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Addendum StartPage: 0

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

TEXAS INDUSTRIAL ENERGY CONSUMERS' INITIAL BRIEF

REDACTED

June 17, 2021

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625

SOAH DOCKET NO. 473-21-0538
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APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR AUTHORITY TO CHANGE RATES	§ § § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

TABLE OF CONTENTS

GLOSSARY OF ACRONYMS

1CP	Single Coincident Peak
A&E/4CP	Average and Excess Demand, Four Coincident Peak
ADFIT	Accumulated Deferred Federal Income Taxes
AEP	American Electric Power
ALJ	Administrative Law Judge
ATC	Approved Transmission Charges
BTM	Behind the Meter
BTMG	Behind the Meter Generation
CAPM	Capital Asset Pricing Model
CARD	Cities Advocating Reasonable Deregulation
CCGT	Combined Cycle Gas Turbine
CCOSS	Class-Cost-of-Service Study
CLECO	Cleco Power LLC
CoL	Conclusion of Law
DCF	Discounted Cash Flow
DCRF	Distribution Cost Recovery Factor
DHPS	Dolet Hills Power Station
DSP	Distribution Service Provider
EBITDA	Earnings Before Interest, Taxes, Depreciation, and Amortization
ECAPM	Empirical Capital Asset Pricing Model
EECRF	Energy Efficiency Cost Recovery Factor
ERCOT	Electric Reliability Council of Texas
ETI	Entergy Texas, Inc.
ETSWD	East Texas Salt Water Disposal Company
FERC	Federal Energy Regulatory Commission
FFO	Funds From Operations
FoF	Finding of Fact
GAAP	Generally Accepted Accounting Principles

GCRR	Generation Cost Recovery Rider
GDP	Gross Domestic Product
IRP	Integrated Resource Planning
LLP	Large Lighting and Power
LLP-T	Large Lighting and Power-Transmission
MISO	Midcontinent Independent System Operator
MW	Megawatt, a unit of power
MWh	Megawatt-Hour, a unit of energy
NBV	Net Book Value
O&M	Operations and Maintenance
OATT	Open Access Transmission Tariff
OP	Ordering Paragraph
OPUC	Office of Public Utility Counsel
PFD	Proposal For Decision
PO	Preliminary Order
PPA	Purchased Power Agreement
PRPM	Predictive Risk Premium Model
PUC, or the "Commission"	Public Utility Commission of Texas
PURA	Public Utility Regulatory Act, Tex. Util. Code §§ 11.001 et seq.
PURPA	Public Utility Regulatory Policies Act
QF	Qualifying Facility
REC	Renewable Energy Credit
ROE	Return On Equity
RTO	Regional Transmission Organization
S&P	Standard & Poor's
SPP	Southwest Power Pool
SPS	Southwestern Public Service Company
SSGL	Synchronized Self-Generation Load

SSMBAA	Specialty Supplementary, Backup, Maintenance, and As-Available Standby Power Service
SWEPCO	Southwestern Electric Power Company
T&D	Transmission and Distribution
TCJA	Tax Cuts and Jobs Act of 2017
TCRF	Transmission Cost Recovery Factor
TIEC	Texas Industrial Energy Consumers
WACC	Weighted-Average Cost of Capital

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TEXAS INDUSTRIAL ENERGY CONSUMERS' INITIAL BRIEF

I. Introduction/Summary [Preliminary Order (PO) Issues 1, 2, and 3]

This case has the usual issues associated with major rate cases. There are also at least two issues that are unique to this case and warrant particular attention.

First, Southwestern Electric Power Company (SWEPCO) has shifted $5.7 million in costs to Texas from Louisiana and Arkansas in its jurisdictional allocation study by including, in the Texas jurisdiction demand, the electricity that a single customer self-generates. SWEPCO has ignored all such customer-generated electricity in both other states, and it does not even know how much there is in those states. SWEPCO has yet to offer an explanation for why it is appropriate to include only Texas retail self-served load in the allocation between jurisdictions. Further, SWEPCO's half-hearted explanation of why it has now decided to include a single customer's load in its reporting of Monthly Network Load to the Southwest Power Pool (SPP) is not only unconvincing, it is contrary to SWEPCO's own recent position on the issue.

Second, SWEPCO has proposed to accelerate the recovery of the $45.4 million remaining balance of the Dolet Hills Power Station (DHPS) from over a span of 26 years to merely four years, while simultaneously including $6 million of operations and maintenance (O&M) and other expenses in rates for a plant that will no longer be in service nine months into the rate year. SWEPCO's proposal is inconsistent with the Commission's recent precedent regarding SWEPCO's own Welsh Unit 2, another plant that was retired significantly earlier than its expected useful life.

TIEC appreciates the Administrative Law Judges' (ALJs) careful attention to this important case.[1]

II. Invested Capital - Rate Base [PO Issues 4, 5, 10, 11, 12, 13, 14, 15, 16, 18, 19, 20, 21, 22]

A. Generation, Transmission, and Distribution Capital Investment [PO Issues 4, 5, 10, 11, 13, 14, 15, 16]

1. Dolet Hills Power Station [PO Issues 67, 68, 69, 70, 71]

In May 2020, SWEPCO announced that DHPS, a 650 MW lignite plant it jointly owns with Cleco Power LLC (CLECO), will be retired no later than December 2021, 25 years earlier than its previously established retirement date of 2046.[2] Five months after this announcement, SWEPCO filed this rate case, seeking to recover DHPS's entire $45.4 million (Texas retail) undepreciated balance from ratepayers in four years.

Under SWEPCO's proposal, the $45.4 million remaining balance of DHPS would first be offset with SWEPCO's excess ADFIT balance of $39 million.[3] Then, SWEPCO would amortize the remaining $6.4 million balance over four years with a return.[4] At the same time, rates would be set to continue recovering SWEPCO's test-year level O&M expense, insurance expense, and federal income taxes associated with DHPS.[5] SWEPCO would thus not only recover all of its remaining investment in DHPS in four years, but recover up to four years of O&M and other expenses for a plant that it plans to retire less than a year after the effective date of rates in this case. SWEPCO's proposal is inconsistent with Commission precedent and inequitable to ratepayers. It should be rejected.

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[1] For the ALJs' reference, TIEC notes that its citations to all prefiled testimony reference the native pagination, as the versions filed on the Interchange do not have Bates pagination.

[2] TIEC Ex. 4, Direct Testimony and Exhibits of Billie S. LaConte Dir. at 5 (LaConte Dir.). All citations to Ms. LaConte's testimony refer to native pagination.

[3] SWEPCO Ex. 6, Direct Testimony of Michael A. Baird at 48-49 (Baird Dir.).

[4] *Id*

[5] TIEC Ex. 4, LaConte Dir. at 6-7.

As set forth in TIEC witness Billie LaConte's testimony, the Commission should treat DHPS as either an operational plant or a retired plant, consistent with the Commission's treatment of SWEPCO's Welsh Unit 2.[6] If the Commission determines DHPS should be treated as an operational plant, then its current useful life of 2046 should be maintained. Alternatively, if the Commission determines that DHPS should be treated as a retired plant, then all costs associated with DHPS should be taken out of rates, and the undepreciated balance should be placed into a regulatory asset that is amortized through 2046, without a return. While either option is reasonable, under the facts of this case, TIEC submits that the Commission should treat DHPS as a retired plant.

a. SWEPCO's DHPS proposal should be rejected, and the Commission should treat the plant as either operational or retired.

After depreciating DHPS on a 60-year schedule throughout its useful life, SWEPCO now proposes to abruptly accelerate the cost recovery of the plant such that SWEPCO would recover all of the remaining $45.4 million balance—which would have otherwise been recovered through 2046—in just four years.[7] SWEPCO's proposal is driven at least in part by its recently announced early retirement of DHPS, which is a part of AEP's national strategy to create rate-base growth by retiring coal plants early and replacing them with new-build renewable and gas generation.[8]

As laid out in the testimony of Ms. LaConte, SWEPCO's proposal to accelerate the recovery of DHPS contravenes recent Commission precedent—dealing with SWEPCO's own Welsh Unit 2—regarding the ratemaking treatment of the early retirement of a plant.[9] When SWEPCO filed Docket No. 40443, its 2012 rate case, it had already announced that it would retire Welsh Unit 2 in 2016, more than 20 years earlier than previously anticipated.[10] In fact, SWEPCO

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[6] *See generally id.* at 8-13.

[7] *Id.* at 6-8.

[8] Tr. at 56:25-57:11 (Smoak Cross) (May 19, 2021); TIEC Ex. 6 at Bates 015.

[9] TIEC Ex. 4, LaConte Dir. at 8-10.

[10] *Id* at 9.

had entered into a federal consent decree requiring it to retire Welsh Unit 2 no later than December 31, 2016.[11] In that case, SWEPCO requested that the recovery of Welsh Unit 2 be accelerated such that all of the undepreciated balance would be recovered through the new retirement date of 2016.[12] The Commission denied SWEPCO's request and maintained the existing useful life for Welsh Unit 2 of 2040,[13] including the following finding of fact and conclusion of law in its order:

> FoF 124: The retirement of Welsh Unit 2 has not yet occurred. Consequently, it is inappropriate to consider the unit's retirement costs before it actually happens.
>
> CoL 37: It is premature to consider the future potential costs associated with the retirement of Welsh Unit 2 in this proceeding.

Additionally, SWEPCO's proposal is inconsistent with Commission precedent on the treatment of retired plants. As the Commission determined with respect to Welsh Unit 2 in SWEPCO's last rate case, Docket No. 46449, if a plant is retired, then it should be removed from rate base, and the utility should be allowed to earn a return of, but not on, the undepreciated balance.[14] At the same time, the O&M expenses associated with the plant should be removed from rates.[15] Nevertheless, SWEPCO not only proposes to accelerate the recovery of DHPS, it is also

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[11] *Id.* (citing Consent Decree, *Sierra Club, et al v. United States Army Corps of Engineers, et al.*, Civil No. 4:10-cv-04017-RGK (W.D. Ark. Dec. 22, 2011)).

[12] *Id.* (citing *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 40443, Proposal for Decision (PFD) at 176 (May 20, 2013), *adopted by* Order on Rehearing (May 6, 2014)).

[13] *Id.* at 9-10 (citing *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 40443, PFD).

[14] *Id.* at 10-11 (citing *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 46449, Order on Rehearing at FoF 70 (Mar. 19, 2018)). This precedent is consistent with the Commission's practice regarding prudently cancelled plants. *Application of Gulf States Utilities Company for a Rate Increase*, Docket No. 5560, Revised Examiner's Report, 1984 WL 274017 at *20 (July 13, 1984), *adopted by* Order on Rehearing (Sept. 7, 1984) (stating that "the general rule in Texas regarding plant cancellations is that if the utility demonstrates that it acted prudently in planning and managing the project, cost of service amortization of the loss over some future period is allowed but return on unamortized balances is allowed").

[15] TIEC Ex. 4, LaConte Dir. at 10 (citing Docket No. 46449, Order on Rehearing at FoFs 166-67).

requesting a return on the \$6.4 million post-offset balance and a full year's worth of O&M expense in the rates it will charge for the next four years.[16]

Indeed, SWEPCO's proposal is not only inconsistent with Commission precedent regarding the treatment of retired plants, it is internally inconsistent. SWEPCO proposes to simultaneously treat DHPS as a retired plant (by requesting a special ratemaking treatment relating to the impending retirement) and an operational plant (by requesting O&M expense and a return on the undepreciated balance).[17]

SWEPCO's chief justification for its proposal is that it happens to have a large amount of excess ADFIT on hand at the moment, and that using these dollars as an offset to the undepreciated balance of DHPS purportedly results in a "win-win" for ratepayers and SWEPCO.[18] But as SWEPCO witness Mr. Baird acknowledged at the hearing, the issues of excess ADFIT and the treatment of DHPS are entirely distinct from each other.[19] As Ms. LaConte explained, excess ADFIT represents ratepayer money that SWEPCO has held onto since January 1, 2018.[20] Thus, SWEPCO's proposal to offset DHPS's remaining balance with its \$39 million excess ADFIT balance deprives ratepayers of a \$39 million refund they are entitled to immediately.[21] Mr. Baird's claim that the offset results in a "win-win" ignores this critical fact.[22] SWEPCO's offset proposal does not provide any additional benefit to ratepayers relative to what should occur regardless—the immediate refund of \$39 million of excess ADFIT.[23] It is only SWEPCO who benefits from its

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[16] *Id* at 8.

[17] *Id.*

[18] SWEPCO Ex. 36, Rebuttal Testimony of Michael A. Baird at 6 (Baird Reb.).

[19] Tr. at 115:25-116:24 (Baird Cross) (May 19, 2021).

[20] TIEC Ex. 4, LaConte Dir. at 7-8, 14-15.

[21] *Id.* at 7-8.

[22] SWEPCO Ex. 36, Baird Reb. at 6.

[23] Tr. at 117:21-118:10 (Baird Cross) (May 19, 2021).

excess ADFIT offset proposal, to the tune of the immediate recovery of $39 million of the undepreciated balance of DHPS.

SWEPCO also argues that if its proposal is not adopted, the alternative would be the inequitable result of depreciating the entire remaining balance by the end of 2021.[24] But as discussed above, this argument is belied by the Commission's decision regarding Welsh Unit 2 in Docket No. 40443, which maintained the existing depreciation schedule for a plant despite the fact that SWEPCO had entered into a federal consent decree to retire it 20-plus years early.

Ignoring this precedent, SWEPCO claims that generally accepted accounting principles (GAAP) require DHPS to be depreciated in less than a year.[25] That argument is unavailing. As the Commission made clear in SWEPCO's most recent case, "[a]ccounting does not determine the appropriate ratemaking treatment."[26] Indeed, Mr. Baird acknowledged at the hearing that the Commission has ordered a different treatment than what GAAP would call for in the past, and that it could do so in this case.[27] SWEPCO also claims that "standard regulatory practice" requires this treatment, apparently referring to a portion of the Commission's cost-of-service rule regarding straight-line depreciation.[28] However, this provision does not specifically address the unusual circumstance of an early retired plant, and it explicitly provides that other methods of depreciation may be used if doing so is more equitable.[29] Further, SWEPCO's argument proves too much. Mr. Baird agreed at the hearing that SWEPCO's own proposal violates the purported GAAP standard,[30] and noted that SWEPCO has proposed in Louisiana to recover all of the remaining undepreciated

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[24] SWEPCO Ex. 4, Direct Testimony of Thomas P. Brice at 7 (Brice Dir.).

[25] *Id.*

[26] Docket No. 46449, PFD at 94, *adopted by* Order on Rehearing.

[27] Tr. at 472:21-473:1 (Baird Cross) (May 21, 2021).

[28] SWEPCO Ex. 4, Brice Dir. at 7; *see also* Tr. at 370:20-371:1 (LaConte Cross) (May 20, 2021).

[29] 16 T.A.C. § 25.231(b)(1)(B). For all of the reasons discussed in section II.A.1.c below, depreciating DHPS over its previously established useful life would be a more equitable result than accelerating 26 years of recovery into a four-year span.

[30] Tr. at 473:2-5 (Baird Cross) (May 21, 2021).

balance in DHPS in five years.[31] There is simply no requirement that the remaining balance of DHPS be recovered in a single year, or that it be accelerated. SWEPCO's proposal should be rejected.

As set forth above, Commission precedent on SWEPCO's Welsh Unit 2 clearly establishes the appropriate treatment for an operational plant with an impending retirement date, as well as for a retired plant. The Commission should set rates for SWEPCO in this proceeding either based on the assumption that DHPS is fully operational, or that DHPS is retired.[32] If the Commission decides to treat DHPS as an operational plant, then it should maintain the existing useful life of 2046, consistent with the treatment of Welsh Unit 2 in Docket No. 40443. If the Commission determines instead that DHPS should be treated as a retired plant, then all costs associated with DHPS should be removed from rates, and the remaining balance should be placed in a regulatory asset, to be recovered over the previous useful life without a return.[33] Ms. LaConte showed the rate impact of the two alternatives in the following table from her testimony:[34]

Table 3
Operational Plant or Retired Plant
Ratemaking Treatments
($Millions)

Description	Operational Plant	Retired Plant
Remaining Plant Balance	$45 4	$45 4
Return	3.9	-
Amortization Period (Years)	25	25
Depreciation	1.7	1.7
O&M	4 6	-
Taxes	1 2	-
Revenue Requirement	$11.4	$1 7

31 TIEC Ex. 23.

32 TIEC Ex. 4, LaConte Dir. at 13.

33 *Id*

34 *Id.* at 14.

b. There is good cause to treat DHPS as a retired plant and remove it from rate base.

Under the circumstances presented here, TIEC submits that DHPS should be treated as retired plant and removed from rate base. As Ms. LaConte testified, there are several reasons why there is good cause in this proceeding to treat DHPS as a retired.[35]

First, the new retirement date for DHPS represents a significant change in circumstances, as SWEPCO has not only accelerated the retirement date for DHPS by 25 years, it is proposing to reflect that change in rates less than a year before the new retirement date.[36] As a result, there is a $45.4 million remaining balance associated with a plant that will be in service for at most nine months after the date rates are effective in this case.[37] The magnitude of this accelerated recovery is significant and unusual, since plants are generally not retired that much earlier than their expected useful life with that much of an undepreciated balance.[38]

Second, the retirement of DHPS should not be viewed in isolation, as it is merely the first of a series of early retirements that will impose substantial costs on ratepayers for assets that will be retired and no longer used and useful. In addition to DHPS, SWEPCO plans to retire the Pirkey plant in 2023 and, at minimum, the coal assets at Welsh Units 1 and 3 in 2028.[39] In total, DHPS, Pirkey, and Welsh Units 1 and 3 have a remaining net book value (NBV) of $950 million total company, or approximately $350 million Texas retail.[40] Moreover, both DHPS and Pirkey are mine-mouth lignite plants that obtain fuel from nearby lignite mines. Under the contracts governing these lignite-mining arrangements, SWEPCO is responsible for all of the unrecovered

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[35] *Id* at 11-12.

[36] *Id.* at 11.

[37] *Id.*

[38] *Id.*

[39] Tr. at 73:19-74:2, 77:7-9 (Brice Cross) (May 19, 2021). SWEPCO has not yet decided whether it will convert Welsh Units 1 and 3 to gas. Tr. at 109:9-22 (Brice Redir.) (May 19, 2021).

[40] Tr. at 75:7-78:14 (Brice Cross) (May 19, 2021) (testifying that the remaining NBVs for DHPS, Pirkey, and Welsh Units 1 and 3 is $151 million, $212 million, and $587 million, respectively); TIEC Ex. 15; SWEPCO Ex. 16, Direct Testimony of Jason A. Cash Exhibit JAC-2 at 18 (Cash Dir.). As Mr. Brice testified, Texas's share is approximately 37 percent. Tr. at 75:19-25 (Brice Cross) (May 19, 2021).

fixed costs associated with the mining operations.[41] The unrecovered fixed costs associated with the mines that fuel DHPS and Pirkey combine to be $324 million total company, or approximately $120 million Texas retail.[42] In total, there is approximately $470 million in remaining costs associated with the plants that SWEPCO plans to retire, which will create a significant financial burden on ratepayers, particularly if SWEPCO is allowed to accelerate recovery of these assets or earn a return on them at a time when they are no longer used and useful.

Third, the retirements of DHPS, Pirkey, and Welsh are a part of AEP's national strategy of retiring coal-fired units and replacing them with renewable and gas resources. SWEPCO's President and Chief Operating Officer Mr. Malcolm Smoak confirmed as much at the hearing:

> Q Okay. So if we look at the top in the box, it says, Reduce coal generation by approximately 5,600 megawatts by 2030 and decrease coal net book value through retirements and depreciation. This creates the opportunity to own replacement wind, solar, and natural gas resources. Did I read that correctly?
>
> A That's correct.
>
> Q So the retirement of this Dolet Hills plant, and the other two plants we just went over, are part of this retirement progress and plan [sic] strategy. Right?
>
> A That's correct.[43]

In the same vein, AEP in a recent roadshow presentation to investors touted the retirements of DHPS, Pirkey, and Welsh as the "SWEPCO Generation Replacement Plan," stating that the planned retirements will "drive[] a capacity need of nearly 2 GW," which will in turn "create[] a renewable energy and dispatchable resource replacement opportunity."[44] Thus, at the same time that ratepayers are paying off the remaining balance associated with the retired plants and lignite mines, SWEPCO will also be seeking to increase rates through the addition of new renewable

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[41] Tr. at 74:3-21 (Brice Cross) (May 19, 2021); *see also* TIEC Ex. 4, LaConte Dir. at 11-12.

[42] Tr. at 76:1-77:6 (Brice Cross) (May 19, 2021) (testifying that the unbilled fuel costs for the mines fueling DHPS and Pirkey are $131 million and $193 million, respectively); TIEC Ex. 15.

[43] Tr. at 56:25-57:11 (Smoak Cross) (May 19, 2021).

[44] TIEC Ex. 6 at Bates 015.

generation. Notably, this strategy appears to be driven by AEP's self-imposed net zero carbon by 2050 goal, to which it has tied long-term incentive compensation.[45] Given that SWEPCO is executing a strategy to retire and replace DHPS and other plants with new renewable generation in order to grow rate base and increase earnings, it would be inequitable to permit SWEPCO to accelerate recovery of the retired DHPS or earn a return on the remaining balance for years after the plant is retired.

Fourth, the remaining NBV of DHPS includes $47 million (total company) of investment for environmental retrofits that were approved in SWEPCO's 2017 rate case based on the assumption of a 2046 useful life.[46] In the 2013 timeframe, SWEPCO and CLECO installed environmental retrofits at DHPS, of which SWEPCO's share was $56 million.[47] These investments were approved as prudent by the Commission and included in rate base.[48] Notably, the economic analysis that SWEPCO provided to the Commission in Docket No. 46449 to justify the decision to retrofit rather than retire DHPS assumed a 2046 useful life for DHPS.[49] This was despite the fact that SWEPCO had proposed a 2026 useful life for DHPS in its prior rate case, Docket No. 40443, on the grounds that there was only enough lignite reserves to run DHPS until that year.[50] As Mr. Brice testified at the hearing, the depletion of the lignite reserves that fuel DHPS is the primary driver for the early retirement of the plant in 2021.[51]

Finally, SWEPCO chooses when to file its rate cases, and it chose to file this rate case at a time that resulted in DHPS being operational during the rate year, but for no more than nine months.[52] This timing facilitates SWEPCO's central contention on this issue, which is that it is

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[45] *Id.* at Bates 011-015; Tr. at 52:10-53:21, 55:10-21 (Smoak Cross) (May 19, 2021); TIEC Ex. 5.

[46] TIEC Ex. 18; Sierra Club Ex. 9; Tr. at 130:23-131:17 (Baird Cross) (May 19, 2021).

[47] Tr. at 79:13-25 (Brice Cross) (May 19, 2021); Docket No. 46449, Order on Rehearing at FoFs 27-28.

[48] Tr. at 79:12-21 (Brice Cross) (May 19, 2021).

[49] *Id.* at 80:2-82:9; TIEC Ex. 18.

[50] TIEC Ex. 18; Tr. at 81:18-82:8 (Brice Cross) (May 19, 2021); Docket No. 40443, PFD at 173-74.

[51] Tr. at 74:19-21 (Brice Cross) (May 19, 2021).

[52] *Id* at 71:11-72:1.

entitled to a return on the remaining balance of DHPS because the plant will be operational during the rate year.[53] Notably, SWEPCO was not required to file a rate case under PURA and the Commission's rules until 2022,[54] and, in fact, a January 2020 internal presentation discussing rate recovery issues with respect to DHPS shows that SWEPCO at the time was contemplating filing its Texas rate case in 2022, after DHPS was expected to retire.[55]

In light of these considerations, TIEC submits that there is good cause to treat DHPS as a retired plant notwithstanding that it will still be operational at the outset of the rate year. In any event, these equitable considerations strongly weigh against SWEPCO's proposal to impose significant costs on ratepayers by massively accelerating the cost recovery of DHPS.

2. Retired Gas-Fired Generating Units [PO Issue 13]

Consistent with Commission precedent established in Docket No. 46449 and set out in detail in the preceding section, SWEPCO should only be permitted to earn a return of, not on, the undepreciated balance of several gas-fired generating units it has retired since its last base rate case. This treatment is not only consistent with statute,[56] it also balances ratepayer and shareholder interests by allowing the utility to recover all of its prudently incurred investment, while ensuring that ratepayers are not paying for a return on an investment that is no longer serving them. These retired gas units include Lone Star Unit 1, Lieberman Unit 2, and Knox Lee Units 2, 3, and 4.[57] TIEC agrees with the recommendation of Staff witness Ms. Stark that the appropriate treatment is to remove the NBV (totaling $13.2 million) of these assets from rate base, and to place them in a

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[53] *Id* at 70:23-71:4.

[54] *Id.* at 71:5-10.

[55] *Id.* at 69:13-70:22 (Brice Cross) (May 19, 2021); TIEC Ex. 9 (HSPM). Mr. Brice stated at the hearing that this information was not HSPM. Tr. at 69:13-16 (Brice Cross) (May 19, 2021).

[56] PURA § 36.051.

[57] Staff Ex. 3, Direct Testimony of Ruth Stark at 18-19 (citing Docket No. 46449, Order on Rehearing at FoFs 65-71) (Stark Dir.).

regulatory asset that SWEPCO may recover, but not earn a return on.[58] Further, TIEC agrees with Ms. Stark's recommendation to amortize the regulatory assets over four years.[59]

C. Accumulated Deferred Federal Income Tax [PO Issues 20]

1. Net Operating Loss ADFIT

2. Excess ADFIT

ADFIT are income taxes that SWEPCO has already collected from ratepayers but that have not yet been paid to the federal government due to timing differences between book depreciation and tax depreciation.[60] Thus, ADFIT represents ratepayer-supplied capital.[61] Excess ADFIT is the reduction in ADFIT that resulted from the reduction in the corporate tax rate from 35% to 21% enacted by the Tax Cuts and Jobs Act of 2017 (TCJA).[62] In Docket No. 46449, the Commission ordered that the regulatory treatment of the excess ADFIT resulting from the TCJA be addressed in SWEPCO's next rate case.[63]

As TIEC witness Ms. LaConte recommends, the $39 million of excess ADFIT that SWEPCO would use to offset DHPS should instead be refunded to ratepayers over a period of one year.[64] This $39 million balance includes all of SWEPCO's unprotected excess ADFIT, which SWEPCO has already retained for over three years, as well as the protected excess ADFIT that accumulated from January 1, 2018 through March 2021.[65] These amounts represent excess income taxes previously paid by SWEPCO's ratepayers, and ratepayers are entitled to be promptly and fully compensated for the excess income taxes they have previously paid. Ms. LaConte's proposal

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[58] *Id.* at 19-20.

[59] *Id.*

[60] TIEC Ex. 4, LaConte Dir. at 14-15.

[61] *Id*

[62] *Id.* at 15.

[63] Docket No. 46449, Order on Rehearing at Ordering Paragraph (OP) 10.

[64] TIEC Ex. 4, LaConte Dir. at 17.

[65] *Id.* at 16. Protected excess ADFIT must be amortized over the remaining life of the assets under the average rate assumption method (ARAM). *Id.* at 15-16.

of a one-year refund is consistent with the practice of several other utilities, including SWEPCO's sister company, AEP Texas, and Entergy Texas, Inc. (ETI), and should be adopted.[66] The refund should include appropriate carrying costs, accruing at SWEPCO's weighted-average cost of capital (WACC) as of the effective date of rates in this case.[67] Further, the refund should be allocated to the rate schedules in proportion to the amount of allocated ADFIT in the class cost of service study, (CCOSS) as laid out in Table 3 in the direct testimony of Mr. Pollock.[68]

E. Regulatory Assets and Liabilities [PO Issues 19, 21, 22, 41, 50]

1. Self-Insurance Reserve [PO Issue 19 and 40]

SWEPCO has not presented the cost-benefit analysis required by the Commission's rules to establish a self-insurance reserve. But even if SWEPCO had adhered to the legal requirements for establishing the reserve, its estimates of the necessary size of the reserve are too high because they are based on uncertain estimates. SWEPCO's self-insurance proposal should be denied or, if the Commission does adopt a self-insurance reserve for SWEPCO, the target reserve should be reduced to $2,722,000 with a total annual storm cost accrual of $1,255,000, as set forth in Ms. LaConte's direct testimony.

PUC Substantive Rule § 25.231(b)(1)(G) allows an electric utility to request a self-insurance plan providing for accruals to be credited to reserve accounts. The Commission will approve a self-insurance plan to the extent it finds it to be in the public interest, which requires the electric utility to "present a cost benefit analysis performed by a qualified independent insurance consultant who demonstrates that, with consideration of all costs, self-insurance is a lower-cost alternative than commercial insurance and the ratepayers will receive the benefits of the self-insurance plan."[69]

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[66] *Id.* at 16-17.

[67] *Id.* at 17; Tr. at 356:12-25 (LaConte Dir.) (May 20, 2021) (making errata changes).

[68] TIEC Ex. 1, Direct Testimony and Exhibits of Jeffry C. Pollock at 40-41 (Pollock Dir.). All citations to Mr. Pollock's testimony refer to native pagination.

[69] 16 T.A.C. § 25.231(b)(1)(G).

Mr. Wilson is the independent insurance consultant SWEPCO presented in this case,[70] but he did not present a cost-benefit analysis as required by the Commission's rules.[71] In fact, no numerical cost *or* benefit is presented anywhere in the section of Mr. Wilson's direct testimony where he claims to perform a cost-benefit analysis.[72] Mr. Wilson's cost-benefit analysis also lacks "consideration of all costs" as it does not present any numerical costs; it just presents "generic cost categories."[73]

Instead of presenting a numerical cost-benefit analysis, Mr. Wilson relies on his "understanding" of self- and commercial insurance.[74] When asked at hearing when he last updated his understanding of insurance, Mr. Wilson replied: "I think the last time I remember getting a quote is probably three or four years ago."[75] A purely theoretical, three or four years old analysis based on a general understanding is not sufficient to allow the Commission to find that the self-insurance reserve would be in the public interest.[76] Without a quantitative cost-benefit analysis or actual cost information, it is impossible for the Commission to determine that with consideration of all costs, self-insurance "is a lower-cost alternative than commercial insurance and the ratepayers will receive the benefits of the self-insurance plan," as required by 16 T.A.C. § 25.231(b)(1)(G).

Additionally, it appears that Mr. Wilson failed to conduct a quantitative analysis because of his belief that self-insurance is *always* less expensive than commercial insurance in the state of Texas.[77] But if such a belief was sufficient, there would be no reason for the Commission's rules

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[70] Tr. at 284:11-13 (Wilson Cross) (May 19, 2021).

[71] *Id* at 284:16-17 (stating that Mr. Wilson's analysis "does not present a number for the cost of insurance").

[72] SWEPCO Ex. 28, Direct Testimony of Gregory S. Wilson at 10-12 (Wilson Dir.).

[73] Tr. at 288:23-289:3 (Wilson Cross) (May 19, 2021) (agreeing that the theoretical costs listed on Page 11 of Mr. Wilson's direct testimony are "kind of generic cost categories").

[74] *Id.* at 12.

[75] Tr. at 290:20-201:1 (Wilson Cross) (May 19, 2021).

[76] 16 T.A.C. § 25.231(b)(1)(G) ("The commission will approve a self-insurance plan to the extent it finds it to be in the public interest.").

[77] Tr. at 286:11-287:4; *see generally* SWEPCO Ex. 28, Wilson Dir.

to require a utility to present a cost-benefit analysis. SWEPCO cannot meet the requirements of the rule simply based on Mr. Wilson's conclusory testimony that self-insurance is always less costly than commercial insurance.

Even if Mr. Wilson had properly presented a cost-benefit analysis, his calculation of the target reserve is too high because he used estimates of storm damage from 2000 and 2004 to develop his annual storm cost and a target reserve amount instead of actual storm damage figures.[78] This increased Mr. Wilson's annual storm cost and target reserve amounts significantly because the estimated inflation-adjusted 2000 storm costs were over five times higher than those of the next largest year.[79] Specifically, Mr. Wilson estimated the storm damage from 2000 and 2004 by subtracting from the total storm costs for those years the amount of the highest-cost minor storm from the other years in which there was actual data.[80] However, this estimate assumes that only one minor storm occurred in those years.[81] Because SWEPCO would use the self-insurance reserve only for major storms, all minor storms must be subtracted from the 2000 and 2004 estimates, but Mr. Wilson presents no reason to believe that just one minor storm occurred in each of those years.

While the Commission should not approve a self-insurance reserve due to SWEPCO's failure to provide a cost-benefit analysis, if the Commission were to approve a self-insurance reserve it should remove the estimated costs from 2000 and 2004 in its analysis. The self-insurance reserve is comprised of the target amount to maintain in the reserve and the annual accrual, the latter of which is determined by the sum of the amount needed to meet the target reserve over some period of time (four years in SWEPCO's proposal) and the annual expected losses from storms that cause over $500,000 in damage. Excluding the estimated storm costs from 2000 and 2004 decreases the inflation-adjusted average storm cost by $1,340,000 (to $1,410,000).[82] Mr. Wilson's

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[78] TIEC Ex. 4, Direct Testimony of Billie S. LaConte at 20-21 (LaConte Dir.).

[79] *Id.* at 20.

[80] SWEPCO Ex. 50, Rebuttal Testimony of Gregory S. Wilson at 4-5 (Wilson Reb.).

[81] SWEPCO Ex. 28, Wilson Dir. at 3.

[82] TIEC Ex. 4, LaConte Dir. at 21.

Monte Carlo simulation model then generates a target reserve of $2,722,000 ($838,000 less than Mr. Wilson's proposal).[83] The amount needed to meet that target reserve over four years is $680,500 per year.[84] This amount plus the annual expected loss from storms causing over $500,000 in damage ($575,000) equals a total annual storm cost accrual of $1,255,000, which is $244,700 less than Mr. Wilson's proposal.[85] While SWEPCO has not met its burden to demonstrate that self-insurance is less costly than commercial insurance, if the Commission nevertheless approves SWEPCO's request for a self-insurance reserve, the annual accrual should be set at $1,255,000.

III. Rate of Return [PO Issues 4, 5, 8, 9]

A. Overall Rate of Return, Return on Equity, Cost of Debt [PO Issue 8]

1. Return on Equity

SWEPCO's proposed ROE of 10.35% is significantly higher than the cost of capital for utilities in current market conditions and is unsupported by the evidence.

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83 *Id* at 21-22.

84 *Id.* at 22.

85 *Id.* at 21-22.

The parties' recommendations regarding SWEPCO's ROE are:

Party	Recommendation
TIEC[86]	9.15%
Staff[87]	9.225%
CARD[88]	9.00%
SWEPCO[89]	10.35%

The intervenors' and Staff's ROE recommendations reflect the current low cost-of-capital environment and SWEPCO's low business risk, both of which have only improved since SWEPCO's last rate case in 2017, when it was awarded a 9.6% ROE.[90] Among other indicators, the reduction in the cost of capital since SWEPCO's last rate case is evident from the marked decline in interest rates since 2017,[91] as well as the reduction in regulatory commission-authorized ROEs that has occurred around the country during that same period.[92] Further, SWEPCO's business and operating risk has improved since its last rate case due to, among other factors, the enactment in 2019 of the generation cost recovery rider (GCRR) statute, which allows SWEPCO

86 TIEC Ex. 3, Direct Testimony and Exhibits of Michael P. Gorman at 5 (Gorman Dir.). All citations to Mr. Gorman's testimony refer to native pagination.

87 Staff Ex. 1, Direct Testimony of Mark Filarowicz at 8 (Filarowicz Dir.). Mr. Filarowicz recommended an ROE of 9.35%, while Staff witness John Poole recommended a 12.5-basis-point downward adjustment. *Id.*; *see also* Staff Ex. 5, Direct Testimony of John Poole at 12 (Poole Dir.).

88 CARD Ex. 4, Direct Testimony of J. Randall Woolridge at 4 (Woolridge Dir.).

89 SWEPCO Ex. 8, Direct Testimony of Dylan W. D'Ascendis at 6 (D'Ascendis Dir.).

90 Docket No. 46449, Order on Rehearing at FoF 158.

91 TIEC Ex. 46.

92 TIEC Ex. 3, Gorman Dir. at 7.

to begin recovering its capital investment in a new generation facility on the day the facility goes into service.[93]

SWEPCO justifies its request to increase its authorized ROE through the testimony of Mr. Dylan D'Ascendis, who systematically overstates his recommended ROE and ignores the realities of the current capital market environment. For example, Mr. D'Ascendis uses a faulty DCF analysis on the S&P 500 to calculate an unreasonably high expected market return, which results in an inflated equity risk premium in his Risk Premium analysis and an inflated market risk premium in his capital asset pricing model (CAPM) analysis. On top of his inflated models, Mr. D'Ascendis further increases his ROE estimate by adding a 20-basis-point "size adjustment" and a 27-basis-point "credit-risk adjustment," completely ignoring the fact that SWEPCO is an operating subsidiary of AEP, one of the largest utility holding companies in the United States with an A- credit rating.

For these reasons and others, described below, Mr. D'Ascendis's recommendation significantly overstates SWEPCO's cost of equity and results in an excessive, unjustified ROE recommendation. The evidence supports an ROE of 9.15% for SWEPCO as recommended by Mr. Gorman.

a. The cost of capital has declined significantly since SWEPCO's last rate case, and SWEPCO's ROE should be adjusted accordingly.

SWEPCO's requested 10.35% ROE is entirely unjustified in the current market environment, where utilities have been able to maintain robust access to low-cost capital despite lower average authorized ROEs. That is because the cost of capital has decreased significantly since SWEPCO's last rate case, as evidenced by the steep decline in interest rates. This decline can be seen in the following chart from Mr. Gorman's testimony:[94]

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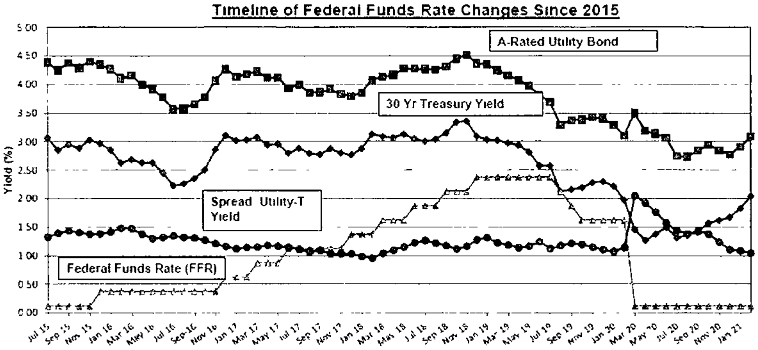
[93] Tr. at 1070:16-23 (D'Ascendis Cross) (May 24, 2021); PURA § 36.213.

[94] TIEC Ex. 3, Gorman Dir. at 13.

FIGURE 4

Timeline of Federal Funds Rate Changes Since 2015



Fed FFR Actions

1	December 2015	0 25	-	0 50	8	September 2018	2 00	-	2 25
2	December 2016	0 50	-	0 75	9	December 2018	2 25	-	2 50
3	March 2017	0 75		1 00	10	August 2019	2 00	-	2 25
4	June 2017	00		1 25	11	September 2019	1 75	-	2 00
5	December 2017	1 25		1 50	12	October 2019	1 50	-	1 75
6	March 2018	50		1 75	13	March 2020	1 00	-	1 25
7	June 2018	1 75	-	2 00	14	March 2020	0 00	-	0 25

Sources
Federal Reserve Bank of New York https //apps newyorkfed org/markets/autorates/fed-funds-search-page
Board of Governors of the Federal Reserve System https //www federalreserve gov/datadownload/
Moody's Credit Trends https //credittrends moodys com/

As the chart shows, long-term and short-term rates have fallen dramatically since 2017, and are currently at near-historic lows.[95] In fact, both 30-year Treasury yields and Aaa-rated corporate bond yields are currently more than 100 basis points lower than what they were during the pendency of Docket No. 46449.[96] Moreover, the current low cost-of-capital environment is expected to continue into at least the intermediate term, as market participants have grown comfortable with the Federal Reserve's actions and low interest rates.[97]

The decrease in the cost of capital is also reflected in utilities' awarded ROEs, though regulatory commissions have lagged behind the steep decline in interest rates in lowering utility ROEs. Over the same period since 2017, authorized ROEs have decreased, but not nearly as dramatically as the reduction in interest rates.[98] Mr. Gorman's Figure 1 shows that authorized

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[95] *Id.* at 17.

[96] TIEC Ex. 46.

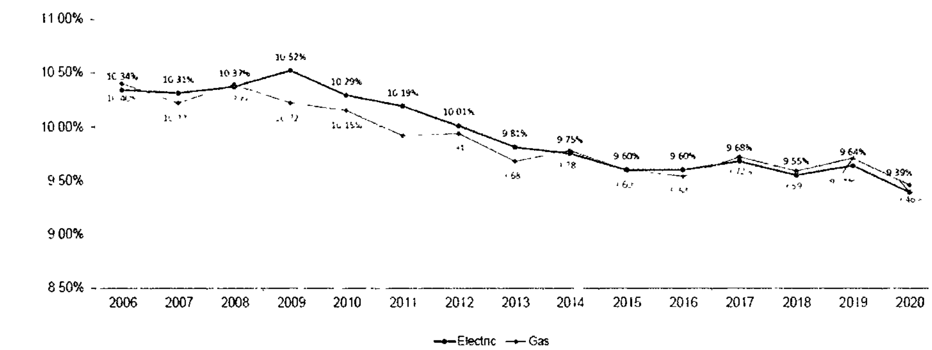
[97] TIEC Ex. 3, Gorman Dir. at 14-15.

[98] *Id* at 7.

electric utility ROEs have only slightly decreased since SWEPCO's last rate case in 2017, from an average ROE of 9.6% in 2017 to an average ROE of 9.39% in 2020:[99]

FIGURE 1

Authorized Returns on Equity[1]
(Exclude Limited Issue Riders)



ROE Distributions[2]

Electric Utilities	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
<= Average	56.0%	59.5%	51.4%	59.0%	51.7%	55.0%	51.9%	52.4%	57.6%	60.0%	53.1%	60.5%	47.4%	45.5%	33.3%
> Average	44.0%	40.5%	48.6%	41.0%	48.3%	45.0%	48.1%	47.6%	42.4%	40.0%	46.9%	39.5%	52.6%	54.5%	66.7%
Gas Utilities															
<= Average	46.7%	51.4%	50.0%	50.0%	56.4%	31.3%	45.7%	47.6%	50.0%	50.0%	53.8%	70.8%	47.5%	53.1%	52.9%
> Average	53.3%	48.6%	50.0%	50.0%	43.6%	68.8%	54.3%	52.4%	50.0%	50.0%	46.2%	29.2%	52.5%	46.9%	47.1%

Source and Notes
S&P Global Market Intelligence, RRA Regulatory Focus: Major Rate Case Decisions - January - December 2020, February 2, 2021, at page 1.
[2] Download from S&P Global Market Intelligence, March 18, 2021.
[1] Electric Returns exclude Limited Issue Rider Decisions.
[*] RRA excludes the 2017 Alaska ENSTAR decision from its Industry Average.

Thus, while interest rates have declined by over 100 basis points since 2017, average authorized ROEs have only dropped by approximately 20 basis points.[100] The result is that the spread between authorized ROEs and interest rates (or the implied equity risk premium) is higher than it has ever been, as Moody's noted in an October 2020 report:[101]

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[99] *Id.*

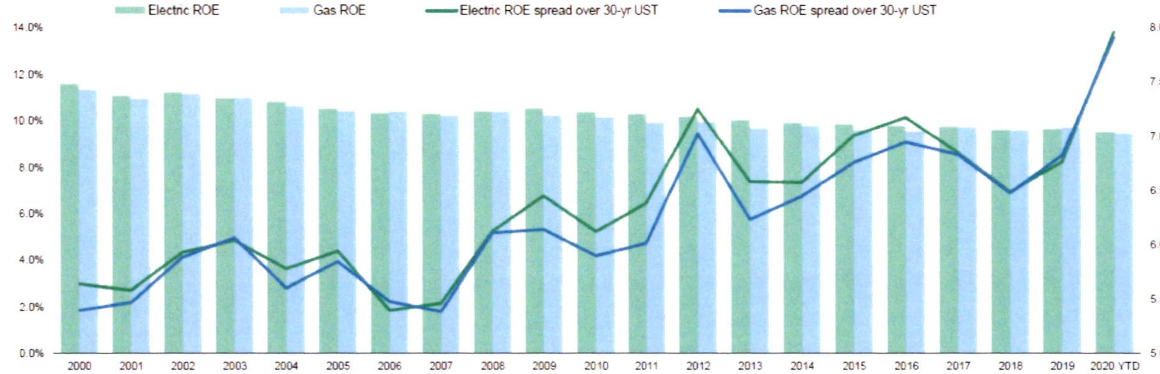
[100] *Id.*

[101] TIEC Ex. 3B, Confidential Workpapers to the Direct Testimony of Michael P. Gorman at MPG Confidential WP 15 (Moody's Investors Service, *2021 Outlook Stable on Strong Regulatory Support and Robust Residential Demand* (Oct. 29, 2020)) at 5 (Gorman Conf. Workpapers).

Exhibit 4

Spread between allowed utility ROEs and 30-year Treasury yield has widened

US regulated utilities' average authorized return on equity versus yield on 30-year US Treasury bonds



2020 YTD through October 2020

Sources: S&P Global Market Intelligence, U.S. Department of the Treasury, Moody's Investors Service

If Mr. D'Ascendis's ROE recommendation of 10.35% is adopted, it would result in an implied equity risk premium of approximately 800 to 850 basis points.[102] On the other hand, Mr. Gorman's recommended ROE of 9.15% would result in an implied equity risk premium of approximately 675 to 725 basis points, which is slightly higher than the spread in 2017 and still extremely inflated relative to historical spreads.

The reason for the increase in implied equity risk premiums is not that there is an inverse relationship between interest rates and implied equity risk premiums like Mr. D'Ascendis claims—such a simplistic view is unsupported by academic research[103] and confuses correlation for causation.[104] Rather, the increasing spread between authorized ROEs and interest rates is driven

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[102] The average 30-year Treasury yield during the pendency of this proceeding has been 1.87%. TIEC Ex. 46. The 30-year Treasury yield at the time of the hearing was 2.3%. Tr. at 1025:7-10 (Gorman Cross) (May 24, 2021).

[103] TIEC Ex. 3, Gorman Dir. at 68.

[104] TIEC Ex. 3A, Workpapers to the Direct Testimony of Michael P. Gorman at WP 11 (*When "What Goes Up" Does Not Come Down: Recent Trends in Utility Returns*, Charles S. Griffey (Feb. 15, 2017)) at Bates 335-36 (Gorman Dir. Workpapers).

by the fact that regulations, due to structural factors, are often slower to lower ROEs than what market conditions dictate.[105] Indeed, Moody's in the same October 2020 report stated:

> Utility allowed ROEs ***are likely to continue to decline as low interest rates persist*** given the industry's relatively low risk business risk profile, strong monopoly characteristics and the aim of regulators to keep rates affordable. As a result, ***we do not view declining allowed ROEs alone as indicative of weaker regulatory relationships***. . . . Furthermore, mechanisms that reduce regulatory lag and enhance the ability of utilities to earn their authorized ROEs help to mitigate the impact of lower allowed ROEs. For example, in Texas, a new generation cost recovery rider allows non-ERCOT utilities to seek recovery of investments in power generation facilities before the facility is in service and start recovering investments beginning on the day the facility is placed in service.[106]

That authorized ROEs can continue to decline is also apparent from utilities' extremely robust access to capital. For example, in March of this year, SWEPCO was able to issue a $500 million five-year note at an interest rate of 1.65%.[107] SWEPCO's sister company, AEP Texas, issued a $450 million 30-year bond at an interest rate of 3.45% in May.[108] AEP Texas was most recently granted an ROE of 9.4% in 2020,[109] and it has the same credit rating as SWEPCO.[110] The evidence is clear that despite lower ROEs, utilities have had no difficulty in accessing low-cost capital to fund rate-base growth in the current market environment.

SWEPCO witness Mr. D'Ascendis ignores the decline in the cost of capital since SWEPCO's last rate case and instead narrowly focuses on increased volatility, which has been

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[105] *Id.* For instance, the "proxy group" starting point for setting ROEs creates an inherently retrospective feedback loop where regulatory commissions rely heavily on the recent decisions of other commissions. *Id.* Similarly, Dr. Woolridge testified at the hearing that regulators often set ROEs based on interest-rate projections, which have for the past four to five years consistently and significantly overestimated the interest rates that actually occurred. Tr. at 1003:18-1004:21 (Woolridge Redir.) (May 24, 2021).

[106] TIEC Ex. 3B, Gorman Conf. Workpapers at MPG Confidential WP 15 (Moody's Investors Service, *2021 Outlook Stable on Strong Regulatory Support and Robust Residential Demand* (Oct. 29, 2020)) at 5.

[107] Tr. at 960:7-11 (Hawkins Cross) (May 24, 2021); TIEC Ex. 63.

[108] Tr. at 960:19-22 (Hawkins Cross) (May 24, 2021); TIEC Ex. 64.

[109] *Application of AEP Texas for Authority to Change Rates*, Docket No. 49494, Final Order at 2 (Apr. 6, 2020).

[110] Tr. at 960:23-961:1 (Hawkins Cr.) (May 24, 2021); TIEC Ex. 6 at Bates 034.

largely due to the COVID-19 pandemic.[111] As an initial matter, the economy has started—and is expected to continue—to recover from the effects of the pandemic as vaccinations increase and the economy reopens.[112] Further, the utility industry performed well during the pandemic. As S&P stated in a 2021 credit report:

> Encouragingly, the [utility] industry has generally performed well throughout the pandemic. Lower electric and gas deliveries to C&I customers were mostly offset by higher residential deliveries, the industry generally worked well with regulators to defer COVID-19-related costs for future recovery, market returns improved, and the industry generally had consistent access to the capital markets.[113]

Indeed, while Mr. D'Ascendis noted the risk of utilities lowering dividends during a prolonged economic downturn in his direct testimony, he acknowledged at the hearing that only two utility companies lowered dividends, and that other utility companies increased dividends in 2020, including AEP.[114]

The evidence is clear that the required cost of capital for utilities has steeply declined since SWEPCO was awarded an ROE of 9.6% in 2017, and SWEPCO's ROE in this proceeding should be adjusted accordingly.

b. The Commission should adopt Mr. Gorman's ROE recommendation.

As described in detail below, Mr. Gorman used widely accepted methods to estimate SWEPCO's market cost of equity. His resulting ROE recommendation of 9.15% is reasonable, in

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[111] SWEPCO Ex. 38, Rebuttal Testimony of Dylan W. D'Ascendis at 10-11, 14-22 (D'Ascendis Reb.).

[112] *See, e.g.*, SWEPCO Ex. 38A, Workpapers to the Rebuttal Testimony of Dylan W. D'Ascendis (S&P Global Ratings, *North American Regulated Utilities' Negative Outlook Could See Modest Improvement* (Jan. 20, 2021) at 26 ("Widespread immunization, which certain countries might achieve by midyear, will help pave the way for a return to more normal levels of social and economic activity.") (D'Ascendis Reb. Workpapers).

[113] TIEC Ex. 3, Gorman Dir. at 19-20.

[114] Tr. at 875:22-877:16 (D'Ascendis Cross) (May 24, 2021); TIEC Ex. 6 at Bates 010.

line with the recommendations of the other intervenors and Staff, and represents a fair outcome for both SWEPCO and its customers.[115]

i. Mr. Gorman's Discounted Cash Flow (DCF) analysis is reasonable.

The discounted cash flow (DCF) model is based on the principle that a company's stock price can be valued by summing the present value of expected future cash flows (dividends), discounted at its investors' required rate of return, and can be represented by the following equation.

$$K = D_1/P_0 + G \qquad \text{(Equation 2)}$$

K = Investor's required return
D_1 = Dividend in first year
P_0 = Current stock price
G = Expected constant dividend growth rate

Mr. Gorman used three different DCF models to estimate the return that investors would demand in order to invest in SWEPCO: the constant growth DCF, the sustainable growth DCF, and the multi-stage growth DCF.[116]

Mr. Gorman's constant growth DCF model used his proxy group's[117] 13-week average stock price and most recently reported quarterly dividends, along with a 5.46% growth rate, which was based on the mean of professional securities analysts' growth estimates for those

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[115] *See* Staff Ex. 1, Filarowicz Dir. at 8 (recommending a ROE of 9.225%); CARD Ex. 4, Woolridge Dir. at 4 (recommending a ROE of 9.00%).

[116] *Id.* at 27-40.

[117] Mr. Gorman used the same proxy group as Mr. D'Ascendis, except that Mr. Gorman excluded PNM Resources (PNMR) because it recently announced that it was in the process of being acquired by Avangrid. TIEC Ex. 3, Gorman Dir. at 25. In rebuttal testimony, Mr. D'Ascendis also excluded PNMR. SWEPCO Ex. 38, D'Ascendis Reb. at 8.

companies.[118] The resulting average and median constant growth DCF returns for the proxy group were 9.43% and 9.35%, respectively.[119]

Mr. Gorman's sustainable growth DCF model is based on the principle that a utility's earnings will grow over time as it invests in additional utility plant and equipment, which enables it to earn its authorized return on a larger total rate base.[120] To estimate the sustainable growth in SWEPCO's rate base, Mr. Gorman looked to the proportion of total earnings that his proxy group retained for reinvestment rather than paying out in dividends.[121] He found that, on average, the sustainable growth rate for SWEPCO's proxy group is 4.50%.[122] Performing a DCF analysis using this sustainable growth rate resulted in average and median ROE results of 8.44% and 8.45%, respectively.[123]

Mr. Gorman's multi-stage growth DCF model reflects that, while a utility may experience periods of high or low short-term growth, its growth rate will eventually regress toward a long-term sustainable rate.[124] To model this expectation, Mr. Gorman performed a multi-stage growth DCF analysis that starts with the consensus economists' growth rate projections that were used in his constant growth DCF (5.46%), which represent reasonable investor expectations for the next five years.[125] Then, for years six through ten, he adjusted the proxy group's growth rates halfway toward the long-term sustainable growth rate of 4.35%, based on economists' projections for total gross domestic product (GDP) growth.[126] For years eleven and after, Mr. Gorman projected

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[118] TIEC Ex. 3, Gorman Dir. at 28-30, Ex. MPG-4.

[119] *Id* at 30, Ex. MPG-5.

[120] *Id.* at 31.

[121] *Id.* at 31, Ex. MPG-6.

[122] *Id.* at 32, Ex. MPG-7.

[123] *Id.* at 32, Ex. MPG-8.

[124] *Id* at 32-33.

[125] *Id* at 33.

[126] *Id.* at 34-39.

growth at the long-term sustainable rate of 4.35%.[127] As Mr. Gorman testified, the GDP growth rate is a conservative proxy for the long-term growth rate because the long-term growth of a utility cannot exceed the growth rate of the economic in which it sells goods and services.[128] The resulting DCF analysis resulted in average and median DCF ROEs of 8.56% and 8.72%, respectively.[129]

The results of Mr. Gorman's various DCF models are summarized in his Table 6:[130]

TABLE 6

Summary of DCF Results

Description	Median
Constant Growth DCF Model (Analysts' Growth)	9.35%
Constant Growth DCF Model (Sustainable Growth)	8.45%
Multi-Stage Growth DCF Model	8.72%

Mr. Gorman's DCF cost of equity estimate for SWEPCO is the midpoint of the low (8.45%) and high (9.35%) endpoints of the range, or 8.90%.[131]

ii. *Mr. Gorman's Bond Yield Plus Risk Premium (Risk Premium) analysis is reasonable.*

Mr. Gorman also conducted a Bond Yield Plus Risk Premium (Risk Premium) analysis, which is based on the principle that investors will require a higher return for investments with

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127 *Id* at 39.

128 *Id.* at 30, 35-37 (discussing academic research supporting the position that, over the long term, a utility's earnings and dividends cannot grow at a rate greater than the growth of GDP).

129 *Id.* at 40.

130 *Id* at 40.

131 *Id.*

greater risk.[132] While the return that bondholders require can be directly observed through bond yields, the cost of equity cannot be similarly observed.[133] The Risk Premium model estimates the cost of equity by taking the observed cost of debt and adding an equity risk premium, which is the additional return that an equity holder requires over a bondholder.[134]

Mr. Gorman's Risk Premium analysis estimates the additional return that investors will require in order to hold utility stock instead of (1) Treasury bonds and (2) A-rated utility bonds.[135] These analyses are based on a comparison of historically awarded utility ROEs to 30-year Treasury yields and A-rated utility bond yields, respectively, over the period from 1986 through 2020.[136] The calculated spreads can be seen in Exhibits MPG-12 and MPG-13.[137] To reflect the dynamic nature of utility risk premiums and mitigate the impact of anomalous market conditions, Mr. Gorman calculated five- and ten-year rolling average risk premiums.[138] These results are as follows:

Electric Utility Equity Risk Premium Over U.S. Treasury Bond Yields: 1986-2020[139]

Average Indicated Risk Premium	5.65%
Five-Year Rolling Average Risk Premium	4.25% to 7.02%
Ten-Year Rolling Average Risk Premium	4.38% to 6.80%

Electric Utility Equity Risk Premium Over "A" Rated Utility Bond Yields: 1986-2020[140]

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132 *Id.* at 41.

133 Tr. at 878:12-18 (D'Ascendis Cross) (May 24, 2021).

134 *Id.* at 878:19-23.

135 TIEC Ex. 3, Gorman Dir. at 50-51.

136 *Id.* at 41.

137 *Id.* at Exs. MPG-12 & MPG-13.

138 *Id.* at 42.

139 *Id.* at Ex. MPG-12.

140 *Id* at Ex. MPG-13.

Average Indicated Risk Premium	4.28%
Five-Year Rolling Average Risk Premium	2.88% to 5.77%
Ten-Year Rolling Average Risk Premium	3.20% to 5.62%

Rather than simply applying these risk premiums to recent Treasury bond levels, Mr. Gorman analyzed empirical data to determine how the market is currently pricing investment risk.[141] By comparing historical and recent yield spreads for utility bonds and general corporate bonds, Mr. Gorman concluded that the market is currently paying a premium for access to lower-risk utility securities.[142] As a result, Mr. Gorman took a conservative approach and applied risk premium based solely on the high end of his ranges.[143]

This resulted in an equity risk premium over Treasury bonds of 7.02%, which is considerably higher than the 5.57% historical average premium.[144] Combined with a 2.4% projected U.S. Treasury bond yield, this resulted in a Risk Premium ROE estimate of 9.42%.[145] Similarly, his equity risk premium over utility bonds was 5.77%, compared to the historical average of 4.28%.[146] Adding this equity risk premium to current Baa-rated utility bond yields of 3.21% resulted in a Risk Premium ROE estimate of 8.98%.[147] Thus, Mr. Gorman's Risk Premium analysis indicates an ROE in the range of 9.00% to 9.40%, with a midpoint of 9.20%.[148]

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[141] *Id.* at 44-46

[142] *Id* at 45-46.

[143] *Id.* at 46.

[144] *Id* at 46-47.

[145] *Id*

[146] *Id*

[147] *Id.* at 47.

[148] *Id.*

iii. Mr. Gorman's Capital Asset Pricing Model (CAPM) analysis is reasonable.

The Capital Asset Pricing Model (CAPM) posits that in order to hold a security, an investor requires a rate of return equal to the risk-free rate, plus the market risk premium multiplied by "beta," which represents the risks of holding that security that cannot be eliminated by asset diversification.[149] The CAPM can be expressed as follows:[150]

$$R_i = R_f + B_i \times (R_m - R_f) \text{ where:}$$

R_i = Required return for stock i
R_f = Risk-free rate
R_m = Expected return for the market portfolio
B_i = Beta - Measure of the risk for stock

Using the CAPM to determine an appropriate ROE for SWEPCO requires an estimate of the risk-free rate, SWEPCO's beta, and the market risk premium.[151]

For the risk-free rate, Mr. Gorman used both current and projected 30-year Treasury yields of 1.85% and 2.40%, respectively.[152]

Mr. Gorman then reviewed data from *Value Line* to determine that the current average beta for his proxy group is 0.89.[153] Mr. Gorman explained that current published betas are extremely elevated relative to their historical levels, which has generally ranged from 0.6 to 0.8, and that forward-looking beta estimates have consistently been around 0.7.[154] Accordingly, Mr. Gorman conducted two CAPM analyses: (1) a current CAPM analysis that uses current 30-year Treasury

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149 *Id* at 47.

150 *Id*

151 *Id.*

152 *Id.*

153 *Id.* at 49, Ex. MPG-16.

154 *Id.* at 49.

yields (1.85%) and current estimates of beta (0.89) and (2) a normalized CAPM analysis that uses projected 30-year Treasury yields (2.4%) and normalized estimates of beta (0.7).[155]

For the final component of the CAPM analysis, Mr. Gorman derived two market risk premium estimates. His forward-looking estimate projected the returns of the S&P 500 into the future by adding an expected inflation rate to the long-term arithmetic average real return on the market (as determined by Duff & Phelps), which represents the market's achieved return above inflation.[156] This forward-looking method produced an expected market return of 11.29%.[157] Subtracting the estimated projected risk-free rate of 2.4% resulted in a forward-looking market risk premium of 8.89%, and subtracting the current risk-free rate of 1.85% resulted in a current market risk premium of 9.44%.[158]

Mr. Gorman also determined a historical estimate of the market risk premium by reviewing data from Duff & Phelps, which showed that the historical arithmetic average of the achieved total return on the S&P 500 was 12.1%.[159] By subtracting out the historical total return on long-term Treasury bonds of 6.0%, he determined that the historical market risk premium was 6.1%.[160] Based on this analysis, Mr. Gorman found that his market risk premium fell in the range of 6.1% to 9.44%, which is consistent with (though toward the higher end of the range of) market risk premium estimates made by Duff & Phelps, which are in the range of 5.5% to 7.2%.[161]

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155 *Id.* at 53.

156 *Id.* at 51.

157 *Id.* at 50, Ex. MPG-15.

158 *Id.* at 50. Mr. Gorman used the forward-looking market risk premium based current 30-year Treasury yields for his "current" CAPM, described above, and the forward-looking market risk premium based on projected 30-year Treasury yields for his "projected" CAPM, also described above. He used the same historical market risk premium for both the "current" and the "projected" CAPM. *Id.* at Ex. MPG-17.

159 *Id.* at 50-51.

160 *Id.*

161 *Id* at 52-53.

Using the above-described inputs, Mr. Gorman's CAPM analysis resulted in an expected ROE of 8.65% to 10.24%.[162] Mr. Gorman recommended the midpoint of his CAPM indicated ROE range (9.45%, rounded up to 9.5%) as his CAPM return.[163]

c. Mr. Gorman's recommended ROE is a fair assessment of SWEPCO's cost of equity, and will allow SWEPCO to maintain reasonable access to capital at a reasonable cost to ratepayers.

Based on his analyses, Mr. Gorman concluded that a reasonable market cost of equity for SWEPCO is 9.15%, which is the approximate midpoint of his estimated range of 8.90% to 9.35%.[164] The low end of Mr. Gorman's range is based on his DCF analysis, while the high end of his range is based on the average of his Risk Premium and CAPM analyses.[165]

TABLE 8

Return on Common Equity Summary

Description	Results
DCF	8.90%
Risk Premium	9 20%
CAPM	9.50%

This ROE recommendation is conservative, as Mr. Gorman made numerous judgments that actually increased the output of several of his model results. Mr. Gorman's recommendation is a fair assessment of SWEPCO's market cost of equity, and will allow SWEPCO to maintain access capital and earn a fair return on its investments.

162 *Id.* at 53.

163 *Id.*

164 *Id* at 54.

165 *Id*

d. The Commission should reject Mr. D'Ascendis's inflated ROE recommendation.

i. Mr. D'Ascendis's analysis is unreliable.

Mr. D'Ascendis's analysis is not credible, and unnecessarily inflates SWEPCO's requested ROE. As explored in detail at the hearing, Mr. D'Ascendis regularly testifies on behalf of utilities, and consistently recommends unreasonably high ROEs. In fact, Mr. D'Ascendis has only recommended an ROE lower than 10.0% only twice in over the last five years,[166] and during that time period, his recommended ROE point estimate has only once been adopted by a regulator, in a case for a water utility in South Carolina.[167] Further, utility commissions throughout the country have repeatedly found that Mr. D'Ascendis's analysis is unreliable for exactly the same reasons discussed in Mr. Gorman's testimony and described in this section. In this case, while Mr. D'Ascendis's DCF analysis produces a reasonable estimate of SWEPCO's cost of equity (ranging from 8.73% in his direct testimony[168] to 9.32% in his rebuttal testimony[169]), he presents a multitude of other analyses that are significantly inflated due to flawed and biased methodologies and thus should be rejected. As set forth in detail below, when Mr. D'Ascendis's analyses are correctly adjusted, it shows that the cost of equity for SWEPCO is in the range recommended by Mr. Gorman.

ii. Mr. D'Ascendis's Risk Premium analysis is inflated.

Mr. D'Ascendis presented two Risk Premium analyses: the "Predictive Risk Premium Model" (PRPM) and a more traditional Risk Premium model. The result of the PRPM was 10.77% and the result of the more traditional approach was 10.63%.[170]

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[166] TIEC Ex. 50; Tr. at 908:13-20 (D'Ascendis Cross) (May 24, 2021).

[167] TIEC Ex. 50; Tr. at 908:21-909:13 (D'Ascendis Cross) (May 24, 2021).

[168] SWEPCO Ex. 8, D'Ascendis Dir. at 27.

[169] SWEPCO Ex. 38, D'Ascendis Reb. at 9.

[170] *Id* at Schedule DWD-1R at 18.

As explored at the hearing, the PRPM is an opaque, idiosyncratic, and biased model that should be rejected outright. The PRPM was developed by three of Mr. D'Ascendis's former colleagues at AUS Consultants, at least two of whom regularly presented cost of capital testimony on behalf of utilities.[171] It requires proprietary statistical software and produces inflated ROE results.[172] Indeed, in a follow-up article to the original article presenting the PRPM, Mr. D'Ascendis and the original three authors touted that the PRPM "produces a higher average indicated ROE than both the DCF and the CAPM."[173] The article first setting forth the PRPM has only been cited ten times, and three of those citations are by Dr. Michelfelder, one of the original authors.[174] While Mr. D'Ascendis claims that the PRPM has never been rebutted in the academic literature, the article first setting forth the PRPM is behind a paywall and has been accessed a very limited number of times.[175] As the Pennsylvania Public Utility Commission noted in rejecting Mr. D'Ascendis's use of the PRPM, the PRPM is a specialized form of the risk premium method that is not commonly used.[176] It should similarly be rejected here.

Further, the PRPM model overestimates the equity risk premium by failing to account for the volatility of bonds. As Mr. Gorman explained, a significant component of the volatility of both stocks and bonds are created by capital gains and losses (i.e., changes in price).[177] While the PRPM model accounts for the volatility associated with changes in stock prices, it does not do so

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171 Tr. at 880:15-882:13 (D'Ascendis Cross) (May 24, 2021).

172 SWEPCO Ex. 8, D'Ascendis Dir. at 29 (noting that Mr. D'Ascendis used Eviews© statistical software to run the PRPM); SWEPCO Ex. 38, D'Ascendis Reb. at 90 n.148 (explaining that Eviews© costs $600-700 for a single user license and that the PRPM can be run with other proprietary statistical software packages).

173 SWEPCO Ex. 38, D'Ascendis Reb. WP at 1177 of 3214.

174 Tr. at 886:14-887:5 (D'Ascendis Cross) (May 24, 2021); TIEC Ex. 48.

175 Tr. at 887:5-24 (D'Ascendis Cross) (May 24, 2021); TIEC Ex. 48.

176 TIEC Ex. 51 at Bates 025; Tr. at 916:20-917:5 (D'Ascendis's Cross) (May 24, 2021).

177 TIEC Ex. 3, Gorman Dir. at 66-67.

with respect to changes in bond prices.[178] As a result, the PRPM understates the volatility of bond investments, and inflates the equity risk premium.[179]

Mr. D'Ascendis's traditional Risk Premium model also contains several errors and flawed assumptions that serve only to inflate the results. First, Mr. D'Ascendis's methodology inflates the equity risk premium by using a "total market" approach. Mr. D'Ascendis presented three estimates of the equity risk premium: (1) one that estimated the spread between the return on the total market and Aaa-rated corporate bonds, multiplied by beta; (2) one that estimated the spread between the return on utility stocks and A2-rated utility bonds; and (3) one that estimated the spread between historical authorized ROEs and A2-rated utility bonds.[180] While the latter two produced reasonable estimates of the equity risk premium of 5.77% and 5.78%, respectively,[181] the "total market" methodology produced an inflated equity risk premium of 8.46%.[182] This "total market" methodology relies upon six different calculations of the spread between Aaa-rated corporate bonds and the return on the total market, as can be seen in the following table taken from Mr. D'Ascendis's testimony:[183]

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[178] *Id*

[179] *Id*

[180] SWEPCO Ex. 8, D'Ascendıs Dir. at 32-40; Tr. at 890:1-891:5.

[181] SWEPCO Ex. 38, D'Ascendis Reb. at Schedule DWD-1R at 29-30.

[182] *Id.* at Schedule DWD-1R at 25.

[183] *Id.*

Line No.	Equity Risk Premium Measure	Proxy Group of Fourteen Electric Companies
	Ibbotson-Based Equity Risk Premiums	
1	Ibbotson Equity Risk Premium (1)	5 78 %
2	Regression on Ibbotson Risk Premium Data (2)	8 85
3	Ibbotson Equity Risk Premium based on PRPM (3)	9 74
4	Equity Risk Premium Based on Value Line Summary and Index (4)	5 03
5	Equity Risk Premium Based on Value Line S&P 500 Companies (5)	10.77
6.	Equity Risk Premium Based on Bloomberg S&P 500 Companies (6)	12 17
7	Conclusion of Equity Risk Premium	8 72 %
8	Adjusted Beta (7)	0 97
9.	Forecasted Equity Risk Premium	8 46 %

The three highest results in this table are based on flawed methodologies that bias the resulting equity risk premium upward. As explained above, the PRPM estimate of 9.74% is based on a biased and idiosyncratic methodology that should be rejected. The last two results (estimates of 10.77% and 12.17%, respectively) were calculated using a constant-growth DCF model based on analysts' earnings growth expectations from Value Line and Bloomberg for every company in the S&P 500.[184] However, Mr. D'Ascendis used 3-5 year growth rates from Value Line and Bloomberg,[185] in direct contravention of the fundamental assumption of the constant-growth DCF model that growth rates are in perpetuity.[186] For many of the companies in the S&P 500, analysts are projecting three- to five-year growth rates that are much higher than what would be reasonably expected in perpetuity.[187] For example, Amazon's growth rate was projected to be 32.3% and

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184 Tr. at 894:3-895:14 (D'Ascendis Cross) (May 24, 2021).

185 *Id.* at 896:9-15, 898:11-14.

186 *See, e.g.*, SWEPCO Ex. 38, D'Ascendis Reb. at 60; Tr. at 895:19-897:4 (D'Ascendis Cross) (May 24, 2021).

187 TIEC Ex. 3, Gorman Dir. at 34-36 (discussing academic research and actual investment results showing that a company's earnings and dividends cannot grow over the long term at a rate greater than the growth of the U.S. GDP).

33.5% by Value Line and Bloomberg, respectively.[188] It is unreasonable to project that any company will grow at a 33% growth rate, or any growth rate that is significantly higher than the long-term GDP growth rate of 4.35%, in perpetuity.[189] The result of assuming unreasonably high constant growth rates is to inflate the total market return and thus the resulting equity risk premium.[190] Indeed, it is readily apparent that Mr. D'Ascendis's estimates of the total market return, which are 14.21% and 15.61%,[191] are unreasonably high when they are compared with historical returns on the market, which ranged from 6.1% to 7.9% between 1926 and 2019.[192] Mr. D'Ascendis's estimated returns are also nearly double what Value Line projects the return on the overall market to be.[193] For these reasons, multiple regulatory commissions, including the Virginia State Corporation Commission[194] and the Public Utilities Commission of Nevada,[195] have concluded that Mr. D'Ascendis's use of DCF-derived total market returns inflates ROE results.

If these three inflated estimates of the equity risk premium are ignored, the "total market" approach would result in an equity risk premium of 6.36%.[196] However, this figure is still too high because while Mr. D'Ascendis used an A3-rated utility bond as the starting point in his Risk Premium analysis, the total market approach calculated the spread between Aaa-rated corporate bonds and the total market,[197] resulting in an apples-to-oranges comparison. Though Mr. D'Ascendis multiplied the spread by beta, he acknowledged at the hearing that beta would not

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[188] TIEC Ex. 49 at Bates 002, 009.

[189] TIEC Ex. 3 (Gorman Dir.) at 44-46.

[190] *Id* at 71-72.

[191] SWEPCO Ex. 38, D'Ascendis Reb. at Schedule DWD-1R at 26.

[192] TIEC Ex. 3 (Gorman Dir.) at 73.

[193] Tr. at 892:9-893:22 (D'Ascendis Cross) (May 24, 2021) (stating that Value Line projects the total market return to be 8.47%).

[194] TIEC Ex. 54 at Bates 005-006.

[195] TIEC Ex. 53 at Bates 032-033.

[196] (8.85% + 5.03% + 5.78%) / 3 * 0.97 (beta) = 6.36%.

[197] Tr. at 900:3-16 (D'Ascendis Cross) (May 24, 2021).

capture the difference in yields between Aaa-rated corporate bonds and A3-rated utility bonds.[198] Subtracting the difference in yields between Aaa-rated corporate bonds and A3-rated utility bonds of 0.51% results in an equity risk premium of 5.85%,[199] which is similar to Mr. D'Ascendis's other estimates of the equity risk premium of 5.77% and 5.78%.[200] The average equity risk premium would go down from 6.67% to 5.8%, almost identical to Mr. Gorman's equity risk premium estimate of 5.77%.[201]

Finally, Mr. D'Ascendis's traditional Risk Premium analysis is inflated because it uses a projected utility bond yield that exceeds currently observable utility bond yields. As Dr. Woolridge testified at the hearing, interest rate projections are extremely inaccurate.[202] While forecasters have been projecting interest rates to increase for over a decade, they have only decreased in that time.[203] In fact, the Virginia State Corporation Commission has previously rejected Mr. D'Ascendis's use of projected interest rates, noting that doing so inflates the results of ROE analyses.[204] Mr. D'Ascendis's projected bond yield for an A3-rated utility is 3.95%,[205] which is 50 basis points higher than what AEP Texas, a Baa-rated utility, was able to obtain for a 30-year bond in May of this year,[206] and 53 basis points higher than the average Baa-rated utility bond yield in January through March of 2021.[207]

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198 *Id.* at 900:17-901:7. Rather, beta is simply a measure of the correlation between price changes of a certain stock (such as those that make up the utility proxy group) and price changes of the overall market. *Id* at 900:17-20.

199 SWEPCO Ex. 38, D'Ascendis Reb. at Schedule DWD-1R at 20 (showing 42 basis point adjustment for Aaa-corporates to A2-rated utility bonds and a 9 basis point adjustment to reflect A3-rated utility bonds).

200 *Id.* at Schedule DWD-1R at 24.

201 TIEC Ex. 3, Gorman Dir. at 70.

202 Tr. at 1005:12-1006:4 (Woolridge Recross) (May 24, 2021).

203 CARD Ex. 4, Woolridge Dir. at 43; *see also* Tr. at 1003:22-1004:5 (Woolridge Redir.) (May 24, 2021).

204 TIEC Ex. 54 at Bates 006.

205 SWEPCO Ex. 38, D'Ascendis Reb. at Schedule DWD-1R at 20.

206 TIEC Ex. 64.

207 SWEPCO Ex. 38, D'Ascendis Reb. at Schedule DWD-1R at 21.

Using the most recent observable Baa-rated utility bond yields (3.42%) and a corrected version of Mr. D'Ascendis's equity risk premium (5.8%) results in a Risk Premium result of 9.22%, which is similar to the result of Mr. Gorman's Risk Premium study of 9.2%.[208]

iii. Mr. D'Ascendis's CAPM analyses are unreasonably high.

Mr. D'Ascendis's CAPM analyses are inflated for the same reasons as his traditional Risk Premium analysis. The market risk premium that Mr. D'Ascendis used in his CAPM is calculated using the same six methodologies he used to calculate the equity risk premium in his Risk Premium analysis, except that instead of taking the spread between Aaa-rated corporate bonds and the return on the market, he took the spread between 30-year Treasury yields and the return on the market.[209] The six calculations of the market risk resulted in estimates of 7.01%, 9.56%, 10.85%, 5.74%, 11.48%, and 12.88%, averaging out to be 9.59%.[210] If, similar to the Risk Premium analysis, the PRPM and the two S&P 500 DCF results are taken out, then the resulting market risk premium goes down from 9.59% to 7.44%,[211] which is in the middle of Mr. Gorman's range of estimates of the market risk premium.[212]

Mr. D'Ascendis's CAPM analysis also contains the same faulty assumption regarding projected interest rates, as he used a forecast of the 30-year Treasury yield that goes out to 2031. Mr. D'Ascendis's projected risk-free rate is 2.73%,[213] whereas the 30-year Treasury yield at the time of hearing was 2.3% and has been 1.87% during the pendency of this proceeding. Using current 30-year Treasury yields, Mr. D'Ascendis's beta of 0.97, and a corrected market risk premium results in CAPM estimates in the range of 9.1% to 9.5%.[214]

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208 *Cf.* TIEC Ex. 3, Gorman Dir. at 69-70; *see also id.* at 47.

209 Tr. at 902:5-19 (D'Ascendis Cross) (May 24, 2021).

210 SWEPCO Ex. 38, D'Ascendis Reb. at Schedule DWD-1R at 32.

211 (5.74% + 9.56% + 7.01%) / 3 = 7.44%.

212 TIEC Ex. 3, Gorman Dir. at 53.

213 SWEPCO Ex. 38, D'Ascendis Reb. at 32.

214 2.3% + (7.44%) * 0.97 = 9.52%. 1.87% + (7.44% * 0.97) = 9.09%.

Mr. D'Ascendis also presented an empirical CAPM analysis, or ECAPM. As Mr. Gorman explained, the ECAPM model flattens the security market line by adjusting up betas that are less than one and adjusting down betas that are greater than one.[215] However, because utility betas are currently at 0.97 (and extremely high relative to their historical levels), the impact of the ECAPM is minimal, as it only increased Mr. D'Ascendis's ROE estimate from the traditional CAPM by 8 to 10 basis points.[216] Nevertheless, Mr. D'Ascendis's ECAPM should be rejected because the betas reported by Value Line are already adjusted, meaning that the ECAPM results in a double adjustment.[217] Additionally, regulatory commissions generally disregard the use of the ECAPM, particularly when an adjusted beta is used in the model.[218] For instance, the Public Service Commission of Maryland rejected Mr. D'Ascendis's use of the ECAPM in a 2019 proceeding, concluding that "the ECAPM is not widely accepted by the financial community in determining ROEs."[219] The Commission should reject the use of the ECAPM in this proceeding.

iv. Mr. D'Ascendis's non-price-regulated proxy group should be rejected.

In addition to performing the DCF, Risk Premium, and CAPM analyses on a utility proxy group, Mr. D'Ascendis conducted the same analyses on a group of non-price-regulated companies. Unsurprisingly, the non-price-regulated proxy group analyses produced higher ROE results, including a DCF result of 11.62%, a Risk Premium result of 12.47%, and a CAPM result of 11.69%.[220]

Mr. D'Ascendis selected the companies in the non-price-regulated proxy group based solely on two quantitative measures—the betas and the residual standard error of the regression.[221]

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[215] TIEC Ex. 3, Gorman Dir. at 75.

[216] SWEPCO Ex. 38, D'Ascendis Reb. at Schedule DWD-1R at 31.

[217] TIEC Ex. 3, Gorman Dir. at 74-77.

[218] *Id.* at 77.

[219] TIEC Ex. 52 at Bates 030.

[220] SWEPCO Ex. 38, D'Ascendis Reb. at Schedule DWD-1R at 36.

[221] *Id.* at 33; *see also* Tr. at 903:24-904:16 (D'Ascendis Cross) (May 24, 2021).

As a result, Mr. D'Ascendis's non-price-regulated proxy group contains many companies that, when viewed from a qualitative perspective, are simply not comparable in risk to a regulated utility. For example, Mr. Gorman testified that the non-price-regulated proxy group contained large technology firms such as Apple and Alphabet, and that it is simply not credible to believe that these firms have a similar operating and business risk as SWEPCO.[222] Indeed, Mr. D'Ascendis acknowledged at the hearing that the companies in his non-price-regulated proxy group operate in a competitive marketplace,[223] and that they do not provide essential services,[224] making them significantly more risky than regulated utilities. As Mr. Gorman testified, to draw a valid comparison between SWEPCO and the non-price-regulated proxy group requires more than simply similar betas; rather, it is necessary to show that the companies have comparable risk factors that are commonly used by investment professionals to compare risk between different investment alternatives.[225] That is why multiple regulatory commissions, including the Public Service Commission of Maryland[226] and the Pennsylvania Public Utility Commission,[227] have specifically rejected Mr. D'Ascendis's use of a non-price-regulated proxy group. Mr. D'Ascendis has similarly not shown in this proceeding that his non-price-regulated proxy group is comparable in risk to SWEPCO, and his non-price-regulated proxy group analysis should be rejected.

v. *Mr. D'Ascendis's size adjustment should be rejected.*

On top of his inflated ROE results, Mr. D'Ascendis recommended a 20-basis-point adder based on his contention that SWEPCO is small relative to the proxy group, completely ignoring

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[222] TIEC Ex. 3, Gorman Dir. at 78. Notably, while Apple and Alphabet were in Mr. D'Ascendis's non-price-regulated proxy group in his direct testimony, after Mr. Gorman filed testimony criticizing the inclusion of those companies, they were excluded from Mr. D'Ascendis's proxy group in his rebuttal testimony. Tr. at 904:17-22, 906:18-907:13 (D'Ascendis Cross) (May 24, 2021). While Mr. D'Ascendis provided an explanation regarding his quantitative screening criteria, it is not clear how Apple and Alphabet could have been comparable in risk to SWEPCO in October of 2020, when Mr. D'Ascendis prepared his direct testimony, but not in April of 2021, when he prepared his rebuttal testimony.

[223] Tr. at 903:5-8 (D'Ascendis Cross) (May 24, 2021).

[224] *Id.* at 933:6-12.

[225] TIEC Ex. 3, Gorman Dir. at 78.

[226] TIEC Ex. 52 at Bates 029.

[227] TIEC Ex. 51 at Bates 026.

the fact that SWEPCO is a wholly owned subsidiary of AEP, one of the largest publicly traded utility holding companies in the United States. In fact, AEP has a market capitalization of $38 billion, more than double the average market capitalization of the proxy group of $15 billion.[228] As Mr. Gorman testified, being a part of AEP's system reduces SWEPCO's standalone investment risk, as SWEPCO receives equity capital through AEP and accesses the debt markets with its credit standing affiliation with AEP.[229] Additionally, SWEPCO is entitled to services from AEP through affiliate service contracts that provide SWEPCO benefits—such as being able attract larger management and allowing SWEPCO to rely on AEP services including executive, treasury, accounting, legal, engineering—that also reduce SWEPCO's business risk.[230] For these reasons, a small-size adder for SWEPCO is not appropriate.

Mr. D'Ascendis contends that it is not appropriate to consider the size of AEP because ratemaking focuses on SWEPCO as a standalone entity.[231] However, this argument misses the point, which is that SWEPCO's standalone risk is lowered because of its affiliation with AEP.[232] Mr. D'Ascendis cannot simply ignore the fact that SWEPCO's business and operating risk is improved because it is an operating subsidiary of AEP.

Further, if it were the case that ratemaking requires completely ignoring the benefits provided by parent companies, it would be expected that every utility rate case would have a size adjustment, as any operating utility (such as SWEPCO) would be significantly smaller than the publicly traded utility holding companies that make up proxy groups. However, Mr. D'Ascendis could only identify three cases where a size adjustment was adopted, all of which were utilities in rural Pennsylvania with rate bases in the range of $17 million,[233] several orders of magnitude

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[228] TIEC Ex. 3, Gorman Dir. at 62.

[229] *Id.* at 63.

[230] *Id.*

[231] SWEPCO Ex. 38, D'Ascendis Reb. at 81-83.

[232] TIEC Ex. 3, Gorman Dir. at 62-63.

[233] TIEC Ex. 57; TIEC Ex. 51; Tr. at 913:23-916:5 (D'Ascendis Cross) (May 24, 2021).

smaller than SWEPCO's rate base request in this proceeding of $5.4 billion.[234] A small-size adjustment is not justified for SWEPCO, and Mr. D'Ascendis's 20-basis-point adder should be rejected.

vi. Mr. D'Ascendis's credit risk adjustment should be rejected.

In addition to the small-size adjustment, Mr. D'Ascendis recommended a credit-risk adjustment to reflect that SWEPCO's credit ratings are slightly lower than that of the proxy group. Specifically, because SWEPCO's Moody's credit rating is two notches lower than the proxy group average, Mr. D'Ascendis adjusted his ROE upward by two-thirds of the recent spread between A2 and Baa2 utility bond yields, or 27 basis points.[235] As Staff witness Mr. Filarowicz noted in direct testimony, this adjustment completely ignored the fact that SWEPCO's S&P credit rating is one notch higher than the proxy group average.[236] In rebuttal testimony, Mr. D'Ascendis changed his credit-risk adjustment to reflect only a one-notch difference, or 9 basis points.[237] Regardless, Mr. D'Ascendis's credit-risk adjustment should be rejected. As Mr. Gorman testified, SWEPCO is comparable in credit risk to the proxy group, and an external adjustment to the estimated market cost of equity is not justified.[238]

e. Conclusion: Return on Equity

For the foregoing reasons, the Commission should adopt Mr. Gorman's recommended 9.15% ROE and reject Mr. D'Ascendis's excessive and unjustified recommendation of 10.35%.

C. Financial Integrity, Including "Ring Fencing" [PO Issue 9]

1. Financial Integrity

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[234] SWEPCO Ex. 1, Schedule B-1 (showing total company rate base request of $5.4 billion).

[235] SWEPCO Ex. 8, D'Ascendis Dir. at 56-57.

[236] Staff Ex. 1, Filarowicz Dir. at 36.

[237] SWEPCO Ex. 38, D'Ascendis Reb. at 48.

[238] TIEC Ex. 3, Gorman Dir. at 63-64.

Mr. Gorman performed a financial integrity analysis that calculates what SWEPCO's S&P credit metrics would be under his recommended ROE.[239] These credit metrics are taken into account by S&P in setting SWEPCO's credit rating.[240] Mr. Gorman's analysis showed that, based on his recommendation, SWEPCO's Debt to Earnings Before Interest Taxes, Depreciation and Amortization (EBITDA) ratio will be 3.8x, within S&P's "Significant" guideline range of 3.5x to 4.5x, which supports SWEPCO's current credit rating.[241] SWEPCO's Funds From Operations (FFO) to Total Debt ratio will be 19%, which is also within S&P's "Significant" guideline range of 13% to 23%. While Mr. D'Ascendis criticizes Mr. Gorman's analysis by contending that any ROE in the range from 5.8% to 10.89% will maintain SWEPCO in the "Significant" guideline range,[242] what that analysis really shows is that SWEPCO's credit metrics are extremely strong and SWEPCO's ROE can be adjusted downward significantly—in line with the current low cost of capital environment—without resulting in a credit downgrade or affecting SWEPCO's financial integrity or access to capital.

2. Ring-Fencing

TIEC believes it is prudent to put reasonable financial protections, or "ring-fencing," in place before they become necessary. The Commission has adopted reasonable ring-fencing measures for several Texas utilities in recent rate cases, including for Southwestern Public Service Company (SPS) and for SWEPCO's sister company, AEP Texas.[243] TIEC supports the Commission adopting a relatively standardized set of ring-fencing provisions for all Texas investor-owned utilities, though the exact mix of financial protections will vary by company. To that end, TIEC supports the ring-fencing measures listed and described in Mr. Filarowicz's testimony.[244]

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[239] *Id* at 56-57.

[240] *Id.* at 56.

[241] *Id.* at 57.

[242] SWEPCO Ex. 38, D'Ascendis Reb. at 79.

[243] Staff Ex. 2, Filarowicz Dir. at 42-43.

[244] *Id* at 44-45.

IV. Expenses [PO Issues 1, 14, 24, 29, 30, 32, 33, 40, 41, 42, 44, 45, 46, 49, 72, 73, 74]

A. Transmission and Distribution O&M Expenses [PO Issue 14, 24]

3. Proposed Deferral of SPP Wholesale Transmission Costs [PO Issues 72, 73, 74]

SWEPCO's novel proposal to defer the portion of its approved transmission charges (ATC) that is above or below the test year level into a regulatory asset or liability for recovery in a future transmission cost recovery factor (TCRF) or rate case proceeding should be rejected.[245] SWEPCO's proposed mechanism is unprecedented and has no basis in PURA or the Commission's rules. The Legislature enacted a specific statute, PURA § 36.209, to address the recovery of ATC by non-ERCOT utilities outside of a base rate case, and the Commission has implemented that statute through its non-ERCOT TCRF rule, 16 T.A.C. § 25.239. Neither the non-ERCOT statute nor the rule implements a tracker mechanism for the recovery of changes in the amount of ATC.[246] SWEPCO's reliance on the recovery mechanism for distribution service providers (DSPs) under the ERCOT TCRF rule is thus unavailing.[247] The ERCOT TCRF rule was promulgated under a different statute, PURA § 35.004(d),[248] that explicitly allows the Commission to "approve wholesale rates that may be periodically adjusted ensure timely recovery of transmission investment,"[249] and the ERCOT TCRF rule specifically implements a tracker mechanism.[250]

Further, a closer review of the non-ERCOT TCRF rule reveals that it inconsistent with SWEPCO's proposal. As Mr. Pollock testified, the non-ERCOT TCRF rule limits amendments to TCRFs to once per calendar year.[251] The ATC tracker would circumvent this limitation by

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245 SWEPCO Ex. 4, Brice Dir. at 12-13.

246 PURA § 36.209; 16 T.A.C. § 25.239.

247 SWEPCO Ex. 4, Brice Dir. at 13-14 (citing 16 T.A.C. § 25.193).

248 *Rulemaking Proceeding to Amend PUC Subst R. 25 193 Relating to Distribution Service Provider Transmission Cost Recovery Factor (TCRF)*, Proj. No. 37909, Order Adopting Amendment to § 25.193 as Approved at the September 29, 2010 Open Meeting at 33-35 (Oct. 4, 2010).

249 PURA § 35.004(d).

250 16 T.A.C. § 25.193(b)(2)(B).

251 TIEC Ex. 1, Pollock Dir. at 10 (citing 16 T.A.C. § 25.239(f)).

essentially providing for contemporaneous, rather than annual, cost recovery of the ATC component of transmission costs.[252] Additionally, the Commission has interpreted 16 T.A.C. § 25.239 as requiring that the non-ERCOT TCRF be based on a historical test year.[253] In fact, the Commission in Docket No. 42448 denied a request by SWEPCO to make a post-test-year adjustment for SPP expenses, holding that the TCRF "must be based on the unadjusted costs that were actually incurred during a historical test year."[254] The ATC tracker proposal would go entirely beyond the historical test year construct.[255] Ultimately, SWEPCO is attempting in this proceeding to amend the non-ERCOT TCRF statute and rule in order to allow for guaranteed dollar-for-dollar recovery of its SPP transmission costs. That effort should be directed to the Legislature or to the Commission in a rulemaking petition, not in this case, and SWEPCO's ad hoc proposal for the imposition of an ATC tracker should be rejected.

Lastly, there are no special circumstances in this case that would justify SWEPCO's extraordinary proposal. The revenues SWEPCO receives under the SPP OATT have increased in tandem with SWEPCO's SPP charges. The level of SPP revenues and charges in SWEPCO's recent TCRF and rate cases, including this one, can be seen in the following table from Mr. Pollock's testimony:[256]

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[252] *Id*

[253] *See generally* 16 T.A.C. § 25.239.

[254] *Application of Southwestern Electric Power Company for Approval of a Transmission Cost Recovery Factor*, Docket No. 42448, Final Order at FoFs 32-45 & CoL 8 (Nov. 24, 2014).

[255] Further, the ATC tracker would constitute piecemeal ratemaking, as SWEPCO is only proposing to track changes to a single part of its rates—ATC—and not tracking changes in other costs and revenues (such as revenues it receives from ratepayers). TIEC Ex. 1, Pollock Dir. at 10.

[256] *Id.* at 11.

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

As the table demonstrates, SWEPCO's SPP revenues have in fact increased more than SWEPCO's charges have since SWEPCO's last rate case and last TCRF proceeding. SWEPCO has not demonstrated that the ATC tracker is necessary for it to have a reasonable opportunity to earn a reasonable return above its necessary expenses,[257] and it should be rejected.

6. Allocated Transmission Expenses related to retail behind-the-meter generation

The Southwest Power Pool (SPP) is the Regional Transmission Organization (RTO) for SWEPCO and numerous other utilities in the central United States. SPP allocates certain transmission-related costs to its utility members based on each utility's reported Monthly Network Load, defined as its "hourly load coincident with the monthly peak."[258] That term, which has been in the SPP tariff for over 20 years,[259] has a straightforward meaning that caused no controversy in any of SWEPCO's previous rate cases in Texas or elsewhere.[260] In recent years, however, certain members of the SPP staff have begun to argue that this term should include electricity that a retail customer is providing to itself rather than purchasing from a utility.[261] This new and idiosyncratic

[257] *Id.* at 12.

[258] TIEC Ex. 1, Pollock Dir. at Bates 16 (citing 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)).

[259] Tr. at 784:18-21 (Locke Cross) (May 21, 2021).

[260] Tr. at 1197:7-17 (Aaron Cross) (May 25, 2021).

[261] The parties have adopted various precise yet cumbersome phrase for retail self-served load such as "load served by retail behind-the-meter generation (BTMG)." The term refers to electricity that an end user provides to

interpretation of Monthly Network Load is inconsistent with the plain words of the SPP tariff and with SPP's own prior interpretations of the tariff, but it has found an aggressive advocate in SPP's Charles Locke. SWEPCO itself maintains that it "does not have a position on this issue,"[262] and that "TIEC's disagreement over the application of the SPP-OATT is with SPP, not SWEPCO."[263] And SWEPCO's 2019 submission to SPP confirms that SWEPCO did indeed agree with TIEC on this issue.[264] But it is SWEPCO's decision to reinterpret the tariff, to change its reporting practices for a single customer, and to shift $5.7 million in costs from Arkansas and Louisiana to Texas that is at issue in this case.

In October 2018, at the urging of Mr. Locke, SWEPCO began adding the self-served load of a single customer to its reporting of Monthly Network Load to SPP.[265] SWEPCO has hundreds of retail customers who provide their own power in Arkansas, Louisiana, and Texas, including industrial cogenerators outside of Texas.[266] But the single customer that SWEPCO chose to add to its Monthly Network Load was in Texas. SWEPCO then added the electricity that this Texas customer was providing to itself to the Texas demands for purposes of the jurisdictional allocation of *all* transmission-related costs, not merely SPP costs. The result of including load that SWEPCO was not actually serving in Texas, while excluding similar load in Arkansas and Louisiana, was to artificially shift approximately $5.7 million in transmission costs, including both return on invested capital and expenses, from SWEPCO's other jurisdictions.[267] SWEPCO seeks to add those costs to Texas rates in this proceeding.

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itself without using the utility's grid. Rooftop solar and industrial cogeneration are two examples of such service. For convenience, this brief will generally refer to this as retail self-served load.

[262] SWEPCO Ex. 52, Rebuttal Testimony of C. Richard Ross at Bates 10 (Ross Reb.).

[263] *Id.* at Bates 9.

[264] TIEC Ex. 36B.

[265] TIEC Ex. 1, Pollock Dir. At 13-14.

[266] TIEC Ex. 2, Supplemental Testimony of Jeffry C. Pollock at 1 (Pollock Supp. Dir.); Tr. at 1123:25-1124:9 (Ross Cross) (May 25, 2021). All citations to Mr. Pollock's prefiled testimony refer to the native pagination.

[267] Tr. at 647:25-648:20 (Neinast Clarifying) (May 21, 2021). It should be noted that since SWEPCO did not include the Eastman self-served load in its recent Louisiana and Arkansas rate cases, there was no actual reduction to rates in those states as a result, only a $5.7 million increase in Texas.

There was no revision to the SPP tariff that warranted the change in how SWEPCO reports its Monthly Network Load. Nor was there any regulatory decision that warranted the change. There was not even a formal written policy issued by SPP.[268] Numerous other SPP members chose not to adopt this new interpretation.[269] In fact, SPP itself in 2017 considered and rejected a proposed change to its Federal Energy Regulatory Commission (FERC) tariff that would have added retail self-served loads above 1 MW to the definition of Monthly Network Load.[270] Further, SWEPCO continued to explain to SPP that including electricity that a retail customer provides to itself conflicts with the Public Utility Regulatory Policies Act (PURPA)[271] and is inconsistent with the definition of Network Load in the SPP tariff.[272] Yet SWEPCO inexplicably decided to include the load of a single one of its hundreds of self-generating customers in reporting its Monthly Network Load and, since the customer SWEPCO chose to report is in Texas, SWEPCO now seeks PUC approval to raise Texas rates as a result. SWEPCO's request is not only unprecedented, it is contrary to how SWEPCO and the Commission have treated retail self-served load in every prior SWEPCO case.[273] For the reasons discussed below, it should be rejected.

The Definition of "Monthly Network Load" in the SPP Tariff Does not Include Electricity Self-Supplied by a Retail Customer.

As SWEPCO made clear in its September 2019 submission to SPP, "[r]etail load being served with BTM generation does not meet the SPP tariff definition" of Monthly Network Load.[274] SWEPCO's explanation in that submission was correct; Mr. Locke's new interpretation is simply at odds with the plain terms of the tariff.

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[268] Eastman Ex. 1, Direct Testimony and Exhibits of Ali Al-Jabir at 14 (Al-Jabir Dir.).

[269] Tr. at 771:15-775:12 (Locke Cross) (May 21, 2021); TIEC Ex. 44.

[270] TIEC Ex. 42.

[271] *See* Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, 92 Stat. 3117 (codified as amended in scattered sections of 15, 16, 42, and 43 U.S.C.A.) (PURPA).

[272] *See* TIEC Ex. 36B.

[273] Tr. at 1197:7-17 (Aaron Cross) (May 25, 2021).

[274] TIEC Ex. 36B at 1.

The analysis of this issue begins with the section of the tariff at issue. Section 34.4 of the SPP tariff provides in relevant part as follows:

> Determination of Network Customer's Monthly Network Load:
>
> The Network Customer's monthly Network Load is its hourly load (60 minutes, 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.[275]

Charles Locke of SPP has interpreted this provision to mean that all electricity that a retail customer of SWEPCO is providing to itself at the time of the monthly peak must be included in SWEPCO's Monthly Network Load, without exception.[276] In Mr. Locke's' view, this applies to all rooftop solar generation for residential customers and to qualifying facilities under PURPA.[277] It applies even if the retail customer supplied its own electricity for every hour of the month without any use of SWEPCO's grid.[278] In Mr. Locke's view, a customer that could never take more than 10 MW of power off the grid, and which took no power from SWEPCO at the time of the monthly peak, would still have 50 MW of Network Load attributed to it if that is what it was self-generating behind its meter at the time of the peak.[279] On the other hand, the load of a non-self-generating customer that actually took 50MW of power from SWEPCO all month but was off-line at the time of the monthly peak would not be included at all in Monthly Network Load.[280] Mr. Locke has come to this position notwithstanding that there is no way for SWEPCO, or any other utility, to even know how much electricity most of its customers are generating and consuming behind the meter (BTM).[281] Mr. Locke's reading ignores the plain text of Section 34.4,

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[275] TIEC Ex. 34 at Bates 001.

[276] Tr. at 817:2-10 (Locke Cross) (May 21, 2021).

[277] *Id* at 817:20-818:17.

[278] Eastman Ex. 11 at response c.

[279] Eastman Ex. 11 at response d.

[280] Eastman Ex. 11 at response a.

[281] Tr. at 1149:13-1151:3 (Ross Cross) (May 25, 2021) (agreeing that "[y]ou just have no way of knowing what's going on behind that meter"); TIEC Ex. 36B at 1 ("Retail BTM data doesn't exist.").

the longstanding application of this provision by SPP and its Network Customers since 2000,[282] FERC precedent applying an identical MISO tariff to Entergy, and basic principles of cost-causation.

As an initial matter, the term "Network Customer" as used in the SPP tariff is defined as the utilities that receive transmission service under the tariff, not individual retail customers.[283] In this case, it refers to SWEPCO. Thus, the adjective "its" in the above definition refers to *SWEPCO*'s hourly load, not the electricity that a retail customer is providing to itself. Electricity that a residential or commercial customer is providing to itself with rooftop solar or that an industrial customer is providing to itself with BTM cogeneration at the time of the monthly peak is not being taken from SWEPCO and is not being transmitted over SWEPCO's transmission grid.[284]

It is nonsensical to say that electricity that SWEPCO is not providing, that is not using SWEPCO's transmission or distribution system, and that SWEPCO does not even know about is somehow SWEPCO's "hourly load coincident with the peak" and therefore included in SWEPCO's *Monthly* Network Load. Further, as noted by SWEPCO in its 2019 comments to SPP, such load does not meet the definition of "Network Load" in the tariff to begin with. As SWEPCO stated, the definition of Network Load in the SPP tariff is as follows:

> The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer.[285]

As SWEPCO notes, this definition does not apply to self-served retail load because the Network Customer (SWEPCO) "do(es) NOT serve this load" (unless the BTM generation is off-line, in

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[282] Tr. at 784:18-21 (Locke Cross) (May 21, 2021).

[283] TIEC Ex. 34 at Bates 002; Tr. at 762:24-763:16 (Locke Cross) (May 21, 2021).

[284] Tr. at 1144:10-1146:16 (Ross Cross) (May 25, 2021).

[285] TIEC Ex. 36B at 1; TIEC Ex. 34 at Bates 002.

which case the actual load would be included in Network Load if at a monthly peak).[286] SWEPCO also correctly points out that the BTM generation that a retail customer is using to serve its own load does not constitute a "Network Resource" as that term is defined in the SPP tariff.[287]

SWEPCO's 2019 analysis of the definition of Network Customer's Monthly Network Load in the SPP tariff is correct as a matter of simply following the grammar and the definitions in the tariff. Load that SWEPCO is not serving at the time of peak is not SWEPCO's load at the time of peak, and load being served by a retail customer's own BTM generation is not being served with a Network Resource and therefore cannot be considered "Network Load."

This straightforward and common-sense reading of section 34.4 of the SPP tariff prevailed both at SPP and SWEPCO for many years, and it is still being applied in both of SWEPCO's other jurisdictions and to all but one of SWEPCO's 187 Texas customers.[288] It was also the reading of the existing language that the SPP Staff took prior to the involvement of Charles Locke. The language is so straightforward that it is difficult to understand the basis for Mr. Locke's misunderstanding. Of course, Mr. Locke also interpreted a discovery request in this case to produce "all documents" relating to a topic as meaning that if he could not produce every single one, he would not produce any.[289] His reading of Section 34.4 demonstrates a similar liberty with the plain language of the tariff.

SPP's Revision Requests Through 2017 Made Clear That the Existing Tariff Definition of Monthly Network Load Did Not Include Retail Self-Generated Electricity.

In 2016, the SPP Billing Determinants Task Force prepared a revision request to SPP's business practices. As noted by Mr. Locke, a revision request can be for a business practice without any change to the SPP tariff.[290] This SPP-proposed business practice revision would have

[286] TIEC Ex. 36B at 1 (emphasis in original).

[287] TIEC Ex. 36B at 1; TIEC Ex. 34 at Bates 003.

[288] *See* TIEC Ex. 2, Pollock Supp. Dir. at 1, 3.

[289] Tr. at 779:17-781:19 (Locke Cross) (May 21, 2021).

[290] *Id* at 836:4-18.

clarified that Network Load does not include the capacity of "a generator of an individual retail customer where the output of such generator is owned by the retail customer and is intended to be consumed by that retail customer," that is, self-served retail load.[291] There was no proposal to change the tariff.[292] Thus, this SPP business practice revision request reflected an assumption that the existing tariff language in Section 34.4 did not include retail self-served load in Monthly Network Load, otherwise a tariff revision, not a specification in a business practice, would have been required.

The following year, the SPP Staff supported a tariff change that made it even more clear that the *existing* SPP tariff did not include self-served retail usage.[293] The SPP Staff at that time submitted a proposed tariff change intended to revise Section 34.4 of the tariff, the section that is at issue in this proceeding.[294] The objective of this proposal as it relates to self-served retail load was that retail BTM generation greater than 1 MW would for the first time be included in Network Load, while generation under 1 MW would continue to not be included.[295] To accomplish this result, the SPP staff proposed no change whatsoever to the language of Section 34.4 related to under-1MW retail generation.[296] The existing definition of Monthly Network Load in Section 34.4 would apply, and that definition, contrary to Mr. Locke's view, would continue to exclude small retail generation. But to begin *including* retail BTM generation greater than 1 MW, SPP Staff proposed to add a new provision to section 34.4 of the tariff specifically stating that such BTM generation would now be included in Network Load,[297] a provision that would have been entirely unnecessary if Mr. Locke's view of section 34.4 were correct. Mr. Locke claims that he

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[291] TIEC Ex. 45 at Bates 016.

[292] *See id.*

[293] TIEC Ex. 42.

[294] *Id.*

[295] *Id.* at Bates 001.

[296] TIEC Ex. 42 at Bates 005; Tr. at 844:12-845:11 (Locke Cross) (May 21, 2021).

[297] TIEC Ex. 42 at Bates 005 ("The output from a generation unit with a nameplate rating greater than 1.0 MW, or the sum of the output from generation units with a combined nameplate rating greater than 1.0 MW, located behind a retail end-use customer's meter shall be included in the Network Customer's determination of monthly Network Load."); Tr. at 846:10-847:2 (Locke Cross) (May 21, 2021).

was not involved in the development of this SPS proposal and that he disagrees with the way it was drafted.[298] That is no doubt true, but the proposal to do nothing to the tariff to allow small BTM generation to continue to be excluded and to amend the tariff to for the first time begin including large BTM generation reflects not just the plain meaning of the provision, but the SPP Staff's view of that provision prior to Mr. Locke's involvement. It should be noted that SPP stakeholders rejected the SPP Staff's proposal to revise the tariff to begin including over-1MW BTM load. Yet, shortly thereafter, Mr. Locke began interpreting the existing section 34.4 in a way that essentially adopted the rejected tariff amendment.

FERC Has Determined That an Identical Definition of Monthly Network Load Did Not Include Retail BTM Generation.

FERC has determined that virtually identical tariff language to that in section 34.4 of SPP's tariff does *not* include load served by a retail customer's own BTM generation. The MISO tariff definition of Network Monthly Load[299] is identical to SPP's in every relevant respect.[300] When Entergy joined MISO about 10 years ago, it brought with it a number of large customers that generated portions of their own electricity, specifically qualifying facilities (QFs) under PURPA, like Eastman.[301] Entergy's longstanding practice was to use such self-generating customers' net loads for allocating transmission costs; that is, it did not include load served by the customers' BTM generation.[302] MISO prepared an "Integration Plan" (not a tariff change) for the addition of Entergy to MISO that, among other things, dealt with Entergy's continuation of its practice and specifically provided that, for Entergy system QFs providing a portion of a retail customers load, Entergy "would need to designate the *net* withdrawals as a Network Load."[303] That is, only the net electricity that a customer was withdrawing from Entergy's grid would be included, not the

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[298] Tr. at 845:19-847:2 (Locke Cross) (May 21, 2021).

[299] TIEC Ex. 1A, Workpapers to the Direct Testimony of Jeffry C. Pollock at 835 (Pollock Dir. Workpapers); TIEC Ex. 1, Pollock Dir. at Bates 25.

[300] *Compare* TIEC Ex. 1A, Pollock Dir. Workpapers at Bates 835 *with* TIEC Ex. 42.

[301] Tr. at 1187:6-1188:22 (Ross Recross) (May 25, 2021).

[302] Eastman Ex. 1, Al-Jabir Dir. at 19-20.

[303] TIEC Ex. 1A, Pollock Dir. Workpapers at Bates 840 (emphasis added).

electricity that the customer was generating itself and consuming behind the meter. FERC determined that this practice was *consistent* with MISO's existing tariff and that no tariff amendment was required.[304] Thus on the question of whether the same definition of Monthly Network Load that SPP uses includes the load that a QF like Eastman is providing to itself, FERC disagrees completely with Mr. Locke's view.

Mr. Locke does not deny that this was the result of this case, but asserts, first, that it was limited to Qualifying Facilities.[305] That is a curious objection given that the single self-generator that SWEPCO has included in Monthly Network Load is such a facility. Mr. Locke then asserts that the FERC case had many pages of discussion of other issues and little discussion of its rationale for concluding that Monthly Network Load does not include electricity a retail customer provides to itself.[306] But this is hardly surprising given that FERC simply adopted the plain-English definition of Monthly Network Load, a term which has so bedeviled Mr. Locke. In any case, the FERC decision is clear, Monthly Network Load as defined in the MISO and SPP tariffs does not include load that a QF such as Eastman provides to itself.

SWEPCO's Proposed Treatment of Eastman's Self-Served Retail Load Violates the Federal PURPA Regulations and Parallel Texas Regulations.

SWEPCO's proposed singling out of the load of Eastman's qualifying facility is not only inconsistent with the SPP tariff, it also violates the Federal regulations under PURPA and its Texas counterpart.[307] By reason of its decision to treat Eastman's qualifying facility differently than other retail self-generators, SWEPCO is violating the federal and state PURPA regulations.

First, SWEPCO's proposal would discriminate against a qualifying facility in comparison to other customers with retail BTM generation. SWEPCO singles out a single retail customer with

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304 155 FERC ¶ 61, 068 (2016) at 76.

305 SWEPCO Ex. 51, Rebuttal Testimony of Charles J. Locke at 15 (Locke Rebuttal).

306 SWEPCO Ex. 51, Locke Rebuttal at 15-16.

307 TIEC Ex. 72; 16 T.A.C. § 25.242(k)(1)(a), (3)(A).

BTM generation for this new treatment, and that customer is in fact a qualifying facility.[308] Other retail customers who generate their own electricity in Texas, Arkansas, and Louisiana and are not qualifying facilities are not included in Monthly Network Load.[309] Thus SWEPCO's proposal would discriminate against a QF in comparison to SWEPCO's non-QF generators, in violation of 292.305(a)(ii) of the PURPA regulations[310] and section 25.242 of the PUC's Substantive Rules.[311].

Second, Mr. Locke's interpretation of section 34.4 of the tariff would discriminate against QFs as compared to customers that do not generate their own electricity but have similar load characteristics. The PURPA regulations prohibit discrimination against QFs in comparison to rates for other customers with similar load or other cost-related characteristics.[312] As was made clear at the hearing, a customer generating a portion of its own electricity is not using SWEPCO's grid or imposing costs on SWEPCO except to the extent it is actually taking power from SWEPCO.[313] A customer taking 10 MW from SWEPCO imposes the same costs on SWEPCO, irrespective of whether it is also generating electricity for its own use.[314] Yet if that customer happens to be a QF generating, for example, 40MW power for its own use, Mr. Locke's interpretation would require that SWEPCO report as Network Load 50 MW for that customer.[315] Mr. Locke's interpretation applies even if the QF had load that was synced to go down when its generation goes down so that

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[308] Tr. at 1262:23-1263:9 (Jackson Cross) (May 25, 2021); Tr. at 1203:3-13 (Aaron Cross) (May, 25 2021).

[309] TIEC Ex. 1, Pollock Dir. at 25; *see* Tr. at 1166:3-1166:12, 1169:1-6 (Ross Cross) (May 25, 2021); *see* 1212:8-1213:3 (Aaron Cross) (May 25, 2021).

[310] TIEC Ex. 72 ("Shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility.").

[311] 16 T.A.C. § 25.242(k)(1)(A).

[312] TIEC Ex. 72.

[313] Tr. at 1144:10-1145:2, 1146:5-11 (Ross Cross) (May 25, 2021); Tr. at 1333:10-1334:2 (Al-Jabir Redirect) (May 25, 2021).

[314] *See* Tr. at 1149:13-1150:4 (Ross Cross) (May 25, 2021) (stating that whether a customer is generating and using 2 kilowatts, 5 kilowatts, or 20 kilowatts, the load would show up as zero to SWEPCO).

[315] Eastman Ex. 11.

it could never take more than 10 MW from its system.[316] Thus a QF that can never impose a load greater than 10 MW is treated very differently than a non-QF that takes 10 MW.

The discriminatory treatment in reporting Network Load to SPP ultimately results in discriminatory rates to the QF, as is evidenced in this case. SWEPCO seeks $5.7 million in higher rates as a result of reporting Eastman's and only Eastman's self-served load. And, while SWEPCO proposes rate moderation that "only" raises Eastman's rates by $3.3 million in this case,[317] Eastman would presumably in future cases bear the full cost of SWEPCO's report of its load. In either case, SWEPCO's approach results in rates for the Eastman QF that are discriminatory compared to rates charged to ratepayers who impose similar demands on SWEPCO.

SWEPCO's proposal also conflicts with the requirements of section 292.305(c) of the PURPA regulations and parallel PUC regulations.[318] Those provisions prohibit rates for backup power that assume that all QFs' outages (and, therefore, the need to take power from SWEPCO) occur simultaneously or at the time of the system peak. Such an assumption would result in allocating costs to load served by BTM generation as if the user were instead taking power from the system at the time of the peak demand. That is exactly what Mr. Locke's interpretation of the definition of Monthly Network Load would do. It would allocate costs to QFs as if all of their BTM generation were off line at the time of the system peak and they were taking all of their power from the utility. That is an assumption that the PURPA regulations do not permit.

SWEPCO itself was quite clear in its September 2019 submission to SPP that Mr. Locke's interpretation of Monthly Network Load violated these regulations. Specifically SWEPCO stated as follows:

> SPP Conflicts with PURPA by reaching behind the retail meter. SPP position is inconsistent with the spirit of PURPA. PURPA requires that the retail rates for standby power should not be based on the assumption that forced outages and all other reductions in output by QF's will occur simultaneously or during the time of

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[316] *Id.*

[317] Tr. at 1504:22-1505:1 (Jackson Cross) (May 26, 2021).

[318] *See* 18 C.F.R. § 292.305(c).

> system peak. Likewise, we do not assume that each individual retail load will be at its peak usage for billing purposes and allow that diversity. Why should we treat this differently as opposed to load that was just off during the peak?[319]

SWEPCO's 2019 analysis is correct. Treating QFs as if they were taking power from the system during the time of the monthly peak (when they are not) is inconsistent with how SPP treats other load and violates the federal and Texas PURPA regulations.[320]

Violation of PURA Section 36.003

SWEPCO has singled out only one of its 187 Texas retail customers with BTM generation for assessing costs to its self-served load.[321] The other 186 customers continue to have only the actual load served by SWEPCO included in the development of rates in SWEPCO's proposal. None of them, including dozens of other facilities SWEPCO identifies as cogeneration facilities, one of which is over 80 MW,[322] would experience the massive increase SWEPCO proposes for Eastman.

The differential treatment of similarly situated customers is the essence of discrimination, and SWEPCO's proposal could not provide a more stark example. In addition to all its other problems, SWEPCO's proposal to apply this new treatment to one and only one of its customers that self-supply a portion of their electricity violates the prohibition in Section 36.003(b) of PURA against discriminatory rates and would subject Eastman to an unreasonable disadvantage under Section 36.003(c).[323]

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[319] TIEC Ex. 36B.

[320] *See* Tr. at 771:15-775:12 (Locke Cross) (May 21, 2021); TIEC Ex. 44; TIEC Ex. 72; 16 T.A.C. § 25.242(k)(1)(a), (3)(A).

[321] TIEC Ex. 2, Pollock Supp. Dir. at Bates 3-4; Tr. at 1262:23-1263:9 (Jackson Cross) (May 25, 2021).

[322] TIEC Ex. 2, Pollock Sup. Dir. at Ex. JP-S1.

[323] *See* 18 C.F.R. § 292.305(c).

SWEPCO Has Failed to Meet Its Burden of Proof on the Quantification of the Proposed $5.7 Million Increase in Texas Rates.

SWEPCO asserts in this case that its decision to include the electricity Eastman provides to itself in SWEPCO's reporting of Monthly Network Load has increased the payments it makes to SPP for Network service.[324] That may be the case, but nowhere has SWEPCO identified the additional SPP costs it has allegedly incurred as a result of including this single customer from Texas in its Network Load reports. The $5.7 million it requests in additional Texas rates in this case certainly does not represent the additional SPP costs to SWEPCO of its decision to include Eastman.[325] Rather, it represents a shift in *all* transmission-related costs, not just SPP charges, from Arkansas and Louisiana to Texas.[326] This shift results not from calculating the incremental SPP charges, but from adding the self-served load of a single retail BTM customer in Texas to "the load that SWEPCO's resources were actually serving at the time of (the monthly) peaks."[327] The addition of this phantom load to the Texas transmission demand allocator in the jurisdictional separation study is what results in the calculation of the $5.7 million adder to Texas rates.[328]

TIEC Exhibit 73 shows the actual peak demands for the Texas, Louisiana, and Arkansas jurisdictions coincident with the monthly peaks.[329] For example, SWEPCO's actual coincident demand for Texas for April 2019 was 889.9 megawatts.[330] But when it came to the allocation between jurisdictions of transmission costs,[331] SWEPCO added the self-served load of a single

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[324] TIEC Ex. 1, Pollock Dir. at Bates 13.

[325] TIEC Ex. 2, Pollock Supp. Dir. at 1-2.

[326] TIEC Ex. 2, Pollock Supp. Dir at 2.

[327] Tr. at 1201:16-1202:5 (Aaron Cross) (May, 25 2021).

[328] TIEC Ex. 2, Pollock Sup. Dir. at 1-2; TIEC Ex. 1, Pollock Dir. at 25.

[329] *Id.*; TIEC Ex. 73.

[330] TIEC Ex. 73.

[331] Tr. at 1202:18-1203:2 (Aaron Cross) (May, 25 2021).

customer in Texas: Eastman.[332] None of the retail BTMG load in Arkansas or Louisiana, however, was added to the jurisdictional allocators.[333]

The result of adding one retail BTM customer to the Texas jurisdiction while adding none to the others is shown on Exhibit TIEC Exhibit 74.[334] That shows the derivation of the $5.7 million in additional revenue requirement that SWEPCO seeks to impose on Texas ratepayers in this case.[335] Including Texas but not Arkansas and Louisiana retail self-served load reduced the Arkansas revenue requirement by $2 million and the Louisiana revenue requirement by $3.7 million, which was added to the Texas revenue requirement.[336]

If SWEPCO were to consistently apply the new reading of section 34.4 that it proposes to apply to Eastman, it would have to include similar load in other jurisdictions. But SWEPCO has provided no evidence of what the Texas revenue requirement would be if it included the retail BTMG load of all three jurisdictions in its jurisdictional allocation study. Presumably, the addition of that load in Arkansas and Louisiana would reduce Texas's share of allocated transmission costs.

In addition, the jurisdictional allocation methodology Mr. Aaron applied is not limited to the allocation of SPP-related charges. Rather, it includes all of SWEPCO's transmission revenue requirement, roughly 34% of which is unrelated to the SPP load ratio share.[337] While SWEPCO has asserted that the reason it wants to allocate more SPP charges to Texas is because of a change to the interpretation of Network Load imposed by SPP Staff, it has offered no testimony or explanation for why that misguided interpretation would affect the allocation of SWEPCO's non-SPP revenue requirement, including Transmission Invested Capital. These costs represent the same SWEPCO costs that the Commission has allocated based on actual load in all previous cases,

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[332] Tr. at 1262:23-1263:9 (Jackson Cross) (May 25, 2021).

[333] TIEC Ex. 2, Pollock Sup. Dir. at 2.

[334] *Id.*

[335] Tr. at 1209:21-1211:9 (Aaron Cross) (May, 25 2021).

[336] *Id.* at 1211:19-1212:6.

[337] TIEC Ex. 2, Pollock Supp. Dir. at 2.

and there is no cost-based or other rationale whatsoever presented in this case for changing the PUC precedent on the allocation of SWEPCO's non-SPP transmission costs.

SWEPCO's calculation of the proposed \$5.7 shift from Arkansas and Louisiana to Texas is not based on whatever amount SWEPCO may have actually paid to SPP as a result of including Eastman's load, a number which no SWEPCO witness has provided. Rather, it is based on applying one method to develop the Texas jurisdictional demand, and another method to calculate the Arkansas and Louisiana demands. It then applies those erroneous allocators not just to SPP-related costs, but to transmission costs that have nothing to do with Mr. Locke's new interpretation of the SPP tariff's definition of Monthly Network Load. Even if that misguided interpretation were applied, SWEPCO has not met its burden of proof to show what the additional SPP costs are, let alone the effect on Texas ratepayers of a system-wide application of that new definition. SWEPCO's request to add a single customer's self-served load to the Texas jurisdiction in the jurisdictional allocation study should be denied.

Conclusion

As SWEPCO and other SPP members have pointed out, Charles Locke's re-interpretation of Section 34.4 of the SPP tariff is without support. One of the SPP Members responding to SWEPCO's 2019 survey succinctly explained why:

> Electricity that is produced and consumed on site behind a retail meter does not flow over a Network Customer's transmission or distribution system. Indeed, it is entirely possible that the equipment using the behind-the-meter generation would never take service from the grid. There is no rational basis for treating a retail customer's own consumption of its own electricity as Network Load. It has sometimes been argued that load served by behind-the-meter generation should be counted as Network Load because there may be certain circumstances where behind-the-meter generation would be unavailable and the load would then use the T&D system of the Network Customer. At those times, the actual load that such a retail customer places on the grid would be a part of Network Load and, to the extent that it occurs during a monthly peak, would be considered a "Network Customer's Monthly Network Load" under Section 34.4 of the SPP OATT. But customers are not deemed to have their entire potential load counted as Network Load at all times. If any customer, be it residential, commercial, or industrial, is using less than its maximum demand at the time of the monthly peak, Network Load nonetheless uses only the actual demand the customer imposes on the system at the time. Further, it is well established that Network Customers that have retail

interruptible customers that are not on the system at the time of the peak do not have to add the interrupted load to their actual loads. Network Load is based on the actual usage of the grid. To the extent a retail customer provides its own electricity, it is not using the grid, and its usage is not a part of the Network Load at the time of the Monthly Peak when the Network Load is calculated.[338]

Numerous other SPP members explained in their response to SPP's surveys that they did not and/or could not include self-served retail load in Network Load.[339] Eastman's QF has been in place since it was constructed by a SWEPCO affiliate over 20 years ago,[340] without any suggestion by SWEPCO in any prior case that it should be included in the reporting of Monthly Network Load. Nor has SWEPCO sought to apply this new construction in any other jurisdiction.[341] SWEPCO's calculation of the amount it proposes to shift from Arkansas and Louisiana to Texas bears no relation to whatever additional charges it may have incurred from SPP. For the reasons discussed above, SWEPCO's request to add the self-served load of a single Texas customer to the jurisdictional allocators should be denied.

E. Purchased Capacity Expense

1. Imputed Capacity for Wind Purchased Power Agreements

SWEPCO purchases power from four wind projects.[342] These wind projects provide SWEPCO with capacity, and SWEPCO includes these purchased power agreements (PPAs) as capacity resources in its integrated resource planning (IRP) process.[343] SPP has accredited capacity to these PPAs, and they contributed [redacted] MW of capacity toward SWEPCO meeting SPP's minimum capacity requirement during the test year.[344] Thus, while the PPAs do not have an

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[338] TIEC Ex. 36C.

[339] Tr. at 1167:16-21 (Ross Cross) (May 25, 2021) (agreeing that "the thing that's different in this case for the first time we have proposal to include in network load a certain number of megawatts for a retail customer that SWEPCO is not serving at the time of the coincident peak"); Eastman Ex. 1, Al-Jabir Dir. at 11.

[340] Tr. at 784:18-21 (Locke Cross) (May 21, 2021).

[341] Tr. at 1197:7-17 (Aaron Cross) (May 25, 2021).

[342] TIEC Ex. 4, LaConte Dir. at 23.

[343] *Id* at 23-24; *see also* Tr. at 665:3-666:9 (Stegall Cross) (May 21, 2021); TIEC Ex. 28.

[344] TIEC Ex. 4, LaConte Dir. at 23-24.

explicitly stated capacity charge, they are providing SWEPCO with capacity value.[345] Under the Commission's rules, capacity- or demand-related costs are not eligible fuel expenses.[346] Indeed, at the hearing, SWEPCO witness Mr. Stegall agreed that capacity costs should be recovered in base rates.[347] Nevertheless, SWEPCO is currently recovering all of its costs for these PPAs through its fuel factor.[348] To address this discrepancy, Ms. LaConte recommends that the capacity-related costs of the PPAs be removed from the fuel factor and imputed as base-rate expenses.[349]

Ms. LaConte quantified the imputed capacity costs associated with the PPAs by multiplying the accredited capacity by the value of the capacity.[350] To calculate that value, Ms. LaConte began with the avoided cost of capacity used in the energy efficiency cost recovery factor (EECRF) rule to calculate performance bonuses, which is $80/kW-year or $6.67/kW-month.[351] Ms. LaConte then estimated that SWEPCO incurs $0.09/kW-month for ancillary services to support these wind PPAs, which she removed from the avoided cost of capacity, resulting in a final capacity value of $6.58/kW-month.[352] Multiplying this amount by the amount of SPP-accredited capacity for the test year resulted in $[redacted] million of imputed capacity costs.[353] Ms. LaConte recommended that this amount be added to SWEPCO's base rates in this proceeding, and that the same amount should be removed from SWEPCO's fuel costs beginning on the effective date of rates in this case.[354]

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345 *Id*

346 16 T.A.C. § 25.236(a)(6).

347 Tr. at 662:25-663:3 (May 21, 2021).

348 SWEPCO Ex. 47, Rebuttal Testimony of Jason M. Stegall at 11 (Stegall Reb.).

349 TIEC Ex. 4, LaConte Dir. at 24-26.

350 *Id.* at 25.

351 *Id.* at 25.

352 *Id.* at 25-26.

353 *Id* at 26.

354 *Id.*

Several parties took issue with Ms. LaConte's recommendation, though their arguments are unavailing. CARD witness Mr. Norwood agreed with the concept of imputing capacity for the PPAs, and further agreed that they provided [redacted] MW of capacity during the test year.[355] However, he disagreed with the value of capacity that Ms. LaConte used in her calculation.[356] Specifically, Mr. Norwood contended that the $6.58/kW-month value is too high because SWEPCO forecasts that it will have excess capacity on its system until at least 2024.[357] For this proposition, Mr. Norwood relied upon SWEPCO's 2019 IRP.[358] At the hearing, however, he admitted that the 2019 IRP did not account for the subsequently announced planned retirements of DHPS and Pirkey.[359] When SWEPCO's 2019 IRP is adjusted to account for those retirements, it shows that SWEPCO will be capacity short beginning in 2023 or 2024, depending on the timing of the Pirkey retirement.[360] Indeed, SWEPCO has stated that it projects that it will need to add capacity beginning in 2023.[361] Mr. Norwood also noted that SWEPCO's 2019 IRP forecasts the market price of capacity in SPP to be $9.13/kW-year over the next ten years, though he acknowledged at the hearing that SPP does not have a capacity market.[362] Further, the 2019 IRP is outdated, as it does not include the planned retirements of DHPS and Pirkey.[363] On the other hand, Ms. LaConte used the value of capacity that all utilities in Texas, including SWEPCO, use in measuring the cost of avoided capacity for purposes of calculating performance bonuses under the EECRF rule. Mr. Norwood's excess-capacity contentions thus miss the mark.

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[355] Tr. at 1107:14-1108:2 (Norwood Cross) (May 25, 2021).

[356] *Id.* at 1108:3-5.

[357] CARD Ex. 7, Norwood Cross-Reb. at 4.

[358] *Id.*; *see also* Tr. at 1108:6-17 (Norwood Cross) (May 25, 2021).

[359] Tr. at 1109:10-1111:14 (Norwood Cross) (May 25, 2021).

[360] *Id.*; TIEC Ex. 28.

[361] TIEC Ex. 31; Tr. at 666:19-667:20 (Stegall Cross) (May 21, 2021); *see also* 1109:10-1111:14 (Norwood Cross) (May 25, 2021).

[362] Tr. 1111:19-1112:20 (Norwood Cross) (May 25, 2021).

[363] *Id* at 1112:21-1113:6; TIEC Ex. 28.

SWEPCO witness Mr. Stegall and OPUC witness Mr. Georgis disagreed with the concept of imputing capacity for these wind projects altogether, relying on the fact that the contracts do not have a separate capacity charge.[364] But Commission precedent is clear that it is appropriate to impute capacity costs to contracts without an explicitly stated capacity charge if those contracts provide capacity value.[365] As the Commission concluded in Docket No. 23350:

> The Commission disagrees with the ALJ. There is credible evidence to support a determination that these "energy-only" contracts have a capacity value, despite the fact that EGSI [Entergy Gulf States, Inc.] negotiated the contracts without a separately stated capacity charge. In particular, the Commission relies on the Louisiana Public Service Commission's decision regarding the energy versus capacity classification of these same contracts, and EGSI's subsequent decision to reflect a capacity value of 24% in its energy-only contracts after the summer of 2000. The evidence shows that the contracts provide capacity benefits by offering system-wide reliability and firmness supply. Therefore, the Commission concludes that the contracts should reflect the embedded capacity component for purposes of this fuel reconciliation.[366]

Similarly, the evidence in this case shows that SWEPCO includes these wind projects as capacity resources in its system planning, and that they are used to meet SWEPCO's SPP margin requirement.[367] While it is true that wind is an intermittent resource, SPP accounts for this fact in its accreditation process. For example, the wind projects at issue have a combined nameplate rating of 470 MW, but SPP only accredits [redacted] MW, which is the number Ms. LaConte used in her testimony.[368] In sum, the wind PPAs have capacity value, and Ms. LaConte's recommendation to impute [redacted] million of capacity costs to SWEPCO's wind PPAs should be adopted. These capacity

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[364] Tr. at 669:9-670:12 (Stegall Cross) (May 21, 2021); SWEPCO Ex. 47, Rebuttal Testimony of Jason M. Stegall at 11 (Stegall Reb.); OPUC Ex. 60, Cross-Rebuttal Testimony of Tony M. Georgis at 11-12 (Georgis Cross-Reb.).

[365] Tr. at 670:16-673:14 (Stegall Cross) (May 21, 2021); *Application of Entergy Gulf States, Inc for the Authority to Reconcile Fuel Costs*, Docket No. 23350, Final Order at 2-3 (Aug. 2, 2002); *see also City of El Paso v. Pub Util. Comm'n of Tex.*, 344 S.W.3d 609, 619-22 (Tex. App.—Austin 2011, no pet.); *Entergy Gulf States, Inc. v. Pub. Util Comm'n of Tex.*, 173 S.W.3d 199, 211-12 (Tex. App.—Austin 2005, pet. denied).

[366] Docket No. 23350, Final Order at 2-3.

[367] *See, e.g.*, Tr. at 673:13-674:5 (Stegall Cross) (May 21, 2021).

[368] TIEC Ex. 4, LaConte Dir. at 23, 26.

costs should be recovered and allocated on a demand basis in the base rates established in this case, and removed from SWEPCO's fuel costs as of the effective date of rates in this case.

2. Cajun Contract

TIEC supports the inclusion of costs associated with the purchase of capacity under the Cajun contract in SWEPCO's base rates. As SWEPCO witness Mr. Stegall explained, the operating reserve capacity provided by the Cajun contract is a different product than the operating reserve ancillary service addressed in SWEPCO's recent fuel reconciliation proceeding, and is a capacity-related, not an energy-related, product.[369] Accordingly, these costs should be recovered through base rates and allocated on a demand basis.

VI. Functionalization and Cost Allocation [PO Issues 4, 5, 52, 53, 55, 56, 57, 58]

A. Jurisdictional Allocation [PO Issues 55, 57]

SWEPCO has used the actual demands of its Louisiana and Arkansas jurisdictions, but it has added the self-served retail load of a single Texas customer to its Texas jurisdictional demands.[370] For the reasons discussed in Section IV.A.6. above, that adjustment to the Texas jurisdictional allocators should be rejected.

B. Class Allocation [PO Issues 53, 58]

TIEC addresses two aspects of SWEPCO's proposed class-cost-of-service study (CCOSS). First, the Commission should adopt SWEPCO's rebuttal proposal to use a single coincident peak (1CP) system load factor to weight average demand in the Average and Excess/Four Coincident Peaks (A&E/4CP) allocation methodology. Second, the Commission should reject SWEPCO's proposed allocation of costs purportedly caused by SWEPCO's decision to report Eastman's BTMG load to SPP in SWEPCO's Monthly Network Load.

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[369] SWEPCO Ex. 47, Stegall Reb. at 7-10.

[370] Tr. at 1212:8-1213:3 (Aaron Cross) (May 25, 2021); TIEC Ex. 1, Pollock Dir. at Bates 30.

1. System Load Factor

SWEPCO's CCOSS uses the A&E/4CP methodology to allocate production and transmission costs.[371] A key component of that methodology is the system load factor,[372] which is the ratio of the average load over a designated period compared to the peak demand in that period.[373] In its initial application, SWEPCO inadvertently used a system load factor calculated based on the average of SWEPCO's four coincident peaks (4CP) rather than the actual peak demand (1CP).[374] However, after Mr. Pollock pointed out this error in his direct testimony,[375] SWEPCO correctly used a system load factor based on its 1CP in its rebuttal CCOSS.[376] No party filed a statement of position opposing SWEPCO's correction. The use of a 1CP system load factor is consistent with cost-causation and well-established Commission precedent.[377] The Commission should approve it.

2. Allocation of BTMG load in the Class Cost of Service Study (CCOSS)

In evaluating SWEPCO's allocation proposal with respect to Eastman's BTMG load, it is helpful to review the key background facts. As a member of SPP, SWEPCO reports the extent to which its customers use SPP's transmission network on a monthly basis.[378] Specifically, SWEPCO's "Monthly Network Load" is defined under the SPP OATT as SWEPCO's hourly load coincident with the monthly peak of SWEPCO's SPP region, Zone 1.[379] The Monthly Network Load SWEPCO reports is used in determining SWEPCO's SPP load ratio share, which governs

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[371] SWEPCO Ex. 31, Direct Testimony of John O. Aaron Dir. at 17-18 (Aaron Dir.).

[372] TIEC Ex. 1, Pollock Dir. at 30-31.

[373] *Id.* at 33.

[374] SWEPCO Ex. 54, Rebuttal Testimony of John O. Aaron Reb. at 3 (Aaron Reb.); TIEC Ex. 1, Pollock Dir. at 31-32.

[375] TIEC Ex. 1, Pollock Dir. at 32-35.

[376] SWEPCO Ex. 54, Aaron Reb. at 3.

[377] TIEC Ex. 1, Pollock Dir. at 32-24.

[378] *Id.*. at 13-14.

[379] *Id* at 15-16.

the allocation of SPP's transmission costs between regions and ultimately SPP members.[380] Thus, all else equal, the more Monthly Network Load that SWEPCO reports to SPP, the higher SWEPCO's share of SPP's transmission costs will be.[381]

Eastman is a large (roughly 150 MW demand) industrial customer in SWEPCO's Texas service territory that serves its own load through on-site generation.[382] Specifically, Eastman's load is served by Eastman Cogeneration LP (a Qualified Facility (QF) under PURPA[383]) from a combined cycle gas turbine (CCGT) with a net summer capacity rating over 400 MW.[384] Eastman does not purchase full requirements electricity service from SWEPCO under the Large Lighting and Power (LLP) rate schedule or any other schedule.[385] Instead, Eastman purchases backup and maintenance service under the specialty Supplementary, Backup, Maintenance, and As-Available Standby Power Service (SSMBAA)—Class II rate schedule.[386] Notably, SSMBAA and LLP are separate rate schedules that provide different services.[387] SSMBAA customers, like Eastman, own and operate generation, and they occasionally purchase their electrical requirements from SWEPCO.[388] LLP customers, by contrast, purchase all of their electrical requirements from SWEPCO[389].

While SWEPCO thus occasionally supplies power to Eastman under the SSMBAA schedule, Eastman self-supplies the vast majority of its load. In fact, since 2013, the Eastman

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[380] *Id.* at 15.

[381] *Id.*

[382] *Id.* at 13.

[383] *Id.* at 23-24.

[384] *Id.* at 24.

[385] *Id.* at 37.

[386] *Id.*

[387] SWEPCO Ex. 32, Jackson Dir. at 20.

[388] TIEC Ex. 1, Pollock Dir. at 37.

[389] *Id.* at 39.

CCGT has generated more power than Eastman consumed in all but three months.[390] Notably, the CCGT facility also generated more power than Eastman's demand coincident with the SPP Zone 1 peaks in all 12 months during the test year in this case.[391]

Prior to October 2018, SWEPCO reported its Monthly Network Load to SPP without including Eastman's self-supplied load.[392] At that time, however, SWEPCO changed course, and began reporting Eastman's 150 MW of load to SPP, resulting in an increase to SWEPCO's share of SPP transmission costs.[393] While SWEPCO acknowledges that it has nearly 200 customers that use BTMG to supply at least a portion of their own electricity,[394] it decided to include only Eastman's BTMG load in its Monthly Network Load reports to SPP.[395] SWEPCO states that the inclusion of Eastman's BTMG load in its SPP reports increased the Texas retail revenue requirement by $5.7 million.[396]

For the reasons discussed in Section IV.A.6 above, there is no valid basis for SWEPCO to include Eastman's BTMG load in reporting its Monthly Network Load to SPP, and all costs caused by that inclusion should be disallowed. If the Commission agrees, there is no need to reach the allocation of the $5.7 million in costs caused by SWEPCO's decision to impute the BTMG load (because those costs will not be allocated to any Texas customers). However, if the Commission disagrees with TIEC's position and approves SWEPCO's decision to include Eastman's BTMG load in the Monthly Network Reports, the Commission will need to decide how the resulting costs should be allocated among, and charged to, Texas retail customers. TIEC addresses those issues in this section and Section VII of this brief.

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[390] *Id* at 24.

[391] *Id.*

[392] *Id* at 17-18.

[393] *Id.* at 14-15.

[394] TIEC Ex. 2, Pollock Supp. Dir. at JP-S1.

[395] TIEC Ex. 1, Pollock Dir. at 17-18.

[396] *Id.* at 25; TIEC Ex. 76.

For the reasons discussed below, even if SWEPCO's decision to include Eastman's BTMG load is approved, the Commission should reject SWEPCO's proposal to impute that load into the LLP-T class. In that event, SWEPCO should instead create a new customer class for all BTMG load (not just Eastman's), and develop a separate rate designed to recover the costs associated with BTMG service.[397]

- **SWEPCO's allocation of BTMG-related transmission costs improperly imputes Eastman's self-served load into the LLP-T class and is not even based on increased SPP charges.**

It important to clarify exactly how SWEPCO proposes to treat Eastman's BTMG load in its CCOSS. SWEPCO's rationale for its changed treatment of Eastman's BTMG load is that the SPP OATT purportedly requires that this load be included in the Monthly Network Load report.[398] As discussed above, including this self-supplied load increases SWEPCO's share of SPP's transmission costs. These SPP costs are billed to SWEPCO under the SPP OATT, and are sometimes referred to as Approved Transmission Charges or "ATC."[399] Thus, one might expect that the manner in which SWEPCO would address the allocation of BTMG-related transmission costs would be to identify the extent by which its ATC increased as result of including the BTMG load in its reports to SPP, and then allocate those incremental costs to the BTMG customers or classes that purportedly caused them. SWEPCO, however, did not do so.

Instead of identifying the amount by which its ATC increased because it decide to report Eastman's BTMG load, SWEPCO reallocated its ***total*** transmission revenue requirement.[400] Specifically, SWEPCO imputed Eastman's BTMG load into the Texas retail jurisdiction, and then, within that jurisdiction, to the LLP-T customer class.[401] Notably, SWEPCO's total transmission

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[397] TIEC addresses the BTMG rate issue in Section VII.C below. As discussed in that section, there will be a need for moderation with respect to this rate in this case.

[398] SWEPCO Ex. 32, Direct Testimony of Jennifer L. Jackson Dir. at 15 (Jackson Dir.); SWEPCO Ex. 55, Rebuttal Testimony of Jennifer L. Jackson Reb. at 12-13 (Jackson Reb.).

[399] For example, this category of costs is referred to as Approved Transmission Charges (or ATC) in the Commission's TCRF rule. 16 T.A.C. § 25.239(b)(1).

[400] TIEC Ex. 2, Pollock Supp. Dir. at 2.

[401] TIEC Ex. 1 Pollock Dir. at 38-39.

revenue requirement includes numerous components beyond the charges it is billed by SPP (i.e., ATC), including return and depreciation on transmission plant,[402] taxes, and O&M expense.[403] In fact, these cost components other than ATC comprise fully 34% of SWEPCO's transmission revenue requirement.[404] These non-ATC costs are not affected by SWEPCO's SPP load ratio share.[405] Thus, even if it were appropriate for SWEPCO to (1) report Eastman's BTMG load to SPP, and (2) allocate the resulting increased costs first to the Texas retail jurisdiction and then to the LLP-T class (which it is not), SWEPCO has over-allocated transmission costs both to the Texas retail jurisdiction and to the LLP-T class.

The impact to the LLP-T customer class is stark. Specifically, in order to effectuate its reallocation of its transmission revenue requirement, SWEPCO added Eastman's 149 MW of transmission demand to the LLP-T class's demand, notwithstanding the fact that this load is self-supplied.[406] This increased the LLP-T class's purported peak demand by a factor of more than 2.5, from 97.7 MW to 246.7 MW.[407]

As one might expect, the consequence of imputing this load to LLP-T is a massive cost shift. While imputing the load to Texas at the jurisdictional level increased the revenue requirement in this case by $5.7 million, doing so at the CCOSS level increased LLP-T's share of transmission costs by ***nearly $8 million***.[408] Mr. Aaron confirmed this at the hearing:

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[402] For example, "Transmission Invested Capital," or "TIC" is an entire different category of cost than ATC under the TCRF rule. 16 T.A.C. § 25.239(b)(2).

[403] TIEC Ex. 2, Pollock Supp. Dir. at 2.

[404] *Id.*

[405] *Id.*

[406] SWEPCO imputed 149 MW of 4CP demand for Eastman, and 146 MW of average demand, in determining the A&E/4CP transmission allocation factor for the LLP-T class. TIEC Ex. 1, Pollock Dir. at 32.

[407] SWEPCO Ex. 54, Aaron Reb. at Exhibit JOA-1R. This exhibit shows the production and transmission demands by class. As Mr. Aaron explained, the only difference between the peak demand shown for production and transmission for each class is that 149 MW was added to the LLP-T class to account for BTMG. *Id.* at 3.

[408] TIEC Ex. 74 at Bates 002.

Q So the \$5.7 million of additional Texas revenue requirement gets allocated in such a way that the LLP transmission class sees a \$7.956 million increase in its allocated costs?

A Yes.

Q And in this case, you set the revenue distribution based on the cost allocation, don't you?

A The revenue distribution at equalized returns.

Q Right. So that means that if there's \$7.956 million more allocated as a cost, then it also would show up as additional revenue requirements for that LLP transmission class?

A That's correct.[409]

Notably, as discussed in greater detail in Section VII.C below, SWEPCO's current proposal is to assign only roughly \$3.3 million of the \$8 million allocation to Eastman, meaning that the remainder would be charged to other LLP-T customers.[410]

SWEPCO's proposed cost shift can be seen on pages 2-4 of TIEC Ex. 74, which shows SWEPCO's calculated transmission revenue deficiency by Texas retail customer class, with and without Eastman's load imputed. As can be seen, SWEPCO's proposal would not only allocate \$8 million more in transmission costs to the LLP-T class, it would also ***reduce*** the allocation of transmission costs to every other retail class.[411] That is because the transmission allocation must equal 100%. Therefore, increasing the share to the LLP-T class reduces the allocation to all remaining classes.[412] Specifically, the remaining classes see a decrease of approximately \$2.3 million, which is the difference between the \$8 million allocated to LLP-T and the \$5.7 million

[409] Tr. at 1216:13-25 (Aaron Cross) (May 25, 2021).

[410] TIEC Ex. 78 at Bates 002; *see also* Tr. at 1252:13-19 (Jackson Cross) (May 25, 2021) (discussing this dynamic with respect to SWEPCO's original proposal, under which Eastman was assigned \$3.96 million).

[411] TIEC Ex. 74 at Bates 003-05.

[412] Tr. at 1363:13-1364:14 (Pollock Redir.) (May 25, 2021); *cf.* Tr. at 1214:10-125:25 (Aaron Cross) (May 25, 2021)(discussing the same dynamic with respect to the larger rate class groupings shown on TIEC Ex. 74).

Texas retail revenue requirement impact from imputing Eastman's BTMG load in the jurisdictional allocation.[413]

- **SWEPCO's proposed allocation of BTMG-related costs should be rejected.**

SWEPCO's proposal to impute Eastman's BTMG load into the LLP-T class should be rejected. As an initial matter, the proposal does not accurately allocate the costs caused by SWEPCO's decision to include this load in SWEPCO's Monthly Network Load reports to SPP. As discussed above, SWEPCO did not identify the extent to which this decision caused its ATC to increase. Instead, it imputed Eastman's BTMG load itself into the LLP-T class based on the fiction that SWEPCO's transmission system serves 100% of that load during times of peak. This results in the reallocation of SWEPCO's entire transmission revenue requirement, of which 34% is attributable to cost components other than ATC.[414] Even if it were appropriate to include Eastman's BTMG load in SWEPCO's share of SPP costs, this would provide no basis for reallocating all of SWEPCO's transmission costs (including non-ATC costs) as if that load were always served by SWEPCO. The Commission has not previously included SWEPCO's retail BTMG in applying the A&E/4CP method, and SWEPCO has not provided any valid reason for doing so here.[415]

Indeed, SWEPCO's proposal to include Eastman's load in deriving the LLP-T class's A&E/4CP allocator factor for LLP-T is contrary to the facts. SWEPCO imputed 149 MW of peak demand, and 146 MW of average demand, for Eastman, which is equivalent to assuming that Eastman is a 98% load factor customer.[416] Stated differently, this assumes Eastman not only purchases power from SWEPCO (rather than self-generating it), but that Eastman's average demand is 98% of its peak demand.[417] In essence, SWEPCO's proposed allocation therefore

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[413] *See* TIEC Ex. 74.

[414] TIEC Ex. 2, Pollock Supp. Dir. at 2.

[415] TIEC Ex. 1, Pollock Dir. at 32.

[416] *Id.* at 32, 37.

[417] *Id.* at 30 (explaining the concept of a load factor).

assumes that Eastman makes use of SWEPCO's (and thus SPP's) transmission network 98% of the time.[418] That is not the case. As discussed above, Eastman's load is served almost entirely by its own generation, meaning that Eastman rarely uses the transmission network. In fact, Eastman did not put any load on SWEPCO's system at the time of SWEPCO's or SPP Zone 1's monthly peaks during the test year.[419] Nevertheless, SWEPCO's proposed A&E/4CP allocator assumes that Eastman had a 4CP demand of nearly 150 MW. While Eastman purchases backup and maintenance service from SWEPCO (some of which is on an as-available basis), it already pays a cost-based rate for that service.[420] And that rate reflects the probability that service would be required during a peak period.[421] There is simply no basis to assume in the CCOSS that Eastman purchases full requirements service from SWEPCO and does so as a very high load factor customer.

Notably, this type of assumption is prohibited under both federal and state regulations applying to QF facilities. Both PURPA regulations and this Commission's rules prohibit designing backup and maintenance rates for QFs based on an assumption (unless factual) that all of the utility's QFs will be in an outage at the time of system peak.[422] But that is the essence of SWEPCO's CCOSS and rate-design proposals regarding BTMG in this case. SWEPCO proposes to impute Eastman's BTMG load in the LLP-T class as if SWEPCO were providing power to replace 100% of Eastman's generation at the time of monthly peak.[423]

A second problem with SWEPCO's proposal is that it is inappropriate to treat Eastman's BTMG load as part of the LLP-T class. As Mr. Pollock testified, customer classes in a CCOSS should be comprised of customers with similar characteristics.[424] A retail BTMG customer like

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[418] *Id.*

[419] *Id* 38.

[420] *Id* at 37-38.

[421] *Id.* at 37.

[422] TIEC Ex. 72, 18 C.F.R. § 292.305(c); 16 T.A.C. § 25.242(k)(3)(A).

[423] TIEC Ex. 1, Pollock Dir. at 24.

[424] *Id.* at 39.

Eastman is not similar to full requirements LLP-T customers, who not only purchase firm power from SWEPCO but do so with very high load factors. As previously discussed, Eastman currently purchases service under what SWEPCO witness Ms. Jackson refers to as a "specialty tariff sheet" that includes SSMBAA rates.[425] Eastman is not a full service LLP-T customer.[426] Imputing BTMG load in allocating costs to LLP-T (or any full service customer class, for that matter) results in the full service customers subsidizing the BTMG customers.[427] There can be no doubt that LLP-T customers other than Eastman did not cause any costs relating to Eastman BTMG load or SWEPCO's decision to report that load to SPP. Indeed, even ETSWD witness Ms. Pevoto agreed at the hearing that SWEPCO's full service LLP-T customers did not cause SWEPCO to incur any costs relating to Eastman's BTMG.[428] Thus, cost causation does not support allocating any of those costs to the LLP-T customer class.

While Eastman is the only LLP-T customer whose load SWEPCO reports to SPP[429] (to the extent one considers Eastman an LLP-T customer), SWEPCO has numerous other customers with BTMG. In fact, SWEPCO provided in discovery a list of nearly 200 customers who serve at least a portion of their own load with BTMG.[430] These include not only industrial customers, but also residential and commercial ones.[431] Accordingly, as Mr. Pollock testified, it would make more sense to create a separate customer class comprised of all retail BTMG load customers.[432] Notably, in its rebuttal case, SWEPCO modified its proposed charge for BTMG load that it reports to SPP (the Synchronized Self-Generation Load (SSGL) charge) to make it applicable to any qualifying BTMG customer in any class.[433] And, at the hearing, Ms. Jackson confirmed that she believes it

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[425] SWEPCO Ex. 55, Jackson Reb. at 13.

[426] TIEC Ex. 1, Pollock Dir. at 39.

[427] *Id.*

[428] Tr. at 1298:2-16 (Pevoto Cross) (May 25, 2021).

[429] TIEC Ex. 1, Pollock Dir. at 39.

[430] TIEC Ex. 2, Pollock Supp. Dir. at JP-S1 at 2-5.

[431] *Id.*

[432] TIEC Ex. 1, Pollock Dir. at 39.

[433] SWEPCO Ex. 55, Jackson Reb. at 14.

would be appropriate to create a separate rate schedule for SSGL service.[434] This makes sense given that SSGL would not be a standby service, and that SWEPCO has numerous BTMG customers in multiple classes. Ms. Jackson also agreed that SWEPCO's rebuttal revenue distribution could fairly be characterized as moving rate schedules to cost, subject to moderation.[435] This provides further support for creating a separate BTMG-load customer class, as Mr. Pollock proposes.

TIEC Recommendations

As an initial matter, the Commission should reject SWEPCO's proposal to charge any Texas customers any costs associated with imputing Eastman's BTMG load for the reasons discussed in Section IV.6 above. Further, even if the Commission decides that SWEPCO's unprecedented action to include Eastman's BTMG load in its Monthly Network Load should be approved, it still should not allocate any costs to Texas customer classes on that basis in this case. That is because SWEPCO has failed to identify the amount by which its decision to include Eastman's load in its SPP reports increased its ATC, which is the only category of cost that is impacted by including this load in SWEPCO's SPP load ratio share. Accordingly, the BTMG load that SWEPCO imputed into the LLP-T class should be removed in the CCOSS.[436]

Finally, even if the Commission decides that SWEPCO should charge retail BTMG load for SPP network transmission service, this load should still be removed from the LLP-T class. SWEPCO should instead create a separate customer class comprised of all retail BTMG loads and, as discussed in Section VII.C below, design a rate that would apply to all BTMG loads.[437]

VII. Revenue Distribution and Rate Design [PO Issues 4, 5, 47, 48, 52, 59, 60, 61, 62, 75, 76, 77, 78, 79]

A. Rate Moderation / Gradualism [PO Issue 52]

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434 Tr. at 1508:19-1509:3 (Jackson Re-cross) (May 26, 2021).

435 *Id* at 1505:20-23.

436 TIEC Ex. 1, Pollock Dir. at 40.

437 *Id.* at 39.

Revenue distribution is typically one of the more complicated aspects of a rate case, and this case has been no exception. SWEPCO began its revenue distribution process by running a CCOSS with 22 separate Texas retail classes.[438] These CCOSS classes include several very-low population classes.[439] Further, several of these CCOSS classes take service under the same rate schedule. For example, while SWEPCO uses three distinct Light & Power classes in its CCOSS, all three take service under the same rate schedule.[440] Indeed, while SWEPCO uses 22 classes in its CCOSS, it proposes only 10 rate schedules (other than lighting schedules).[441] SWEPCO, however, does not propose to allocate the revenue increase based on these 22 CCOSS classes. Instead, SWEPCO groups these CCOSS classes into four major customer classes: Residential, Commercial & Industrial, Municipal, and Lighting.[442] In SWEPCO's direct case, SWEPCO proposed equal percentage increases for every rate included in each major class.[443] Any subsidies were thus contained within the major group.[444] The different class definitions are depicted in the table below:[445]

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[438] TIEC Ex. 1, Pollock Dir. at 4, 43-44.

[439] *Id* at 44-45. For example, there are seven CCOSS classes with 11 or fewer members, and five classes with six or fewer members. *Id.* at 45.

[440] *Id.* at 44.

[441] *Id.* at 4, 43-44.

[442] *Id.* at 43-44.

[443] *Id.* at 42.

[444] Tr. at 1246:23-1247:2 (Jackson Cross) (May 25, 2021).

[445] TIEC Ex. 1, Pollock Dir. at 43-44.

Class Definitions		
Major Class	**Cost-of-Service Study Customer 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	
Municipal	Municipal Pumping	Municipal Pumping
	Municipal Service	Municipal Service
	Municipal Lighting	Various
	Public Street & Hwy	Various
Lighting	Outdoor Private & Area	Various
	Customer Owned	Various

Following criticism from Staff and intervenor witnesses that its grouping methodology failed to result in sufficient movement to cost, SWEPCO modified its revenue-distribution approach in its rebuttal case.[446] While the methodology is less than clear, Ms. Jackson testified that "the main difference in the rebuttal distribution is application of the individual rate class

[446] SWEPCO Ex. 55, Jackson Reb. at 7-8, Exhibit JLJ-1R.

change to the industrial customer classes."[447] At the hearing, she testified that SWEPCO's rebuttal revenue distribution proposal could fairly be described as moving rate ***schedules*** to cost, subject to moderation.[448] With respect to moderation, SWEPCO's rebuttal proposal is to cap the increase to any class at 1.5 times the system average increase, or approximately 43%.[449] Under SWEPCO's proposed revenue requirement and CCOSS, this moderation proposal results in three classes hitting the cap.[450] As Ms. Jackson explained, this creates a small subsidy among the other classes that share the major class groupings with the capped classes.[451]

TIEC submits that Mr. Pollock's proposed revenue-distribution methodology is more straightforward and should be adopted. Mr. Pollock starts with his revised CCOSS, which initially moves all rate schedules to cost.[452] This results in 13 rate classes.[453] Mr. Pollock's approach better aligns with how the Commission's rules define "Rate Class," which is as "[a] group of customers taking electric service under the same rate schedule."[454] It also mitigates some of the concerns with SWEPCO's use of highly granular, low-population classes in the CCOSS. Any base rate increase approved for SWEPCO should be spread to these rate classes based on the results of the revised CCOSS (incorporating TIEC's recommendations), with the movement to cost limited only by gradualism (as discussed further below).[455]

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[447] *Id.* at 7.

[448] Tr. at 1505:20-23 (Jackson Cross) (May 26, 2021).

[449] SWEPCO Ex. 55, Jackson Reb. at 8; Tr. 1247:14-1248:1 (Jackson Cross) (May 25, 2021). This cap is based on the total base rate increase, meaning that SWEPCO does not include TCRF and DCRF revenues in determining present revenues for purposes of measuring a rate increase. SWEPCO Ex. 55, Jackson Reb. at 8-9, Exhibit JLH-1R.

[450] *Id.* at 8.

[451] *Id.*

[452] TIEC Ex. 1, Pollock Dir. at 45. Due to the multiple lighting rate schedules, Mr. Pollock used the lighting class as defined in SWEPCO's CCOSS.

[453] *Id.* at Exhibit JP-4.

[454] 16 T.A.C. § 25.5(100).

[455] TIEC Ex. 1, Pollock Dir. at 7.

The rate design process should also be cost-based.[456] Once the target revenue for a rate schedule has been established, there remains the task of assigning the appropriate revenue requirement and rate to each type of service provided within that schedule.[457] This should also be based on the CCOSS, meaning that not all customers on a rate schedule should necessarily receive the same base rate increase.[458] Specifically, once the target revenue is established for a rate schedule (the third column in the above table), the CCOSS results should be used to establish the rate increase for each CCOSS class (the second column) within the rate schedule. Each CCOSS class should have its rates set such that it provides the same rate of return as the other CCOSS classes within the rate schedule, subject only to the 42.6% gradualism cap.

For example, the LLP-T and LLP-Primary rates are both on the LLP rate schedule.[459] However, Mr. Pollock's CCOSS indicates that LLP-T customers are providing a much higher rate of return than LLP-Primary customers.[460] Accordingly, in order to set rates such that LLP-Primary and LLP-T provide the same rate of return, it is necessary for LLP-Primary to receive a larger base rate increase than LLP-T.[461] Specifically, Mr. Pollock's CCOSS shows that, at SWEPCO's proposed revenue requirement, LLP-Primary would require a 32% increase, while LLP-T would receive a 3.2% increase.[462]

With respect to gradualism, consistent with the Commission's order in Docket No. 46449, Mr. Pollock defines it as a 42.6% increase in base revenues, including TCRF and DCRF charges.[463] Given that Mr. Pollock does not utilize a grouping approach, his gradualism proposal spreads any

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[456] *Id.* at 45-46.

[457] *Id.*

[458] *Id.* at 46.

[459] *Id.* at 43.

[460] *Id.* at JP-3 at 3.

[461] *Id.* at 46.

[462] *Id.* at 49; TIEC Ex. 1A, Pollock Dir. Workpapers at WP Exhibit JP-4 Errata, Tab "Distribution of Revenue."

[463] TIEC Ex. 1, Pollock Dir. at 46. The maximum base rate increase that was approved in Docket No. 46449 was 42.6%. *Id.*

resulting subsidy among all other rate classes in proportion to their base rate increases, rather keeping it within the "major class."[464] While the Commission in Docket No. 46449 approved the major-class grouping approach, the question of how (and whether to) apply gradualism is a fact- and case-specific inquiry, as both SWEPCO and Staff witnesses testified at the hearing.[465] Indeed, as described above, SWEPCO modified its proposed gradualism/moderation proposal in rebuttal in a manner that diminishes the importance of the major class groups. The Commission has applied gradualism without reference to major-class groupings in prior cases,[466] and TIEC submits that the evidence in this case does not support the use of that technique here. No party has provided any valid cost-based rationale for saddling only the other classes that have been grouped into a major class with the impact of a subsidy, rather than spreading that impact to all other non-capped classes.

Indeed, depending on the outcome of the BTMG issue, it may be necessary to apply gradualism to mitigate a potentially large impact. As discussed elsewhere in this brief, SWEPCO's initial application proposed a 143% base rate increase for Eastman, and its rebuttal proposal would

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464 This can be seen in Mr. Pollock's workpaper, JP-4 Errata, which shows that three classes were capped at Mr. Pollock's 42.6% gradualism constraint, and that this resulted in the non-capped classes each receiving a rate increase of 100.1% (cell M64). TIEC Ex. 1A, Pollock Dir. Workpapers at WP Exhibit JP-4 Errata, Tab "Distribution of Revenue," rows 47-64, columns O-M & cell M64; *see also* Tr. at 1359:21-1360:5 (Pollock Redirect) (May 25, 2021) (describing this approach to spreading the impact of a subsidy to all remaining classes).

465 Tr. at 1256:2-5 (Jackson Cross) (May 25, 2021); Tr. at 1376:2-5 (Narvaez Cross) (May 26, 2021).

466 *Petition of Houston Lighting and Power Company for Authority to Change Rates*, Docket Nos. 6765 and 6766, Examiners' Report, 1986 WL 379673 at *69 (Sept. 19, 1986) (ordering a gradualism limitation of no less than 0.5 times the system average for certain classes, no greater than 1.5 times the system average for other classes, and equal assignment of the remaining dollars to the remaining classes), adopted by Final Order (Nov. 14, 1986); *see also Application of Texas Utilities Electric Company for Authority to Change Rates and Investigation of the General Counsel into the Accounting Practices of Texas Utilities Electric Company*, Docket No. 11735, PFD, 1993 WL856544 at *144 (Nov. 15, 1993) (ordering a gradualism limitation of no less than 0.5 times the system average and no greater than 1.7 times the system average without using major rate class groupings), *adopted by* Order on Rehearing (Apr. 20, 1994); *Application of Gulf States Utilities Company for a Rate Increase*, Docket No. 5560, Revised Examiner's Report, 1984 WL 274017 at *104 (ordering a gradualism limitation of no less than 0.5 times the system average and no greater than 1.5 times the system average without using major rate class groupings); *Application of Texas Utilities Electric Company for a Rate Increase*, Docket Nos. 5640 and 5661, Examiners' Report, 1984 WL 274024 at *202 (Sept. 21, 1984) (same), *adopted by* Final Order (Oct. 12, 1984); *Application of El Paso Electric Company for Authority to Change Rates*, Docket No. 4620, Examiner's Report, 1983 WL 207505 at *22-23 (Dec. 17, 1982) (same), adopted by Final Order (Jan. 5, 1983).

result in a 121% increase.[467] These impacts clearly call for the use of gradualism to mitigate rate shock. And they are caused by SWEPCO's decision to single out Eastman's BTMG load to be reported to SPP and otherwise accounted for in the rate-setting process. There is no cost-based reason to limit the impact of any gradualism constraint applied to Eastman to the LLP-T class, which was SWEPCO's proposal.[468] In fact, Ms. Jackson acknowledged at the hearing that LLP-T customers already pay for the transmission service that they receive through their demand charges.[469] And ETSWD witness Ms. Pevoto agreed that, just as customers in other classes do not cause costs associated with Eastman's BTMG load, the same is true of LLP-T customers other than Eastman.[470] Further, the record shows that SWEPCO has numerous customers with BTMG load, including in the residential and commercial classes.[471] Thus, there is no valid basis to heap the impact of any subsidy to Eastman on only other LLP-T customers or even to keep that impact within only the Commercial & Industrial major class. Further, spreading such a subsidy over more rate classes reduces its impact.

Until the revenue requirement is known and the various cost allocation issues are decided, it is impossible to say whether gradualism will be necessary in this case. For example, TIEC's position is that SWEPCO's proposal to impute Eastman's BTMG load should be rejected altogether, which would eliminate the above-described rate impacts. At this point in the proceeding, TIEC's request is that the Commission apply the CCOSS and revenue distribution methodologies and principles TIEC recommends in this brief and in Mr. Pollock's testimony. That is, rate schedules should be moved to cost using a CCOSS consistent with TIEC's recommendations, limited only by a gradualism cap of 42.6%, with any resulting subsidy absorbed by non-capped classes in proportion to their base rate increases. The distribution of revenues in

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[467] TIEC Ex. 1, Pollock Dir. at 51; TIEC Ex. 1A, Pollock Dir. Workpapers at WP Eastman Impact TIEC_11-7_Attachment_1.xslx. If the $2.20/kW charge in cell C19 in this spreadsheet is changed to $1.82/kW, the resulting net increase of 143% shown in cell S20 decreases to 121%.

[468] Tr. at 1252:13-19 (Jackson Cross) (May 25, 2021).

[469] *Id.* at 1254:2-10.

[470] Tr. at 1298:2-16 (Pevoto Cross) (May 25, 2021).

[471] TIEC Ex. 2, Pollock Supp. Dir. at JP-S1.

the rate design process should also be based on the CCOSS results, as set out above. TIEC's specific recommendation with respect to revenue distribution for any approved BTMG costs is addressed in Section VII.C, below.

B. Rate Design and Tariff Changes [PO Issues 60, 61, 62]

TIEC addresses three rate design issues pertaining to the LLP rate schedule: (1) the proper allocation of revenues within the schedule, (2) the need for a Renewable Energy Credit (REC) opt-out charge, and (3) SWEPCO's proposed increase to the reactive demand charge.

1. LLP rate design

The revenue requirement allocated to the rates within a rate schedule should be informed by the CCOSS results.[472] As shown in Mr. Pollock's CCOSS results, LLP-T is providing a much higher rate of return than LLP-Primary.[473] Accordingly, to the extent that a rate increase is ordered in this case, LLP-Primary should receive a correspondingly higher increase than LLP-T. For example, at SWEPCO's proposed revenue requirement, LLP-Primary customers should receive a 32% increase, while LLP-T customers should receive a 3.2% increase.[474] Mr. Pollock's methodology for distributing revenues to the CCOSS classes within a rate schedule (such as the LLP-Primary and LLP-T classes within the LLP rate schedule) is described in the previous section.

2. REC Opt-Out Tariff

SWEPCO receives RECs for certain renewable energy purchases and, pursuant to the settlement of a prior fuel reconciliation case, SWEPCO has agreed to impute the value of these RECs and treat them as a base-rate expense.[475] Under 16 T.A.C. § 25.173(j), a transmission-voltage customer who submits an opt-out notice to the Commission is not required to pay any costs

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[472] TIEC Ex. 1, Pollock Dir. at 7.

[473] Specifically, LLP-T is providing a relative rate of return of 207 at present rates, compared to a relative rate of return of 96 for LLP-Primary. TIEC Ex. 1, Pollock Dir. at Exhibit JP-3, page 3-4.

[474] *Id.* at 49.

[475] *Id.*; *Application of Southwestern Electric Power Company for Authority to Reconcile Fuel Costs*, Docket No. 47553, Order at 5-6 (Dec. 20, 2018).

incurred by the utility to acquire RECs. SWEPCO does not currently have a REC opt-out charge, which is a mechanism that refunds the REC costs associated with a customer who has opted out. Accordingly, Mr. Pollock proposed that SWEPCO implement such a mechanism in its case.[476] Mr. Pollock calculated that the REC opt-out charge should be a credit of 0.064 cents per kWh.[477]

In rebuttal, SWEPCO agreed to implement a REC opt-out tariff in the compliance phase of this case.[478] However, SWEPCO calculated a smaller credit than Mr. Pollock.[479] The reason for this is that SWEPCO erroneously used a demand allocator to allocate the REC costs.[480] RECs are energy-related. The Commission's rules define a REC as "[a] tradable instrument ***representing the generation attributes of one MWh of electricity***. . . ."[481] And even SWEPCO calculates the REC credit based on kWh at the meter.[482] SWEPCO has provided no valid basis for a demand-based allocation, and Mr. Pollock's calculation of the REC charge credit should be adopted.

3. Reactive Demand Charge

SWEPCO proposes to increase the LLP reactive demand charge by 29.4%.[483] As pointed out by Mr. Pollock, however, SWEPCO did not provide any support whatsoever for this increase in its application.[484] Accordingly, he recommended that no increase to the reactive demand charge be approved unless SWEPCO provided a study justifying the cost-based need for such an increase.[485] In rebuttal, SWEPCO acknowledged that it has not performed a reactive demand study, but argued that it was sufficient for the reactive demand charge to be encompassed in the

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476 TIEC Ex. 1, Pollock Dir. at 49-50.

477 *Id.*

478 SWEPCO Ex. 55, Jackson Rebuttal at 15.

479 *Id* at Exhibit JLJ-2R.

480 *Id*

481 16 T.A.C. § 25.5(107) (emphasis added).

482 SWEPCO Ex. 55, Jackson Reb. at 15.

483 TIEC Ex. 1, Pollock Dir. at 48.

484 *Id.* at 49.

485 *Id*

CCOSS.[486] However, the CCOSS does not demonstrate that SWEPCO's costs relating to reactive demand have increased at all, much less by nearly 30%. Accordingly, there remains no cost basis for the proposed increase to the reactive demand charge, and it should be rejected.

C. Transmission Rate for retail behind-the-meter generation

- **Background**

SWEPCO's proposed Synchronous Self-Generation Load Charge (SSGL) should be rejected. SWEPCO's initial proposal was a $2.20 per CP kW charge that would apply only to retail customers (1) with BTMG that is synchronized to the SPP grid, (2) whose load is included in SWEPCO's SPP load ratio share (i.e., that is reported to SPP by SWEPCO), and (3) take service under SWEPCO's standby rate schedules.[487] The charge would be based on each such customer's contract demand for Backup, Maintenance, and As-Available standby service.[488] SWEPCO derived the charge based on 50% of its all-in Texas retail transmission revenue requirement for commercial and industrial customers on a per-unit basis.[489]

The proposed SSGL charge would apply only to Eastman, and SWEPCO assumed a 150 MW contract demand for that customer.[490] Accordingly, the charge would recover $3.96 million from Eastman annually.[491] The implementation of this charge would, in combination with SWEPCO's other proposals, increase Eastman base revenues by 143%.[492] While that is certainly a jaw-dropping number, it is worth noting that SWEPCO's proposal to impute Eastman's BTMG load into the LLP-T class increases the allocation of transmission costs to that class by $8

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[486] SWEPCO Ex. 55, Jackson Reb. at 14-15.

[487] *Id* at 51. Specifically, the SSGL charge was included on the Specialty Standby, Maintenance, Backup, and As-Available Standby (SSMBAA) schedule. SWEPCO Ex. 55, Jackson Reb. at 13; SWEPCO Ex. 32, Jackson Dir., Exhibit JLJ-2 at 2 of 3 (schedules IV-44,45).

[488] TIEC Ex. 1, Pollock Dir. at 51.

[489] *Id.*

[490] *Id.*

[491] TIEC Ex. 77.

[492] *Id.*

million.[493] Thus, SWEPCO's proposal would leave over $4 million in increased costs purportedly caused by Eastman's BTMG to be paid by non-Eastman LLP-T customers—customers who have nothing to do with Eastman's BTMG load or SWEPCO's decision to report it to SPP.[494]

In rebuttal, SWEPCO modified its proposal. Recognizing parties' criticisms of its original proposal, SWEPCO stated that it had developed a BTMG rate that "could apply to any BTMG customer load appropriately included in SWEPCO's transmission load ratio share."[495] Unlike the original SSGL charge, which was based on SWEPCO's transmission revenue requirement for commercial and industrial customers, the rebuttal SSGL charge was derived using the total SWEPCO retail transmission cost.[496] The rate design for the rebuttal charge was entered into the record at the hearing, and it indicates that the charge would be $1.82 per CP kW.[497] The charge would still apply only to Eastman (because Eastman is the only customer whose BTMG load SWEPCO has included in its Monthly Network Load reports),[498] and would recover $3.27 million annually.[499] Thus, this rebuttal charge would still impose a massive increase on Eastman (121%[500]), and leave well over $4 million of the costs allocated to LLP-T as a result of the BTMG load to be recovered by non-Eastman LLP-T customers.

At the hearing SWEPCO witness Ms. Jackson provided further clarification regarding SWEPCO's rebuttal SSGL proposal. Specifically, she testified that, if this rebuttal framework is

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[493] TIEC Ex. 74; Tr. at 1251:13-1252:19 (Jackson Cross) (May 25, 2021)

[494] Tr. at 1254:2-6 (Jackson Cross) (May 25, 2021).

[495] SWEPCO Ex. 55, Jackson Reb. at 14.

[496] *Id*

[497] TIEC Ex. 78 at Bates 002.

[498] Tr. at 1522:21-1523:2 (Jackson Cross) (May 26, 2021).

[499] Tr. at 1504:22-1505:1 (Jackson Cross) (May 26, 2021)

[500] TIEC Ex. 1A, Pollock Dir. Workpapers at WP Eastman Impact TIEC_11-7_Attachment_1.xslx. If the $2.20/kW charge in cell C19 in this spreadsheet is changed to $1.82/kW, the resulting net increase of 143% shown in cell S20 decreases to 121%.

adopted, it would be appropriate for SSGL to be made its own rate schedule, as Mr. Pollock proposed. Ms. Jackson testified as follows:

> Q Ms. Jackson, were you about to clarify what your rebuttal proposal is?
>
> A I can.
>
> Q With respect to the question as to whether it would be a rate -- the SSGL would be its own rate schedule?
>
> A Right. Based on your line of questioning, it would be appropriate to move it to its own separate rate schedule, given that we are creating a rate that would apply to more than just the LP and LLP classes.[501]

In fact, Ms. Jackson testified that, if the rebuttal version of the SSGL charge is adopted, "we would probably have to put it on a separate tariff sheet."[502]

- **TIEC's Recommended SSGL Charge**

As an initial matter, no SSGL charge (or other rate purporting to charge retail BTMG customers for network transmission service) should be approved in this case because it is not appropriate for SWEPCO to include retail BTMG load in its Monthly Network Load reports to SPP for all of the reasons set out in Section IV.A.6 above.[503] As Mr. Pollock testified, "it is inappropriate to charge retail BTMG load for transmission services that SWEPCO is not providing."[504] To the extent that the Commission nevertheless approves a SSGL rate in this case, it should design that rate as follows.

First, the rate should be provided on a separate rate schedule (not the standby schedule), and it should be applicable to all retail BTMG loads (not just Eastman).[505] SSGL, if approved,

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501 Tr. at 1508:19-1509:3 (Jackson Re-cross) (May 26, 2021).

502 Tr. at 1503:12-13 (Jackson Cross) (May 26, 2025).

503 *See* Section IV.A.6.

504 TIEC Ex. 1, Pollock Dir. at 52.

505 *Id.* at 54.

would not be a standby service; it would apply year round to all retail BTMG load irrespective of whether the customer at issue ever took Backup, Maintenance, or As-Available standby power.[506] Additionally, Eastman is not SWEPCO's only retail customer with BTMG load. In fact, SWEPCO has nearly 200 customers (from multiple classes) that supply at least a portion of their load with BTMG.[507] Accordingly, the SSGL charge should be structured to apply to all loads served by BTMG.[508] SWEPCO's rebuttal proposal recognizes these principles, as it has designed a rate that could apply to all BTMG loads that are included in its load ratio share. And, as noted, SWEPCO witness Ms. Jackson confirmed that it would be appropriate for the SSGL charge to constitute its own rate schedule.[509]

Second, in conjunction with Mr. Pollock's recommendation that a separate customer class should be created for all retail BTMG load customers, the rate should be designed to recover the costs associated serving those customers, subject to moderation.[510] This is consistent with SWEPCO's rebuttal revenue distribution proposal generally, which Ms. Jackson clarified is to move rate schedules to cost, subject to gradualism.[511] The amount by which SWEPCO's transmission costs increased as a result of its decision to include BTMG load in its reports to SPP has not been quantified in this case.[512] Accordingly, SWEPCO has failed to meet its burden of proving that any of its customers should pay a charge to recover those costs. In any event, however, the amount of costs allocated to the new BTMG-load customer class should not exceed $5.7 million, which is the amount by which SWEPCO itself states that costs to the Texas retail

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[506] *Id.* at 53.

[507] TIEC Ex. 2, Pollock Supp. Dir. at JP-S1.

[508] As a practical matter, the rate would still only apply to Eastman for the time being, as Eastman is the only retail customer whose BTMG load SWEPCO has included in its Monthly Network Load reports to SPP. Tr. at 1359:3-11 (Pollock Dir.) (May 25, 2021).

[509] Tr. at 1508:19-1509:3 (Jackson Re-cross) (May 26, 2021).

[510] TIEC Ex. 1, Pollock Dir. at 39; Tr. at 1359:3-1360:5 (Pollock Redirect) (May 25, 2021).

[511] Tr. at 1505:20-23 (Jackson Cross) (May 26, 2021).

[512] *See* Section VI above.

jurisdiction increased by virtue of imputing Eastman's BTMG load.[513] There is no cost-based reason for allocating more than this amount to BTMG-load customers or any other Texas retail customers.

With respect to moderation, the Commission should adopt Mr. Pollock's proposal to phase in the charge at 50%, which would result in the rate being designed to recover $2.85 million at SWEPCO's quantification of a $5.7 million BTMG impact.[514] As noted, the base rate increase for Eastman at SWEPCO's originally proposed SSGL charge of $3.96 million would have been over 140%, and the increase at the rebuttal charge would be 121%. Designing the rate to recover $5.7 million would result in an increase of nearly 200% for Eastman.[515] Moderation is therefore necessary given the potential for rate shock to Eastman. Further, the fact that the SSGL charge is entirely new, and would be designed to recover costs that have not been reliably quantified, counsels in favor of moderation. The remaining amounts not assigned to the SSGL rate schedule should be spread to the remaining (non-capped) customer classes in proportion to those classes' respective rate increases, as discussed above in Section VII.A of this brief.[516] As Mr. Pollock testified, this is consistent with how gradualism is handled in rate cases.[517] Further, given that SWEPCO's rebuttal SSGL charge would apply to qualifying BTMG customers in all customer classes, it is appropriate to spread the subsidy to all classes, [518] which also has the effect of reducing its impact to any particular subsidizing class. In any event, there is no basis in cost causation or equity to simply dump on to the other LLP-T customers any costs caused by SWEPCO's decision to impute Eastman's BTMG load that are not paid by Eastman itself.

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[513] TIEC Ex. 1, Pollock Dir. at 25. As discussed in Section VI above, this does not reflect the actual impact of reporting Eastman's load to SPP. *Id.*

[514] *Id.* at 53.

[515] TIEC Ex. 1A, Pollock Dir. Workpapers at WP Eastman Impact TIEC_11-7_Attachment_1.xlsx. If the $3.96 million recovered under the SSGL in cell R19 in this spreadsheet is changed to $5.7 million, the resulting net increase of 143% shown in cell S20 increases to 199%.

[516] Tr. at 1359:21-1360:5 (Pollock Redirect) (May 25, 2021).

[517] *Id*

[518] Tr. at 1362:12-19 (Pollock Clarifying) (May 25, 2021).

Third, the SSGL charge should not be based on contract demand because the BTMG load that SWEPCO is reporting to SPP is used to determine load ratio shares, and the load ratio shares are based on demands occurring coincident with the monthly SPP Zone 1 peaks.[519] Instead, the billing unit for the charge should be based on each customer's demand coincident with the SPP Zone 1 monthly peak, and the terms and conditions of the new rate schedule should require SWEPCO to advise customers of when a monthly system peak is likely to occur so that BTMG customers can better manage their loads and minimize their use of the transmission network.[520]

XI. Conclusion

TIEC respectfully requests that the Commission adopt the recommendations set forth above. TIEC also requests all other relief to which it is entitled.

Respectfully submitted,

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[519] TIEC Ex. 1, Pollock Dir. at 53-54.

[520] *Id.* at 54.

CERTIFICATE OF SERVICE

I, Benjamin B. Hallmark, Attorney for TIEC, hereby certify that a copy of the foregoing document was served on all parties of record in this proceeding on this 17th day of June 2021 by hand-delivery, facsimile, electronic mail and/or First Class, U.S. Mail, Postage Prepaid.

/s/ Benjamin B. Hallmark
Benjamin B. Hallmark