revenue Allocation, and Rate Design	4/13/2012
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39896	Direct	TX	Revenue Requirements, Class Cost-of-Service Study, Revenue Allocation, and Rate Design	3/27/2012
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Supplemental Rebuttal	TX	Competitive Generation Service Issues	2/24/2012
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Supplemental Direct	TX	Competitive Generation Service Issues	2/10/2012

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AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	39722	Direct	TX	Carrying Charge Rate Applicable to the Additional True-Up Balance and Tax Balances	11/4/2011
GULF POWER COMPANY	Florida Industrial Power Users Group	110138-EI	Direct	FL	Cost Allocation and Storm Reserve	10/14/2011
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	39504	Direct	TX	Carrying Charge Rate Applicable to the Additional True-Up Balance and Taxes	9/12/2011
AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	39361	Cross-Rebuttal	TX	Energy Efficiency Cost Recovery Factor	8/10/2011
AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	39360	Cross-Rebuttal	TX	Energy Efficiency Cost Recovery Factor	8/10/2011
ONCOR ELECTRIC DELIVERY COMPANY, LLC	Texas Industrial Energy Consumers	39375	Direct	TX	Energy Efficiency Cost Recovery Factor	8/2/2011
ALABAMA POWER COMPANY	Alabama Industrial Energy Consumers	31653	Direct	AL	Renewable Purchased Power Agreement	7/28/2011
AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	39361	Direct	TX	Energy Efficiency Cost Recovery Factor	7/26/2011
AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	36360	Direct	TX	Energy Efficiency Cost Recovery Factor	7/20/2011
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39366	Direct	TX	Energy Efficiency Cost Recovery Factor	7/19/2011
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	39363	Direct	TX	Energy Efficiency Cost Recovery Factor	7/15/2011
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-10-971	Surrebuttal	MN	Depreciation; Non-Asset Margin Sharing; Step-In Increase; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	5/26/2011
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-10-971	Rebuttal	MN	Classification of Wind Investment	5/4/2011
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-10-971	Direct	MN	Surplus Depreciation Reserve, Incentive Compensation, Non-Asset Trading Margin Sharing, Cost Allocation, Class Revenue Allocation, Rate Design	4/5/2011
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-381-EA-10	Direct	WY	2010 Protocols	2/11/2011

APPENDIX C

Procedures for Conducting a Class Cost-of-Service Study

Q WHAT PROCEDURES ARE USED IN A COST-OF-SERVICE STUDY?

A The basic procedure for conducting a CCOSS is fairly simple. First, we identify the different types of costs (functionalization), determine their primary causative factors (classification), and then apportion each item of cost among the various rate classes (allocation). Adding up the individual pieces gives the total cost for each class.

Identifying the utility's different levels of operation is a process referred to as functionalization. The utility's investments and expenses are separated into production, transmission, distribution, and other functions. To a large extent, this is done in accordance with the Uniform System of Accounts developed by FERC.

Once costs have been functionalized, the next step is to identify the primary causative factor (or factors). This step is referred to as classification. Costs are classified as demand-related, energy-related or customer-related. Demand (or capacity) related costs vary with peak demand, which is measured in kilowatts (kW). This includes production, transmission, and some distribution investment and related fixed Operation and Maintenance (O&M) expenses. As explained later, peak demand determines the amount of capacity needed for reliable service. Energy-related costs vary with the production of energy, which is measured in kilowatt-hours (kWh). Energy-related costs include fuel and variable O&M expense. Customer-related costs vary directly with the number of customers and include expenses such as meters, service drops, billing, and customer service.

Each functionalized and classified cost must then be allocated to the various customer classes. This is accomplished by developing allocation factors that reflect the percentage of the total cost that should be paid by each class. The allocation factors should reflect cost-causation; that is, the degree to which each class caused the utility to incur the cost.

Q WHAT KEY PRINCIPLES ARE RECOGNIZED IN A CLASS COST-OF-SERVICE STUDY?

A A properly conducted CCOSS recognizes two key cost-causation principles. First, customers are served at different delivery voltages. This affects the amount of investment the utility must make to deliver electricity to the meter. Second, since cost-causation is also related to how electricity is used, both the timing and rate of energy consumption (*i.e.*, demand) are critical. Because electricity cannot be stored for any significant time period, a utility must acquire sufficient generation resources and construct the required transmission facilities to meet the maximum projected demand, including a reserve margin as a contingency against forced and unforced outages, severe weather, and load forecast error. Customers that use electricity during the critical peak hours cause the utility to invest in generation and transmission facilities.

Q WHAT FACTORS CAUSE THE PER-UNIT COSTS TO DIFFER AMONG CUSTOMER CLASSES?

A Factors that affect the per-unit cost include whether a customer's usage is constant or fluctuating (load factor), whether the utility must invest in transformers and distribution systems to provide the electricity at lower voltage levels, the amount of electricity that a customer uses, and the quality of service (*e.g.,* firm or non-firm). In general, industrial consumers are less costly to serve on a per-unit basis because they:

- operate at higher load factors;
- take service at higher delivery voltages; and
- use more electricity per customer.

Further, non-firm service is a lower quality of service than firm service. Thus, non-firm service is less costly per unit than firm service for customers that otherwise have the same characteristics. This explains why some customers pay lower average rates than others.

For example, the difference in the losses incurred to deliver electricity at the various delivery voltages is a reason why the per-unit energy cost to serve is not the same for all customers. More losses occur to deliver electricity at distribution voltage (either primary or secondary) than at transmission voltage, which is generally the level at which industrial customers take service. This means that the cost per kWh is lower for a transmission customer than a distribution customer. The cost to deliver a kWh at primary distribution, though higher than the per-unit cost at transmission, is lower than the delivered cost at secondary distribution.

In addition to lower losses, transmission customers do not use the distribution system. Instead, transmission customers construct and own their own distribution systems. Thus, distribution system costs are not allocated to transmission level customers who do not use that system. Distribution customers, by contrast, require substantial investments in these lower voltage facilities to provide service. Secondary distribution customers require more investment than primary distribution customers. This results in a different cost to serve each type of customer.

Two other cost drivers are efficiency and size. These drivers are important because most fixed costs are allocated on either a demand or customer basis.

Efficiency can be measured in terms of load factor. Load factor is the ratio of average demand (*i.e.*, energy usage divided by the number of hours in the period) to peak demand. A customer that operates at a high load factor is more efficient than a lower load factor customer because it requires less capacity for the same amount of energy. For example, assume that two customers purchase the same amount of energy, but one customer has an 80% load factor and the other has a 40% load factor. The 40% load factor customers would have twice the peak demand of the 80% load factor customers, and the utility would therefore require twice as much capacity to serve the 40% load factor customer as the 80% load factor. Said differently, the fixed costs to serve a high load factor customer are spread over more kWh usage than for a low load factor customer.

EL PASO ELECTRIC COMPANY

Calculation of EPE's Unadjusted 1CP System Load Factor

For The Test Year Ended December 31, 2020

		Native System			
Line	Period	Net Output to Lines (MWh)	System Peak (MW)	Hours	Load Factor*
		(1)	(2)	(3)	(4)
1	Annual	8,674,263	2,173	8,784	45.44%
2	January	609,370	1,078	744	75.98%
3	February	563,992	1,133	696	71.52%
4	March	567,567	1,015	744	75.16%
5	April	562,888	1,386	720	56.41%
6	May	752,315	1,650	744	61.28%
7	June	896,734	1,932	720	64.47%
8	July	1,039,608	2,173	744	64.30%
9	August	1,033,192	2,100	744	66.13%
10	September	769,845	1,870	720	57.18%
11	October	667,494	1,449	744	61.92%
12	November	556,416	1,042	720	74.17%
13	December	654,842	1,097	744	80.23%

Source: Schedule O-1.6.

* $\dfrac{\text{MWh Net Output to Lines}}{\text{Native System Peak x Period Hours x 100}}$

Exhibit JP-2

EL PASO ELECTRIC COMPANY

Derivation of Revised AED-4CP Demand Allocation Using the Actual 1CP Annual System Load Factor For The Test Year Ended December 31, 2020

Line	Description	Coincident Demand at Supply (kW) June	July	August	September	Avg. 4CP Demand (kW)	Average Demand (kW)	Excess Demand (kW)	D1PROD 4-CP Average and Excess*
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Residential Service	769,203	919,158	857,187	754,267	824,954	305,257	519,697	55.5549%
2	Small General Service	70,762	76,679	72,638	63,800	70,970	33,433	37,536	4.7287%
3	Outdoor Recreational Lighting Service	0	0	0	0	0	451	0	0.0284%
4	Street Lighting	0	0	0	0	0	4,427	0	0.2784%
5	Traffic Signals	195	194	194	194	194	255	0	0.0160%
6	Municipal Pumping Service - TOU	21,155	31,935	22,772	19,377	23,810	21,011	2,799	1.5173%
7	Electrolytic Refining Service	7,737	7,737	7,737	7,737	7,737	5,018	2,718	0.5058%
8	Off Peak Water Heating Service	424	391	338	373	381	629	0	0.0396%
9	Irrigation Service	1,384	1,881	1,247	1,282	1,448	471	977	0.0980%
10	General Service	318,545	328,431	308,672	306,945	315,648	178,033	137,615	20.8245%
11	Large Power Service	97,489	103,585	104,810	104,704	102,647	74,433	28,214	6.6553%
12	Petroleum Refining Service	41,374	41,374	41,374	41,374	41,374	36,776	4,599	2.6348%
13	Private Area Lighting Service	0	0	0	0	0	3,294	0	0.2072%
14	Electric Furnace Rate	5,128	5,127	5,129	5,125	5,127	2,523	2,604	0.3409%
15	Military Reservation Service	52,230	52,230	52,230	52,230	52,230	32,556	19,674	3.4240%
16	Cotton Gin Service	20	11	14	22	17	196	0	0.0123%
17	City and County Service	43,949	49,880	47,326	47,640	47,199	23,763	23,436	3.1341%
18	Total Texas Firm Load	1,429,594	1,618,613	1,521,668	1,405,071	1,493,737	722,528	779,869	100.000%
19	Total Texas Interruptible Load	41,056	60,224	42,973	49,167		Load Factor =	0.454444	1CP Sys LF
							1 Minus Load Factor =	0.545556	O-01.06
20	Total Texas Load	1,470,650	1,678,837	1,564,641	1,454,238	1,542,092			

EL PASO ELECTRIC COMPANY
Derivation of Revised Energy Allocation Factors
For The Test Year Ended December 31, 2020

Line	Rate Class	Texas kWh at Meter	Loss Factor	Texas kWh at Source	E1ENERGY Allocator at Source
		(1)	(2)	(3)	(4)
1	Residential Service	2,486,208,912	1.0785	2,681,376,311	42.2709%
2	Small General Service	272,303,567	1.0785	293,679,397	4.6297%
3	Outdoor Rec. Lighting: Secondary	3,639,116	1.0785	3,924,787	0.0619%
4	Outdoor Rec. Lighting Primary	37,410	1.0512	39,327	0.0006%
5	Street Lighting	36,054,763	1.0785	38,885,062	0.6130%
6	Traffic Signals	2,075,778	1.0785	2,238,727	0.0353%
7	Municipal Pumping: Secondary	123,976,228	1.0785	133,708,362	2.1079%
8	Municipal Pumping: Primary	48,374,126	1.0512	50,852,332	0.8017%
9	Electrolytic Refining Service	42,604,774	1.0284	43,815,687	0.6907%
10	Off Peak Water Heating Service	5,123,640	1.0785	5,525,846	0.0871%
11	Irrigation Service	3,840,029	1.0785	4,141,472	0.0653%
12	General Service: Secondary	1,418,502,292	1.0785	1,529,854,722	24.1176%
13	General Service: Primary	32,332,348	1.0512	33,988,734	0.5358%
14	Large Power Service: Secondary	425,051,982	1.0785	458,418,562	7.2268%
15	Large Power Service: Primary	178,355,773	1.0512	187,492,939	2.9558%
16	Large Power Service: Transmission	7,699,293	1.0217	7,866,429	0.1240%
17	Petroleum Refining Service	314,641,719	1.0217	321,471,961	5.0679%
18	Private Area Lighting Service	26,829,319	1.0785	28,935,421	0.4562%
19	Electric Furnace Rate: 69 kV	7,629,850	1.0251	7,821,435	0.1233%
20	Electric Furnace Rate: Transmission	13,938,782	1.0217	14,241,365	0.2245%
21	Military Reservation Service	278,539,097	1.0217	284,585,624	4.4864%
22	Cotton Gin Service	1,596,380	1.0785	1,721,696	0.0271%
23	City and County Service: Secondary	166,997,658	1.0785	180,106,975	2.8393%
24	City and County Service: Primary	27,233,617	1.0512	28,628,795	0.4513%
25	Total Texas Firm Energy	5,923,586,453		6,343,321,968	100.0000%
26	Outdoor Rec. Lighting Service			3,964,113	0.0625%
27	Municipal Pumping			184,560,694	2.9095%
28	General Service			1,563,843,457	24.6534%
29	Large Power Service			653,777,931	10.3066%
30	Electric Furnace Rate			22,062,801	0.3478%
31	City and County Service			208,735,770	3.2906%

Exhibit JP-4

EL PASO ELECTRIC COMPANY

Derivation of Revised AED-4CP Demand Allocation Using
The Revised Energy Loss Factors and the Actual 1CP Annual System Load Factor
For The Test Year Ended December 31, 2020

Line	Description	Coincident kW at Supply June	July	August	September	4-CP Average	Annual Average kW	Excess kW	D1PROD 4-CP Average and Excess*
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Residential Service	769,203	919,158	857,187	754,267	824,954	305,257	519,697	54.7476%
2	Small General Service	70,762	76,679	72,638	63,800	70,970	33,433	37,536	4.7287%
3	Outdoor Recreational Lighting Service	0	0	0	0	0	447	0	0.0304%
4	Street Lighting	0	0	0	0	0	4,427	0	0.3011%
5	Traffic Signals	195	194	194	194	194	255	0	0.0173%
6	Municipal Pumping Service - TOU	21,155	31,935	22,772	19,377	23,810	15,222	8,588	1.5970%
7	Electrolytic Refining Service	7,737	7,737	7,737	7,737	7,737	4,988	2,749	0.5190%
8	Off Peak Water Heating Service	424	391	338	373	381	629	0	0.0428%
9	Irrigation Service	1,384	1,881	1,247	1,282	1,448	471	977	0.0960%
10	General Service	318,545	328,431	308,672	306,945	315,648	174,164	141,484	21.0985%
11	Large Power Service	97,489	103,585	104,810	104,704	102,647	52,188	50,459	6.8494%
12	Petroleum Refining Service	41,374	41,374	41,374	41,374	41,374	36,597	4,777	2.8017%
13	Private Area Lighting Service	0	0	0	0	0	3,294	0	0.2241%
14	Electric Furnace Rate	5,128	5,127	5,129	5,125	5,127	890	4,237	0.3376%
15	Military Reservation Service	52,230	52,230	52,230	52,230	52,230	32,398	19,832	3.5005%
16	Cotton Gin Service	20	11	14	22	17	196	0	0.0133%
17	City and County Service	43,949	49,880	47,326	47,640	47,199	3,259	43,940	3.0950%
18	Total Texas Firm Load	1,429,594	1,618,613	1,521,668	1,405,071	1,493,737	668,116	834,275	100.000%
19	Total Texas Interruptible Load	41,056	60,224	42,973	49,167		Load Factor =	0.454444	1CP Sys LF
							1 Minus Load Factor =	0.545556	O-01.06
20	Total Texas Load	1,470,650	1,678,837	1,564,641	1,454,238	1,542,092			

EL PASO ELECTRIC COMPANY

Revised Class Cost of Service Study
For The Test Year Ended December 31, 2020
(Amount in $000)

Line	Description	Texas Retail	R01- Residential	R02- Small Gen Serv	R07- Rec Light	R08- Street Light	R09-Traffic Signs	R11TOU- Muni Pump	R15- Elec Refining	R22- Irrig Serv	R24- Gen Serv
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Rate Base	$2,043,902	$1,181,523	$102,269	$2,650	$10,199	$290	$34,665	$6,873	$2,028	$413,588
2	Overall Return	7.985%	7.985%	7.985%	7.985%	7.985%	7.985%	7.985%	7.985%	7.985%	7.985%
3	Return on Rate Base	$163,210	$94,347	$8,166	$212	$814	$23	$2,768	$549	$162	$33,026
4	Operating Expense	561,309	240,148	22,266	364	2,134	69	6,867	1,610	316	80,279
5	Federal Income Taxes	23,584	13,708	1,197	32	124	3	402	76	23	4,732
6	State Income Taxes	3,529	2,042	177	5	18	1	60	12	3	713
7	Total Revenue Requirement	751,632	350,245	31,806	613	3,090	96	10,096	2,247	505	118,749
8	Other Operating Revenues	(177,101)	(18,116)	(1,604)	(11)	(50)	(4)	(458)	(131)	(7)	(6,168)
9	Base Revenue Requirement	$574,531	$332,129	$30,202	$602	$3,041	$92	$9,638	$2,116	$498	$112,581
10	Current Base Revenue	$532,714	$273,639	$33,320	$463	$4,047	$95	$10,102	$1,830	$423	$125,006
11	Required Increase	$41,818	$58,490	($3,118)	$139	($1,006)	($3)	($464)	$286	$75	($12,425)
12	Less COVID Surcharge	$2,196	$1,342	$137	$3	$15	$0	$34	$7	$2	$378
13	Base Revenue Increase	$39,622	$57,148	($3,255)	$136	($1,021)	($3)	($498)	$279	$73	($12,802)
14	Percent Increase	7.4%	20.9%	-9.8%	29.4%	-25.2%	-3.4%	-4.9%	15.3%	17.2%	-10.2%

EL PASO ELECTRIC COMPANY

Revised Class Cost of Service Study
For The Test Year Ended December 31, 2020
(Amount in $000)

Line	Description	R25- Large Power	R26- Petro Refining	R28- P Area Light	R30- Elec Furnace	R31- Mili Reserv	R34- Cotton Gin	R41- Cty/Cnty	RWH- Water Heating
		(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
1	Rate Base	$126,463	$36,196	$9,046	$4,600	$46,473	$789	$63,556	$2,692
2	Overall Return	7.985%	7.985%	7.985%	7.985%	7.985%	7.985%	7.985%	7.985%
3	Return on Rate Base	$10,098	$2,890	$722	$367	$3,711	$63	$5,075	$215
4	Operating Expense	25,840	9,179	1,804	1,029	10,789	106	11,909	595
5	Federal Income Taxes	1,443	402	107	51	513	9	727	34
6	State Income Taxes	218	62	16	8	80	1	110	5
7	Total Revenue Requirement	37,599	12,534	2,649	1,455	15,093	179	17,821	849
8	Other Operating Revenues	(1,908)	(702)	(32)	(87)	(884)	(3)	(883)	(49)
9	Base Revenue Requirement	$35,692	$11,833	$2,617	$1,368	$14,209	$176	$16,938	$800
10	Current Base Revenue	$35,956	$10,965	$2,933	$1,192	$13,010	$133	$19,127	$475
11	Required Increase	($264)	$868	($315)	$177	$1,199	$43	($2,189)	$326
12	Less COVID Surcharge	$120	$41	$7	$4	$46	$1	$56	$5
13	Base Revenue Increase	($384)	$827	($322)	$172	$1,153	$42	($2,245)	$320
14	Percent Increase	-1.1%	7.5%	-11.0%	14.5%	8.9%	31.9%	-11.7%	67.5%

EL PASO ELECTRIC COMPANY
EPE's Proposed Class Revenue Alocation
For the Test Year Ended December 31, 2020
Amounts in ($000)

Line	Rate Class	Base Revenues at Present Rates	Base Revenues at Proposed Rates	Proposed Increase Amount	Proposed Increase Percent
		(1)	(2)	(3)	(4)
1	Residential Service	$273,639	$310,833	$37,194	13.6%
2	Small General Service	$33,320	$32,373	($947)	-2.8%
3	Recreational Lighting Service	$463	$628	$165	35.6%
4	Street Lighting	$4,047	$3,134	($913)	-22.6%
5	Traffic Signals	$95	$100	$5	5.0%
6	Municipal Pumping Service - TOU	$10,102	$10,389	$287	2.8%
7	Electrolytic Refining Service	$1,830	$2,280	$450	24.6%
8	Off Peak Water Heating Service	$475	$539	$65	13.6%
9	Irrigation Service	$423	$569	$146	34.4%
10	General Service	$125,006	$122,112	($2,893)	-2.3%
11	Large Power Service	$35,956	$37,975	$2,019	5.6%
12	Petroleum Refining Service	$10,965	$13,184	$2,220	20.2%
13	Private Area Lighting Service	$2,933	$2,696	($236)	-8.1%
14	Electric Furnace Rate	$1,192	$1,535	$343	28.8%
15	Military Reservation Service	$13,010	$15,056	$2,046	15.7%
16	Cotton Gin Service	$133	$182	$49	36.6%
17	City and County Service	$19,126	$18,435	($691)	-3.6%
18	Total Firm Revenues	$532,714	$572,021	$39,308	7.4%
19	Non-Firm Revenues	$3,642	$4,174	$532	14.6%
20	Total Texas Retail	$536,356	$576,196	$39,840	7.4%

Source: Schedule Q-1.

EL PASO ELECTRIC COMPANY
EPE's Proposed Vs. Cost-Based Increases
For the Test Year Ended December 31, 2020
(Amounts in $000)

Line	Rate Class	Proposed Increase Amount	Proposed Increase Percent	Cost-Based Increase Per EPE CCOSS Amount	Cost-Based Increase Per EPE CCOSS Percent	Proposed As a % of Cost-Based Increase
		(1)	(2)	(3)	(4)	(5)
1	Residential Service	$37,194	13.6%	$51,265	18.7%	73%
2	Small General Service	($947)	-2.8%	($3,318)	-10.0%	29%
3	Recreational Lighting Service	$165	35.6%	$151	32.6%	109%
4	Street Lighting	($913)	-22.6%	($983)	-24.3%	93%
5	Traffic Signals	$5	5.0%	$3	3.2%	155%
6	Municipal Pumping Service - TOU	$287	2.8%	$61	0.6%	470%
7	Electrolytic Refining Service	$450	24.6%	$400	21.9%	112%
8	Off Peak Water Heating Service	$65	13.6%	$330	69.5%	20%
9	Irrigation Service	$146	34.4%	$134	31.5%	109%
10	General Service	($2,893)	-2.3%	($11,145)	-8.9%	26%
11	Large Power Service	$2,019	5.6%	$1,201	3.3%	168%
12	Petroleum Refining Service	$2,220	20.2%	$1,936	17.7%	115%
13	Private Area Lighting Service	($236)	-8.1%	($296)	-10.1%	80%
14	Electric Furnace Rate	$343	28.8%	$310	26.0%	111%
15	Military Reservation Service	$2,046	15.7%	$1,720	13.2%	119%
16	Cotton Gin Service	$49	36.6%	$45	33.5%	109%
17	City and County Service	($691)	-3.6%	($2,192)	-11.5%	32%

EL PASO ELECTRIC COMPANY
EPE's Proposed Vs. Cost-Based Increases
For the Test Year Ended December 31, 2020
(Amounts in $000)

		Proposed Increase		Cost-Based Increase Per FMI CCOSS		Proposed As a % of Cost-Based
Line	Rate Class	Amount	Percent	Amount	Percent	Increase
		(1)	(2)	(3)	(4)	(5)
1	Residential Service	$37,194	13.6%	$57,148	20.9%	73%
2	Small General Service	($947)	-2.8%	($3,255)	-9.8%	29%
3	Recreational Lighting Service	$165	35.6%	$136	29.4%	121%
4	Street Lighting	($913)	-22.6%	($1,021)	-25.2%	89%
5	Traffic Signals	$5	5.0%	($3)	-3.4%	-144%
6	Municipal Pumping Service - TOU	$287	2.8%	($498)	-4.9%	-58%
7	Electrolytic Refining Service	$450	24.6%	$279	15.3%	161%
8	Off Peak Water Heating Service	$65	13.6%	$320	67.5%	20%
9	Irrigation Service	$146	34.4%	$73	17.2%	200%
10	General Service	($2,893)	-2.3%	($12,802)	-10.2%	23%
11	Large Power Service	$2,019	5.6%	($384)	-1.1%	-526%
12	Petroleum Refining Service	$2,220	20.2%	$827	7.5%	268%
13	Private Area Lighting Service	($236)	-8.1%	($322)	-11.0%	73%
14	Electric Furnace Rate	$343	28.8%	$172	14.5%	199%
15	Military Reservation Service	$2,046	15.7%	$1,153	8.9%	177%
16	Cotton Gin Service	$49	36.6%	$42	31.9%	114%
17	City and County Service	($691)	-3.6%	($2,245)	-11.7%	31%

Exhibit JP-8

EL PASO ELECTRIC COMPANY
Change in Energy Sales and Base Revenues
Since EPE's Last Rate Case

		Energy Sales (MWh)			Base Revenues ($000)		
Line	Rate Class	D46831	D52195	Percent Change	D46831 Settlement Rates	D52195 Present Rates	Percent Change
		(1)	(2)	(3)	(4)	(5)	(6)
1	Residential Service	2,122,892	2,478,851	17%	$231,250	$273,639	18%
2	Small General Service	277,318	272,309	-2%	$32,913	$33,320	1%
3	Outdoor Recreational Lighting Service	5,319	7,316	38%	$570	$463	-19%
4	Street Lighting	33,231	36,055	8%	$3,738	$4,047	8%
5	Traffic Signals	2,629	2,655	1%	$91	$95	5%
6	Municipal Pumping Service - TOU	159,476	172,350	8%	$8,913	$10,102	13%
7	Electrolytic Refining Service	55,781	42,605	-24%	$2,260	$1,830	-19%
8	Off Peak Water Heating Service	8,664	5,124	-41%	$679	$475	-30%
9	Irrigation Service	5,046	3,840	-24%	$481	$423	-12%
10	General Service	1,532,875	1,450,802	-5%	$124,721	$125,006	0%
11	Large Power Service	647,278	611,107	-6%	$38,132	$35,956	-6%
12	Petroleum Refining Service	334,025	314,642	-6%	$11,823	$10,965	-7%
13	Private Area Lighting Service	27,182	26,829	-1%	$2,762	$2,933	6%
14	Electric Furnace Rate	18,429	21,569	17%	$1,291	$1,192	-8%
15	Military Reservation Service	264,627	278,539	5%	$12,437	$13,010	5%
16	Cotton Gin Service	1,604	1,596	0%	$120	$133	10%
17	City and County Service	289,710	193,241	-33%	$26,857	$19,126	-29%
18	Total Firm Revenues	5,786,085	5,919,429	2%	$499,040	$532,714	7%

EL PASO ELECTRIC COMPANY
FMI's Recommended Class Revenue Allocation
For the Test Year Ended December 31, 2020
(Amounts in $000)

Line	Rate Class	Base Revenues at Present Rates	FMI's Recommended Allocation Amount	FMI's Recommended Allocation Percent
		(1)	(2)	(3)
1	Residential Service	$273,639	$57,148	20.9%
2	Small General Service	$33,320	($3,236)	-9.7%
3	Recreational Lighting Service	$463	$136	29.4%
4	Street Lighting	$4,047	($1,015)	-25.1%
5	Traffic Signals	$95	($3)	-3.4%
6	Municipal Pumping Service - TOU	$10,102	($496)	-4.9%
7	Electrolytic Refining Service	$1,830	$279	15.3%
8	Off Peak Water Heating Service	$475	$204	43.0%
9	Irrigation Service	$423	$73	17.2%
10	General Service	$125,006	($12,730)	-10.2%
11	Large Power Service	$35,956	($382)	-1.1%
12	Petroleum Refining Service	$10,965	$827	7.5%
13	Private Area Lighting Service	$2,933	($320)	-10.9%
14	Electric Furnace Rate	$1,192	$172	14.5%
15	Military Reservation Service	$13,010	$1,153	8.9%
16	Cotton Gin Service	$133	$42	31.9%
17	City and County Service	$19,126	($2,232)	-11.7%
18	Total Firm Revenues	$532,714	$39,622	7.4%