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SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR AUTHORITY TO CHANGE RATES	§ § § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

Direct Testimony and Exhibits

of

JEFFRY POLLOCK

On Behalf of

Texas Industrial Energy Consumers

March 31, 2021

J. POLLOCK
INCORPORATED

313

SOAH DOCKET NO. 473-21-0538
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LIST OF EXHIBITS

GLOSSARY OF ACRONYMS

Term	Definition
1CP	Annual System Peak
4CP	Four Coincident Peak
A&E	Average and Excess
ATC	Approved Transmission Charges
BTMG	Behind-the-Meter Generation
CCOSS	Class Cost-of-Service Study
Eastman	Eastman Chemical Company
FERC	Federal Energy Regulatory Commission
kW / kWh	Kilowatt / Kilowatt-Hour
LLP	Large Lighting & Power
LLP-T	Large Lighting & Power - Transmission
MW	Megawatt
NARUC CAM	National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual
OATT	Open Access Transmission Tariff
REC	Renewable Energy Credit
SBMA	Supplemental, Backup, Maintenance, and As-Available
SPP	Southwest Power Pool
SPP Zone 1	SPP Transmission Pricing Zone 1
SPS	Southwestern Public Service Company
SSGL	Synchronous Self-Generation Load
SWEPCO	Southwestern Electric Power Company
T.A.C.	Texas Administrative Code
TCRF	Transmission Cost Recovery Factor
TIEC	Texas Industrial Energy Consumers
QF	Qualifying Facility

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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 Texas Industrial Energy Consumers 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 and B, which have been prepared in written form for introduction into evidence in SOAH Docket No. 473-21-0538 and Public Utility Commission of Texas Docket No. 51415; and,

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

Jeffry Pollock

Subscribed and sworn to before me this 31st day of March 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 Masters 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 Texas Industrial Energy Consumers (TIEC). TIEC members purchase substantial amounts of electricity from Southwestern Electric Power Company (SWEPCO) under various rate schedules.

Q WHAT ISSUES ARE YOU ADDRESSING?

A I am addressing the following issues:

- The proposed tracker for Approved Transmission Costs (ATC).
- Whether SWEPCO should be allowed to recover ATC associated with retail load served from behind-the-meter generation (BTMG).
- The class cost-of-service study (CCOSS) and, in particular, the application of the Average and Excess Four Coincident Peak (A&E/4CP) method.
- Class revenue allocation.
- The design of the Large Lighting & Power (LLP) rate.
- The proposed Synchronous Self-Generation Load (SSGL) charge.

Q ARE YOU SPONSORING ANY EXHIBITS TO YOUR DIRECT TESTIMONY?

A Yes. I am sponsoring **Exhibits JP-1** through **JP-5**.

Q ARE YOU ENDORSING SWEPCO'S PROPOSALS ON THE ISSUES NOT ADDRESSED IN YOUR TESTIMONY?

A No. The fact that I am not addressing every issue should not be interpreted as an endorsement of SWEPCO's proposals in this proceeding.

Summary

Q PLEASE SUMMARIZE YOUR FINDINGS.

A My findings are as follows:

ATC Tracker

- SWEPCO is proposing a mechanism to defer only that portion of on-going Southwest Power Pool (SPP) charges that qualify as ATC under 16 Texas Admin. Code (T.A.C.) § 25.239(b)(1) that are either above or below the ATC component of the baseline Transmission Cost Recovery Factor (TCRF) revenue requirement established in this case.
- The ATC is but one element of the TCRF. SWEPCO also receives revenue credits from SPP for the use of SWEPCO's transmission facilities. The

revenue credits generally exceed the ATC by between $1.9 million and $4 million. Further, over time, changes in revenue credits have generally paralleled the changes in ATC.

- A tracker is not required to provide SWEPCO a reasonable opportunity to earn a reasonable return on its used and useful facilities and to recover its reasonable and necessary expenses. Accordingly, the Commission should reject SWEPCO's proposed ATC tracker.

ATC Cost Related to Retail Behind-the-Meter Generation

- SWEPCO asserts that it is incurring $5.7 million of additional transmission expense because, beginning in October 2018, it reported the load served by Eastman Chemical Company's (Eastman's) BTMG to the SPP. This load was included in determining the Load Ratio Shares that are used to spread regional transmission costs to each of the transmission pricing zones including SPP Transmission Pricing Zone 1 (SPP Zone 1), which includes SWEPCO.

- Prior to October 2018, SWEPCO did not report retail BTMG load to SPP, and none of SWEPCO's retail BTMG load was included in determining SWEPCO's share of regional and zonal transmission costs.

- SWEPCO now claims that the SPP's Open Access Transmission Tariff (OATT) requires including retail BTMG load in spreading transmission costs to the various zones, even though it did not apply that interpretation prior to October 2018. However, a careful reading of the OATT and the various Federal Energy Regulatory Commission (FERC) Orders interpreting the various provisions of the OATT demonstrate that self-supplied electricity by retail customers does not fall within the definition of SWEPCO's "Monthly Network Load" under Section 34.4. This provision only applies to wholesale BTMG.

- Retail customers are not Network Customers under the OATT.

- There is no consensus within SPP that retail BTMG load should be included in determining the Load Ratio Shares. A majority of the responding SPP

Network Customers believed that some or all load served by retail BTMG was not included in the meaning of Network Customer's Monthly Network Load. In fact, SPP considered *and rejected* a proposal to amend its OATT to add load served by retail BTMG to Network Load. Thus, SWEPCO's new practice of including retail BTMG load is not required under the SPP OATT.

- MISO's OATT contains virtually identical language to SPP's OATT when addressing the allocation of "Network Load" costs. Yet, MISO has determined that it need not report retail BTMG load, and FERC has approved that approach.
- SWEPCO does not actually serve Eastman's BTMG load except during a generator outage, which occurs infrequently, when Eastman purchases Backup, Maintenance, and As-Available standby services. During the test year, none of the Eastman load was supplied by SWEPCO at the time of the monthly SPP Zone 1 peaks.
- The Eastman facility is a qualifying facility (QF). Including the full retail loads served from on-site self-supplied generation would be contrary to both federal and state regulations applicable to QFs. These regulations include a requirement that in designing rates for standby power, a utility cannot assume, unless supported by factual data, that forced outages or other reductions in output by all QFs on an electric utility's system will occur simultaneously, or during the time of system peak, or both.
- SWEPCO should immediately discontinue the practice of adding certain load served by retail BTMG in determining its hourly load coincident with the SPP zonal monthly peak in determining the Load Ratio Shares used to determine SWEPCO's share of SPP's region-wide expenses.
- The $5.7 million is the additional *all-in* transmission revenue requirement assuming that Eastman's BTMG load is imputed entirely to the Texas retail jurisdiction, and there is no other retail BTMG load served by SWEPCO in Arkansas, Louisiana, or Texas. However, the transmission costs billed to SWEPCO by SPP are only a subset of SWEPCO's all-in transmission costs.

Accordingly, SWEPCO's calculation does not actually reflect the incremental cost of including Eastman's BTMG load in reporting Network Load to SPP.

- If the Commission rejects SWEPCO's treatment of Eastman's BTMG load, it should disallow $5.7 million of transmission expense.

Class Cost-of-Service Study

- SWEPCO is proposing significant changes in how it is applying the A&E/4CP method. The changes are:
- Using a 4CP (rather than a 1CP) load factor to weight average demand;
- For transmission plant and related expenses, the 4CPs were based on loads coincident with SPP Zone 1 monthly system peaks rather than SWEPCO's actual 4CPs; and
- Imputing retail BTMG load in determining the allocation of transmission costs to a single customer class: Large Lighting & Power Transmission (LLP-T).
- The Commission previously directed SWEPCO to use the 1CP load factor in applying A&E/4CP. Nothing has changed to warrant using a different load factor in this case.
- Although it may be reasonable to use allocation methodologies consistent with FERC's policies to separate costs between regulatory jurisdictions, retail class allocations have always been based on the practices adopted by this Commission, which use SWEPCO's system characteristics. Accordingly, SWEPCO's Texas retail transmission costs should continue to be allocated to retail customer classes using demands coincident with SWEPCO's system peaks.
- The A&E/4CP transmission plant allocator assumed that SWEPCO served Eastman's BTMG load at the equivalent of a 98% load factor. Not only is this contrary to the facts because the Eastman load was served almost entirely from its own generation, it specifically violates this Commission's rules and ratemaking practices applicable to QFs. Accordingly, retail BTMG load should be removed from the A&E/4CP transmission plant allocator.

- All of Eastman's retail BTMG load was allocated to the LLP-T class. Eastman is the only LLP-T customer that operates BTMG synchronized to the SPP grid. Because synchronous BTMG is not a characteristic of LLP-T customers, none of this load should be attributed to the LLP-T class.

- Eastman is not the only retail customer that serves load from BTMG, but it is the only one which SWEPCO has chosen to include in its reported Network Load. If retail BTMG load is to be included in allocating transmission costs, it would be appropriate to establish a separate rate schedule applicable to all retail BTMG loads.

- Ms. LaConte is recommending that $30.4 million of excess accumulated deferred income taxes be refunded to customers. The $30.4 million should be allocated to rate schedules based on the allocation of accumulated deferred income taxes in the approved CCOSS.

<u>Class Revenue Allocation</u>

- SWEPCO is proposing equal percentage increases for the rates included in each major class. The proposed increases for each major class were based on the results of SWEPCO's CCOSS.

- SWEPCO defines just four major customer classes: Residential, Commercial & Industrial, Municipal, and Lighting. This is in contrast to the 22 separate Texas retail classes used in SWEPCO's CCOSS and the 10 separate rate schedules (excluding lighting).

- The 22 customer classes used in SWEPCO's CCOSS are far too granular and include several low-population classes. Further, several customer classes take service under the same rate schedule. The concern with low population customer classes is that changes in the characteristics of only one or two customers may have a significant impact on the revenues and costs allocated to the class. Combining similarly situated classes may alleviate any instability caused by these changing loads.

- To minimize instability while moving all rates closer to cost, the class definitions should generally correspond to SWEPCO's retail rate schedules.

- Any base rate increase authorized for SWEPCO should be spread to each rate schedule using the results of a CCOSS that incorporates the recommendations summarized above. The movement to cost should be limited only by gradualism.
- Consistent with the Order in Docket No. 46449, gradualism should be defined as a 46.2% increase in base revenues, including TCRF and DCRF charges.

Large Lighting & Power Rate Design

- The revenue requirement allocated to the LLP class should be informed by the CCOSS results. Specifically, because the LLP-T class is providing a much higher return than the LLP-Primary class, the LLP-T class should be assigned a much smaller base rate increase than the LLP-Primary class.
- SWEPCO has not provided support for increasing the Reactive Demand charge. Accordingly, SWEPCO's proposal should be rejected.
- During the test year, SWEPCO incurred renewable energy certificate (REC) costs associated with its wind energy purchases. These costs were allocated to all customer classes. However, under 16 T.A.C. § 25.173(j), transmission level customers may elect to opt-out of these charges.
- SWEPCO does not currently have an opt-out mechanism for transmission level customers. Accordingly, SWEPCO should be required to implement an opt-out credit for REC costs applicable to LLP-T customers.

Synchronous Self-Generation Load Charge

- SWEPCO is proposing a $2.20 per kW (of contract demand) charge for SSGL service. The charge would be implemented in SWEPCO's Supplementary, Backup, Maintenance, and As-Available (SBMA) rate schedules. Thus, it would not apply to other retail BTMG customers unless SWEPCO requires these customers to take standby service.
- SSGL is not a standby service.
- Only retail BTMG load taking standby service (Eastman) would pay the proposed charge. SWEPCO estimates that Eastman would pay $3.96 million

annually. Coupled with the increase in standby charges, Eastman's base rate costs would increase by 143%.

- The Commission should reject the proposed SSGL charge because it is not a retail service that SWEPCO is actually providing.
- However, if the Commission approves a SSGL charge:
    - It should be provided under a separate rate schedule applicable to all retail BTMG customers.
    - Further, given the controversies surrounding this service and the severe impact of SWEPCO's proposed SSGL charge, it should be phased in at not more than 50% of the actual cost.
    - Because the cost is based on demand occurring coincident with the SPP Zone 1 monthly system peak, the SSGL charge should be billed on a coincident demand basis.

2. ATC TRACKER

Q IS SWEPCO PROPOSING A CHANGE IN HOW CERTAIN TRANSMISSION EXPENSES ARE RECOVERED?

A Yes. SWEPCO witness, Mr. Thomas Brice, describes a proposed ATC tracker as follows:

> SWEPCO proposes that the portion of its ongoing SPP OATT charges that is above or below the net Test Year level approved for recovery by the Commission, be deferred into a regulatory asset or liability until they can be addressed in a future Transmission Cost Recovery Factor (TCRF) or base-rate proceeding.[1]

Specifically, SWEPCO would defer only that portion of on-going SPP charges that qualify as ATC under 16 T.A.C. § 25.239(b)(1) that are either above or below the ATC component of the baseline TCRF revenue requirement established in this case.[2]

During the test-year, ATC accounted for $72 million of the $81 million (or 89%) of SWEPCO's proposed TCRF baseline costs.[3] Thus, the proposed ATC tracker would guarantee dollar-for-dollar recovery of the vast majority of SWEPCO's total baseline transmission costs.

Q IS THERE ANY PRECEDENT FOR IMPLEMENTING A TRACKER THAT GUARANTEES FULL RECOVERY OF WHOLESALE TRANSMISSION COSTS FOR NON-ERCOT UTILITIES?

A No. The only authorized mechanism applicable to non-ERCOT utilities is the TCRF. The TCRF authorizes a non-ERCOT utility to recover, after notice and hearing:

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[1] Direct Testimony of Thomas P. Brice at 12-13.

[2] Direct Testimony of John O. Aaron at 30.

[3] *Id.*, Exhibit JOA-5.

> ...its reasonable and necessary costs for transmission infrastructure improvement and changes in wholesale transmission charges to the electric utility under a tariff approved by a federal regulatory authority to the extent that the costs or charges have not otherwise been recovered and are incurred after December 31, 2005. Any such recovery shall be made through the use of a transmission cost recovery factor (TCRF) approved by an order of the commission.[4]

Q ARE THERE ANY LIMITS TO HOW OFTEN A NON-ERCOT UTILITY CAN ADJUST ITS TCRF?

A Yes. The limits are as follows:

> An electric utility may not apply to amend its TCRF more frequently than once each calendar year, but a TCRF shall be reviewed or amended at least once every three years. Upon completion of a base rate case for a utility, the TCRF shall be set to zero.[5]

Q HOW WOULD THE PROPOSED ATC TRACKER BE DIFFERENT THAN THE TCRF?

A SWEPCO's proposed ATC tracker would effectively provide for contemporaneous, rather than annual, cost recovery.

Q SHOULD SWEPCO'S PROPOSED ATC TRACKER BE ADOPTED?

A No. First, the proposed ATC tracker is not consistent with either 16 T.A.C. § 25.239 or PURA § 36.209, which pertain to the recovery of certain transmission costs and are applicable only to non-ERCOT utilities.

Second, SWEPCO's proposal would also constitute piecemeal ratemaking, as SWEPCO is not proposing to track changes in its other costs and revenues. Indeed, SWEPCO's proposal amounts to piecemeal ratemaking even as to TCRF eligible

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[4] 16 T.A.C. § 25.239(c).

[5] 16 T.A.C. § 25.239(f).

costs. This is because ATC is not the only TCRF component that is affected by SPP's billing processes. In addition to ATC, SWEPCO also receives revenue credits from other SPP members for their use of SWEPCO's transmission system. However, SWEPCO is not proposing to track changes in the revenue credits.

Q **ARE THE TRANSMISSION REVENUE CREDITS RECEIVED BY SWEPCO SIGNIFICANT?**

A Yes. Table 1 provides a summary of the transmission revenue credits received by SWEPCO. Also shown are the ATC-related expenses.

Table 1
Texas Retail Transmission Revenue Credits and Approved Transmission Costs[6]
($Million)

Docket	Revenue Credits	ATC	Net
46449	$60.2	$56.8	$3.4
49042	$79.9	$78.0	$1.9
51415	$75.7	$71.7	$4.0

For example, during the test year in this rate case, SWEPCO received $75.7 million of revenue credits, but it paid only $71.7 million of ATC. Thus, the revenue credits exceeded the ATC expenses by $4 million. As Table 1 demonstrates, this was also the case in SWEPCO's last rate case (Docket No. 46449) and its last TCRF filing (Docket No. 49042). Not only have the revenue credits exceeded the ATC, they have closely tracked changes in ATC. Had SWEPCO implemented the ATC tracker in

[6] Direct Testimony of John O. Aaron, WP_Exhibit JOA-5; *Application of Southwestern Electric Power Company for Authority to Amend Transmission Cost Recovery Factor*, Docket No. 49042, Direct Testimony and Exhibits of John O. Aaron, Exhibit JOA-2 (Dec. 19, 2018).

Docket No. 46449, it would have collected approximately $21 million in higher rates while ignoring the approximately $20 million in higher revenues.[7] Creating opportunities for windfall profits is both inequitable to customers and unnecessary to provide SWEPCO a reasonable opportunity to earn a reasonable return on its invested capital in excess of its reasonable and necessary expenses.

Q WHAT DO YOU RECOMMEND?

A SWEPCO's proposed ATC tracker should be rejected because it is contrary to the ratemaking practices adopted for non-ERCOT utilities would constitute piecemeal ratemaking and is not needed to provide SWEPCO a reasonable opportunity to earn a reasonable return. Furthermore, because the change in revenue credits has closely tracked changes in ATC, the proposed ATC tracker would not even accurately capture SWEPCO's net wholesale transmission costs.

[7] Referring to Table 1, $21.2 million is the increase in ATC from Docket No. 46449 to Docket No. 49042 ($78.0 million – $56.8 million). The corresponding increase in the Revenue Credits is $19.7 million ($79.9 million - $60.2 million).

3. BEHIND-THE-METER GENERATION

Q ARE THERE ANY ISSUES SURROUNDING THE DETERMINATION OF SWEPCO'S TEST-YEAR TRANSMISSION EXPENSES?

A Yes. There is an issue with SWEPCO's proposed test-year transmission wheeling expenses booked to FERC Account No. 565. SWEPCO reports its total load for purposes of calculating its share of costs under the SPP OATT. However, beginning in October 2018, SWEPCO reported not just its native load (which is the load that SWEPCO actually serves) but also the load (approximately 146 MW during the test year) of one retail customer, Eastman. Eastman supplies the vast majority of its electricity from its own BTMG.[8] Because SWEPCO began reporting this additional 146 MW of Eastman's self-supplied load as if it were SWEPCO's load, it was used by SPP to derive the Load Ratio Shares that determine the portion of regional transmission costs allocable to SPP Zone 1, which includes SWEPCO.

As a consequence of SWEPCO's decision to begin including Eastman's self-supplied BTMG load in its Network Load reports to SPP, it purportedly has incurred $5.7 million of additional transmission expense for the test year.[9]

However, as discussed later, this new practice is not required under the SPP OATT. Many SPP load serving entities previously stated that they do not include retail BTMG in the loads they report to SPP in determining their respective Load Ratio Shares. SWEPCO itself did not include this load until October 2018, and there was no change to SPP's OATT at that time requiring this change. Consequently, SWEPCO's test-year transmission expenses are unnecessarily overstated.

[8] SWEPCO Response to TIEC 6-11, Attachment 1.

[9] SWEPCO Response to TIEC 5-1.

Q WHAT DO YOU MEAN BY LOAD RATIO SHARE?

A Load Ratio Share is calculated as the proportion of a Network Customer's or Transmission Owner's Resident Load relative to the total Resident Load in the SPP Region. The Network Customer's or Transmission Owner's monthly zonal Resident Load is itself determined as its integrated hourly load coincident with the monthly peak of the zone where the Resident Load is physically located.[10] The Base Plan Zonal Load Ratio Share is defined in the OATT as follows (both before and after October 2018):

> ***Ratio of a Network Customer's or Transmission Owner's Resident Load in a Zone to the total load in that Zone computed in accordance with Section II.B to Schedule 11*** of this Tariff and calculated on a calendar year basis, for the prior calendar year.[11] (emphasis added)

Q WHAT DO YOU MEAN BY TRANSMISSION PRICING ZONE 1?

A SPP Zone 1 is the geographic area that includes SWEPCO's transmission facilities. It is one of 19 zones established by SPP. The other entities located in SPP Zone 1 include Public Service Company of Oklahoma, East Texas Electric Cooperative, Arkansas Electric Cooperative Corporation, and several smaller entities. SWEPCO's native load constitutes approximately 37% of the SPP Zone 1 loads.[12]

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[10] SPP OATT, *Sixth Revised Volume No. 1*, Schedule 11 Base Plan Zonal Charge and Region-wide Charge, II.B. (Eff. Jul. 1, 2018).

[11] *Id.*, Definitions (Eff. Jan. 1, 2021).

[12] Derived from SWEPCO Response to TIEC 6-11, Attachment 1.

Q IS IT SWEPCO'S POSITION THAT IT WILL REPORT LOAD SERVED BY A CUSTOMER'S OWN GENERATION EVEN IF SWEPCO NEVER SERVES THAT LOAD?

A Yes. Since October 2018, SWEPCO's position is that it reports retail BTMG load to the SPP even if it never serves that load. It should be noted that SWEPCO has not reported the retail BTMG load of residential and commercial customers.[13]

Q DOES SWEPCO'S REPORTING OF RETAIL BTMG LOAD AFFECT THE LOAD RATIO SHARES USED BY SPP TO BILL CERTAIN REGIONAL TRANSMISSION EXPENSES?

A Yes. The Load Ratio Share calculation includes both SWEPCO's own native load and the electricity that retail customers are providing and consuming behind the retail customer's meter. Thus, by including retail BTMG load, the Load Ratio Share for SPP Zone 1 and SWEPCO's share of any other transmission expenses directly assigned to this Zone are inflated.

Q SWEPCO ASSERTS THAT THE SPP OATT REQUIRES ITS MEMBERS TO REPORT ALL RETAIL LOAD SERVED BY A RETAIL CUSTOMER'S OWN BEHIND-THE-METER GENERATION IN DETERMINING THE MONTHLY NETWORK LOAD OF EACH LOAD ZONE. DO YOU AGREE?

A No. SWEPCO's application of SPP OATT prior to October 2018 was correct — its new interpretation is incorrect. Self-supplied electricity by retail customers does not fall within the definition of SWEPCO's "Monthly Network Load" under Section 34.4 of

[13] SWEPCO Response to TIEC 5-3.

the SPP OATT. "Network Customer's Monthly Network Load" is defined by Section 34.4 as the Network Customer's:

> ...hourly load (60 minute, clock-hour); provided, however, the Network Customer's monthly Network Load will be its hourly load coincident with the monthly peak of the Zone where the Network Customer load is physically located.[14]

The "Network Customer's Monthly Network Load" thereby excludes everything other than the Network Customer's hourly load coincident with the monthly peak. The "Network Customer" is the "entity receiving transmission service pursuant to the terms of the Transmission Provider's [SPP's] Network Integration Transmission Service under Part III of the Tariff."[15] That is, the Network Customer is SWEPCO. If a business or residential customer of SWEPCO is generating its own electricity behind its own meter for its own use at the time of SWEPCO's monthly peak, that use is irrelevant in determining SWEPCO's "hourly load coincident with the monthly peak" as used in Section 34.4. That applies whether the electricity is provided by rooftop solar or by a QF. SWEPCO is simply not providing the electricity produced and consumed on-site by a retail customer.

Indeed, as discussed later, SWEPCO may seldom provide backup power for the customer's self-supplied electricity, and it may not even know how much electricity, if any, a business or residence in its service area is providing to itself at the time of the monthly peak since electricity that is self-provided is often not even metered by the utility. In any event, electricity that is being self-provided behind a retail meter is not

[14] SPP OATT, *Sixth Revised Volume No. 1,* III Network Integration Transmission Service, 34.4 Determination of Network Customer's Monthly Network Load (Eff. Jul. 1, 2016).

[15] *Id.*, Definitions.

being provided by SWEPCO, nor is it being delivered over SWEPCO's transmission and distribution system. Accordingly, it cannot be fairly characterized as the utility's "hourly load coincident with the monthly peak."

Q DO THE SAME PRINCIPLES APPLY TO RETAL BTMG AS APPLY TO WHOLESALE BTMG?

A No. Some of the confusion about the treatment of load served by retail BTMG results from failing to distinguish between retail and wholesale generation. The above analysis would not apply to whatever portion of a Network Customer's load is served by wholesale BTMG—which would use the Network Customer's transmission and distribution system to deliver electricity to retail customers of the Network Customer. That load is a part of the Network Customer's load, as FERC has determined. To the extent that load is being served by wholesale BTMG at the time of the monthly coincident peak, it would fall within the definition of "Network Customer's Monthly Network Load" under Section 34.4. That is not true, however, of electricity being provided by a retail customer's own on-site generation at the time of the monthly coincident peak.

Q HAVE SPP MEMBERS ALWAYS INCLUDED RETAIL BTMG LOAD IN DETERMINING THE LOAD RATIO SHARES?

A No. SWEPCO only began reporting retail BTMG load in October 2018.[16] Even then, SWEPCO only reported the retail BTMG Load of industrial customers, even though other customer classes have retail BTMG load and the SPP tariff makes no distinction

[16] SWEPCO Response to TIEC 6-3.

in the treatment of retail load based on customer class. Further, many SPP members have stated that they did not report their retail customers' self-supplied electricity in calculating the loads used to determine Load Ratio Shares.[17]

Q IS THERE A CONSENSUS WITHIN SPP TO REQUIRE UTILITIES TO ADD LOAD SELF-SUPPLIED BY RETAIL BEHIND-THE-METER GENERATION TO NETWORK LOAD?

A No. A 2019 survey conducted by SPP revealed that a majority of the responding SPP Network Customers believed that some or all load served by retail BTMG was not included in the meaning of Network Customer's Monthly Network Load.[18]

Q IS THE ISSUE OF RETAIL BTMG LOAD ADDRESSED IN THE FERC ORDERS UNDERLYING THE SPP'S OPEN ACCESS TRANSMISSION TARIFF?

A No. In FERC proceedings, electric cooperatives and municipal utilities have argued that FERC should allow them to net their own Wholesale BTMG, which uses the Network Customer's transmission and distribution system to serve the Network Customer's load, against their Network Load.[19] Their argument can be summarized as follows:

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[17] *Id.*, Attachment 1 at 30-32.

[18] SPP Market and Operations Policy Committee, *MOPC Policy Survey: Behind-The-Meter Generation* at 6 (Oct. 15-16, 2019).

[19] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*; Docket Nos. RM95-8-000 and RM94-7-001, Initial Comments of Cajun Electric Power Cooperative, Inc. at 17-19 (Aug. 3, 1995) (noting that QF load behind the meter would not be included in the load ratios shown under the OATT); *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*; Docket Nos. RM95-8-001 and RM94-7-002, Request for Clarification and Rehearing of American Municipal Power-Ohio, Inc. at 15-17 (May 24, 1996) (where AMP-Ohio sought an offset against their NITS load so that certain municipalities would not have to rely on point-to-point service after those municipalities installed generation to serve local loads).

- A retail customer's load that is served by its own retail BTMG *is not included* in the allocation of transmission costs;
- Network Customers' load served by its own Wholesale BTMG *is included* in the allocation of transmission cost;
- Therefore, not netting loads served by Wholesale BTMG would cause Network Customers to be treated differently than retail native load customers;
- To avoid disparate treatment of Network Customers and retail customers, just as retail BTMG is not included in the allocation of transmission costs neither should Wholesale BTMG be included in the allocation of transmission costs.

This argument unambiguously seeks to amend FERC's treatment of *Network Customers*, not retail customers.

The FERC understood that electric cooperatives and municipal utilities were arguing about Network Customers, not retail customers. That's why FERC referred to "customers" to mean "Network Customers"—because those were the customers at issue in these proceedings.[20] For example, FERC stated that "customers" could exclude particular load if they obtained alternative transmission service—something that applies only to Network Customers.[21] Similarly, FERC concluded that its allocation of Network Service costs was "based on readily available data."[22] Data on how much electricity retail customers were self-generating (such as from rooftop solar or a QF) was not available, meaning that FERC must have been talking about Network, not retail Customers, when it used the word "customers.

[20] *See for example:* Docket Nos. RM95-8-000 and RM94-7-001; Order No. 888 (Apr. 24, 1996); Docket Nos. RM95-8-001 and RM94-7-002; Order No. 888-A (Mar. 14, 1997); and *Preventing Undue Discrimination and Preference in Transmission Service*, Docket Nos. RM05-17-000 and RM05-25-000, Order No. 890 ¶1614 (Feb. 16, 2007).

[21] *Id.*, Order No. 888 at 91, 97.

[22] *Id.* at 91.

Q WHAT DO YOU CONCLUDE?

A Based on my understanding of FERC policy, FERC has not addressed the issue of *retail* BTMG load in its Orders underlying the SPP's OATT. The FERC Orders on which SWEPCO relies apply to wholesale BTMG load and acknowledge that retail BTMG load is not included.

Q HAS FERC INTERPRETED SIMILAR TARIFF LANGUAGE TO EXCLUDE BEHIND-THE-METER RETAIL LOAD?

A Yes. FERC has allowed MISO to exclude BTMG retail load.[23] Importantly, the OATTs for MISO and SPP contain virtually identical language when addressing the allocation of "Network Load" costs.[24]

MISO determined that this OATT language dictates that a Network Customer (namely, Entergy in MISO's case) need report only the net usage of a QF to determine Network Load and ergo need not report retail BTMG load.[25] That is, load served by a retail customer's BTMG should not be included in Network Load—the exact opposite of SWEPCO's new interpretation. FERC affirmed this interpretation of the OATT by determining that no tariff change was required to the language in MISO's OATT, meaning that FERC agreed that the language in MISO's OATT—virtually the same language as exists in SPP's OATT—does not require a Network Customer to report retail BTMG load.[26]

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[23] 155 FERC ¶ 61, 068 (2016) at 76.

[24] MISO FERC Electric Tariff, Module B, Section 34.2.

[25] *Occidental Chemical Corporation v. Midwest Independent Transmission System Operator, Inc.*, Docket No. EL13-41-000, Petition for Declaratory Order and Compliant Requesting Fast Track Processing of Occidental Chemical Corporation Against the Midwest Independent Transmission System Operator, Inc., Attachment A, dated Oct. 10, 2012 "Qualifying Facility (QF) Generator Readiness for MISO Reliability Coordination and Market Integration" at 17-18 (Jan. 17, 2013).

[26] 155 FERC ¶ 61, 068 (2016) at 76.

Q HAS SPP CONSIDERED AMENDING ITS OATT TO BE CONSISTENT WITH SWEPCO'S NEW INTERPRETATION?

A. Yes. SPP considered *and rejected* a proposal to amend its OATT to add load served by retail BTMG. In 2017, the SPP Regional Tariff Working Group proposed to revise the SPP OATT, specifically Section 34.4 discussed above, to, for the first time, *add* load served by retail BTMG greater than 1 MW to the definition of Monthly Network Load.[27] The proposed amendment would not have applied to load equal to or less than 1 MW served by retail BTMG.

Q. WHAT DOES SPP'S REJECTION OF THE PROPOSED AMENDMENT DEMONSTRATE ABOUT THE MEANING OF THE CURRENT OATT?

A. It shows that the current definition of "Network Customer's Monthly Network Load" does not include load served by retail BTMG, and it does this in two ways. First, the proposed amendment to add load served by retail BTMG over 1MW would have been entirely unnecessary if that load was already included in the definition of Network Load. The fact that a proposed amendment was required to add this load demonstrates that it was not included absent the amendment. Second, the proposed amendment did not address load served by BTMG under 1 MW whatsoever. That is, the treatment of that load would continue as it was under current language. And it is clear that SPP's view was that such load would not be included in Network Load.

[27] SPP, RR 241. https://www.spp.org/spp-documents-filings/?document_name=MOPC+Policy+on+Determination+of+Network+Load&docket=&start=&end=&filter_filetype=&search_type=filtered_search

In summary, SPP realized that it needed to amend the OATT if it wanted to add load served by retail BTMG for over 1 MW load. SPP also recognized that leaving the language completely unchanged for under 1 MW BTMG load maintained the status quo of not including that load in Network Load. SPP adopted no tariff change, leaving the status quo in place for all load served by retail BTMG.

Q DOES SWEPCO APPLY ITS NEW INTERPRETATION OF THE SPP OATT CONSISTENTLY TO ALL RETAIL BTMG?

A. No. SPP's OATT makes no distinction based on the size of the BTMG or the customer class of the BTM generator. Yet, SWEPCO has unilaterally decided to interpret the language one way for commercial or residential BTMG and a completely opposite way for industrial BTMG.[28] The identical words in the same provision cannot mean completely different things for industrial customers than for commercial and residential customers.

Q IS SWEPCO'S PROPOSED TREATMENT OF LOAD SERVED BY RETAIL BTMG CONSISTENT WITH HOW IT TREATS SIMILAR RETAIL LOAD?

A No. For example, for an interruptible customer that takes 50 MW of power from SWEPCO most hours of the month but is not taking power at the time of the peak, SWEPCO would include zero MW in its reported Network Load. Yet a similar customer that takes no power from SWEPCO the entire month because it is providing its own power would have its entire 50 MW load reported by SWEPCO to SPP. SWEPCO would report that 50 MW of load even if the customer could never possibly take more

[28] SWEPCO Response to TIEC 5-3.

than 10 MW of power from SWEPCO.[29] It makes no sense to report load that SWEPCO is not serving and perhaps could never serve, while ignoring similar sized load that SWEPCO actually does serve. And SWEPCO's decision to do so for a single customer has resulted in it incurring unnecessary costs.

Q WHAT DO YOU CONCLUDE?

A If a retail customer of SWEPCO is generating its own electricity behind its own meter for its own use at the time of SWEPCO's monthly peak, that use is not part of SWEPCO's "hourly load coincident with the monthly peak" as stated in Section 34.4 of the SPP OATT. Further, unless SWEPCO is providing the electricity produced and consumed on-site by a retail customer, it would not fall within the definition of "Network Customer's Monthly Network Load" in Section 34.4 of the SPP OATT. Accordingly, SWEPCO should not have included any of this load in its hourly load coincident with the monthly peak.

Q WOULD THE PRACTICE OF ADDING LOAD SERVED BY RETAIL BEHIND-THE-METER GENERATION BE CONSISTENT WITH FEDERAL AND STATE REGULATIONS?

A No. The Eastman facility is a QF. Including the full retail loads served from on-site self-supplied generation would be contrary to both federal and state regulations applicable to QFs. These regulations include a requirement that in designing rates for standby power, a utility cannot assume, unless supported by factual data, that forced outages or other reductions in output by all QFs on an electric utility's system will occur

[29] *Id.*

simultaneously, or during the time of system peak, or both.[30] The Eastman facility at issue here is a QF. SWEPCO proposes to attribute SPP network costs to Eastman as if SWEPCO were providing power to replace 100% of Eastman's generation at the time of the monthly peak. That is the very assumption that the regulations concerning QFs prohibits.

Q IS THERE ANY EVIDENCE THAT EASTMAN'S LOAD REQUIRED NETWORK TRANSMISSION SERVICE AT THE TIME OF THE SYSTEM PEAK OF EITHER SWEPCO OR THE SPP ZONE 1?

A No. Eastman's load is served by Eastman Cogeneration LP from a two-on-one combined cycle gas turbine with a summer net capacity of over 400 megawatts (MWs).[31] Since 2013, the facility generated more energy than Eastman consumed in all but three months.[32] Further, during the test year, the facility generated more power than Eastman's coincident demand with the SPP Zone 1 system peaks in all 12 months. Based on my review of the Eastman generation data, outages have been infrequent and have not occurred coincident with the monthly system peaks of either SWEPCO or SPP Zone 1.

Thus, there is no evidence that Eastman's load requires any network transmission service during the SWEPCO and SPP Zone 1 monthly system peaks.

[30] 18 C.F.R. Subchapter K, § 292.305(c)(i); P.U.C. SUBST. R. 25.242(k)(3)(A).

[31] S&P Global Market Intelligence, Eastman Cogeneration Facility.

[32] *Id.*

Q HOW DID SWEPCO DERIVE THE $5.7 MILLION IMPACT OF EASTMAN'S BTMG LOAD?

A The $5.7 million is based on comparing the Texas retail revenue requirement excluding ($99.3 million) and including ($105.0 million) Eastman's BTMG load. In other words, SWEPCO assumed that it does not serve any other retail BTMG load in Arkansas, Louisiana, or Texas other than Eastman. Thus, SWEPCO's analysis merely changed how *total* transmission costs, of which ATC is only a subset, would be allocated between regulatory jurisdictions solely as a result of imputing Eastman's BTMG load to Texas.[33]

Q IS THIS AN APPROPRIATE WAY TO QUANTIFY THE IMPACT OF RETAIL BTMG LOAD?

A No. The $5.7 million is not the actual impact of Eastman's BTMG load.

Q WHAT DO YOU RECOMMEND?

A The Commission should disallow $5.7 million of transmission expense. Further, SWEPCO should cease reporting any retail BTMG load in determining Load Ratio Shares to the SPP and revert back to the practice it was using prior to October 2018. Not only is this new practice contrary to federal and state regulations, it is not a requirement of the SPP OATT or any FERC Orders.

[33] SWEPCO Response to TIEC 11-1.

4. CLASS COST-OF-SERVICE STUDY

Q DO YOU HAVE ANY SPECIFIC CONCERNS WITH SWEPCO'S CLASS COST-OF-SERVICE STUDY?

A Yes. SWEPCO is proposing significant changes in how it is applying the A&E/4CP method. The changes include:

- Using a 4CP (rather than a 1CP) load factor to weight average demand;
- For transmission plant and related expenses, the 4CPs were based on loads coincident with SPP Zone 1 monthly system peaks rather than SWEPCO's actual 4CPs; and
- Imputing retail load served from BTMG to just one customer class: LLP-T.

Background

Q WHAT IS A CLASS COST-OF-SERVICE STUDY?

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 on behalf of the various customer groups. Most of a utility's costs are incurred to jointly serve many customers. For purposes of rate design and revenue allocation, customers are grouped into homogeneous customer classes according to their usage patterns and service characteristics.

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 (kWs). This includes production, transmission, and some distribution investment and related fixed 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 (kWhs). 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 several 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. Finally, customers who self-serve all or a portion of their power needs from BTMG will have dramatically different load characteristics than customers who purchase all or most of the power from the utility. Thus, they should be costed separately.

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 either primary distribution or primary substation customers. More investment is required to serve a primary distribution than a primary substation customer. 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.

A&E/4CP Method

Q WHAT IS THE A&E/4CP METHOD?

A A&E/4CP is a variation of the Average and Excess method. Average and Excess is one of several methodologies recognized in the National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual (NARUC CAM) that explicitly considers energy usage in developing allocation factors.[34] The A&E/4CP allocation factors are derived as follows:

$$A\&E = (AD\% \times SLF\%) + [ED\% \times (1\text{-}SLF\%)]$$

[34] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual* (Jan. 1992).

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

SLF% = System Load Factor.[35]

The AD component of the A&E allocation factors is the product of each class's percent of Average Demand (*i.e.,* energy consumption) and the SLF. 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.[36]

The ED component of A&E 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 A&E/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. This recognizes two important cost drivers:

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

Q IS SWEPCO PROPOSING TO CHANGE HOW IT APPLIES THE A&E/4CP METHOD SINCE ITS LAST RATE CASE?

A Yes. SWEPCO is proposing several changes. First, SWEPCO is proposing to change

[35] *Id.* at 49-50.

[36] *Id.*

the load factor used to weight average demand. Specifically, it is now proposing to calculate the system load factor using the average peak demand in the four summer months (4CP) rather than the actual annual peak demand. However, in Docket No. 46449, the Commission specifically rejected the approach SWEPCO proposes in this case and directed it to use the annual system peak (1CP) load factor. SWEPCO complied with the Commission's directive in its compliance filing pursuant to the Order in Docket No. 46449, but it ignored that directive in this filing.

Second, SWEPCO is using different 4CP demands to derive the excess demand used in the A&E/4CP formula for transmission plant than for production plant. For production plant, SWEPCO properly uses the 4CPs that correspond to SWEPCO's monthly summer system peaks. However, for transmission, the 4CP demands are based on the demands occurring coincident with the SPP Zone 1 monthly summer peaks, not SWEPCO's actual monthly peak demands.

Third, as previously discussed, SWEPCO imputed retail load served from BTMG. Specifically, SWEPCO imputed 149 MW of 4CP demand and 146 MW of average demand in determining the A&E/4CP transmission allocation factor for the LLP-T class. Prior to October 2018, retail BTMG load was not included in applying A&E/4CP. Further, unlike the other LLP-T customers, SWEPCO did not physically provide generation and transmission to actually serve this BTMG load for the vast majority of the hours during the test year. I will discuss the imputed retail load later.

Q HOW WAS THE A&E/4CP METHOD APPLIED IN SWEPCO'S LAST RATE CASE?

A First, the Commission approved the 1CP load factor for weighting average demand. The same weighting was used for both production and transmission plant. Second, the 4CPs used to derive the excess demand were based on SWEPCO's system peak, not the SPP Zone 1 monthly summer peaks. Finally, no retail BTMG load was imputed in determining the transmission A&E/4CP allocation factors.

Q WHY USE A 1CP LOAD FACTOR IN APPLYING THE AVERAGE AND EXCESS METHOD?

A First, the NARUC CAM states that the annual (*i.e.*, 1CP) load factor should be used in applying the A&E method.[37] Second, using the annual system peak (1CP) is consistent with the way that SPP assesses resource adequacy. Specifically, each SPP member is obligated to provide a 12% capacity margin. The 12% capacity margin is measured relative to each utility's annual system peak.[38] Thus, using the 1CP load factor is consistent with system planning.

Q HOW IS SYSTEM LOAD FACTOR DEFINED?

A System load factor is defined as the ratio of the average load over a designated period to the peak demand occurring in that period.[39] Thus, if average load is measured over a year, it follows that the system load factor should be measured using the annual system peak or 1CP. In other words, system load factor is measured using the 1CP (not the average of four coincident peaks).

Q HAS THE LOAD FACTOR ISSUE BEEN LITIGATED IN PRIOR CASES?

A Yes. The load factor issue was first litigated in a prior Southwestern Public Service

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[37] *Id.* at 81-82.

[38] *SPP Planning Criteria*, Revision 2.3 (Jan. 11, 2021).

[39] NARUC CAM at 81.

Company (SPS) rate case, Docket No. 43695. In that case, the Commission rejected SPS's proposal to use a 4CP load factor and approved a 1CP load factor.

Q DID THE COMMISSION APPROVE THE SAME TREATMENT FOR SWEPCO?

A Yes. This issue was litigated in SWEPCO's last rate case, Docket No 46449, and the Commission cited the aforementioned SPS case in its Final Order requiring SWEPCO to use the annual coincident peak. 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 0-1.6.
>
> 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.
>
> 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.[40]

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

Q HAS ANYTHING CHANGED SINCE SWEPCO'S LAST RATE CASE TO JUSTIFY USING A 4CP, RATHER THAN A 1CP, LOAD FACTOR?

A No.

Q SHOULD THE COMMISSION ADOPT SWEPCO'S PROPOSAL TO USE THE SPP ZONE 1 LOADS, RATHER THAN SWEPCO'S OWN SYSTEM PEAK DEMANDS, TO DETERMINE HOW TRANSMISSION PLANT AND RELATED EXPENSES ARE ALLOCATED TO RETAIL CUSTOMER CLASSES?

A No. As previously discussed, the SPP Zone 1 monthly peaks include not only SWEPCO's native load, but also the load served by Public Service Company of Oklahoma and other wholesale entities. While this practice is authorized under the provisions of the SPP OATT for reporting Network Load to SPP, there is no precedent for applying FERC ratemaking practices in allocating costs to Texas retail customers. Even more unprecedented is SWEPCO's proposal to impute retail BTMG load, which I discuss later.

Q ARE THERE LARGE DIFFERENCES BETWEEN THE MONTHLY SYSTEM PEAKS OF SWEPCO AND SPP ZONE 1?

A No. Table 2 provides a comparison of the date, time and magnitude of SWEPCO's native loads that occur coincident with the monthly system peaks of SWEPCO and SPP Zone 1.

Table 2
SWEPCO Vs. SPP Zone 1 Monthly System Peaks[41]

SWEPCO			SPP Zone 1		
Date	Time	Native Load (MW)	Date	Time	Native Load (MW)
6/21/2019	16:00	3,453	6/21/2019	17:00	3,431
7/17/2019	17:00	3,545	7/17/2019	17:00	3,545
8/12/2019	16:00	3,767	8/12/2019	16:00	3,767
9/6/2019	16:00	3,599	9/6/2019	17:00	3,578

As can be seen, both the SWEPCO and SPP Zone 1 peaks occurred on the same day. The only difference is that the time that the peak occurred is shifted by one hour in two of the summer months.

Q SHOULD THE SPP ZONE 1 PEAKS BE USED TO ALLOCATE TRANSMISSION COSTS TO RETAIL CUSTOMER CLASSES?

A No. Although it may be reasonable to use allocation methodologies consistent with FERC's policies to separate costs between regulatory jurisdictions, retail class allocations have always been based on the practices adopted by this Commission, which use SWEPCO's system characteristics. Accordingly, SWEPCO's Texas retail transmission costs should continue to be allocated to retail customer classes using demands coincident with SWEPCO's system peaks.

[41] Schedule O-1.5; SWEPCO Response to TIEC 2-1aa; SWEPCO Response to TIEC 6-11, Attachment 1.

Q DOES THE WAY THAT SWEPCO IMPUTED RETAIL BTMG LOAD IN DETERMINING THE A&E/4CP TRANSMISSION ALLOCATION FACTOR MAKE SENSE?

A No. As previously stated, SWEPCO imputed 149 MW of peak demand and 146 MW of average demand. This is equivalent to a 98% load factor. In other words, SWEPCO's retail A&E/4CP transmission allocator assumes that the transmission system provided 98% of Eastman's average requirements. This is contrary to the facts. As discussed previously, the Eastman load was served almost entirely from its own generation.

Q DOES EASTMAN PURCHASE ANY ELECTRICITY FROM SWEPCO?

A Yes. Eastman purchases backup and maintenance power, some of which is on an as-available basis, under SWEPCO's SSBMA Class II rate schedule for standby power service. Under this rate schedule, Eastman pays a monthly rate for Backup, Maintenance, and As-Available contract demand regardless of whether any service is actually supplied. In addition, if either Backup or Maintenance service is provided for more than four and eight days, respectively, Eastman would also pay a Daily Demand charge. Both the monthly and Daily Demand charges include generation and transmission system costs that reflect the probability that service is required during a peak period. Further, SWEPCO does not have an obligation to provide Maintenance and As-Available services unless sufficient resources are available, and in the case of Maintenance, service has to be scheduled well in advance and is normally limited to 60 days per calendar year. Therefore, contrary to the assumptions underlying SWEPCO's imputed retail BTMG load, Eastman is not a high load factor consumer of either generation or transmission services. Further, the Class II SBMA rate schedule is a fully cost-based rate for the type of electricity service that Eastman requires.

Q DOES SWEPCO SERVE ANY OTHER RETAIL CUSTOMERS THAT HAVE BEHIND-THE-METER LOAD?

A Yes. SWEPCO has acknowledged that there are retail BTMG loads in other customer classes (*e.g.*, Residential DG, General Service DG). These other retail BTMG loads are comprised of solar facilities having a total capacity of approximately 2.1 MW and approximately 88.7 MW of cogeneration and self-generation.[42] As previously stated, SWEPCO is not reporting any of this other load to SPP at this time.

Q IS IT APPROPRIATE TO INCLUDE RETAIL BTMG LOAD IN DETERMINING HOW SWEPCO'S TRANSMISSION PLANT AND RELATED EXPENSES ARE ALLOCATED TO CUSTOMER CLASSES?

A No. First, as previously stated, the net incremental cost of including retail BTMG load in the Network Load used to derive the Load Ratio Shares is unknown. Thus, there are no incremental costs to be allocated to any retail BTMG load. Second, FERC does not require SPP to impute retail BTMG load in applying its OATT, and in the case of Eastman, its generation serves the entirety of its load except during outages. Further, none of this load occurred coincident with SWEPCO's or the SPP Zone 1 monthly system peaks during the test year. Therefore, SWEPCO is not providing any substantive transmission service to Eastman. None of Eastman's retail BTMG load should be imputed in allocating transmission plant and related expenses.

[42] SWEPCO Response to TIEC 11-4, Attachment 1.

Q IS IT APPROPRIATE TO INCLUDE RETAIL BTMG LOAD IN ALLOCATING COSTS TO THE VARIOUS CUSTOMER CLASSES?

A No. As previously stated, the customer classes in a retail CCOSS are generally comprised of customers with similar characteristics (*i.e.*, size, delivery voltage, load factor, quality of service). Retail customers with BTMG bear no resemblance to other retail customers that purchase most, or all, of their electricity from SWEPCO. Accordingly, it would be inappropriate to include retail BTMG load in allocating costs to full service customer classes. To do so could result in subsidies between the full-service and retail BTMG customers.

Q IS SWEPCO PROPOSING TO CREATE A SEPARATE CUSTOMER CLASS FOR RETAIL CUSTOMERS WITH BTMG LOAD?

A No. Eastman's BTMG load was imputed to the LLP-T class. This is totally inappropriate because Eastman is the only LLP-T customer with BTMG load that SWEPCO currently reports to SPP. SWEPCO has identified other retail BTMG customers that are not currently reported to SPP. Thus, it would make more sense to create a separate customer class comprised of retail BTMG load customers.

Q HOW SHOULD THIS ISSUE BE RESOLVED?

A If the Commission determines that SWEPCO should charge retail BTMG load for network transmission service provided by SPP, this load should be removed from the LLP-T class. Further, as discussed later, SWEPCO should create a separate customer class comprised of all retail BTMG loads and develop a separate rate that would only apply to the loads served from BTMG.

Q WHAT DO YOU RECOMMEND?

A The A&E/4CP method should be restored to the version that was previously approved by the Commission in SWEPCO's last rate case. Specifically:

- The 1CP load factor should be used to weight average demand;
- SWEPCO's monthly system peak should be used to determine the 4CP portion of the formula; and
- No retail BTMG load should be imputed in determining the allocation of transmission costs to the LLP-T class.

Q HAVE YOU DEVELOPED REVISED A&E/4CP ALLOCATION FACTORS FOR BOTH TRANSMISSION AND PRODUCTION RELATED COSTS?

A Yes. This is shown in **Exhibit JP-1**. I have used SWEPCO's system peaks and average demands, excluding retail BTMG load, and the 1CP load factor to weight average demand. The derivation of the system load factor is shown in **Exhibit JP-2**.

Revised Class Cost-of-Service Study

Q HAVE YOU REVISED SWEPCO'S CLASS COST-OF-SERVICE STUDY BASED ON THE CHANGES DESCRIBED ABOVE?

A Yes. **Exhibit JP-3** is a revised CCOSS that reflects the changes I have made to SWEPCO's study.

Refund of Excess Accumulated Deferred Income Taxes

Q MS. LACONTE RECOMMENDS THAT $30.4 MILLION OF EXCESS DEFERRED TAXES SHOULD BE REFUNDED TO CUSTOMERS OVER ONE YEAR. HOW SHOULD THAT REFUND BE ALLOCATED TO CUSTOMER CLASSES?

A Excess deferred taxes should be refunded to rate schedules in proportion to the amount of allocated accumulated deferred income taxes in the CCOSS. The allocation of accumulated deferred income taxes to customer classes is shown in **Exhibit JP-3**, line 8. Table 3 summarizes the allocations by rate schedule.

Table 3
Allocation of Accumulated Deferred Income Tax

Rate Schedule	Percent of Texas Retail
Residential	42.75%
Cotton Gin	0.11%
General Service	6.55%
Lighting & Power Service	37.25%
Large Lighting & Power Service	6.53%
Metal Melting Dist. Voltages	0.44%
Metal Melting ≥ 69 kV	0.32%
Oil Field Large Industrial Power	3.33%
Municipal Pumping	0.57%
Municipal Service	0.35%
Municipal Lighting	0.63%
Public Street & Hwy	0.02%

5. CLASS REVENUE ALLOCATION

Q HOW IS SWEPCO PROPOSING TO ALLOCATE THE $105 MILLION BASE RATE INCREASE?

A SWEPCO's proposed class revenue allocation is shown in Table 4.

Table 4
SWEPCO Proposed
Target Base Rate Increases[43]

Rate Schedule	Increase
Residential	27.93%
Cotton Gin	32.98%
General Service	32.98%
Lighting & Power Service	32.98%
Large Lighting & Power Service	32.98%
Metal Melting Dist. Voltages	32.98%
Metal Melting ≥ 69 kV	32.98%
Oil Field Large Industrial Power	32.98%
Municipal Pumping	13.49%
Municipal Service	13.49%
Municipal Lighting	13.48%
Public Street & Hwy	13.51%

As Table 4 demonstrates, SWEPCO is proposing equal percentage increases for the rates included in each of the four major classes. The proposed increases for each major class were based on the results of SWEPCO's CCOSS. As explained by SWEPCO witness, Ms. Jennifer Jackson:

> The second goal of the proposed rate design is to develop rates that move all major classes of customers closer to an equalized return, meaning the

[43] Direct Testimony of Jennifer L. Jackson, Exhibit JLJ-1.

> proposed rates for each customer class are designed to recover the class responsibility for the cost to serve each respective major rate class.[44]

However, Ms. Jackson also stated that factors other than the CCOSS results were taken into account. These other factors included moderation of customer impact and customer migration. With respect to moderation, Ms. Jackson stated:

> …classes with similarly-situated customers were combined into a major rate class and the combined change in class revenue requirement at an equalized rate of return was applied to the individual classes[45]

Q HOW DID MS. JACKSON DEFINE THE MAJOR CUSTOMER CLASSES?

A SWEPCO's definition of major customer classes is shown in Table 5.

Table 5
Customer Class Definitions

Major Class	CCOSS Class	Rate Schedule
Residential	Residential	Residential
	Residential DG	
Commercial & Industrial	Cotton Gin	Cotton Gin
	General Service w/Dem	General Service
	General Service No Dem	
	General Service DG	
	Light & Power Primary	Lighting & Power Service
	Light & Power Secondary	
	Light & Power Secondary DG	
	Large Lighting & Power Primary	Large Lighting & Power Service
	Large Lighting & Power Transmission	
	Metal Melting Primary	Metal Melting Distribution Voltages
	Metal Melting Secondary	
	Metal Melting Transmission	Metal Melting ≥ 69 kV
	Oilfield Primary	Oil Field Large Industrial Power
	Oilfield Secondary	

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44 *Id.*, Executive Summary at 1.

45 *Id.* at 10.

Table 5
Customer Class Definitions

Major Class	CCOSS Class	Rate Schedule
Municipal	Municipal Pumping	Municipal Pumping
	Municipal Service	Municipal Service
	Municipal Lighting	Various
	Public Street & Hwy	Various
Lighting	Outdoor Private & Area	Various
	Customer Owned	Various

As Table 5 demonstrates, SWEPCO defines four major classes. These four major classes, however, include multiple customer classes as used in SWEPCO's CCOSS. Many of the CCOSS customer classes, however, are priced under the same rate schedule. For example, the three General Service classes take service under the General Service rate schedule. The three Light & Power customer classes take service under the Lighting & Power Service rate schedule. The Large Lighting & Power and Oil Field classes take service under the LLP and Oilfield rate schedules, respectively. Metal Melting Primary and Secondary classes take service under SWEPCO's Metal Melting Distribution Voltages rate schedule. In other words, the customer class definitions employed in SWEPCO's CCOSS are far more granular than the applicable rate schedules. This can create problems when designing rates to serve ultra-low population customer classes.

Q DOES SWEPCO SERVE ANY LOW POPULATION CUSTOMER CLASSES?

A Yes. Table 6 shows the year end number of customers for those customer classes with 11 or fewer customers.

Table 6 Year-End Customer Count: Low Population Customer Classes[46]	
Customer Class	**Amount**
Cotton Gin	8
General Service DG	5
Light & Power DG	11
Large Lighting & Power: Primary	2
Large Lighting & Power: Transmission	6
Metal Melting Dist. Voltages	6
Metal Melting ≥ 69 kV	1

The concern with low population customer classes is that changes in the characteristics of only one or two customers may have a significant impact on the revenues and costs allocated to the class. Combining similarly situated classes may alleviate any instability caused by these changing loads.

Q **HOW SHOULD THE RATE CLASSES BE DEFINED IN DETERMINING CLASS REVENUE ALLOCATION?**

A With the notable exception of the Lighting classes, which differ based on the type of fixture, the rate class definition used for class revenue allocation should correspond to each specific rate schedule. Once a target revenue has been determined for each rate schedule, the rate design process would be used for intra-class class allocation; that is, to assign the appropriate revenue requirement and applicable rate to each different type of service provided within that schedule.

[46] Schedule O-1.1.

For example, if the CCOSS indicates a larger increase for LLP-Primary service than for LLP-T service, the revenue requirement assigned to the LLP class can then be reallocated between Primary and Transmission level customers to reflect the different costs.

Q HAVE YOU DEVELOPED A RECOMMENDED CLASS REVENUE ALLOCATION BASED ON THE RESULTS OF YOUR CLASS COST-OF-SERVICE STUDY?

A Yes. My recommendation is provided in **Exhibit JP-4**. Specifically, I spread the claimed revenue deficiency to each rate schedule based on the results of my CCOSS (**Exhibit JP-3**). However, because two rate classes (Cotton Gin and Public Street and Highway Lighting) are currently producing negative rates of return and would require excessive base rate increases, I limited the increases to these classes to 42.6%. This is the same maximum base rate increase that was approved in Docket No. 46449.

Q DOES THE CLASS REVENUE ALLOCATION SHOWN IN EXHIBIT JP-4 INCLUDE ANY AMOUNTS FOR SWEPCO'S PROPOSED SYNCHRONOUS SELF-GENERATION LOAD CHARGE?

A No. If the Commission approves a SSGL charge, the base revenue increases shown in **Exhibit JP-4** should be reduced by the amount of the SSGL base revenues.

Q SHOULD ALL CUSTOMERS WITHIN EACH RATE CLASS RECEIVE THE SAME BASE RATE INCREASE AS THE CLASS?

A No. The design of the rates within each class should be informed by the CCOSS results. For example, LLP-T customers are providing a much higher rate of return than LLP-Primary customers. Accordingly, LLP-Primary customers should receive a larger base rate increase than LLP-T customers.

Q IF THE COMMISSION APPROVES A LOWER BASE RATE INCREASE THAN SWEPCO HAS PROPOSED, WHAT WOULD BE YOUR RECOMMENDATION?

A My recommendation would be to re-run the CCOSS using the approved revenue requirement and apply the same revenue allocation and rate design principles as discussed above.

6. LARGE LIGHTING & POWER RATE DESIGN

Q WHAT LLP RATE DESIGN ISSUES ARE YOU ADDRESSING?

A I am addressing the design of the LLP rate assuming that the Commission approves an increase for the class. Regardless of the change in rate level, the LLP rate should also have an opt-out credit for REC costs applicable to LLP-T customers.

Q HOW IS SWEPCO PROPOSING TO DESIGN THE LLP RATES?

A Table 7 summarizes SWEPCO's proposed LLP rate design.

Table 7
SWEPCO Proposed LLP Rate Design[47]

Bill Component	Present Rate	Proposed Rate	Percent Increase
Transmission			
Energy Charge (¢/kWh)	1.0382	1.2212	17.6%
Demand Charge ($/kW)	6.87	7.93	15.4%
Primary			
Energy Charge (¢/kWh)	1.0382	1.3816	33.1%
Demand Charge ($/kW)	$10.02	13.32	32.9%
Other Charges			
Reactive Charge ($/kVAR)	0.51	0.66	29.4%
Synchronized Self-Generation Load	N/A	$2.20	N/A

SWEPCO is proposing approximately equal percentage increases in the Demand and Energy charges for Primary and Transmission services, respectively. However, the increases for Primary service would be higher than for Transmission service. Finally,

[47] Schedule Q 7.

SWEPCO is proposing to add a new Synchronous Self-Generation Load (SSGL) charge. I will discuss this charge later.

Q DO YOU RECOMMEND ANY CHANGES TO SWEPCO'S PROPOSED LLP RATE DESIGN?

A Yes. First, based on the revised CCOSS results, LLP-T charges should increase by only 3.2%, while LLP-Primary charges should increase by 32%. Second, SWEPCO has not provided any support for increasing the Reactive Demand charge. Therefore, I recommend no increase in the Reactive Demand charge. If SWEPCO wishes to increase this charge, it should be required to provide a study demonstrating the cost basis for this increase.

Q WHAT IS A REC OPT-OUT CHARGE?

A Under 16 T.A.C. § 25.173(j), a transmission-level voltage customer who submits an opt-out notice to the Commission is not required to pay any costs incurred by an investor-owned utility for acquiring RECs. A REC opt-out charge is a mechanism that refunds the REC costs associated with a customer that has opted-out.

Q DOES SWEPCO CURRENTLY HAVE A REC OPT-OUT CHARGE IN ITS RETAIL RATE SCHEDULES?

A No.

Q IS SWEPCO INCURRING ANY REC COSTS?

A Yes. As a result of the settlement in Docket No. 47533 (SWEPCO's prior fuel reconciliation), SWEPCO agreed to impute a value of the RECs for its renewable energy purchases. The test year REC value is $1.281 million.[48] The Texas retail share of these REC costs is approximately $466,500. The LLP-T class would be allocated approximately $52,800 of test-year REC costs. Assuming that all of the LLP-T customers were to submit opt-out letters pursuant to 16 T.A.C. § 25.173(j), they would not be charged for these costs.

Q HAVE YOU ESTIMATED THE AMOUNT OF THE OPT-OUT CHARGE?

A Yes. Assuming $52,800 of REC costs are allocated to the LLP-T class, the REC opt-out charge would be a credit of 0.064¢ per kWh.

Q WHAT DO YOU RECOMMEND?

A SWEPCO should implement an opt-out credit of approximately 0.064¢ per kWh. This credit would apply to those LLP-T customers who submit opt-out letters to the Commission pursuant to 16 T.A.C. § 25.173(j).

[48] SWEPCO Response to CARD 1-9.

7. SYNCHRONOUS SELF-GENERATION LOAD CHARGE

Q PLEASE EXPLAIN SWEPCO'S PROPOSED SYNCHRONOUS SELF-GENERATION LOAD CHARGE.

A SWEPCO is proposing a new charge for what it calls Synchronous Self-Generation service. The SSGL charge would apply to each retail customer having BTMG that is synchronized to the SPP grid whose load is assigned demand through SWEPCO's Load Ratio Share calculated by the SPP and who is taking service under SWEPCO's SBMA rate schedules.[49] The proposed $2.20 per kW charge would be based on each customer's contract demand for Backup, Maintenance and As-Available standby service.

Q HOW DID SWEPCO DERIVE THE PROPOSED SSGL CHARGE?

A The $2.20 per kW charge is based on 50% of SWEPCO's *all-in* Texas retail transmission cost to serve commercial and industrial customers. This is shown in SWEPCO Response to TIEC 1-8, which is provided in **Exhibit JP-5**. Thus, SWEPCO appears to be proposing to phase-in the charge.

Q WHAT CUSTOMERS WOULD BE AFFECTED BY THE PROPOSED CHARGE?

A Initially, the proposed SSGL charge would apply only to Eastman. SWEPCO has assumed that Eastman's contract demand would be 150 MW. Thus, the proposed charge would recover $3.96 million annually from Eastman.[50] Applying this charge, coupled with SWEPCO's proposed increase in the standby rates, would result in Eastman experiencing a 143% base revenue increase.[51]

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[49] SWEPCO has two SBMA rate schedules: Class I (Sheet No. IV-44) and Class II (Sheet No. IV-45).

[50] Schedule Q-7.

[51] SWEPCO Response to TIEC 11-7, Attachment 1.

Q SHOULD THE COMMISSION APPROVE A SSGL CHARGE?

A No. For the reasons previously addressed, it is inappropriate to charge retail BTMG load for transmission services that SWEPCO is not providing, and the customer is not receiving.

Q IF THE COMMISSION APPROVES A SSGL CHARGE, HOW SHOULD IT BE IMPLEMENTED?

A I agree with SWEPCO that the SSGL charge should be phased in. However, it should be phased-in more gradually. Under SWEPCO's proposal, the SSGL charge applied to Eastman would result in Eastman paying nearly 70% of the incremental cost ($5.7 million) asserted by SWEPCO. Eastman's contribution would be higher considering that it already pays transmission costs for standby service.

There are good policy reasons for a more gradual phase-in the SSGL charge. First, it would be an entirely new charge for a service that SWEPCO has not previously supplied. Second, coupled with the proposed increase in SBMA charges, Eastman's overall base rate costs would increase by 143%. Third, a more gradual phase-in would also be appropriate given the serious concerns about the legitimacy of imposing a charge solely on retail BTMG load and my understanding of FERC policy that retail customers are not considered Network Transmission Customers under the OATT.

Q SHOULD THE SSGL CHARGE ALSO APPLY TO OTHER RETAIL CUSTOMERS WITH BTMG?

A As proposed, the charge would only apply to customers taking standby service. However, SWEPCO's proposed rate design indicates that Eastman would be the sole source of the revenues generated by the new charge during the test year. Unless other retail BTMG customers are subsequently required to take service under the SBMA rate schedules, the proposed SSGL charge would not apply to any retail customer other than Eastman.

Q DO YOU AGREE WITH THE WAY SWEPCO DERIVED THE PROPOSED SSGL CHARGE?

A Yes, if it were appropriate to begin including such a charge (which it is not), I agree that the charge should be phased in. SWEPCO has estimated that the incremental cost of Eastman's BTMG load is $5.7 million. Phasing-in the SSGL charge at not more than 50% would result in $2.85 million of annual base revenues.

Additionally, all retail loads served from BTMG should be subject to the SSGL charge. Finally, the SSGL charge should be billed based on each retail BTMG customer's coincident demand. I discuss this issue later.

Q DO YOU HAVE ANY OTHER CONCERNS WITH THE PROPOSED SSGL CHARGE?

A Yes. The charge should not be part of SWEPCO's SBMA rate schedules because SSGL is not a standby service. It would apply year round to all retail BTMG load, irrespective of whether Backup, Maintenance, or As-Available standby power is actually provided.

Furthermore, the charge should not be based on contract demand because the retail BTMG load that SWEPCO is reporting to SPP is used to determine Load Ratio

Shares. The Load Ratio Shares are based on the demands occurring coincident with the monthly SPP Zone 1 peaks.

Q WHAT DO YOU RECOMMEND?

A The SSGL charge should be rejected. If a SSGL charge is approved, I recommend the following. First, it should be provided in a separate rate schedule. The SSGL charge would apply to load year-round. Thus, it is not a standby service, and it would be inappropriate to limit it applicability to customers taking standby service under SWEPCO's SBMA rate schedules.

Second, the SSGL charge should apply to all retail BTMG loads.

Third, because it is entirely new, and recognizing gradualism, it should be designed to recover $2.85 million of annual base revenues.

Fourth, the billing unit should be based on each customer's demand coincident with the SPP Zone 1 monthly system peak. Additionally, the terms and conditions of the new rate schedule should obligate SWEPCO to advise customers of when a monthly system peak is likely to occur. This would allow customers to better manage their loads and minimize the use of network transmission service.

8. CONCLUSION

Q WHAT FINDINGS SHOULD THE COMMISSION MAKE BASED ON YOUR RECOMMENDATIONS?

A The Commission should make the following findings:

- Reject SWEPCO's proposed ATC tracker.
- Disallow $5.7 million of transmission costs allocated to Texas retail customers and the actual incremental cost billed by SPP for Eastman's BTMG load.
- Order SWEPCO to cease reporting retail BTMG load to SPP.
- Reject SWEPCO's application of the A&E/4CP method.
- Revise the A&E/4CP production and transmission demand allocators as follows:
    - Weight average demand by the annual system peak (1CP) load factor.
    - Use SWEPCO's monthly system peak demands.
    - Exclude imputed retail BTMG from the LLP-T class transmission allocator.
- Refund $30.4 million of excess accumulated deferred income taxes to rate schedules using the allocation of accumulated deferred income tax derived from the approved class cost-of-service study.
- Require that, for class revenue allocation, customer classes be defined based on the applicable rate schedule.
- Move all customer classes to cost, but cap the increase at 42.6% for those classes currently providing negative rates of return.

- Adjust the LLP-T and LLP-Primary Demand and Energy charges consistent with the CCOSS results.
- Adopt a REC opt-out provision for eligible transmission customers and provide an opt-out credit of 0.064¢ per kWh for LLP-T customers who submit appropriate opt-out letters to the Commission.
- Reject SWEPCO's proposed increase in the Reactive Demand charge.
- Reject SWEPCO's proposed Synchronous Self-Generation Load charge.
- Alternatively, if a Synchronous Self-Generation Load charge is adopted:
    - It should be implemented in a separate rate schedule (and not the SBMA rate schedules) and apply to all retail customers with BTMG.
    - The charge should be phased in to initially recover not more than 50% of the net incremental cost of serving retail BTMG load, and it should be billed based on the BTMG customers' demands coincident with the SPP Zone 1 monthly peak.

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.

Q PLEASE DESCRIBE J. POLLOCK, INCORPORATED.

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.

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
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
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

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
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
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

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by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
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
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
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

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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
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

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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
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

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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
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

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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
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

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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
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

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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
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 Decoupling	7/21/2015
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd	15-00083	Direct	NM	Long-Term Purchased Power Agreements	7/10/2015

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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 Distribution Grid Resiliency Program	7/9/2015
ENTERGY TEXAS, INC	Texas Industrial Energy Consumers	43958	Supplemental Direct	TX	Certificate 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
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	Certificate 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

Exhibit JP-1

SOUTHWESTERN ELECTRIC POWER COMPANY
A&E/4CP Method Using 1CP Load Factor
Test Year Ended March 31, 2020

Line	Customer Class	4CP Average (kW)	Energy At Source (kWh)	Average Demand Amount (kW)	Average Demand Percent	System 1CP Load Factor	Weighted Average Demand	Excess Demand Amount (kW)	Excess Demand Adjusted (kW)	Excess Demand Percent	1 Minus System 1CP Load Factor	Weighted Excess Demand	A&E/4CP Factors
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Residential												
1	Residential	543,534	2,333,567,648	266,389	31.705%	56.450%	17.898%	277,145	277,145	55.925%	43.550%	24.355%	42.253%
2	Residential DG	338	2,884,892	329	0.039%	56.450%	0.022%	9	9	0.002%	43.550%	0.001%	0.023%
	Commercial												
3	Cotton Gin	5	4,923,865	562	0.067%	56.450%	0.038%	(557)	0	0.000%	43.550%	0.000%	0.038%
4	General Service w/ Demand	57,102	221,626,321	25,300	3.011%	56.450%	1.700%	31,802	31,802	6.417%	43.550%	2.795%	4.495%
5	General Service No Demand	18,385	71,544,830	8,167	0.972%	56.450%	0.549%	10,217	10,217	2.062%	43.550%	0.898%	1.447%
6	General Service DG	32	193,926	22	0.003%	56.450%	0.001%	10	10	0.002%	43.550%	0.001%	0.002%
7	Light & Power Pri	91,509	692,599,672	79,064	9.410%	56.450%	5.312%	12,445	12,445	2.511%	43.550%	1.094%	6.406%
8	Light & Power Sec	418,073	2,329,300,117	265,902	31.647%	56.450%	17.865%	152,171	152,171	30.707%	43.550%	13.373%	31.238%
9	Light & Power Sec DG	374	2,565,227	293	0.035%	56.450%	0.020%	81	81	0.016%	43.550%	0.007%	0.027%
	Industrial												
10	Large Light & Power Pri	26,145	168,785,396	19,268	2.293%	56.450%	1.295%	6,877	6,877	1.388%	43.550%	0.604%	1.899%
11	Large Light & Power Trans	97,761	830,239,725	94,776	11.280%	56.450%	6.368%	2,985	2,985	0.602%	43.550%	0.262%	6.630%
12	Metal Melting Dist Pri	4,189	39,212,692	4,476	0.533%	56.450%	0.301%	(287)	0	0.000%	43.550%	0.000%	0.301%
13	Metal Melting Dist Sec	151	2,139,614	244	0.029%	56.450%	0.016%	(93)	0	0.000%	43.550%	0.000%	0.016%
14	Metal Melting Trans	4,193	54,525,288	6,224	0.741%	56.450%	0.418%	(2,032)	0	0.000%	43.550%	0.000%	0.418%
15	Oilfield Pri	44,187	400,247,515	45,690	5.438%	56.450%	3.070%	(1,503)	0	0.000%	43.550%	0.000%	3.070%
16	Oilfield Sec	3,461	22,330,541	2,549	0.303%	56.450%	0.171%	912	912	0.184%	43.550%	0.080%	0.251%
	Municipal												
17	Municipal Pumping	7,229	64,742,435	7,391	0.880%	56.450%	0.497%	(161)	0	0.000%	43.550%	0.000%	0.497%
18	Municipal Service	4,226	29,060,484	3,317	0.395%	56.450%	0.223%	909	909	0.183%	43.550%	0.080%	0.303%
	Lighting												
19	Customer Owned	0	7,231,106	825	0.098%	56.450%	0.055%	(825)	0	0.000%	43.550%	0.000%	0.055%
20	Municipal Public & Hwy	0	28,047,402	3,202	0.381%	56.450%	0.215%	(3,202)	0	0.000%	43.550%	0.000%	0.215%
21	Outdoor Private & Area	0	53,278,838	6,082	0.724%	56.450%	0.409%	(6,082)	0	0.000%	43.550%	0.000%	0.409%
22	Public & Hwy Street	0	1,154,689	132	0.016%	56.450%	0.009%	(132)	0	0.000%	43.550%	0.000%	0.009%
23	**TOTAL TEXAS RETAIL**	**1,320,895**	**7,360,202,223**	**840,206**	**100.000%**	**56.450%**	**56.450%**	**480,689**	**495,564**	**100.000%**	**43.550%**	**43.550%**	**100.000%**

SOUTHWESTERN ELECTRIC POWER COMPANY
System Load Factor
For Test Year Ended March 31, 2020

Line	Month	Monthly System Peak (MW)	Net Energy (MWh)	Monthly Load Factor
		(1)	(2)	(3)
1	April 2019	3,245	1,612,170	69.01%
2	May	3,854	1,901,590	66.32%
3	June	4,307	2,056,987	66.33%
4	July	4,436	2,329,778	70.59%
5	August	4,727	2,484,038	70.63%
6	September	4,493	2,282,017	70.55%
7	October	4,209	1,791,984	57.23%
8	November	4,063	1,767,778	60.35%
9	December	3,900	1,893,635	65.27%
10	January 2020	3,590	1,873,540	70.15%
11	February	3,713	1,767,955	68.41%
12	March	2,930	1,614,974	74.34%
13	Annual System Peak	4,727	23,376,445	56.45%

Source: Schedule O-1.6.

SOUTHWESTERN ELECTRIC POWER COMPANY
Summary of Class Cost-of-Service Study Results at Present Rates
Test Year Ended March 31, 2020

Line	Description	TOTAL TX RETAIL JURISDICTION	TOTAL RESIDENTIAL	TOTAL COMMERCIAL	TOTAL INDUSTRIAL	TOTAL MUNICIPAL	TOTAL LIGHTING
		(1)	(2)	(3)	(4)	(5)	(6)
	SUMMARY OF RATE BASE						
1	GROSS ELECT PLANT IN SERVICE	$3,663,414,787	$1,565,541,064	$1,605,861,388	$394,054,109	$33,453,419	$64,504,807
2	LESS. ACCUM PROV FOR DEPR	1,205,785,224	515,719,397	528,427,807	128,429,427	11,111,860	22,096,734
	NET ELECT PLANT IN SERVICE	2,457,629,564	1,049,821,667	1,077,433,581	265,624,682	22,341,560	42,408,074
3	PLUS:						
4	PLANT HELD FOR FUTURE USE	220,915	97,625	98,802	10,158	2,806	11,524
5	WORKING CAPITAL	40,286,387	13,631,018	17,492,313	8,134,800	516,559	511,697
6	MISCELLANEOUS OTHER ADDITIONS	(86,328,496)	(35,511,305)	(37,982,162)	(10,911,800)	(791,992)	(1,131,238)
7	TOTAL ADDITIONS	(45,821,194)	(21,782,661)	(20,391,047)	(2,766,841)	(272,628)	(608,016)
	LESS:						
8	ACCUM DEFERRED INCOME TAX	371,341,206	158,736,814	163,074,628	39,442,406	3,397,971	6,689,388
9	CUSTOMER DEPOSITS	14,926,505	9,781,005	4,876,645	248,500	264	20,091
10	TOTAL DEDUCTIONS	386,267,711	168,517,819	167,951,273	39,690,906	3,398,235	6,709,478
11	TOTAL RATE BASE	$2,025,540,659	$859,521,187	$889,091,261	$223,166,935	$18,670,697	$35,090,579
	OPERATING REVENUES						
12	TOTAL FIRM SALES OF ELECTRICITY	$346,503,301	$147,077,995	$146,798,138	$41,956,723	$3,929,551	$6,740,893
13	450-FORFEITED DISCOUNTS	465,556	-	417,534	19,815	28,206	-
14	451-MISCELLANEOUS SERVICE REVENUE	591,678	481,515	98,800	4,689	6,674	-
15	454 - RENT FROM ELECTRIC PROPERTY	3,381,258	1,494,223	1,512,228	155,477	42,943	176,387
16	GENERATION RELATED	1,925,692	814,106	840,591	242,353	15,393	13,250
17	GENERAL OFFICE RENTAL	605,672	266,668	253,206	67,692	6,068	12,037
18	TRANS RELATED REVENUE	75,545,381	31,937,567	32,976,592	9,507,565	603,860	519,797
19	TOTAL OPERATING REVENUES	$429,018,538	$182,072,074	$182,897,090	$51,954,314	$4,632,696	$7,462,364
	SUMMARY OF OPERATING EXPENSES						
20	OPERATIONS AND MAINT EXP	$215,192,901	$92,128,751	$92,722,589	$25,191,643	$2,076,230	$3,073,689
21	DEPRECIATION & AMORTIZATION EXP	105,928,834	45,121,672	46,431,204	11,396,722	987,133	1,992,104
22	SO2 ALLOWANCE	1.477	0.624	0 645	0.186	0 012	0 010
23	TAXES OTHER THAN INCOME	39,087,610	16,633,250	17,591,992	3,763,031	379,854	719,484
25	FEDERAL INCOME TAXES	3,207,689	1,286,689	538,687	1,075,879	141,888	164,545
26	TOTAL OPERATING EXPENSES	$363,417,036	$155,170,362	$157,284,472	$41,427,275	$3,585,105	$5,949,821
	SUMMARY OF RETURN						
27	RATE BASE	$2,025,540,659	$859,521,187	$889,091,261	$223,166,935	$18,670,697	$35,090,579
28	RETURN	$65,601,502	$26,901,711	$25,612,618	$10,527,039	$1,047,591	$1,512,543
29	RATE OF RETURN ON RATE BASE	3.24%	3.13%	2.88%	4.72%	5 61%	4.31%
30	RELATIVE RATE OF RETURN	100	97	89	146	173	133

SOUTHWESTERN ELECTRIC POWER COMPANY
Summary of Class Cost-of-Service Study Results at Present Rates
Test Year Ended March 31, 2020

		RESIDENTIAL		COMMERCIAL						
								LIGHT & POWER		
Line	Description	BASIC	RESIDENTIAL DG	GS W/DEMAND	GS WO/DEMAND	COTTON GIN	GS DG	SEC	PRI	DG SEC
		(7)	(8)	(9)	(10)	(11)	(13)	(14)	(15)	(16)
	SUMMARY OF RATE BASE									
1	GROSS ELECT PLANT IN SERVICE	$1,564,305,723	$1,235,341	$175,520,171	$63,769,177	$3,920,603	$104,311	$1,136,845,512	$224,331,092	$1,370,521
2	LESS: ACCUM PROV FOR DEPR	515,304,290	415,107	58,008,675	21,267,507	1,341,655	34,732	373,689,555	73,618,163	467,519
	NET ELECT PLANT IN SERVICE	1,049,001,433	820,234	117,511,495	42,501,670	2,578,948	69,579	763,155,957	150,712,929	903,002
3	PLUS									
4	PLANT HELD FOR FUTURE USE	97,473	152	12,719	5,853	742	10	67,867	11,471	140
5	WORKING CAPITAL	13,618,924	12,094	1,325,957	540,525	24,669	652	11,957,895	3,611,044	31,570
6	MISCELLANEOUS OTHER ADDITIONS	(35,485,935)	(25,370)	(3,846,920)	(1,319,195)	(68,650)	(2,166)	(26,980,865)	(5,737,211)	(27,156)
7	TOTAL ADDITIONS	(21,769,538)	(13,123)	(2,508,244)	(772,816)	(43,239)	(1,504)	(14,955,103)	(2,114,696)	4,554
	LESS									
8	ACCUM DEFERRED INCOME TAX	158,609,781	127,033	17,843,120	6,470,120	412,288	10,712	115,526,190	22,679,353	132,844
9	CUSTOMER DEPOSITS	9,775,678	5,327	942,056	281,397	-	973	3,209,395	442,824	-
10	TOTAL DEDUCTIONS	168,385,459	132,360	18,785,176	6,751,517	412,288	11,685	118,735,585	23,122,177	132,844
11	TOTAL RATE BASE	$858,846,436	$674,751	$96,218,075	$34,977,337	$2,123,421	$56,390	$629,465,269	$125,476,057	$774,712
	OPERATING REVENUES									
12	TOTAL FIRM SALES OF ELECTRICITY	$146,937,937	$140,058	$16,988,207	$5,669,225	$265,617	$10,162	$99,913,765	$23,827,679	$123,483
13	450-FORFEITED DISCOUNTS	-	-	142,628	152,952	107	67	119,510	2,121	148
14	451-MISCELLANEOUS SERVICE REVENUE	481,181	334	33,750	36,193	25	16	28,279	502	35
15	454 - RENT FROM ELECTRIC PROPERTY	1,491,896	2,327	194,670	89,588	11,353	160	1,038,744	175,570	2,143
16	GENERATION RELATED	813,664	441	86,552	27,858	727	44	601,540	123,354	516
17	GENERAL OFFICE RENTAL	266,450	218	30,140	13,272	586	16	172,618	35,972	602
18	TRANS RELATED REVENUE	31,920,248	17,320	3,395,463	1,092,858	28,529	1,728	23,598,582	4,839,206	20,227
19	TOTAL OPERATING REVENUES	$181,911,376	$160,697	$20,871,411	$7,081,946	$306,944	$12,193	$125,473,039	$29,004,404	$147,153
	SUMMARY OF OPERATING EXPENSES									
20	OPERATIONS AND MAINT EXP	$92,055,459	$73,292	$10,073,773	$3,955,205	$209,948	$5,802	$64,757,499	$13,543,452	$176,910
21	DEPRECIATION & AMORTIZATION EXP	45,084,900	36,772	5,077,956	1,849,579	118,127	3,053	32,816,369	6,526,334	39,785
22	SO2 ALLOWANCE	0.624	0.000	0.066	0.021	0.001	0.000	0.461	0.095	0.000
23	TAXES OTHER THAN INCOME	16,620,389	12,861	1,873,543	664,821	36,418	1,235	12,518,053	2,480,682	17,239
25	FEDERAL INCOME TAXES	1,282,448	4,241	296,125	(55,114)	(23,511)	142	(274,324)	617,731	(22,363)
26	TOTAL OPERATING EXPENSES	$155,043,196	$127,166	$17,321,397	$6,414,492	$340,982	$10,233	$109,817,597	$23,168,200	$211,572
	SUMMARY OF RETURN									
27	RATE BASE	$858,846,436	$674,751	$96,218,075	$34,977,337	$2,123,421	$56,390	$629,465,269	$125,476,057	$774,712
28	RETURN	$26,868,180	$33,531	$3,550,014	$667,454	($34,038)	$1,960	$15,655,442	$5,836,204	($64,419)
29	RATE OF RETURN ON RATE BASE	3.13%	4.97%	3.69%	1.91%	-1.60%	3.48%	2.49%	4.65%	-8.32%
30	RELATIVE RATE OF RETURN	97	153	114	59	(49)	107	77	144	(257)

SOUTHWESTERN ELECTRIC POWER COMPANY
Summary of Class Cost-of-Service Study Results at Present Rates
Test Year Ended March 31, 2020

		INDUSTRIAL						
		LLP		OILFIELD	METAL MELTING			OILFIELD
Line	Description	PRI	TRAN	PRI	PRI	TRANS	SEC	SEC
		(17)	(18)	(19)	(20)	(21)	(22)	(23)
	SUMMARY OF RATE BASE							
1	GROSS ELECT PLANT IN SERVICE	$56,670,233	$187,113,577	$113,193,991	$14,473,097	$11,845,436	$1,504,673	$9,253,102
2	LESS ACCUM PROV FOR DEPR	18,387,216	60,502,177	37,309,471	4,839,331	3,834,010	513,888	3,043,333
	NET ELECT PLANT IN SERVICE	38,283,017	126,611,399	75,884,519	9,633,766	8,011,427	990,785	6,209,769
3	PLUS.						-	
4	PLANT HELD FOR FUTURE USE	857	37	6,867	1,546	7	270	574
5	WORKING CAPITAL	906,722	4,457,909	2,138,544	209,100	300,156	10,564	111,806
6	MISCELLANEOUS OTHER ADDITIONS	(1,522,932)	(5,540,752)	(2,916,120)	(327,576)	(353,692)	(26,796)	(223,932)
7	TOTAL ADDITIONS	(615,352)	(1,082,806)	(770,709)	(116,930)	(53,529)	(15,962)	(111,552)
	LESS.						-	
8	ACCUM DEFERRED INCOME TAX	5,671,922	18,582,336	11,434,525	1,481,133	1,173,932	157,435	941,123
9	CUSTOMER DEPOSITS	-	-	231,367	-	-	11,197	5,936
10	TOTAL DEDUCTIONS	5,671,922	18,582,336	11,665,891	1,481,133	1,173,932	168,632	947,059
11	TOTAL RATE BASE	$31,995,742	$106,946,257	$63,447,919	$8,035,703	$6,783,966	$806,191	$5,151,157
	OPERATING REVENUES							
12	TOTAL FIRM SALES OF ELECTRICITY	$5,298,104	$22,387,847	$10,636,387	$1,402,858	$1,498,929	$143,749	$588,848
13	450-FORFEITED DISCOUNTS	27	81	19,117	81	13	40	456
14	451-MISCELLANEOUS SERVICE REVENUE	6	19	4,524	19	3	10	108
15	454 - RENT FROM ELECTRIC PROPERTY	13,123	572	105,102	23,663	104	4,129	8,784
16	GENERATION RELATED	36,566	127,672	59,114	5,791	8,053	316	4,841
17	GENERAL OFFICE RENTAL	9,270	32,414	19,704	2,526	2,162	245	1,371
18	TRANS RELATED REVENUE	1,434,474	5,008,614	2,319,058	227,201	315,923	12,397	189,897
19	TOTAL OPERATING REVENUES	$6,791,571	$27,557,220	$13,163,006	$1,662,138	$1,825,188	$160,886	$794,305
	SUMMARY OF OPERATING EXPENSES							
20	OPERATIONS AND MAINT EXP	$3,418,742	$12,458,776	$7,000,240	$885,934	$815,051	$82,613	$530,287
21	DEPRECIATION & AMORTIZATION EXP	1,617,207	5,397,149	3,300,024	428,069	342,797	45,509	265,965
22	SO2 ALLOWANCE	0 028	0 098	0 045	0 004	0 006	0 000	0.004
23	TAXES OTHER THAN INCOME	729,781	1,481,228	1,095,787	184,644	182,282	16,293	73,016
25	FEDERAL INCOME TAXES	28,762	1,056,112	(10,160)	(11,928)	58,958	(879)	(44,986)
26	TOTAL OPERATING EXPENSES	$5,794,493	$20,393,266	$11,385,892	$1,486,718	$1,399,087	$143,537	$824,282
	SUMMARY OF RETURN							
27	RATE BASE	$31,995,742	$106,946,257	$63,447,919	$8,035,703	$6,783,966	$806,191	$5,151,157
28	RETURN	$997,078	$7,163,954	$1,777,114	$175,420	$426,100	$17,349	($29,977)
29	RATE OF RETURN ON RATE BASE	3 12%	6 70%	2 80%	2.18%	6 28%	2.15%	-0 58%
30	RELATIVE RATE OF RETURN	96	207	86	67	194	66	(18)

SOUTHWESTERN ELECTRIC POWER COMPANY
Summary of Class Cost-of-Service Study Results at Present Rates
Test Year Ended March 31, 2020

		MUNICIPAL		LIGHTING			
Line	Description	PUMPING SERVICE	MUNICIPAL SERVICE	MUNICIPAL LIGHTING	PUBLIC/HWY LIGHTING	PRIV AREA LIGHTING	CUST-OWNED LIGHTING
		(26)	(27)	(28)	(29)	(30)	(31)
	SUMMARY OF RATE BASE						
1	GROSS ELECT PLANT IN SERVICE	$20,794,560	$12,658,860	$22,117,274	$802,876	$38,568,554	$3,016,102
2	LESS: ACCUM PROV FOR DEPR	6,903,609	4,208,251	7,569,638	274,167	13,238,568	1,014,361
	NET ELECT PLANT IN SERVICE	13,890,951	8,450,608	14,547,637	528,710	25,329,986	2,001,741
3	PLUS.						-
4	PLANT HELD FOR FUTURE USE	1,754	1,051	4,163	143	6,845	374
5	WORKING CAPITAL	342,723	173,835	124,687	5,647	341,893	39,470
6	MISCELLANEOUS OTHER ADDITIONS	(502,649)	(289,343)	(381,682)	(14,341)	(670,594)	(64,620)
7	TOTAL ADDITIONS	(158,171)	(114,457)	(252,832)	(8,551)	(321,856)	(24,777)
	LESS:						-
8	ACCUM DEFERRED INCOME TAX	2,115,551	1,282,419	2,322,642	83,934	3,973,117	309,695
9	CUSTOMER DEPOSITS	-	264	-	-	19,790	300
10	TOTAL DEDUCTIONS	2,115,551	1,282,684	2,322,642	83,934	3,992,908	309,995
11	TOTAL RATE BASE	$11,617,228	$7,053,468	$11,972,163	$436,225	$21,015,222	$1,666,970
	OPERATING REVENUES						
12	TOTAL FIRM SALES OF ELECTRICITY	$2,279,333	$1,650,219	$2,267,085	$30,170	$4,150,616	$293,022
13	450-FORFEITED DISCOUNTS	8,149	20,057	-	-	-	-
14	451-MISCELLANEOUS SERVICE REVENUE	1,928	4,746	-	-	-	-
15	454 - RENT FROM ELECTRIC PROPERTY	26,851	16,092	63,711	2,190	104,768	5,718
16	GENERATION RELATED	9,562	5,831	4,142	171	7,869	1,068
17	GENERAL OFFICE RENTAL	3,571	2,497	3,388	131	7,972	546
18	TRANS RELATED REVENUE	375,121	228,739	162,508	6,690	308,701	41,898
19	TOTAL OPERATING REVENUES	$2,704,515	$1,928,181	$2,500,835	$39,352	$4,579,927	$342,251
	SUMMARY OF OPERATING EXPENSES						
20	OPERATIONS AND MAINT EXP	$1,279,958	$796,271	$949,627	$37,311	$1,901,581	$185,171
21	DEPRECIATION & AMORTIZATION EXP	613,816	373,317	674,308	23,914	1,204,175	89,706
22	SO2 ALLOWANCE	0 007	0 004	0 003	0 000	0 006	0 001
23	TAXES OTHER THAN INCOME	226,674	153,180	250,172	7,830	426,878	34,604
25	FEDERAL INCOME TAXES	54,353	87,535	67,868	(8,581)	107,811	(2,552)
26	TOTAL OPERATING EXPENSES	$2,174,802	$1,410,303	$1,941,975	$60,473	$3,640,445	$306,928
	SUMMARY OF RETURN						
27	RATE BASE	$11,617,228	$7,053,468	$11,972,163	$436,225	$21,015,222	$1,666,970
28	RETURN	$529,713	$517,878	$558,860	($21,122)	$939,482	$35,323
29	RATE OF RETURN ON RATE BASE	4 56%	7.34%	4.67%	-4.84%	4 47%	2 12%
30	RELATIVE RATE OF RETURN	141	227	144	(150)	138	65

SOUTHWESTERN ELECTRIC POWER COMPANY
Recommended Class Revenue Allocation
Based on the Revised Class Cost-of-Service Study
Test Year Ended March 31, 2020
Dollar Amounts ($000)

Line	Customer Class	Present Base Revenues*	Recommended Allocation Amount	Recommended Allocation Percent
		(1)	(2)	(3)
1	Residential	$153,228	$45,859	29.9%
2	General Service	23,514	6,858	29.2%
3	Lighting & Power	129,140	43,226	33.5%
4	Cotton Gin	284	121	42.6%
5	Large Lighting & Power	29,009	2,434	8.4%
6	Metal Melting	3,320	664	20.0%
7	Oil Field	11,726	4,182	35.7%
8	Municipal Pumping	2,390	403	16.9%
9	Municipal Service	1,702	0	0.0%
10	Municipal Lighting	2,351	399	17.0%
11	Public Street & Hwy Ltg	33	14	42.6%
12	Private Outdoor Area Ltg	4,307	754	17.5%
13	Customer-Owned Ltg	324	111	34.2%
14	Total Firm Retail	$361,330	$105,026	29.1%

* Includes Current TCRF & DCRF Revenues.

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' FIRST REQUEST FOR INFORMATION

Question No. TIEC 1-8:

Please provide workpapers supporting the proposed $2.20 per CP-kW charge for synchronized self-generation load.

Response No. TIEC 1-8:

Please see the filed Schedule Q-7 Proof of Revenue, the tab entitled, SBMA, for the workpapers supporting the charge.

Synchronized Self Generation SPP Load	$2.20
Total Commercial & Industrial Transmission Revenue	$57,181,325
Total Commercial & Industrial NCP	13,008,187.52
Transmission Unit Cost	$4.40
50% of Transmission Unit Cost	$2.20

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