Filing Receipt

Received - 2021-10-22 02:08:37 PM
Control Number - 52195
ItemNumber - 284

SOAH NO. 473-21-2606
PUC DOCKET NO. 52195

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

DIRECT TESTIMONY

OF

KEVIN C. HIGGINS

FOR

TEXAS INDUSTRIAL ENERGY CONSUMERS

October 22, 2021

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kevin C. Higgins. My business address is 111 East Broadway, Suite 1200, Salt Lake City, Utah, 84111.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. My testimony is being sponsored by Texas Industrial Energy Consumers ("TIEC").

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND QUALIFICATIONS.

A. My academic background is in economics, and I have completed all coursework and field examinations toward a Ph.D. in Economics at the University of Utah. Previously I was awarded a B.S. in Education at the State University of New York at Plattsburgh. Subsequent to my graduate coursework, I served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was an economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE ANY STATE UTILITY REGULATORY COMMISSIONS?

A. Yes. I have filed testimony and/or testified at hearings in approximately 270 proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arizona, Arkansas, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Texas, Utah, Virginia, Washington, West Virginia, and Wyoming. I have also filed affidavits in proceedings at the Federal Energy Regulatory Commission.

II. OVERVIEW AND CONCLUSIONS

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony addresses both revenue requirement and cost allocation/rate design issues. I recommend adjusting the revenue requirement proposed by El Paso Electric Company ("EPE" or the "Company") for several specific items. I did not, however, undertake a full review of EPE's revenue case. I also address a jurisdictional allocation issue concerning EPE's proposed treatment of directly assigned solar plants.

My testimony also addresses the distribution of any increase or decrease among rate schedules, or revenue allocation.

The absence of comment on my part regarding a particular issue does not signify support for EPE's filing with respect to that issue.

Q. WHAT REVENUE INCREASE IS EPE RECOMMENDING FOR THE TEXAS JURISDICTION?

A. In its direct filing, EPE proposes an increase of $69.7 million in Texas base (non-fuel) revenues. This increase is offset by $27.9 million in combined Transmission Cost Recovery Factor and Distribution Cost Recovery Factor revenues that are being reset to zero in this case, for a net base increase of $41.8 million, which is an average increase of 7.79% over current non-fuel revenue.[1] This $41.8 million increase is comprised of an increase of $39.3 million to base firm revenue, an increase of $324 thousand to interruptible base revenue, and $2.2 million recovered annually through a proposed COVID rider for 3 years. In addition, EPE proposes a $721 thousand decrease to Miscellaneous Service Charges, for a net increase of $41.1 million.[2] EPE's request is based on its proposed overall return of 7.985%, incorporating a return on equity of 10.30%.[3] TIEC witness Michael Gorman is addressing the return-on-equity issue.

Q. PLEASE SUMMARIZE THE REVENUE REQUIREMENT ADJUSTMENTS YOU ARE RECOMMENDING.

A. In total, my recommended revenue requirement adjustments reduce EPE's Texas base revenue requirement deficiency by **$2,387,267** relative to EPE's direct filing. My revenue requirement adjustments are presented in Table KCH-1 below.

Table KCH-1
Summary of Texas Revenue Requirement Adjustments

Description	Texas Revenue Requirement Amount
SERP Adjustment	($875,549)
Excess Benefit Adjustment	($794,125)
Palo Verde Incentive Compensation	($128,494)
Revolving Credit Facilities Commitment Fees Adjustment	($468,164)
Accumulated Depreciation - Annualization Adjustment	($120,935)
Total Adjustments	($2,387,267)

As noted, I also address a jurisdictional allocation issue concerning the direct assignment of solar plants. I will explain the basis for each of these adjustments in the following sections.

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[1] Direct Testimony of James Schichtl at 3 (Schichtl Dir.).

[2] Derived from Schedule Q-07.00.

[3] *See* Schedule K-01.00.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS CONCERNING EPE'S PRODUCTION COST ALLOCATION.

A. As a general proposition, I support EPE's use of the Average and Excess Four Coincident Peak ("A&E/4CP") method to allocate most of its production plant. However, I disagree with certain aspects of the Company's production cost allocation and recommend several changes to EPE's proposed approach. The primary changes I recommend to EPE's production cost allocation are:

- The capacity attributed to directly-assigned solar plants in EPE's jurisdictional allocation should be adjusted to be consistent with EPE's solar purchased power agreement ("PPA") capacity imputation. EPE removed the generation from solar plants it directly assigns to New Mexico and Texas from each state's respective 4CP demand, which is used in the jurisdictional 4CP allocator applied to peaking units and the jurisdictional A&E/4CP allocator. This reduces the 4CP for New Mexico by approximately 68% of its directly-assigned solar capacity and the 4CP for Texas by approximately 70% of its directly-assigned solar capacity. I recommend basing the reduction to each state's 4CP demand on the energy production output from these solar resources (i.e., annual capacity factors). This is consistent with the approach EPE uses for imputing capacity costs to the Newman 10 and Macho Springs PPAs.

  In the alternative, I recommend that the capacity value imputed to the Newman 10 and Macho Springs PPAs be increased to be consistent with the approach EPE uses to attribute capacity to the directly-assigned solar resources, with a corresponding reduction to EPE's eligible fuel cost.

- The load factor used for weighting average demand in the A&E/4CP allocator calculation should be based on single highest actual firm system coincident peak for EPE's system (1CP). EPE's proposal to calculate the load factor using the average of the adjusted 4CPs should be rejected.

- The A&E/4CP allocation method should be applied to all allocable production plant, including EPE's peaking units (Montana Power Station Units 1-4, Rio Grande Generating Station Unit 9, and Copper Generating Station), rather than adopting EPE's proposal to change to the 4CP method for these units.[4]

- Palo Verde Operations & Maintenance ("O&M") expenses (FERC Accounts 519, 520, 523, 530, 531, and 532) should be allocated using the A&E/4CP allocator rather than EPE's proposed energy allocator.

[4] Direct Testimony of Adrian Hernandez at 11 (Hernandez Dir.).

- Generation System Control and Load Dispatching (FERC Account 556) should be allocated using the A&E/4CP allocator, consistent with EPE's allocation of most generation plant.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS CONCERNING EPE'S TRANSMISSION COST ALLOCATION.

A. I generally support EPE's use of the 4CP method to allocate transmission plant and most transmission expenses. However, I recommend two changes to EPE's transmission cost allocation approach:

- Transmission Load Dispatching (FERC Account 561) should be allocated using the 4CP method, consistent with all other transmission costs, rather than EPE's 12CP allocator.

- Customers that receive service at 115 kV voltage should not be allocated costs associated with EPE's 69 kV transmission system, since, as a general matter, 115 kV customers do not utilize the 69 kV system.

Q. DO YOU RECOMMEND ANY CHANGES TO EPE'S ALLOCATION OF MISCELLANEOUS EXPENSES?

A. Yes, I recommend that Contributions and Donations expense be allocated based on customer count, because it is appropriate to allocate these costs in a manner that reflects the broad community benefit of these gifts.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS CONCERNING THE ALLOCATION OF ANY INCREASE OR DECREASE.

A. I recommend moving all rate classes to full cost recovery. Moving each class to full cost recovery eliminates inter-class subsidies and is consistent with the Commission's strong preference for aligning class revenues with costs.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS CONCERNING RATE DESIGN.

A. I recommend that the applicability provision in Rate 25 be modified to remove the language that prohibits customers eligible for other rate schedules from taking service under this rate schedule. The choice of the appropriate rate schedule should be the customer's, not EPE's. If a customer meets the eligibility requirements for a rate schedule, that customer should be able to receive service under that schedule.

III. REVENUE REQUIREMENT

Supplemental Executive Retirement Plan and Excess Benefit Plan

Q. WHAT IS A SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN/EXCESS BENEFIT PLAN?

A. Supplemental executive retirement plans ("SERP") and excess benefit plans are also known as non-qualified retirement plans. Such plans provide benefits in excess of the earnings limitations set in Section 415 of the Internal Revenue Code, and therefore lack the tax advantages conferred upon qualified pension plans. For 2021, for qualified plans, the Internal Revenue Code limits the maximum annual benefit that can be paid through a defined benefit plan to $230,000 per year and limits the compensation that can be included in determining benefits to $290,000.[5] In contrast, there is no statutory restriction on the amount of the benefit that may be offered under a non-qualified pension plan. Typically, non-qualified plans are intended to benefit a select group of highly-compensated employees.

Q. PLEASE DESCRIBE EPE'S NON-QUALIFIED RETIREMENT PLANS.

A. EPE has two non-qualified retirement income plans: (i) its SERP and (ii) its Excess Benefit Plan. EPE closed its SERP to new participants in 1996 in conjunction with its emergence from bankruptcy. However, the plan covers 17 former officers and 9 former employees who were grandfathered on the plan.[6]

The Excess Benefit Plan was adopted in 2004, and covers 13 current officers and 19 former officers.[7] According to EPE's most recent 10-K, the Excess Benefit Plan is offered to employees holding the office of Vice President and above, as well as "a select group of management or highly compensated employees."[8]

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[5] The limitations are summarized here: irs.gov/retirement-plans/cola-increases-for-dollar-limitations-on-benefits-and-contributions.

[6] Schedule G-2 at 2-3; Direct Testimony of Cynthia S. Prieto at 10-11 (Prieto Dir.); EPE's response to RFI TIEC 2-1.

[7] Schedule G-2 at 2-3; Prieto Dir. at 10-11; EPE's response to RFI TIEC 2-1.

[8] El Paso Electric Company Form 2019 10-K/A, Amendment No. 1, p. 24.

Q. WHAT RATEMAKING TREATMENT HAS EPE PROPOSED REGARDING ITS SERP AND EXCESS BENEFIT PLAN?

A. EPE is proposing to include the cost of its SERP and Excess Benefit Plan in its proposed revenue requirement.

Q. DO YOU AGREE WITH EPE'S PROPOSAL TO INCLUDE THE COST OF ITS SERP AND EXCESS BENEFIT PLAN IN RATES?

A. No, I do not. Customers should not be forced to fund the extraordinary retirement benefits reflected in non-qualified retirement plans. I do not see the provision of a non-qualified retirement income plan to be essential for the provision of electricity service to customers, but rather a discretionary benefit. The cost of these exceptional retirement benefits granted to a select group of highly-compensated employees and officers should be borne by shareholders, not customers. These costs should be excluded from the revenue requirement.

This recommendation is consistent with Commission precedent that non-qualified executive retirement benefits are not reasonable or necessary to provide utility service to the public, not in the public interest, and should not be included in cost of service.[9]

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION ON THIS ISSUE?

A. I recommend that the Company's SERP and Excess Benefit Plan expenses be removed from the revenue requirement. The adjustment to remove SERP expenses reduces the Texas revenue requirement by approximately **$875,549** and is presented in Exhibit KCH-1, while the adjustment to remove Excess Benefit Plan expenses reduces the Texas revenue requirement by approximately **$794,125** and is presented in Exhibit KCH-2.

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[9] *Application of Entergy Texas, Inc. for Authority to Change Rates, Reconcile Fuel Costs, and Obtain Deferred Accounting Treatment*, Docket No. 39896, Order at Finding of Fact 142 (Sept. 14, 2012); *see also Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 51415, Proposal for Decision, at 335 (Aug. 27, 2021) (where the ALJs acknowledge that SWEPCO removed the SERP expense that comes from pension benefits that exceed the compensation limit for qualified pension plans from its requested cost of service "based on the Commission's precedents in Docket Nos. 40443 and 46449.").

Palo Verde Incentive Compensation

Q. PLEASE DESCRIBE EPE'S OWNERSHIP INTEREST IN PALO VERDE NUCLEAR GENERATING STATION ("PVNGS").

A. PVNGS, the largest nuclear power station in the U.S., consists of three identical units with an electric design rating totaling 4,003 MW. EPE owns a 15.8% share of each of the three units and the common facilities and receives an allocation of approximately 633 MW when at full power.[10] PVNGS is jointly owned by seven southwestern utilities and operated by Arizona Public Service Company ("APS") under a Participation Agreement. The PVNGS capital and O&M budgets are reviewed and approved by the joint owners.[11]

Q. WHAT ADJUSTMENT DO YOU RECOMMEND FOR PALO VERDE INCENTIVE COMPENSATION?

A. My adjustment removes the incentive compensation included in the Test Year for PVNGS employees that is associated with APS's Company Earnings. EPE excludes incentive compensation for its own employees that is explicitly tied to financial performance from its requested cost of service,[12] but does not make the corresponding adjustment for financially-based incentive compensation for PVNGS employees.[13] It is appropriate to consistently apply this approach to financially-based incentive compensation allocated to EPE for PVNGS employees.

The Commission has found that the benefits of financially-based incentive compensation "inure most immediately and predominantly to…shareholders, rather than electric customers."[14] In the case of PVNGS incentive compensation tied to Company Earnings, it is APS's shareholders who are the primary beneficiaries, not EPE's ratepayers.

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[10] Direct Testimony of Todd Horton at 2-3, 6 (Horton Dir.).

[11] *Id.* at 10, 32-33.

[12] Prieto Dir. at 7.

[13] EPE response to RFI CEP 10-17.

[14] *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 40443, Order on Rehearing at Finding of Fact No. 147 (Mar. 6, 2014).

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION ON THIS ISSUE?

A. I recommend that the PVNGS incentive compensation expense associated with APS Company Earnings be removed from the revenue requirement.[15] This adjustment reduces the Texas revenue requirement by approximately **$128,494** and is presented in Exhibit KCH-3.

Revolving Credit Facility Commitment Fees

Q. WHAT IS EPE PROPOSING REGARDING ITS REVOLVING CREDIT FACILITY ("RCF") FEES?

A. EPE maintains a $400 million RCF to fund nuclear fuel purchases, working capital requirements, and general corporate purposes.[16] Since nuclear fuel costs are recovered in the Fixed Fuel Factor, EPE does not seek to include associated commitment fees in its non-fuel revenue requirement. EPE proposes to include $571,211 in Total Company RCF commitment fees in its revenue requirement, which the Company asserts is the portion of commitment fees associated with non-nuclear fuel purposes.[17]

EPE is charged a commitment fee of 0.175% on the unused amount of the commitment.[18] EPE's RCF commitment fees thus represent a cost associated with EPE's use of short-term debt to finance its operations. EPE calculates its proposed RCF commitment fee by subtracting the highest level of borrowing for nuclear fuel during the Test Year from its $400 million RCF, and multiplying the difference by 0.175%.

Q. YOU MENTIONED THAT THE RCF COMMITMENT FEES ARE ASSOCIATED WITH EPE'S USE OF SHORT-TERM DEBT. DOES EPE PROPOSE TO INCLUDE SHORT-TERM DEBT IN ITS CAPITAL STRUCTURE FOR RATEMAKING PURPOSES?

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[15] EPE provided data on the PVNGS incentive compensation in its response to RFI CEP 10-16.

[16] Direct Testimony of Lisa D. Budtke at 16-19 (Budtke Dir.).

[17] *Id.* at 19.

[18] *Id.* at 17.

A. No. EPE's proposed capital structure that is used to determine the weighted average cost of capital does not include short-term debt, which has a lower interest rate than long-term debt. The weighted average interest rate on EPE's RCF notes payable outstanding as of December 31, 2020 was approximately 1.41%,[19] whereas EPE's proposed cost of long-term debt is 5.576%. EPE's proposed return on equity is 10.30%.[20] Thus, while EPE actually uses short-term debt as a source of capital, it proposes that its cost of capital be set as if it only used long-term debt and equity to finance its operations, both of which are far more expensive to ratepayers than short-term debt.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING THE INCLUSION OF RCF COMMITMENT FEES IN RATES?

A. I recommend that the RCF commitment fees not be included in EPE's revenue requirement. Since customers are not afforded the benefit of EPE's use of lower-cost short-term debt financing in the capital structure used for ratemaking, it is not appropriate for customers to fund the RCF commitment fees. Stated differently, if EPE's use of short-term debt is ignored for purposes of setting a ratemaking capital structure, it would not be appropriate to turn around and charge ratepayers for fees associated with that short-term debt. Accordingly, I recommend that the Company's RCF commitment fees be removed from the revenue requirement. This adjustment reduces the Texas revenue requirement by approximately **$468,164** and is presented in Exhibit KCH-4.

<u>**Accumulated Depreciation – Annualization Adjustment**</u>

Q. PLEASE EXPLAIN YOUR ANNUALIZATION ADJUSTMENT TO ACCUMULATED DEPRECIATION.

A. EPE makes annualization adjustments to depreciation expense for new plant added during the Test Year.[21] That is, the Company adjusts depreciation expense to reflect the forward-

[19] Derived from Schedule K-04.00_PUBLIC. Based on annual interest rates of 3.5% applicable to the RCF ABR Loan and 1.36% applied to the RCF Eurodollar loans.

[20] Schedule K-01.00.

[21] Direct Testimony of Larry J. Hancock at 33 (Hancock Dir.).

going depreciation expense associated with new investments rather than using the depreciation expense actually booked during the Test Year ended December 31, 2020.

In making its annualization adjustments for depreciation, EPE does not make a corresponding annualization adjustment for accumulated depreciation.[22] That is, the adjusted depreciation expense that EPE proposes to recover is not accompanied by an annualized increase in accumulated depreciation to be offset against rate base. The absence of such a corresponding adjustment produces a mismatch for ratemaking purposes. EPE's approach is asymmetric. It provides the Company with the revenue benefit of the annualized depreciation expense without recognizing any corresponding reduction in the rate base against which the new plant is being depreciated. My adjustment corrects this mismatch by increasing accumulated depreciation for ratemaking purposes by the amount of the incremental depreciation expense added in EPE's annualization adjustment. This approach represents the increase in accumulated depreciation that corresponds to EPE's annualized depreciation expense adjustment.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION ON THIS ISSUE?

A. I recommend that the Commission adopt my annualization adjustment for accumulated depreciation to be consistent with the matching principle in ratemaking. My recommendation reflects a higher level of accumulated depreciation as an attendant impact of EPE's proposed depreciation expense annualization adjustment. This adjustment reduces the Texas revenue requirement by approximately **$120,935** at EPE's requested rate of return and is presented in Exhibit KCH-5.

[22] EPE's response to RFI TIEC 4-4 b.

IV. JURISDICTIONAL COST ALLOCATION

Summary of EPE's Methods

Q. PLEASE SUMMARIZE THE METHODS USED BY EPE TO ALLOCATE PRODUCTION COSTS TO THE TEXAS JURISDICTION.

A. As explained in the Direct Testimony of Adrian Hernandez, EPE utilizes the A&E/4CP method to allocate its non-peaking production demand costs to the state of Texas. This method uses EPE's adjusted system coincident peaks during the summer months of June through September.[23] In this case, EPE calculated the load factor used to weight each jurisdiction's proportion of the system average firm demand (or energy) using the average of the adjusted firm <u>4CP</u> demands, rather than the actual highest coincident firm peak (1CP) demand.[24]

Next, each jurisdiction's "excess" firm demand is weighted by 1 minus the load factor, where excess demand represents the difference between each jurisdiction's proportion of system 4CP demand and average demand. EPE has made adjustments to both the 4CP demand and energy components that are intended to remove the output of solar facilities directly assigned to the Texas and New Mexico jurisdictions from the jurisdictional allocation of costs.

In this case, EPE proposes to change the method used to allocate the cost of its peaking units (Montana Power Station Units 1-4, Rio Grande Generating Station Unit 9, and Copper Generating Station) from the A&E/4CP method to the 4CP method. [25]

EPE allocates production O&M expenses using a combination of A&E/4CP, 4CP, energy, direct assignment, and uses an A&E/12CP allocator for Generation System Control and Load Dispatching (Account 556).[26]

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[23] Hernandez Dir. at 9.

[24] Direct Testimony of George Novela at 8-9 (Novela Dir.). *See also* EPE's response to RFI CEP 4-6, CEP 04-06_Attachment_02 VOLUMINOUS.

[25] Hernandez Dir. at 11.

[26] *Id.* at 13. *See also* EPE Regulatory Case Working Model - As Filed - Dkt 52195.

Q. PLEASE SUMMARIZE THE METHODS USED BY EPE TO ALLOCATE TRANSMISSION, DISTRIBUTION, AND OTHER COSTS TO THE TEXAS JURISDICTION.

To allocate transmission plant costs to the state of Texas, EPE utilizes a 4CP demand method, based on each jurisdiction's proportion of system firm coincident peak demand for the months June through September.[27]

EPE directly assigns distribution plant between Texas and New Mexico based on geographical location and allocates general plant using a labor allocator based on payroll costs for the production, transmission, distribution and customer service functions.[28]

EPE allocates most transmission O&M expenses using the 4CP allocator, but uses a 12CP method to allocate Transmission Load Dispatching costs (Account 561).[29] Distribution O&M expenses are allocated based on the jurisdictional distribution plant or a composite allocator. Texas customer O&M expenses are determined based on a combination of direct assignment, composite allocators, and customer-based allocators. Uncollectible accounts are allocated based on firm revenues excluding Other Public Authority and Large Commercial & Industrial classes.[30]

Many Administrative and General ("A&G") expenses are allocated using a labor allocator. Some A&G expenses are allocated consistent with their associated function, while others are directly assigned.[31] Depreciation and amortization expense is allocated consistent with the underlying plant.[32]

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[27] Hernandez Dir. at 11.

[28] *Id.*

[29] *Id.* at 14.

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

[31] *Id.*

[32] *Id.* at 16.

Solar Plant Capacity Attribution

Q. HOW DOES EPE TREAT THE OUTPUT FROM THE SOLAR PLANTS DIRECTLY ASSIGNED TO NEW MEXICO AND TEXAS IN THE JURISDICTIONAL COST ALLOCATION PROCESS?

A. For jurisdictional cost allocation, EPE removes the generation from the directly-assigned solar plants from each state's load used in the A&E/4CP allocator, its proposed 4CP generation allocator for peaking units, and its energy allocators. EPE's bases its 4CP adjustment on the output of a subset of the directly-assigned solar plants during the summer monthly peak hours.[33] EPE's adjustment reduces the 4CP for New Mexico by approximately 68% of its directly-assigned solar capacity and the 4CP for Texas by approximately 70% of its directly-assigned solar capacity.[34] This adjustment reduces New Mexico's 4CP demand by approximately 35.5 MW and reduces Texas's 4CP demand by approximately 120 kW. The combined effect of these reductions is to allocate more costs to Texas ratepayers.[35]

Q. IS THE COMPANY'S APPROACH CONSISTENT WITH THE METHOD IT USES TO IMPUTE CAPACITY COSTS TO THE NEWMAN 10 AND MACHO SPRINGS SOLAR RESOURCES?

A. No. As explained in the Direct Testimony of David C. Hawkins, EPE's imputed capacity rates for the Newman 10 and Macho Springs PPAs are $2.33/kW-month and $2.35/kW-month, respectively.[36] These rates were calculated by EPE in its last general rate case, Docket No. 46831, based on the energy production output percentages (i.e., annual capacity

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[33] *See* EPE's response to RFI CEP 4-07, CEP 04-07_Attachment_01. EPE's adjustment is based on the weighted average capacity factors of the NRG, Hatch, and Sun Edison 1&2 plants during the hour of the monthly CP each day of June – September 2020.

[34] Derived from EPE's response to RFI CEP 4-06, CEP 4-06_Attachment_02. This includes the impact of the loss factor gross-up EPE applies to solar output.

[35] Includes Holloman in the New Mexico 4CP impacts.

[36] Direct Testimony of David C. Hawkins at 8-9 (Hawkins Dir.).

factors) for Newman 10 and Macho Springs, of 32.3% and 32.6%, respectively.[37] This is approximately half the solar plant capacity level EPE uses in its jurisdictional allocation.[38]

To calculate the Newman 10 and Macho Springs imputed capacity rates, EPE started with the WSPP (formerly known as Western Systems Power Pool) Agreement capacity rate of $7.32/kW-month. EPE then discounted this rate for the additional ancillary services attributable to an intermittent resource to arrive at an adjusted rate of $7.20/kW-month. To this rate, EPE applied the energy production output percentages for Newman 10 and Macho Springs, resulting in the imputed capacity rates of $2.33/kW-month and $2.35/kW-month, respectively.[39]

The imputed capacity portion of the Newman 10 and Macho Springs PPA costs is allocated using the A&E/4CP method and included in the base revenue requirement. The remaining Texas-allocated portion of the PPA costs is deemed to be energy-related and included in the Fixed Fuel Factor.

Q. WHAT IS YOUR RECOMMENDATION ON THIS ISSUE?

A. I recommend reducing the adjustment to each jurisdiction's 4CP demands used for jurisdictional allocation purposes to be consistent with the Test Year energy production output (i.e., annual capacity factor) for the state-assigned solar plants. This is consistent with the approach used by EPE to impute capacity costs to the Newman 10 and Macho Springs solar resources. This change decreases the reduction to New Mexico's 4CP demand to 15.6 MW and to Texas's 4CP demand to 28 kW to reflect solar plant capacity. An illustration of the resulting jurisdictional A&E/4CP allocator is presented in Exhibit KCH-6.

In the alternative, I recommend that the capacity value imputed to the Newman 10 and Macho Springs resources be increased to be consistent with the approach EPE uses to

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[37] EPE's response to RFI FMI 1-5. These capacity factors are based on the Docket No. 46831 Test Year ended September 30, 2016.

[38] Based on RFI CEP 4-07, CEP 04-07_Attachment_01, the weighted average summer peak capacity factors for NRG, Hatch, and Sun Edison 1&2 average approximately 65%.

[39] EPE's response to RFI FMI 1-5.

attribute capacity to the directly-assigned solar resources in its jurisdictional cost allocation. Based on the Test Year output of these plants at the monthly summer peak times, Newman 10 operated at an average of 73.3% of its capacity and Macho Springs at 66.2% of its capacity.[40] This would correspond to a capacity value of approximately $5.28/kW-month for Newman 10 and $4.76/kW-month for Macho Springs using the adjusted WSPP capacity rate of $7.20/kW-month.[41] Under this alternative, the base revenue requirement would be increased by approximately $1.8 million (Total Company) to reflect the incremental increase in imputed capacity for these resources,[42] with EPE being ordered to remove the corresponding amount from its fuel costs on the effective date of the rates set in this case. Any increase in imputed capacity costs should be allocated based on A&E/4CP, consistent with the current treatment of imputed capacity costs.

V. CLASS COST ALLOCATION

Q. PLEASE SUMMARIZE THE METHODS USED BY EPE TO ALLOCATE COSTS AMONG THE TEXAS RATE CLASSES.

A. EPE uses the A&E/4CP method for non-peaking production plant costs, using a system load factor based on the average of the adjusted firm 4CP demands. The 4CP method is used for peaking generation costs and transmission plant costs.[43]

EPE uses Maximum Class Demand to allocate substation and primary distribution feeder system costs and Non-Coincident Peak demand to allocate secondary voltage distribution feeders and line transformer costs.[44] Services are allocated using a service drop investment allocator and meters are allocated using a weighted meter cost allocator.[45] General plant is allocated based on labor.[46]

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[40] Derived from EPE's response to RFI FMI 2-1, Attachment 15 2020 -Newman and Attachment 13 2020-Macho.

[41] 73.27% × $7.20 = $5.28. 66.18% × $7.20 = $4.76.

[42] ([$5.28 – $2.33] × 10,000 x 12) + ([$4.76 – $2.35] × 50,000 x 12) = $1,800,000.

[43] Hernandez Dir. at 20.

[44] *Id.*

[45] *Id.*at 22.

[46] *Id.*

Non-fuel production O&M expenses are allocated using A&E/4CP, 4CP, and energy allocators, while Generation System Control and Load Dispatching expense (Account 556) is allocated using an A&E/12CP method.[47]

Most transmission O&M expenses are allocated using the 4CP allocator, while Load Dispatching expense (Account 561) is allocated using a 12CP allocator.[48] Distribution O&M costs are largely allocated consistent with the related distribution plant.[49] Customer-based allocators are used for most customer-related O&M expenses. Uncollectible accounts are allocated based on firm revenues excluding Other Public Authority and Large Commercial & Industrial classes.[50]

Depreciation and amortization expense is allocated consistent with the underlying plant.[51] A&G expenses are allocated based on the labor allocator or their underlying functions.[52] Payroll and unemployment taxes are allocated based on labor, and property taxes are allocated consistent with their underlying functions.[53]

Revenues from non-firm (interruptible) schedules are credited to the firm service schedules using the 4CP method.[54]

Q. WHAT IS YOUR GENERAL ASSESSMENT OF EPE'S APPROACH TO ALLOCATING PRODUCTION PLANT COSTS?

A. As a general proposition, I support EPE's use of the A&E/4CP method to allocate the majority of its production plant costs. However, I disagree with the way in which Company has applied the A&E/4CP method. I also recommend that A&E/4CP allocation method be applied to all allocable production plant, including EPE's peaking units, rather than

47 *Id.* at 23.

48 *Id.* at 23-24.

49 *Id.* at 24.

50 *Id.*

51 *Id.* at 25.

52 *Id.*

53 *Id.*

54 *Id.* at 26.

adopting EPE's proposal to change to the 4CP method for these units. Accordingly, I recommend several changes to EPE's production plant allocations that I will explain below.

Q. BEFORE TURNING TO YOUR RECOMMENDED CHANGES, PLEASE EXPLAIN WHY YOU SUPPORT EPE'S USE OF THE A&E/4CP METHOD TO ALLOCATE PRODUCTION PLANT.

A. The Average and Excess Demand method is a well-accepted method for allocating production costs. The A&E/4CP method is widely used in Texas.

The A&E/4CP method recognizes both class energy usage (average demand) and class demand at the time of system peak (through the 4CP) in allocating costs to customer classes. In the case of EPE, the 4CP corresponds to the Company's system peak demands in each of the four summer months, when system demand is at its greatest levels. As such, the method accurately captures the requirements that each class makes on the need for investment in generating facilities.

Specifically, the A&E/4CP method uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor.[55] This portion of the cost is weighted by the system load factor. The cost of capacity above average demand is then allocated in proportion to each class's <u>excess</u> demand, where excess demand is measured as the *difference* between each class's 4CP demand and its average demand. This portion of the cost is weighted by 1 minus the system load factor. In this manner, the incremental amount of production plant that is required to meet loads that are above average demand is assigned to the users who create the need for the additional capacity. In Texas, the A&E/4CP methodology has been adopted by the Commission for each of three other major non-ERCOT utilities.[56]

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[55] This concept is discussed in the NARUC Electric Utility Cost Allocation Manual, January 1992, p. 49.

[56] *E.g.*, Docket No. 39896, Final Order at Finding of Fact 183 (Sept. 12, 2014); *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 46449, Final Order at Finding of Fact 277 (Jan. 11, 2018); *Application of Southwestern Public Service Company for Authority to Change Rates*, Docket No. 43695, Final Order at Finding of Fact 359 (Dec. 18, 2015).

Load Factor

Q. WHAT ROLE DOES LOAD FACTOR PLAY IN THE A&E/4CP CALCULATION?

A. As I explained above, in the A&E/4CP method, system load factor is utilized to determine the proportion of production plant cost that is allocated on the basis of average demand (or energy). It thus plays a critical role in cost allocation.

Q. HOW IS LOAD FACTOR CALCULATED?

A. As a general matter, load factor is calculated by dividing the energy used by an entity during a time period by the product of the entity's single highest peak demand during the time period, multiplied by the number of hours in the same time period.[57] It thus provides a measure of an entity's actual energy usage relative to its theoretical maximum, given the peak demand of the measured entity (which can be a customer, customer class, or utility system). In the context of the A&E/4CP calculation, load factor should be calculated for the utility system based on its annual system coincident peak (1CP).

Q. DOES EPE ADHERE TO THIS NORMAL CONVENTION IN CALCULATING SYSTEM LOAD FACTOR?

No. EPE's calculation of system load factor departs from standard practice. Rather than using the single highest CP, EPE calculates system load factor using the average of the four summer CPs. I also note that EPE uses adjusted loads rather than actual (unadjusted) loads.

Q. HAS EPE PROVIDED AN EXPLANATION FOR ITS USE OF THE 4CP AVERAGE DEMANDS IN THE CALCULATION OF SYSTEM LOAD FACTOR?

A. Yes. EPE argues that using a load factor based on the average of the 4CP months is consistent with the purpose of the allocation factor, since 4CPs are used to determine the excess demand in the A&E/4CP method. In his Direct Testimony, George Novela argues that System Planning uses a forecasted CP, not an historical CP for planning. A forecasted CP is an estimate reflecting the expected value of the peak. Mr. Novela contends that using the single CP from the historical test year does not truly reflect the peak for planning purposes. Rather, he argues that averaging the 4CPs more likely reflects the expected peak

[57] This calculation can also be expressed as average demand divided by peak demand.

value since it reflects a range of peak values, each of which has some expectation of occurring.[58]

Q. DO YOU FIND EPE'S EXPLANATION ADEQUATE?

A. No, not at all. System load factor for the Test Year should be based on the system's single highest peak demand for that year. This treatment is consistent with the method for measuring system load factor presented in the discussion of the Average and Excess Demand method in the Electric Utility Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners.[59] This measurement is not only the correct measurement of Test Year load factor, it is also the most appropriate measurement from a conceptual standpoint given the task at hand.

Q. PLEASE EXPLAIN THIS LATTER POINT.

A. Recall that the *purpose* of using system load factor in the A&E/4CP method is to identify the proportion of costs that are to be allocated on the basis of average demand, which in turn is capturing the production plant that each class would require if its respective kilowatt-hour usage was consumed at a 100% load factor for the entire year. Consistent with this purpose, the calculation of average demand in this exercise is a single annual value.

This point is critical to the logic here because excess demand, which is measured using 4CP, only exists as a concept in relation to annual average demand (i.e., it is the excess above average demand). Thus, the load factor weight that is attached to this annual average demand should be measured using the single peak demand for the test year. The number of CPs used in calculating excess demand – be it 1, 4, or some other number – is irrelevant to the determination of annual average demand and irrelevant to the determination of system load factor for the test period. There is but one system load factor during the year, not multiple load factors depending on how many CPs are used to calculate excess demand.

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[58] Novela Dir. at 9-10.

[59] NARUC Electric Utility Cost Allocation Manual, January 1992, p. 50.

In addition to being conceptually correct from the standpoint of cost allocation, measuring load factor with respect to the maximum system peak demand is consistent with the approach EPE uses in assessing its loads and resources balance to calculate its planning reserve margin. For example, in its Integrated Resource Plan, EPE calculates its planning reserve based on its projected highest system demand annually, which is 2,122 MW in 2021.[60] Indeed, in EPE's last rate case, Docket No. 46831, Mr. Novela, who agreed with parties' recommendations to use a 1CP load factor in that case, specifically noted that, "The use of a 1CP load factor is also consistent with how EPE plans and builds its generation and transmission systems."[61]

Q. IS EPE'S USE OF THE 4CP AVERAGE DEMANDS IN THE CALCULATION OF SYSTEM LOAD FACTOR CONSISTENT WITH COMMISSION PRECEDENT?

A. No. This issue was litigated in two recent cases before the Commission: Docket No. 43695 (Southwestern Public Service Company ["SPS"]),[62] and Docket No. 46449 (Southwestern Electric Power Company ["SWEPCO"]).[63] In both cases the Commission required the use of the single annual coincident peak in calculating the system load factor.

Q. SHOULD EPE USE ACTUAL OR ADJUSTED DEMANDS IN CALCULATING SYSTEM LOAD FACTOR?

A. I recommend using actual system firm loads in calculating system load factor. Using the actual (i.e., unadjusted) firm loads for this purpose best represents system load factor during the test period. In contrast, EPE used adjusted firm loads for this purpose.

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[60] *See* EPE 2021 Integrated Resource Plan (September 16, 2021), Figure 11. Initial L&R at 59. 2021 demand cited is Total System Demand net of Distributed Generation and Energy Efficiency. *See also* Hawkins Dir. at Exhibit DCH-3.

[61] *Application of El Paso Electric Company for Authority to Change Rates*, Docket No. 46831, Rebuttal Testimony of George Novella at 23 (July 21, 2017).

[62] Docket No. 43695, Final Order at 10-11, Findings of Fact 246A-251A (Dec. 18, 2015).

[63] Docket No. 46449, Final Order at Findings of Fact 277-284 (Jan. 11, 2018).

Q. WHAT LOAD FACTOR DOES EPE CALCULATE FOR CLASS COST ALLOCATION PURPOSES?

A. EPE's calculation using the average of the 4CPs artificially inflates the system load factor. Using the average of the adjusted firm 4CP demands of 1,841 MW, EPE calculates a system load factor of 49.73%.[64]

Q. WHAT IS THE CORRECT CALCULATION OF SYSTEM LOAD FACTOR FOR CLASS COST ALLOCATION PURPOSES?

A. Using the actual system firm peak demand in July 2020 of 2,106 MW,[65] I calculate that the system load factor is 45.47%. This calculation is shown in Exhibit KCH-7.[66] The derivation of the A&E/4CP class allocation factors using this correct system load factor is presented in Exhibit KCH-8.

Peaking Generation Unit Allocation

Q. HOW DO YOU RESPOND TO EPE'S PROPOSAL TO CHANGE FROM THE A&E/4CP METHOD TO A 4CP METHOD TO ALLOCATE THE COST OF ITS PEAKING UNITS?

A. I recommend that the A&E/4CP method, with the corrections I describe above, be applied to the entirety of EPE's generation demand costs. The A&E/4CP method is a robust cost allocation method that can properly be used to allocate a utility's entire generation fleet. It is neither necessary nor desirable to allocate individual generation facilities piecemeal on a different basis.

Further, my recommended correction to the load factor utilized in the A&E/4CP calculation to be based on the 1CP will place the proper emphasis on EPE's system peak demand for cost allocation purposes. It is not necessary to carve out EPE's peaking units for a different allocation approach than the rest of its generation fleet.

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[64] *See* EPE's WP P-07.

[65] Schedule O-01-03.

[66] Exhibit KCH-7 also presents the 1CP load factor applicable to the jurisdictional A&E/4CP allocator. The jurisdictional cost allocation includes an adjustment that removes from the calculation the solar generation that has been directly assigned to a jurisdiction.

For consistency, I also recommend using my corrected A&E/4CP allocator to allocate the non-firm revenue credit to firm classes, rather than EPE's recommended production 4CP allocator.

Palo Verde O&M Expense Allocation

Q. HOW DOES EPE ALLOCATE THE PVNGS GENERATION O&M EXPENSES?

A. EPE allocates Palo Verde generation O&M expenses using a combination of A&E/4CP and energy allocators.[67]

Q. DOES EPE PROPOSE TO CHANGE THE ALLOCATION METHOD USED FOR CERTAIN PVNGS O&M EXPENSES RELATIVE TO ITS LAST RATE CASE FILING, DOCKET NO. 46831?

A. Yes, EPE has changed from allocating FERC Accounts 519, 520, and 523 using A&E/4CP to an energy allocator.[68]

Q. DO YOU AGREE THAT ENERGY IS AN APPROPRIATE ALLOCATION BASIS FOR NON-FUEL PVNGS O&M EXPENSES?

A. No, PVNGS O&M expenses are a pass-through of costs from APS, based on EPE's 15.8% capacity share of PVNGS. These costs are more reasonably treated as a fixed cost related to EPE's capacity share than variable energy throughput.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE ALLOCATION OF PVNGS O&M EXPENSES?

A. I recommend that PVNGS non-fuel generation O&M expenses be allocated using A&E/4CP. I thus recommend that EPE's proposed allocation of Accounts 519, 520, 523, 530, 531, and 532 on an energy basis be replaced with an A&E/4CP allocation.

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[67] EPE Regulatory Case Working Model - As Filed - Dkt 52195.

[68] *See* Docket No. 46831, Cross Rebuttal Testimony of Kevin C. Higgins, p. 12, lines 16-18.

Generation System Control & Load Dispatching Allocation

Q. HOW DOES EPE PROPOSE TO ALLOCATE GENERATION SYSTEM CONTROL AND LOAD DISPATCHING (ACCOUNT 556) EXPENSE?

A. EPE allocates Account 556 using a variant of the Average & Excess method utilizing 12 coincident peaks, or A&E/12CP.[69]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE ALLOCATION OF ACCOUNT 556?

A. I recommend that Account 556 be allocated using the A&E/4CP allocator, consistent with EPE's allocation of most generation demand costs. The A&E/4CP method places greater emphasis on EPE's summer peaks, and therefore gives greater weight to the months in which meeting the system's demand is the most challenging. My recommended approach is consistent with the allocation method for Account 556 approved for SWEPCO[70] and ETI.[71]

Transmission Load Dispatching Expense Allocation

Q. GENERALLY, DO YOU SUPPORT EPE'S USE OF THE 4CP METHOD TO ALLOCATE ITS TRANSMISSION COSTS?

A. Yes. There is little basis for arguing that cost responsibility for transmission plant is anything but demand related. Therefore, using a 100% demand allocator such as the 4CP method is appropriate. In the case of EPE, with its summer peaking demand profile, allocating transmission plant using each class's share of system peak demand during the four summer months is reasonable. EPE utilizes the 4CP method to allocate all transmission costs except for Load Dispatching expense.

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[69] Hernandez Dir. at 13. The class DPROD12 allocator is derived in WP P-07, 12CP Adj tab (labeled "D1PROD 12CP-A&E").

[70] Docket No. 46449, Commission Number Run Based on December 14, 2017 Open Meeting Discussion, 46449 Commission Number Run CCOSS, Tab GEN DEMAND, line 421. (Dec. 20, 2017).

[71] *Application of Entergy Texas, Inc. for Authority to Change Rates*, Docket No. 48371, Cost Allocation/Rate Design Rebuttal Testimony of Richard Lain at 8-9 (Aug. 16, 2018).

Q. HOW DOES EPE PROPOSE TO ALLOCATE TRANSMISSION LOAD DISPATCHING (ACCOUNT 561) EXPENSE?

A. EPE proposes to allocate Account 561 using the 12CP method.[72]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE ALLOCATION OF ACCOUNT 561?

A. I recommend that Account 561 be allocated using the 4CP method, consistent with all other transmission costs. My recommendation is consistent with the Commission's Substantive Rule 25.192, under which ERCOT utilities recover Account 561 expenses in their transmission service rates on a 4CP basis. Although EPE is not an ERCOT utility, this substantive rule provides useful guidance for the proper allocation of Account 561 costs. And it is appropriate to allocate transmission load dispatching expense in the same manner as the underlying assets.

<u>69 kV Transmission System Allocation</u>

Q. PLEASE BRIEFLY DESCRIBE EPE'S TRANSMISSION SYSTEM.

A. According to the Direct Testimony of R. Clay Doyle, EPE owns, in whole or in part, approximately 946 miles of multiple 345 kV transmission lines, most of which are located within New Mexico. EPE also has a partial ownership interest in three 500 kV transmission lines in Arizona from PVNGS's switchyard to the Kyrene and Westwing substations in the Phoenix area.[73]

EPE's local high voltage transmission system consists of 115 kV lines and 69 kV lines in and around El Paso, Texas, and Las Cruces, New Mexico.[74]

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[72] Hernandez Dir. at 14.

[73] Direct Testimony of R. Clay Doyle at 5-6 .

[74] *Id.* at 6.

Q. HOW DOES EPE ALLOCATE THE COST OF ITS 69 KV TRANSMISSION LINES TO CUSTOMER CLASSES?

A. EPE does not separate the cost of its 69 kV lines in its cost-of-service study. Therefore, all customers are allocated a portion of the 69 kV transmission line costs based on the 4CP allocator.

Q. IS IT APPROPRIATE TO ALLOCATE 69 KV LINE COSTS TO CUSTOMER CLASSES SERVED AT 115 KV VOLTAGE?

A. No. Customers who take service directly at 115 kV voltage generally do not utilize the 69 kV system. It is not appropriate to allocate 69 kV line costs to rate schedules served at 115 kV voltage on the same basis as other classes who directly utilize the 69 kV system.

Q. HAVE YOU CHANGED THE ALLOCATION OF 69 KV TRANSMISSION COSTS IN YOUR MODIFIED VERSION OF THE COST-OF-SERVICE MODEL?

A. No. Since EPE does not separate its transmission costs into sub-functions based on voltage, I was not able to precisely reallocate the 69 kV costs in a manner excluding 115 kV rate schedules. However, EPE did estimate the 69 kV rate base, depreciation expense, O&M expense, and property tax in response to discovery.[75] Using this information, I have estimated the incremental impact of reallocating this portion of costs to customer classes excluding the 115 kV schedules. This calculation is presented in Exhibit KCH-9. Exhibit KCH-10, discussed below, incorporates this estimated impact into the summary of my modified version of the class cost-of-service study, using EPE's proposed revenue requirement.

Q. WHAT IS YOUR RECOMMENDATION ON THIS ISSUE?

A. I recommend that EPE separate the cost of its transmission system into (i) 69 kV and (ii) 115 kV and above sub-functions for class cost-of-service purposes, and exclude customers served at 115 kV from the allocation of 69 kV costs. This additional granularity will allow for more precise cost allocation that is aligned with the manner in which costs are incurred.

[75] EPE's response to RFI TIEC 5-2, Attachments 1 and 2.

This treatment is also consistent with the differentiation of transmission loss factors between 69 kV and 115 kV, as reflected in this case.

Q. DO YOU HAVE ANY COMMENTS ON THE TRANSMISSION LOSS FACTORS EPE APPLIES TO 69 KV AND 115 KV LOADS IN ITS COST ALLOCATION?

Yes. I am concerned that the loss factors EPE uses to calculate its class loads at source exhibit some anomalies.[76] Namely, the energy loss factors that EPE applies to its 69 kV and 115 kV classes are higher than the demand loss factors for these classes. This is unusual because line losses should be greater during peak load conditions. While my cost allocation does not incorporate any corrections to the transmission loss factors, such corrections may be warranted.

<u>Contributions and Donations Expense Allocation</u>

Q. HOW DOES EPE ALLOCATE CONTRIBUTIONS AND DONATIONS EXPENSE?

A. EPE allocates Contributions and Donations expense using the Labor allocator.[77]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE ALLOCATION OF CONTRIBUTIONS AND DONATIONS EXPENSE?

A. I recommend that Contributions and Donations be allocated based on customer count. To the extent EPE is permitted to recover contributions and donations from customers instead of its shareholders, it is presumably due to the broad community benefit that these gifts provide. Consequently, allocating these costs in a manner that best reflects a wide dispersion of benefit is most appropriate. This is best achieved using the customer allocator.

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[76] EPE's loss factors are based on a 2017 Analysis of System Losses by Management Applications Consulting, Inc., provided in Schedule O-6.3.

[77] EPE Regulatory Case Working Model - As Filed - Dkt 52195, "Jurisdiction Allocation" and "Rate Class Allocation" tabs. Contributions and Donations are included in the "930200-GENL-MISC GENERAL EXP" item.

Summary of Recommended Allocation Impacts

Q. HAVE YOU SUMMARIZED THE EFFECT OF YOUR RECOMMENDED CHANGES ON CLASS COST ALLOCATION?

A. Yes. The effects of my recommended changes on class cost allocation – using EPE's proposed revenue requirement increase, are presented in Exhibit KCH-10. The estimated impact of my recommendation regarding the allocation of EPE's 69 kV transmission system is included as a separate column in this exhibit.

VI. REVENUE ALLOCATION

Q. WHAT GENERAL GUIDELINES SHOULD BE EMPLOYED IN SPREADING ANY CHANGE IN RATES?

A. In determining revenue allocation, it is important to align rates with cost causation to the greatest extent practicable. Properly aligning rates with the costs caused by each customer group is essential for ensuring fairness, as it minimizes cross-subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization. In some cases, the Commission has applied gradualism to mitigate the full movement to cost of service.

Q. PLEASE DESCRIBE THE APPROACH USED BY EPE TO DISTRIBUTE THE PROPOSED RATE INCREASE AMONG THE TEXAS RATE CLASSES.

A. According to the Direct Testimony of Manuel Carrasco, EPE is proposing to cap the base increase to certain classes (Residential and Water Heating) at 1.5 times the average non-fuel base revenue increase, as an initial step in the revenue allocation. EPE also applies a floor to the decreases for certain rate classes (Rate 2 – Small General Service, Rate 24 – General Service, and Rate 41 – City and County Service), initially limiting the decreases for these classes to 50% of the decreases indicated by the cost-of-service study.[78] Caps and floors are not applied to other classes. Then, after applying the initial caps and floors,

[78] Direct Testimony of Manuel Carrasco at 14-15, Exhibit MC-4.

EPE allocates the resulting revenue shortfall to all the classes in proportion to their allocated base revenue (after applying the initial cap or floor, as applicable).[79]

Q. WHAT IS YOUR RESPONSE TO EPE'S REVENUE ALLOCATION PROPOSAL?

A. As an initial matter, EPE's cap and floor are inconsistently applied among rate classes. For example, according to Mr. Carrasco's Table MC-8, the Residential class requires an increase of 18.67% under EPE's cost-of-service study and receives an increase of 13.59% under EPE's revenue allocation due to the proposed cap. However, Rate 26 – Petroleum Refinery Service, requires an increase of 17.57% under EPE's cost-of-service and receives an increase of 20.25% in order to fund the Residential/Water Heating subsidy.[80]

While I recommend eliminating cross-subsidies among rate classes in this case, it is particularly notable that EPE's inconsistent application of its proposed caps and floors produces inequitable results for certain classes.

Q. IS YOUR PROPOSAL TO ELIMINATE CROSS-SUBSIDIES CONSISTENT WITH YOUR UNDERSTANDING OF THE POLICIES ADOPTED BY THE COMMISSION IN RECENT YEARS?

A. Yes. I am aware that the Commission has shown a strong preference for aligning class revenue requirement with the costs that each class causes to be incurred. For example, the Commission's Order in the SPS rate case, Docket No. 43695, issued December 18, 2015, contained a clear statement affirming its commitment to aligning rates with the cost of service:

> The Commission declines to adopt any gradualism adjustment in this proceeding. The Commission has often stated that one of its primary responsibilities in setting rates is ensuring those rates are, to the greatest extent reasonable, consistent with cost causation. Further, as SPS conceded, the wisdom of a gradualism adjustment is affected by the size of the rate change. While there is no magic threshold at which a change in rates automatically justifies an aberration from basing rates on classes' costs of service, in Docket 40443, the Commission determined that an increase as large as 29% did not warrant rate mitigation. Here, SPS's overall Texas

[79] *Id.* at 15.

[80] The cited percentage increases do not include EPE's proposed COVID rider.

> retail revenue requirement will be decreased by less than 1% and class allocations based purely on each classes' cost of service will result in relatively small rate changes. All but one class will experience less than a 14% change to its base-revenue responsibilities. The largest change will be borne by Street Lighting customers, whose revenue responsibility will increase 24.28%. Thus, moving from classes' costs of service and mandating inter-class cost subsidization is not warranted in this proceeding.[81]

In addition, in cases involving SWEPCO (Docket No. 40443) and ETI (Docket No. 39896), the Commission rejected the position of the parties that recommended gradualism and directed that rates be set at cost. In Docket No. 40443, the range was from a 17.05% decrease to a 29.20% increase,[82] and for Docket No. 39896, the range was from a 7.89% decrease to a 10.43% increase.[83] In each case the Commission set rates for each class at cost and rejected the application of gradualism proposals.

Q. WHAT IS YOUR RECOMMENDED APPROACH TO REVENUE ALLOCATION IN THIS CASE?

A. I recommend that all Texas rate classes be moved to full cost of service, at the revenue requirement ultimately approved in this proceeding and incorporating my recommended changes to cost allocation. Moving each class to full cost recovery eliminates inter-class subsidies, sets efficient price signals, and is consistent with the Commission's strong preference for aligning class revenues with costs. At EPE's requested revenue requirement, my recommended revenue allocation is the same as my recommended class cost allocation presented in Exhibit KCH-10.

VII. RATE SCHEDULE NO. 25 – LARGE POWER SERVICE TARIFF LANGUAGE

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING TARIFF LANGUAGE?

A. Yes. Schedule No. 25 is the generally applicable rate schedule for customers with demands greater than 600 kW. However, the current and proposed EPE tariff indicates that Schedule

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[81] Docket No. 43695, Order at 10. (Dec. 18, 2015) (Citations omitted.)

[82] Docket No. 40443, Order on Rehearing, Attachment C, p. 1 (Mar. 6, 2014).

[83] Docket No. 39896, Commission Number Run 39896 ETI COS (Aug. 28, 2012).

No. 25 is "limited to Customers who otherwise do not qualify for service under the Company's other rate schedules…"[84] Thus, a customer who otherwise would qualify for Schedule No. 25, but also qualifies for another rate schedule, is ineligible for service under Schedule No. 25. I believe this exclusion is unreasonable.

Q. WHY DO YOU BELIEVE THIS PRECLUSION IS UNREASONABLE?

A. Customers should be permitted to choose the Commission-approved rate that best suits their needs, assuming they meet the applicable voltage and size requirements. The choice of rate schedule should belong to the customer. EPE's tariff language allows EPE to deny service on Schedule No. 25 to an otherwise eligible customer and require that the customer take service under a rate that may be more expensive or less compatible with the customer's needs. That is inappropriate.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION ON THIS ISSUE?

A. I recommend that the applicability provision in Schedule No. 25 be modified to remove the language that prohibits customers eligible for other rate schedules from taking service under this rate schedule.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

[84] Schedule Q-8.8, p. 51.

SOAH NO. 473-21-2606
PUC DOCKET NO. 52195

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

AFFIDAVIT OF KEVIN C. HIGGINS

STATE OF UTAH)
)
COUNTY OF SALT LAKE)

Kevin C. Higgins, being first duly sworn, deposes and states that:

1. He is a Principal with Energy Strategies, L.L.C., in Salt Lake City, Utah;

2. He is the witness who sponsors the accompanying testimony entitled "Direct Testimony of Kevin C. Higgins;"

3. Said testimony and attached exhibits were prepared by him and under his direction and supervision;

4. If inquiries were made as to the facts in said testimony and exhibits he would respond as therein set forth; and

5. The aforesaid testimony and exhibits are true and correct.

Kevin C. Higgins

Subscribed and sworn to or affirmed before me this 19th day of October, 2021, by Kevin C. Higgins.

Millicent Pichardo
Notary Public

My Commission Expires: June 13, 2022

Notary Public - State of Utah
Millicent Pichardo
Comm. #700882
My Commission Expires
June 13, 2022

TIEC Supplemental Executive Retirement Plan (SERP) Expense Adjustment
For The Test Year Ended December 31, 2020

Line No.	(a) Income Statement	(b) Texas Amount
1	Operating Revenues	
2	Base Revenue	
3	Fuel & Purchased Power Revenue	
4	Total Sales Revenue	
5	Other Operating Revenue	
6	Total Revenues	$0
7	Operating Expenses	
8	Operation and Maintenance	
9	Fuel and Purchased Power Expense	
10	Production O&M	
11	Transmission O&M	
12	Distribution O&M	
13	Customer Accounts (excl. Uncollectibles)	
14	Uncollectible Accounts	(3,160)
15	Customer & Information Systems	
16	A&G Expenses	(814,369)
17	Total Non-Fuel & PP O&M Expense	(817,529)
18	Total O&M Expense	($817,529)
19	Depreciation/Amortization Expense	
20	Taxes Other Than Income Expense	(19,182)
21	Revenue Related Tax Expense	(38,839)
22	Federal Income Tax Expense	0
23	State Income Tax Expense	0
24	Other Expenses	
25	Total Expenses	($875,549)
	Rate Base	**Texas Amount**
26	Electric Plant in Service	
27	Accumulated Reserve for Depreciation	
28	Net Electric Plant in Service	$0
29	Additions	
30	Cash Working Capital	
31	Fuel Inventory	
32	Materials and Supplies	
33	Prepayments	
34	Coal Reclamation Asset	
35	Property Insurance Reserve	
36	Nuclear Fuel Dry Cask Storage	
37	Injuries and Damages Reserve	
38	Unamortized Transition Costs	
39	Miscellaneous Deferred Debits - Allocated	
40	Miscellaneous Deferred Debits - Assigned	
41	CWIP	
42	Total Additions	$0
43	Deductions	
44	Accumulated Deferred Income Taxes	
45	Coal Reclamation Liability	
46	Customer Deposits	
47	Regulatory Assets/Liabilities (SFAS 109)	
48	Customer Advances for Construction	
49	Accumulated Deferred ITC - Pre 1971	
50	Total Deductions	$0
51	Total Rate Base	$0
	Estimated Revenue Requirement Impact:	
52	Total Income Statement RR Impact	($875,549)
53	Rate Base Impact	$0
54	EPE Requested Rate of Return on Rate Base (EPE Schedule K-1.0)	7.985%
55	Rate Base RR Impact	$0
56	**Total Revenue Requirement Impact**	**($875,549)**

TIEC Supplemental Executive Retirement Plan (SERP) Expense Adjustment
For The Test Year Ended December 31, 2020

Line No.		FERC Account	Total Company	Allocation Factor	Allocation Percent [1]	Texas Allocated
1	**Adjustment to Expense**					
2	SERP Expense	926	(1,033,409)	LABOR	78.804%	(814,369)
3	Associated Payroll Tax	408	(24,341)	LABOR	78.804%	(19,182)
4	Total Expense Adjustment		(1,057,750)			(833,551)

TIEC Supplemental Executive Retirement Plan (SERP) Expense Adjustment
For The Test Year Ended December 31, 2020

		Total Company Amounts		
Line No.		EPE Proposed Expense Amount	TIEC Recommended Expense Amount	TIEC Recommended Adjustment Amount
		(a)	(b)	(c) = (b) - (a)
1	SERP Expense [1]	1,033,409	0	(1,033,409)
2	Associated Payroll Tax [2]	24,341	0	(24,341)
3	Total Expense	1,057,750	0	(1,057,750)

Data Sources:
1. EPE's response to RFI Staff 1-22.
2. EPE's response to RFI TIEC 3-2. Allocated between SERP and Excess Benefit Plan based on EPE's requested expenses.

TIEC Excess Benefit Plan Expense Adjustment
For The Test Year Ended December 31, 2020

Line No.	(a) Income Statement	(b) Texas Amount
1	Operating Revenues	
2	Base Revenue	
3	Fuel & Purchased Power Revenue	
4	Total Sales Revenue	
5	Other Operating Revenue	
6	Total Revenues	$0
7	Operating Expenses	
8	Operation and Maintenance	
9	Fuel and Purchased Power Expense	
10	Production O&M	
11	Transmission O&M	
12	Distribution O&M	
13	Customer Accounts (excl. Uncollectibles)	
14	Uncollectible Accounts	(2,866)
15	Customer & Information Systems	
16	A&G Expenses	(738,634)
17	Total Non-Fuel & PP O&M Expense	(741,500)
18	Total O&M Expense	($741,500)
19	Depreciation/Amortization Expense	
20	Taxes Other Than Income Expense	(17,398)
21	Revenue Related Tax Expense	(35,227)
22	Federal Income Tax Expense	0
23	State Income Tax Expense	0
24	Other Expenses	
25	Total Expenses	($794,125)
	Rate Base	**Texas Amount**
26	Electric Plant in Service	
27	Accumulated Reserve for Depreciation	
28	Net Electric Plant in Service	$0
29	Additions	
30	Cash Working Capital	
31	Fuel Inventory	
32	Materials and Supplies	
33	Prepayments	
34	Coal Reclamation Asset	
35	Property Insurance Reserve	
36	Nuclear Fuel Dry Cask Storage	
37	Injuries and Damages Reserve	
38	Unamortized Transition Costs	
39	Miscellaneous Deferred Debits - Allocated	
40	Miscellaneous Deferred Debits - Assigned	
41	CWIP	
42	Total Additions	$0
43	Deductions	
44	Accumulated Deferred Income Taxes	
45	Coal Reclamation Liability	
46	Customer Deposits	
47	Regulatory Assets/Liabilities (SFAS 109)	
48	Customer Advances for Construction	
49	Accumulated Deferred ITC - Pre 1971	
50	Total Deductions	$0
51	Total Rate Base	$0
	Estimated Revenue Requirement Impact:	
52	Total Income Statement RR Impact	($794,125)
53	Rate Base Impact	$0
54	EPE Requested Rate of Return on Rate Base (EPE Schedule K-1.0)	7.985%
55	Rate Base RR Impact	$0
56	**Total Revenue Requirement Impact**	**($794,125)**

TIEC Excess Benefit Plan Expense Adjustment
For The Test Year Ended December 31, 2020

Line No.		FERC Account	Total Company	Allocation Factor	Allocation Percent [1]	Texas Allocated
1	**Adjustment to Expense**					
2	Excess Benefit Plan Expense	926	(937,304)	LABOR	78.804%	(738,634)
3	Associated Payroll Tax	408	(22,077)	LABOR	78.804%	(17,398)
4	Total Expense Adjustment		(959,381)			(756,032)

TIEC Excess Benefit Plan Expense Adjustment
For The Test Year Ended December 31, 2020

		Total Company Amounts		
Line No.		EPE Proposed Expense Amount	TIEC Recommended Expense Amount	TIEC Recommended Adjustment Amount
		(a)	(b)	(c) = (b) - (a)
1	Excess Benefit Plan Expense [1]	937,304	0	(937,304)
2	Associated Payroll Tax [2]	22,077	0	(22,077)
3	Total Expense	959,381	0	(959,381)

Data Sources:
1. EPE's response to RFI Staff 1-22.
2. EPE's response to RFI TIEC 3-2. Allocated between SERP and Excess Benefit Plan based on EPE's requested expenses.

TIEC Palo Verde Incentive Compensation Adjustment
For The Test Year Ended December 31, 2020

Line No.	(a) Income Statement	(b) Texas Amount
1	Operating Revenues	
2	Base Revenue	
3	Fuel & Purchased Power Revenue	
4	Total Sales Revenue	
5	Other Operating Revenue	
6	Total Revenues	$0
7	Operating Expenses	
8	Operation and Maintenance	
9	Fuel and Purchased Power Expense	
10	Production O&M	(116,290)
11	Transmission O&M	
12	Distribution O&M	
13	Customer Accounts (excl. Uncollectibles)	
14	Uncollectible Accounts	(464)
15	Customer & Information Systems	
16	A&G Expenses	
17	Total Non-Fuel & PP O&M Expense	(116,753)
18	Total O&M Expense	($116,753)
19	Depreciation/Amortization Expense	
20	Taxes Other Than Income Expense	(6,041)
21	Revenue Related Tax Expense	(5,700)
22	Federal Income Tax Expense	0
23	State Income Tax Expense	0
24	Other Expenses	
25	Total Expenses	($128,494)

Line No.	Rate Base	Texas Amount
26	Electric Plant in Service	
27	Accumulated Reserve for Depreciation	
28	Net Electric Plant in Service	$0
29	Additions	
30	Cash Working Capital	
31	Fuel Inventory	
32	Materials and Supplies	
33	Prepayments	
34	Coal Reclamation Asset	
35	Property Insurance Reserve	
36	Nuclear Fuel Dry Cask Storage	
37	Injuries and Damages Reserve	
38	Unamortized Transition Costs	
39	Miscellaneous Deferred Debits - Allocated	
40	Miscellaneous Deferred Debits - Assigned	
41	CWIP	
42	Total Additions	$0
43	Deductions	
44	Accumulated Deferred Income Taxes	
45	Coal Reclamation Liability	
46	Customer Deposits	
47	Regulatory Assets/Liabilities (SFAS 109)	
48	Customer Advances for Construction	
49	Accumulated Deferred ITC - Pre 1971	
50	Total Deductions	$0
51	Total Rate Base	$0
	Estimated Revenue Requirement Impact:	
52	Total Income Statement RR Impact	($128,494)
53	Rate Base Impact	$0
54	EPE Requested Rate of Return on Rate Base (EPE Schedule K-1.0)	7.985%
55	Rate Base RR Impact	$0
56	**Total Revenue Requirement Impact**	**($128,494)**

TIEC Palo Verde Incentive Compensation Adjustment
For The Test Year Ended December 31, 2020

Line No.		FERC Account	Total Company	Allocation Factor	Allocation Percent [1]	Texas Allocated
1	**Adjustment to Expense**					
2	Palo Verde Incentive Compensation Expense	Various	(144,579)	D1PROD	80.433%	(116,290)
3	Associated Payroll Tax	408	(7,510)	D1PROD	80.433%	(6,041)
4	Total Expense Adjustment		(152,089)			(122,330)

Data Source:
1. EPE Regulatory Case Working Model - Dkt 52195 TIEC Direct WP.

TIEC Palo Verde Incentive Compensation Adjustment
For The Test Year Ended December 31, 2020

Line No.		EPE Proposed Expense Amount	TIEC Recommended Expense Amount	TIEC Recommended Adjustment Amount
		Total Company Amounts		
		(a)	(b)	(c) = (b) - (a)
1	Palo Verde Incentive Compensation - Company Earnings [1]	144,579	0	(144,579)
2	PV Company Earnings Incentive Comp - Payroll Tax [2]	7,510	0	(7,510)
3	Total Expense	152,089	0	(152,089)

Total EPE Allocated PV Incentive Comp	6,134,106
Total EPE Allocated PV Incentive Comp Payroll Tax	318,646
Company Earnings Share of Total	2.4%

Data Sources:
1. EPE's response to RFI CEP 10-16. Adjustment removes EPE's share of PV Incentive Compensation tied to Company Earnings.
2. EPE's response to RFI CEP 10-18, CEP 10-18_Attachment 07. Allocated to Company Earnings based on proportionate share of total.

TIEC Revolving Credit Facility Commitment Fees Adjustment
For The Test Year Ended December 31, 2020

Line No.	(a) Income Statement	(b) Texas Amount
1	Operating Revenues	
2	Base Revenue	
3	Fuel & Purchased Power Revenue	
4	Total Sales Revenue	
5	Other Operating Revenue	
6	Total Revenues	$0
7	Operating Expenses	
8	Operation and Maintenance	
9	Fuel and Purchased Power Expense	
10	Production O&M	
11	Transmission O&M	
12	Distribution O&M	
13	Customer Accounts (excl. Uncollectibles)	
14	Uncollectible Accounts	(1,690)
15	Customer & Information Systems	
16	A&G Expenses	(445,707)
17	Total Non-Fuel & PP O&M Expense	(447,397)
18	Total O&M Expense	($447,397)
19	Depreciation/Amortization Expense	
20	Taxes Other Than Income Expense	0
21	Revenue Related Tax Expense	(20,767)
22	Federal Income Tax Expense	0
23	State Income Tax Expense	0
24	Other Expenses	
25	Total Expenses	($468,164)
	Rate Base	**Texas Amount**
26	Electric Plant in Service	
27	Accumulated Reserve for Depreciation	
28	Net Electric Plant in Service	$0
29	Additions	
30	Cash Working Capital	
31	Fuel Inventory	
32	Materials and Supplies	
33	Prepayments	
34	Coal Reclamation Asset	
35	Property Insurance Reserve	
36	Nuclear Fuel Dry Cask Storage	
37	Injuries and Damages Reserve	
38	Unamortized Transition Costs	
39	Miscellaneous Deferred Debits - Allocated	
40	Miscellaneous Deferred Debits - Assigned	
41	CWIP	
42	Total Additions	$0
43	Deductions	
44	Accumulated Deferred Income Taxes	
45	Coal Reclamation Liability	
46	Customer Deposits	
47	Regulatory Assets/Liabilities (SFAS 109)	
48	Customer Advances for Construction	
49	Accumulated Deferred ITC - Pre 1971	
50	Total Deductions	$0
51	Total Rate Base	$0
	Estimated Revenue Requirement Impact:	
52	Total Income Statement RR Impact	($468,164)
53	Rate Base Impact	$0
54	EPE Requested Rate of Return on Rate Base (EPE Schedule K-1.0)	7.985%
55	Rate Base RR Impact	$0
56	**Total Revenue Requirement Impact**	**($468,164)**

TIEC Revolving Credit Facility Commitment Fees Adjustment
For The Test Year Ended December 31, 2020

Line No.		FERC Account	Total Company	Allocation Factor	Allocation Percent [1]	Texas Allocated
1	**Adjustment to Expense**					
2	Miscellaneous General Expenses	930200	(571,211)	NETPLT	78.028%	(445,707)
3	Total Expense Adjustment		(571,211)			(445,707)

TIEC Revolving Credit Facility Commitment Fees Adjustment
For The Test Year Ended December 31, 2020

		Total Company Amounts		
Line No.		EPE Proposed Expense Amount	TIEC Recommended Expense Amount	TIEC Recommended Adjustment Amount
		(a)	(b)	(c) = (b) - (a)
1	Miscellaneous General Expenses [1]	571,211	0	(571,211)
2	Total Expense	571,211	0	(571,211)

Data Source:
1. WP A-3 Adj 21 Miscellaneous General Expenses, p. 2.

TIEC Accumulated Depreciation and Amortization Rate Base Adjustment
For The Test Year Ended December 31, 2020

Line No.	(a) Income Statement	(b) Texas Amount
1	Operating Revenues	
2	Base Revenue	
3	Fuel & Purchased Power Revenue	
4	Total Sales Revenue	
5	Other Operating Revenue	
6	Total Revenues	$0
7	Operating Expenses	
8	Operation and Maintenance	
9	Fuel and Purchased Power Expense	
10	Production O&M	0
11	Transmission O&M	
12	Distribution O&M	
13	Customer Accounts (excl. Uncollectibles)	
14	Uncollectible Accounts	(436)
15	Customer & Information Systems	
16	A&G Expenses	
17	Total Non-Fuel & PP O&M Expense	(436)
18	Total O&M Expense	($436)
19	Depreciation/Amortization Expense	
20	Taxes Other Than Income Expense	0
21	Revenue Related Tax Expense	(5,365)
22	Federal Income Tax Expense	(16,933)
23	State Income Tax Expense	(1,374)
24	Other Expenses	
25	Total Expenses	($24,108)
	Rate Base	**Texas Amount**
26	Electric Plant in Service	
27	Accumulated Reserve for Depreciation	(1,212,615)
28	Net Electric Plant in Service	($1,212,615)
29	Additions	
30	Cash Working Capital	
31	Fuel Inventory	
32	Materials and Supplies	
33	Prepayments	
34	Coal Reclamation Asset	
35	Property Insurance Reserve	
36	Nuclear Fuel Dry Cask Storage	
37	Injuries and Damages Reserve	
38	Unamortized Transition Costs	
39	Miscellaneous Deferred Debits - Allocated	
40	Miscellaneous Deferred Debits - Assigned	
41	CWIP	
42	Total Additions	$0
43	Deductions	
44	Accumulated Deferred Income Taxes	
45	Coal Reclamation Liability	
46	Customer Deposits	
47	Regulatory Assets/Liabilities (SFAS 109)	
48	Customer Advances for Construction	
49	Accumulated Deferred ITC - Pre 1971	
50	Total Deductions	$0
51	Total Rate Base	($1,212,615)
	Estimated Revenue Requirement Impact:	
52	Total Income Statement RR Impact	($24,108)
53	Rate Base Impact	($1,212,615)
54	EPE Requested Rate of Return on Rate Base (EPE Schedule K-1.0)	7.985%
55	Rate Base RR Impact	($96,827)
56	**Total Revenue Requirement Impact**	**($120,935)**

TIEC Accumulated Depreciation and Amortization Rate Base Adjustment
For The Test Year Ended December 31, 2020

Line No.		FERC Account	Total Company [1]	Allocation Factor	Allocation Percent [2]	Texas Allocated
1	**Adjustment to Rate Base**					
2	Production Plant					
3	Accumulated Depreciation - Steam Plant	108	(1,244,315)	D1PROD	80.433%	(1,000,842)
4	Accumulated Depreciation - Other Prod. Plant [3]	108	199,069	D1PROD	80.433%	160,118
5	Accumulated Depreciation - TX Solar	108	(910)	DIRECT_TX	100.000%	(910)
6	Accumulated Depreciation - NM Solar	108	(1)	DIRECT_OTHER	0.000%	0
7	Transmission Plant					
8	Accumulated Depreciation	108	(167,070)	D2TRAN	79.590%	(132,971)
9	Distribution Plant					
10	Accumulated Depreciation - Texas	108	(588,910)	DIRECT_TX	100.000%	(588,910)
11	Accumulated Depreciation - Other	108	(213,593)	DIRECT_OTHER	0.000%	0
12	General Plant					
13	Accumulated Depreciation	108	(513,067)	LABOR	78.804%	(404,318)
14	Total Accumulated Depreciation		(2,528,797)			(1,967,834)
15	Intangible Plant					
16	Accumulated Amortization	111	958,349	LABOR	78.804%	755,218
17	Total Accum. Depreciation & Amortization Adj.		(1,570,449)			(1,212,615)

Data Sources:
1. EPE's response to RFI TIEC 4-4, TIEC 04-04_Attachment 1. This adjustment increases accumulated depreciation in the amount of EPE's depreciation and amortization expense adjustment related to the annualization of plant balances.

2. EPE Regulatory Case Working Model - Dkt 52195 TIEC Direct WP.

3. EPE proposes to allocate this item based on 4CP (D2PROD). This adjustment reflects allocation based on D1PROD.

ILLUSTRATIVE JURISDICTIONAL ALLOCATORS
WITH TIEC RECOMMENDED SOLAR PLANT ADJUSTMENTS
ADJUSTED TEST YEAR PERIOD ENDED DECEMBER 31, 2020

Prior to Solar Project Adjustments

Line No.	Rate	Rate Class	Annual Energy at Source, kWh	Jun 2020 Coincident kW @ Source	Jul 2020 Coincident kW @ Source	Aug 2020 Coincident kW @ Source	Sep 2020 Coincident kW @ Source	4-CP Average Demand, kW	Annual Average Demand, kW	Excess Demand, kW	D2TRAN 4CP
		Texas									
1	TXRT01	Residential Service	2,681,376,311	769,203	919,158	857,187	754,267	824,954	305,257	519,697	
2	TXRT02	Small General Service	293,679,397	70,762	76,679	72,638	63,800	70,970	33,433	37,536	
3	TXRT07	Outdoor Recreational Lighting Service	3,964,113	0	0	0	0	0	451	0	
4	TXRT08 - S	Street Lighting	38,885,062	0	0	0	0	0	4,427	0	
5	TXRT09 - S	Traffic Signals	2,238,727	195	194	194	194	194	255	0	
6	TXRT11	Municipal Pumping Service	184,560,694	21,155	31,935	22,772	19,377	23,810	21,011	2,799	
7	TXRT15	Electrolytic Refining Service	44,081,882	7,737	7,737	7,737	7,737	7,737	5,018	2,718	
8	TXRTWH	Off Peak Water Heating Service	5,525,846	424	391	338	373	381	629	0	
9	TXRT22	Irrigation Service	4,141,472	1,384	1,881	1,247	1,282	1,448	471	977	
10	TXRT24	General Service	1,563,843,457	318,545	328,431	308,672	306,945	315,648	178,033	137,615	
11	TXRT25	Large Power Service	653,816,289	97,489	103,585	104,810	104,704	102,647	74,433	28,214	
12	TXRT26	Petroleum Refining Service	323,039,506	41,374	41,374	41,374	41,374	41,374	36,776	4,599	
13	TXRT28	Private Area Lighting Service	28,935,421	0	0	0	0	0	3,294	0	
14	TXRT30	Electric Furnace Rate	22,163,145	5,128	5,127	5,129	5,125	5,127	2,523	2,604	
15	TXRT31	Military Reservation Service	285,973,306	52,230	52,230	52,230	52,230	52,230	32,556	19,674	
16	TXRT34	Cotton Gin Service	1,721,696	20	11	14	22	17	196	0	
17	TXRT41	City and County Service	208,735,770	43,949	49,880	47,326	47,640	47,199	23,763	23,436	
18		Texas Total Firm Load	6,346,682,091	1,429,594	1,618,613	1,521,668	1,405,071	1,493,737	722,528	779,869	79.5900%
19		Total Texas Interruptible Load	405,090,611	41,056	60,224	42,973	49,167	48,355	46,117		
20		Total Texas Load	6,751,772,701	1,470,650	1,678,837	1,564,641	1,454,238	1,542,092	768,644		
		New Mexico									
21	NMRT01	Residential Service	828,028,974	206,526	230,697	195,539	172,704	201,366	94,266	107,101	
22	NMRT03	Small General Service	171,847,703	35,655	42,410	40,674	36,896	38,909	19,564	19,345	
23	NMRT04	General Service	306,637,285	49,822	56,000	53,394	51,782	52,749	34,909	17,841	
24	NMRT05	Irrigation Service	43,504,407	5,634	9,586	9,168	11,744	9,033	4,953	4,081	
25	NMRT07	City and County Service	54,330,148	7,943	9,090	10,607	9,944	9,396	6,185	3,211	
26	NMRT08	Municipal Pumping Service	41,932,284	6,539	7,319	6,415	6,700	6,743	4,774	1,970	
27	NMRT09	Large Power Service	167,919,635	22,533	24,212	22,726	22,723	23,048	19,117	3,932	
28	NMRT10	Military Research and Development	61,824,838	10,249	11,665	10,282	9,830	10,507	7,038	3,468	
29	NMRT10 -T115	MRDS - HAFB	64,814,966	11,663	12,719	11,633	8,317	11,083	7,379	3,704	
30	NMRT11	Municipal Street Lighting Service	1,926,663	0	0	0	0	0	219	0	
31	NMRT12	Private Area Lighting Service	5,545,207	0	0	0	0	0	631	0	
32	NMRT19	Seasonal-Agricultural Processing Service	8,951,595	853	2,650	2,745	1,262	1,877	1,019	858	
33	NMRT25	Outdoor Recreational Lighting Service	430,845	0	0	0	0	0	49	0	
34	NMRT26	State University Service	28,889,213	6,311	5,756	5,307	4,177	5,388	3,289	2,099	
35		Total New Mexico Firm Load	1,786,583,763	363,730	412,103	368,490	336,078	370,100	203,391	167,609	19.7199%
36		Total New Mexico Interruptible Load	8,374,472	988	797	684	857	831	953		
37		Total New Mexico Load	1,794,958,235	364,718	412,900	369,174	336,935	370,932	204,344		
38	TXRT94 - T/69	Rio Grande Co-Op - Van Horn	22,663,105	5,162	4,984	4,463	3,353	4,490.48	2,580	1,910	
39	TXRT95 - T/115	Rio Grande Co-Op - Dell City	42,296,544	8,603	8,947	9,033	7,263	8,461.28	4,815	3,646	
		Total FERC	64,959,649	13,765	13,931	13,495	10,616	12,952	7,395	5,557	0.6901%
40		Total System Firm Load	8,198,225,503	1,807,089	2,044,647	1,903,654	1,751,765	1,876,789	933,313	953,035	100.0000%
41		Total System Load	8,611,690,585	1,849,133	2,105,668	1,947,310	1,801,788	1,925,975	980,384		

ILLUSTRATIVE JURISDICTIONAL ALLOCATORS
WITH TIEC RECOMMENDED SOLAR PLANT ADJUSTMENTS
ADJUSTED TEST YEAR PERIOD ENDED DECEMBER 31, 2020

Adjusted for Texas Solar Projects

Line No.	Rate	Rate Class	Annual Energy at Source, kWh	E1ENERGY Energy Allocator	Jun 2020 Coincident kW @ Source	Jul 2020 Coincident kW @ Source	Aug 2020 Coincident kW @ Source	Sep 2020 Coincident kW @ Source	4-CP Average Demand, kW	Annual Average Demand, kW	Excess Demand, kW	D1PROD 4CP-A&E	D2PROD 4CP
		Texas											
1	TXRT01	Residential Service	2,681,273,311		769,188	919,142	857,171	754,253	824,939	305,245	519,693		
2	TXRT02	Small General Service	293,668,116		70,760	76,677	72,637	63,799	70,968	33,432	37,536		
3	TXRT07	Outdoor Recreational Lighting Service	3,964,113		0	0	0	0	0	451	0		
4	TXRT08 - S	Street Lighting	38,885,062		0	0	0	0	0	4,427	0		
5	TXRT09 - S	Traffic Signals	2,238,641		195	194	194	194	194	255	0		
6	TXRT11	Municipal Pumping Service	184,553,605		21,154	31,935	22,772	19,377	23,809	21,010	2,799		
7	TXRT15	Electrolytic Refining Service	44,080,188		7,737	7,737	7,737	7,737	7,737	5,018	2,718		
8	TXRTWH	Off Peak Water Heating Service	5,525,633		424	391	338	373	381	629	0		
9	TXRT22	Irrigation Service	4,141,313		1,384	1,881	1,247	1,282	1,448	471	977		
10	TXRT24	General Service	1,563,783,384		318,539	328,425	308,666	306,939	315,642	178,026	137,616		
11	TXRT25	Large Power Service	653,791,174		97,487	103,584	104,808	104,702	102,645	74,430	28,215		
12	TXRT26	Petroleum Refining Service	323,027,097		41,374	41,374	41,374	41,374	41,374	36,774	4,599		
13	TXRT28	Private Area Lighting Service	28,935,421		0	0	0	0	0	3,294	0		
14	TXRT30	Electric Furnace Rate	22,162,293		5,127	5,127	5,129	5,125	5,127	2,523	2,604		
15	TXRT31	Military Reservation Service	285,962,320		52,229	52,229	52,229	52,229	52,229	32,555	19,674		
16	TXRT34	Cotton Gin Service	1,721,630		20	11	14	22	17	196	0		
17	TXRT41	City and County Service	208,727,752		43,948	49,879	47,325	47,639	47,198	23,762	23,436		
18		Texas Total Firm Load	6,346,441,052	78.7148%	1,429,567	1,618,585	1,521,641	1,405,044	1,493,709	722,500	779,869	80.4332%	80.2555%
19		Total Texas Interruptible Load	405,090,611		41,056	60,224	42,973	49,167	48,355	46,117			
20		Total Texas Load	6,751,531,663		1,470,623	1,678,810	1,564,613	1,454,210	1,542,064	768,617			
		Adjusted for New Mexico Solar Projects											
		New Mexico											
21	NMRT01	Residential Service	768,921,274		198,249	222,539	187,803	165,211	193,450	87,537	105,914		
22	NMRT03	Small General Service	159,580,592		34,226	40,910	39,065	35,295	37,374	18,167	19,207		
23	NMRT04	General Service	284,748,407		47,825	54,019	51,281	49,536	50,665	32,417	18,249		
24	NMRT05	Irrigation Service	40,398,905		5,409	9,247	8,806	11,234	8,674	4,599	4,075		
25	NMRT07	City and County Service	50,451,865		7,625	8,768	10,187	9,513	9,023	5,744	3,280		
26	NMRT08	Municipal Pumping Service	38,939,006		6,277	7,060	6,161	6,409	6,477	4,433	2,044		
27	NMRT09	Large Power Service	155,932,924		21,630	23,356	21,827	21,737	22,137	17,752	4,385		
28	NMRT10	Military Research and Development	57,411,558		9,839	11,253	9,875	9,403	10,092	6,536	3,556		
29	NMRT10 -T115	MRDS - HAFB	51,750,129		10,205	11,274	10,182	6,969	9,658	5,891	3,766		
30	NMRT11	Municipal Street Lighting Service	1,926,663		0	0	0	0	0	219	0		
31	NMRT12	Private Area Lighting Service	5,545,207		0	0	0	0	0	631	0		
32	NMRT19	Seasonal-Agricultural Processing Service	8,312,598		818	2,556	2,637	1,207	1,805	946	858		
33	NMRT25	Outdoor Recreational Lighting Service	430,845		0	0	0	0	0	49	0		
34	NMRT26	State University Service	26,826,997		6,058	5,552	5,097	3,996	5,176	3,054	2,122		
35		Total New Mexico Firm Load	1,651,176,971	20.4795%	348,161	396,534	352,922	320,509	354,532	187,976	167,456	18.8833%	19.0486%
36		Total New Mexico Interruptible Load	8,374,472		988	797	684	857	831	953			
37		Total New Mexico Load	1,659,551,443		349,149	397,331	353,605	321,366	355,363	188,929			
38	TXRT94 - T/69	Rio Grande Co-Op - Van Horn	22,663,105		5,162	4,984	4,463	3,353	4,490	2,580	1,910		
39	TXRT95 - T/115	Rio Grande Co-Op - Dell City	42,296,544		8,603	8,947	9,033	7,263	8,461	4,815	3,646		
		Total FERC	64,959,649	0.8057%	13,765	13,931	13,495	10,616	12,952	7,395	5,557	0.6834%	0.6959%
40		Total System Firm Load	8,062,577,672	100.0000%	1,791,493	2,029,051	1,888,058	1,736,169	1,861,192	917,871	952,881	100.000%	100.000%
41		Total System Load	8,476,042,754		1,833,537	2,090,072	1,931,714	1,786,192	1,910,379	964,941			
42										Load Factor [1] =	0.4507		
										1 Minus Load Factor =	0.5493		

Data Sources:
Based on EPE's response to RFI CEP 4-06, CEP 04-06_Attachment_02 VOLUMINOUS, reflecting TIEC's recommended solar plant adjustments.
1. Load Factor from Exhibit KCH-7.

TIEC Dedicated Solar Adjustment per Jurisdiction

		Demand Losses	Energy Losses	Demand Capacity kW	Energy kWh	Jun 2020 Coincident kW @ Source	Jul 2020 Coincident kW @ Source	Aug 2020 Coincident kW @ Source	Sep 2020 Coincident kW @ Source	Annual Capacity Factor [2]	Degradation Factor [2]
	New Mexico Solar Projects [1]										
1	Hatch	1.06265	1.05123	5,000	13,524,288	1,540	1,540	1,540	1,540	30.9%	0.5%
2	NRG	1.06265	1.05123	20,000	50,566,661	5,757	5,757	5,757	5,757	29.0%	0.8%
3	Sun Edison 1 and 2	1.06265	1.05123	22,000	55,991,797	6,374	6,374	6,374	6,374	29.2%	0.8%
4	Rio Grande	1.08212	1.07850	64	79,231	9	9	9	9	14.2%	0.8%
5	Total Solar PV directly assigned to NM				126,320,036	14,537	14,537	14,537	14,537		
6	Holloman	1.02412	1.02669	5,000	8,850,536	1,008	1,008	1,008	1,008	20.3%	0.7%
7	Total Solar PV directly assigned to military				9,086,756	1,032	1,032	1,032	1,032		
	Texas Solar Projects										
8	Wrangler	1.08212	1.0785	48	3,970	0	0	0	0	1.0%	0.8%
9	Stanton Tower	1.08212	1.0785	31	66,296	8	8	8	8	24.5%	0.8%
10	EPCC	1.08212	1.0785	14	23,755	3	3	3	3	19.5%	0.8%
11	Van Horn	1.08212	1.0785	15	34,119	4	4	4	4	25.4%	0.8%
12	Newman	1.08212	1.0785	64	95,354	11	11	11	11	17.1%	0.8%
13	Total Solar PV directly assigned to TX				241,039	28	28	28	28		

Data Sources:
1. Based on EPE's response to RFI CEP 4-6, CEP 04-06_Attachment_02 VOLUMINOUS.
2. Based on EPE's response to RFI CEP 4-7, CEP 04-07_Attachment_01.

TIEC Calculation of Load Factor
Using July 2020 Unadjusted Firm Peak

Line No.	(a)	(b)
1	**Energy at Source[1]**	
2	Texas	
3	Firm	6,500,865,622
4	Non-Firm	383,471,591
5	Total	6,884,337,213
6	New Mexico	
7	Firm	1,846,721,750
8	Non-Firm	8,374,472
9	Total	1,855,096,222
10	FERC	64,959,649
11	Total Firm Energy	8,412,547,021
12	**July 2020 Coincident Demand at Source[1]**	
13	Texas	
14	Firm	1,664,286
15	Non-Firm	65,970
16	Total	1,730,256
17	New Mexico	
18	Firm	428,016
19	Non-Firm	797
20	Total	428,813
21	FERC	13,931
22	Total Firm July CPD	2,106,233
23	**Load Factor for Class COS:**	45.47%
24	**Solar Adjustment - TIEC Solar Capacity Proposal[2]**	
25	Energy - NM Solar	126,320,036
26	Energy - Holloman	9,086,756
27	Energy - TX Solar	241,039
28	July CP kW - NM Solar	14,537
29	July CP kW - Holloman	1,032
30	July CP kW- TX Solar	28
31	Firm Energy Minus Solar	8,276,899,189
32	July Firm CP Minus Solar	2,090,637
33	**Load Factor Minus Solar For Jur. COS**	45.07%

Data Sources:
1. Schedule O-01.03.

2. Based on solar data provided in EPE's response to RFI CEP 4-7, CEP 04-07_Attachment_01, as adjusted for TIEC's recommended solar capacity attribution (consistent with annual energy production output)

TIEC Calculation of Class A&E/4CP Allocator

Line No.	(a) Rate	(b) Texas Rate Class	(c) Annual Energy at Source, kWh	(d) E1ENERGY Energy Allocator	(e) 4-CP Demand, kW	(f) Annual Average Demand, kW	(g) Excess Demand, kW	(h) D1PROD 4CP-A&E
1	TXRT01	Residential Service	2,681,376,311	42.2485%	824,954	305,257	519,697	55.5486%
2	TXRT02	Small General Service	293,679,397	4.6273%	70,970	33,433	37,536	4.7286%
3	TXRT07	Outdoor Recreational Lighting Service	3,964,113	0.0625%	0	451	0	0.0284%
4	TXRT08	Street Lighting	38,885,062	0.6127%	0	4,427	0	0.2786%
5	TXRT09	Traffic Signals	2,238,727	0.0353%	194	255	0	0.0160%
6	TXRT11TOU	Municipal Pumping Service - TOU	184,560,694	2.9080%	23,810	21,011	2,799	1.5180%
7	TXRT15	Electrolytic Refining Service	44,081,882	0.6946%	7,737	5,018	2,718	0.5059%
8	TXRTWH	Off Peak Water Heating Service	5,525,846	0.0871%	381	629	0	0.0396%
9	TXRT22	Irrigation Service	4,141,472	0.0653%	1,448	471	977	0.0980%
10	TXRT24	General Service	1,563,843,457	24.6403%	315,648	178,033	137,615	20.8263%
11	TXRT25	Large Power Service	653,816,289	10.3017%	102,647	74,433	28,214	6.6570%
12	TXRT26	Petroleum Refining Service	323,039,506	5.0899%	41,374	36,776	4,599	2.6359%
13	TXRT28	Private Area Lighting Service	28,935,421	0.4559%	0	3,294	0	0.2073%
14	TXRT30	Electric Furnace Rate	22,163,145	0.3492%	5,127	2,523	2,604	0.3409%
15	TXRT31	Military Reservation Service	285,973,306	4.5059%	52,230	32,556	19,674	3.4245%
16	TXRT34	Cotton Gin Service	1,721,696	0.0271%	17	196	0	0.0123%
17	TXRT41	City and County Service	208,735,770	3.2889%	47,199	23,763	23,436	3.1341%
18		Texas Firm	6,346,682,091	100.0000%	1,493,737	722,528	779,869	100.0000%
19		Texas Non-Firm	405,090,611			46,117		
20		Total Texas	6,751,772,701			768,644		

Unadjusted 1CP Load Factor [1] = 45.47%
1 Minus Load Factor = 54.53%

Data Source:
Load Factor from Exhibit KCH-7.

TIEC 69 kV Transmission Reallocation Calculation

Line No.	(a) Texas Firm	(b) Adjusted 4CP [1]	(c) Share of Total System Firm 4CP	(d) Estimated EPE-Allocated 69 kV Tran. Costs	(e) Adjusted 4CP ≤69 kV [1]	(f) Share of Total System Firm 4CP ≤69 kV	(g) TIEC Reallocated 69 kV Tran. Costs	(h) Estimated Impact of Reallocation
1	R01-Residential TX	824,954	43.96%	$1,313,443	824,954	46.95%	$1,402,961	$89,517
2	R02-Small Gen Serv	70,970	3.78%	$112,994	70,970	4.04%	$120,695	$7,701
3	R07-Rec Light	0	0.00%	$0	0	0.00%	$0	$0
4	R08-Street Light	0	0.00%	$0	0	0.00%	$0	$0
5	R09-Traffic Signs	194	0.01%	$309	194	0.01%	$330	$21
6	R11TOU-Muni Pump	23,810	1.27%	$37,908	23,810	1.36%	$40,492	$2,584
7	R15-Elec Ref	7,737	0.41%	$12,318	7,737	0.44%	$13,158	$840
8	R22-Irrig Serv	1,448	0.08%	$2,306	1,448	0.08%	$2,463	$157
9	R24-Gen Serv	315,648	16.82%	$502,557	315,648	17.96%	$536,808	$34,252
10	R25-Large Power	102,647	5.47%	$163,429	101,111	5.75%	$171,954	$8,526
11	R26-Petroleum Ref	41,374	2.20%	$65,874	0	0.00%	$0	-$65,874
12	R28-P Area Light	0	0.00%	$0	0	0.00%	$0	$0
13	R30-Elec Furnace	5,127	0.27%	$8,163	1,807	0.10%	$3,073	-$5,090
14	R31-Mili Reserv	52,230	2.78%	$83,158	0	0.00%	$0	-$83,158
15	R34-Cotton Gin	17	0.00%	$27	17	0.00%	$29	$2
16	R41-Cty/Cnty	47,199	2.51%	$75,147	47,199	2.69%	$80,269	$5,122
17	RWH-Water Heating	381	0.02%	$607	381	0.02%	$648	$41
18	Total Texas Firm	1,493,737	79.59%	$2,378,240	1,395,276	79.41%	$2,372,880	-$5,360
19	New Mexico Firm							
20	69 kV and Below	357,272	19.04%	$568,828	357,272	20.33%	$607,596	$38,768
21	115 kV	12,828	0.68%	$20,424	0	0.00%	$0	-$20,424
22	Total New Mexico Firm	370,100	19.72%	$589,252	357,272	20.33%	$607,596	$18,344
23	FERC Jurisdiction							
24	Rio Grande Co-Op - Van Horn - 69 kV	4,490	0.24%	$7,149	4,490	0.26%	$7,637	$487
25	Rio Grande Co-Op - Dell City -115 kV	8,461	0.45%	$13,472	0	0.00%	$0	-$13,472
26	Total FERC	12,952	0.69%	$20,621	4,490	0.26%	$7,637	-$12,984
27	Total Company at Source							
28	Total Company - Firm	1,876,789	100.00%	$2,988,113	1,757,038	100.00%	$2,988,113	$0

Data Source:
1. Based on Schedule O-01.04.

TIEC 69 kV Transmission Cost Calculation
For The Test Year Ended December 31, 2020

Line No.	(a) Income Statement	(b) Total Company Amount
1	Operating Revenues	
2	Base Revenue	
3	Fuel & Purchased Power Revenue	
4	Total Sales Revenue	
5	Other Operating Revenue	
6	Total Revenues	$0
7	Operating Expenses	
8	Operation and Maintenance	
9	Fuel and Purchased Power Expense	
10	Production O&M	
11	Transmission O&M	332,877
12	Distribution O&M	
13	Customer Accounts (excl. Uncollectibles)	
14	Uncollectible Accounts	10,784
15	Customer & Information Systems	
16	A&G Expenses	
17	Total Non-Fuel & PP O&M Expense	343,661
18	Total O&M Expense	$343,661
19	Depreciation/Amortization Expense	610,459
20	Taxes Other Than Income Expense	216,073
21	Revenue Related Tax Expense	132,550
22	Federal Income Tax Expense	247,864
23	State Income Tax Expense	20,117
24	Other Expenses	
25	Total Expenses	$1,570,725
	Rate Base	**Total Company Amount**
26	Electric Plant in Service	$38,131,274
27	Accumulated Reserve for Depreciation	(15,557,161)
28	Net Electric Plant in Service	$22,574,113
29	Additions	
30	Cash Working Capital	
31	Fuel Inventory	
32	Materials and Supplies	
33	Prepayments	
34	Coal Reclamation Asset	
35	Property Insurance Reserve	
36	Nuclear Fuel Dry Cask Storage	
37	Injuries and Damages Reserve	
38	Unamortized Transition Costs	
39	Miscellaneous Deferred Debits - Allocated	
40	Miscellaneous Deferred Debits - Assigned	
41	CWIP	
42	Total Additions	$0
43	Deductions	
44	Accumulated Deferred Income Taxes	($4,823,476)
45	Coal Reclamation Liability	
46	Customer Deposits	
47	Regulatory Assets/Liabilities (SFAS 109)	
48	Customer Advances for Construction	
49	Accumulated Deferred ITC - Pre 1971	
50	Total Deductions	($4,823,476)
51	Total Rate Base	$17,750,637
	Estimated Revenue Requirement Impact:	
52	Total Income Statement RR Impact	$1,570,725
53	Rate Base Impact	$17,750,637
54	EPE Requested Rate of Return on Rate Base (EPE Schedule K-1.0)	7.985%
55	Rate Base RR Impact	$1,417,388
56	**Total Revenue Requirement Impact**	**$2,988,113**

TIEC 69 kV Transmission Reallocation Calculation
For The Test Year Ended December 31, 2020

Line No.		FERC Account	Total Company [1]
1	**Rate Base**		
2	Transmission- Gross Plant		
3	Land and Land Rights	350	403,085
4	Structures and Improvements	352	299,244
5	Station Equipment	353	1,658,423
6	Towers and Fixtures	354	3,200,078
7	Poles and Fixtures	355	28,995,927
8	O.H. Conductors & Devices	356	3,557,201
9	Roads and Trails	359	17,316
10	Transmission - Accumulated Depreciation		
11	Land and Land Rights	350	(85,363)
12	Structures and Improvements	352	(104,537)
13	Station Equipment	353	(775,367)
14	Towers and Fixtures	354	(1,625,003)
15	Poles and Fixtures	355	(10,920,725)
16	O.H. Conductors & Devices	356	(2,026,057)
17	Roads and Trails	359	(20,110)
18	Accumulated Deferred Income Tax	282	(4,823,476)
19	Total Rate Base		17,750,637
20	**Expenses**		
21	Transmission - Depreciation Expense		
22	Land and Land Rights	350	8,641
23	Structures and Improvements	352	3,945
24	Station Equipment	353	16,341
25	Towers and Fixtures	354	41,338
26	Poles and Fixtures	355	492,505
27	O.H. Conductors & Devices	356	47,511
28	Roads and Trails	359	178
29	Total Depreciation Expense		610,459
30	Transmission - O&M		
31	Operation Supervision & engineering	560	15,330
32	Station Expenses	562	3,125
33	Overhead line expense	563	25,739
34	Misc. transmission expenses	566	1,412
35	Rents	567	5,243
36	Maintenance of station equipment	570	257
37	Maintenance of overhead lines	571	280,074
38	Maintenance of misc. transmission plant	573	1,697
39	Total O&M Expense		332,877
40	Transmission - Property Tax [2]	4081	216,073

Data Sources:

1. EPE's response to RFI TIEC 5-2, TIEC 5_02 Attachment 1.

2. EPE's response to RFI TIEC 5-2, TIEC 5_02 Attachment 2.
Applies the effective property tax rate of 0.95717% to 69kV Transmission net plant.

TIEC Class Cost-of-Service Results and Recommended Revenue Allocation

At EPE's Proposed Total Revenue Requirement

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
Line No.	Rate Class	Current Base Revenues [1]	Base Revenue Requirement from TIEC COS [2]	Estimated Impact of TIEC 69 kV Reallocation [3]	Base Revenue Req. with 69 kV Impact [4]	Non-Firm Rev. Increase [5]	TIEC A&E/4CP Allocator [6]	COVID Rider [7]	TIEC LABOR Allocator [8]	Net Base Revenue Requirement [9]	Base Increase/ (Decrease) at COS $ [10]	Base Increase/ (Decrease) at COS % [11]
1	R01-Residential TX	$273,638,830	$331,740,022	$89,517	$331,829,539	$180,609	55.55%	$1,353,280	61.62%	$330,295,650	$56,656,820	20.70%
2	R02-Small Gen Serv	$33,319,685	$30,102,752	$7,701	$30,110,453	$15,374	4.73%	$136,869	6.23%	$29,958,209	($3,361,476)	-10.09%
3	R07-Rec Light	$462,980	$601,618	$0	$601,618	$92	0.03%	$2,427	0.11%	$599,098	$136,118	29.40%
4	R08-Street Light	$4,046,620	$3,060,118	$0	$3,060,118	$906	0.28%	$14,983	0.68%	$3,044,229	($1,002,391)	-24.77%
5	R09-Traffic Signs	$95,204	$91,784	$21	$91,805	$52	0.02%	$364	0.02%	$91,389	($3,815)	-4.01%
6	R11TOU-Muni Pump	$10,102,350	$9,513,838	$2,584	$9,516,422	$4,935	1.52%	$33,159	1.51%	$9,478,328	($624,022)	-6.18%
7	R15-Elec Ref	$1,830,063	$2,127,091	$840	$2,127,931	$1,645	0.51%	$6,641	0.30%	$2,119,645	$289,582	15.82%
8	R22-Irrig Serv	$423,413	$573,667	$157	$573,824	$319	0.10%	$2,040	0.09%	$571,466	$148,053	34.97%
9	R24-Gen Serv	$125,005,740	$111,839,351	$34,252	$111,873,603	$67,714	20.83%	$373,829	17.02%	$111,432,060	($13,573,680)	-10.86%
10	R25-Large Power	$35,955,664	$35,384,643	$8,526	$35,393,169	$21,644	6.66%	$117,166	5.34%	$35,254,358	($701,306)	-1.95%
11	R26-Petroleum Ref	$10,964,770	$11,720,764	($65,874)	$11,654,890	$8,570	2.64%	$38,682	1.76%	$11,607,637	$642,867	5.86%
12	R28-P Area Light	$2,932,614	$2,633,158	$0	$2,633,158	$674	0.21%	$6,592	0.30%	$2,625,891	($306,723)	-10.46%
13	R30-Elec Furnace	$1,191,760	$1,481,954	($5,090)	$1,476,864	$1,108	0.34%	$4,147	0.19%	$1,471,609	$279,849	23.48%
14	R31-Mili Reserv	$13,009,892	$14,152,723	($83,158)	$14,069,565	$11,134	3.42%	$44,403	2.02%	$14,014,028	$1,004,136	7.72%
15	R34-Cotton Gin	$132,972	$176,411	$2	$176,413	$40	0.01%	$609	0.03%	$175,764	$42,792	32.18%
16	R41-Cty/Cnty	$19,126,500	$16,846,314	$5,122	$16,851,436	$10,190	3.13%	$55,637	2.53%	$16,785,609	($2,340,891)	-12.24%
17	RWH-Water Heating	$474,582	$793,394	$41	$793,435	$129	0.04%	$5,230	0.24%	$788,076	$313,494	66.06%
18	Total Texas	$532,713,639	$572,839,603	($5,360)	$572,834,243	$325,136	100.00%	$2,196,060	100.00%	$570,313,047	$37,599,408	7.06%

Data Sources/Notes

1. EPE Regulatory Case Working Model - As Filed - Dkt 52195, Revenue Requirement tab.
2. EPE Regulatory Case Working Model - Dkt 52195 TIEC Direct WP. Reflects the impact of my recommended treatment of directly-assigned solar plants. Also includes, for illustrative purposes, the impact of reflecting my class cost allocation recommendations on a jurisdictional basis, in case the Commission decides to also apply those changes to jurisdictional cost allocation.
3. Exhibit KCH-9, p. 1.
4. Columns (c) + (d)
5. Total non-firm increase from Exhibit MC-4. Allocated to classes based on A&E/4CP.
6. Exhibit KCH-8.
7. Allocated to classes based on TIEC's LABOR allocator.
8. EPE Regulatory Case Working Model - Dkt 52195 TIEC Direct WP.
9. Columns (e) - (f) - (h). Excludes the impact of the COVID rider for comparability with Exhibit MC-4.
10. Column (j) - Column (b).
11. Column (k) ÷ Column (b).

SOAH NO. 473-21-2606
PUC DOCKET NO. 52195

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

DIRECT TESTIMONY

OF

KEVIN C. HIGGINS

FOR

TEXAS INDUSTRIAL ENERGY CONSUMERS

October 22, 2021

TABLE OF CONTENTS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kevin C. Higgins. My business address is 111 East Broadway, Suite 1200, Salt Lake City, Utah, 84111.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. My testimony is being sponsored by Texas Industrial Energy Consumers ("TIEC").

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND QUALIFICATIONS.

A. My academic background is in economics, and I have completed all coursework and field examinations toward a Ph.D. in Economics at the University of Utah. Previously I was awarded a B.S. in Education at the State University of New York at Plattsburgh. Subsequent to my graduate coursework, I served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was an economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE ANY STATE UTILITY REGULATORY COMMISSIONS?

A. Yes. I have filed testimony and/or testified at hearings in approximately 270 proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arizona, Arkansas, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Texas, Utah, Virginia, Washington, West Virginia, and Wyoming. I have also filed affidavits in proceedings at the Federal Energy Regulatory Commission.

II. <u>OVERVIEW AND CONCLUSIONS</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony addresses both revenue requirement and cost allocation/rate design issues. I recommend adjusting the revenue requirement proposed by El Paso Electric Company ("EPE" or the "Company") for several specific items. I did not, however, undertake a full review of EPE's revenue case. I also address a jurisdictional allocation issue concerning EPE's proposed treatment of directly assigned solar plants.

My testimony also addresses the distribution of any increase or decrease among rate schedules, or revenue allocation.

The absence of comment on my part regarding a particular issue does not signify support for EPE's filing with respect to that issue.

Q. WHAT REVENUE INCREASE IS EPE RECOMMENDING FOR THE TEXAS JURISDICTION?

A. In its direct filing, EPE proposes an increase of $69.7 million in Texas base (non-fuel) revenues. This increase is offset by $27.9 million in combined Transmission Cost Recovery Factor and Distribution Cost Recovery Factor revenues that are being reset to zero in this case, for a net base increase of $41.8 million, which is an average increase of 7.79% over current non-fuel revenue.[1] This $41.8 million increase is comprised of an increase of $39.3 million to base firm revenue, an increase of $324 thousand to interruptible base revenue, and $2.2 million recovered annually through a proposed COVID rider for 3 years. In addition, EPE proposes a $721 thousand decrease to Miscellaneous Service Charges, for a net increase of $41.1 million.[2] EPE's request is based on its proposed overall return of 7.985%, incorporating a return on equity of 10.30%.[3] TIEC witness Michael Gorman is addressing the return-on-equity issue.

Q. PLEASE SUMMARIZE THE REVENUE REQUIREMENT ADJUSTMENTS YOU ARE RECOMMENDING.

A. In total, my recommended revenue requirement adjustments reduce EPE's Texas base revenue requirement deficiency by **$2,387,267** relative to EPE's direct filing. My revenue requirement adjustments are presented in Table KCH-1 below.

Table KCH-1
Summary of Texas Revenue Requirement Adjustments

Description	Texas Revenue Requirement Amount
SERP Adjustment	($875,549)
Excess Benefit Adjustment	($794,125)
Palo Verde Incentive Compensation	($128,494)
Revolving Credit Facilities Commitment Fees Adjustment	($468,164)
Accumulated Depreciation - Annualization Adjustment	($120,935)
Total Adjustments	($2,387,267)

[1] Direct Testimony of James Schichtl at 3 (Schichtl Dir.).

[2] Derived from Schedule Q-07.00.

[3] *See* Schedule K-01.00.

As noted, I also address a jurisdictional allocation issue concerning the direct assignment of solar plants. I will explain the basis for each of these adjustments in the following sections.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS CONCERNING EPE'S PRODUCTION COST ALLOCATION.

A. As a general proposition, I support EPE's use of the Average and Excess Four Coincident Peak ("A&E/4CP") method to allocate most of its production plant. However, I disagree with certain aspects of the Company's production cost allocation and recommend several changes to EPE's proposed approach. The primary changes I recommend to EPE's production cost allocation are:

- The capacity attributed to directly-assigned solar plants in EPE's jurisdictional allocation should be adjusted to be consistent with EPE's solar purchased power agreement ("PPA") capacity imputation. EPE removed the generation from solar plants it directly assigns to New Mexico and Texas from each state's respective 4CP demand, which is used in the jurisdictional 4CP allocator applied to peaking units and the jurisdictional A&E/4CP allocator. This reduces the 4CP for New Mexico by approximately 68% of its directly-assigned solar capacity and the 4CP for Texas by approximately 70% of its directly-assigned solar capacity. I recommend basing the reduction to each state's 4CP demand on the energy production output from these solar resources (i.e., annual capacity factors). This is consistent with the approach EPE uses for imputing capacity costs to the Newman 10 and Macho Springs PPAs.

  In the alternative, I recommend that the capacity value imputed to the Newman 10 and Macho Springs PPAs be increased to be consistent with the approach EPE uses to attribute capacity to the directly-assigned solar resources, with a corresponding reduction to EPE's eligible fuel cost.

- The load factor used for weighting average demand in the A&E/4CP allocator calculation should be based on single highest actual firm system coincident peak for EPE's system (1CP). EPE's proposal to calculate the load factor using the average of the adjusted 4CPs should be rejected.

- The A&E/4CP allocation method should be applied to all allocable production plant, including EPE's peaking units (Montana Power Station Units 1-4, Rio Grande

Generating Station Unit 9, and Copper Generating Station), rather than adopting EPE's proposal to change to the 4CP method for these units.[4]

- Palo Verde Operations & Maintenance ("O&M") expenses (FERC Accounts 519, 520, 523, 530, 531, and 532) should be allocated using the A&E/4CP allocator rather than EPE's proposed energy allocator.

- Generation System Control and Load Dispatching (FERC Account 556) should be allocated using the A&E/4CP allocator, consistent with EPE's allocation of most generation plant.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS CONCERNING EPE'S TRANSMISSION COST ALLOCATION.

A. I generally support EPE's use of the 4CP method to allocate transmission plant and most transmission expenses. However, I recommend two changes to EPE's transmission cost allocation approach:

- Transmission Load Dispatching (FERC Account 561) should be allocated using the 4CP method, consistent with all other transmission costs, rather than EPE's 12CP allocator.

- Customers that receive service at 115 kV voltage should not be allocated costs associated with EPE's 69 kV transmission system, since, as a general matter, 115 kV customers do not utilize the 69 kV system.

Q. DO YOU RECOMMEND ANY CHANGES TO EPE'S ALLOCATION OF MISCELLANEOUS EXPENSES?

A. Yes, I recommend that Contributions and Donations expense be allocated based on customer count, because it is appropriate to allocate these costs in a manner that reflects the broad community benefit of these gifts.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS CONCERNING THE ALLOCATION OF ANY INCREASE OR DECREASE.

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[4] Direct Testimony of Adrian Hernandez at 11 (Hernandez Dir.).

A. I recommend moving all rate classes to full cost recovery. Moving each class to full cost recovery eliminates inter-class subsidies and is consistent with the Commission's strong preference for aligning class revenues with costs.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS CONCERNING RATE DESIGN.

A. I recommend that the applicability provision in Rate 25 be modified to remove the language that prohibits customers eligible for other rate schedules from taking service under this rate schedule. The choice of the appropriate rate schedule should be the customer's, not EPE's. If a customer meets the eligibility requirements for a rate schedule, that customer should be able to receive service under that schedule.

III. REVENUE REQUIREMENT

Supplemental Executive Retirement Plan and Excess Benefit Plan

Q. WHAT IS A SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN/EXCESS BENEFIT PLAN?

A. Supplemental executive retirement plans ("SERP") and excess benefit plans are also known as non-qualified retirement plans. Such plans provide benefits in excess of the earnings limitations set in Section 415 of the Internal Revenue Code, and therefore lack the tax advantages conferred upon qualified pension plans. For 2021, for qualified plans, the Internal Revenue Code limits the maximum annual benefit that can be paid through a defined benefit plan to $230,000 per year and limits the compensation that can be included in determining benefits to $290,000.[5] In contrast, there is no statutory restriction on the amount of the benefit that may be offered under a non-qualified pension plan. Typically, non-qualified plans are intended to benefit a select group of highly-compensated employees.

Q. PLEASE DESCRIBE EPE'S NON-QUALIFIED RETIREMENT PLANS.

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[5] The limitations are summarized here: irs.gov/retirement-plans/cola-increases-for-dollar-limitations-on-benefits-and-contributions.

A. EPE has two non-qualified retirement income plans: (i) its SERP and (ii) its Excess Benefit Plan. EPE closed its SERP to new participants in 1996 in conjunction with its emergence from bankruptcy. However, the plan covers 17 former officers and 9 former employees who were grandfathered on the plan.[6]

The Excess Benefit Plan was adopted in 2004, and covers 13 current officers and 19 former officers.[7] According to EPE's most recent 10-K, the Excess Benefit Plan is offered to employees holding the office of Vice President and above, as well as "a select group of management or highly compensated employees."[8]

Q. WHAT RATEMAKING TREATMENT HAS EPE PROPOSED REGARDING ITS SERP AND EXCESS BENEFIT PLAN?

A. EPE is proposing to include the cost of its SERP and Excess Benefit Plan in its proposed revenue requirement.

Q. DO YOU AGREE WITH EPE'S PROPOSAL TO INCLUDE THE COST OF ITS SERP AND EXCESS BENEFIT PLAN IN RATES?

A. No, I do not. Customers should not be forced to fund the extraordinary retirement benefits reflected in non-qualified retirement plans. I do not see the provision of a non-qualified retirement income plan to be essential for the provision of electricity service to customers, but rather a discretionary benefit. The cost of these exceptional retirement benefits granted to a select group of highly-compensated employees and officers should be borne by shareholders, not customers. These costs should be excluded from the revenue requirement.

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[6] Schedule G-2 at 2-3; Direct Testimony of Cynthia S. Prieto at 10-11 (Prieto Dir.); EPE's response to RFI TIEC 2-1.

[7] Schedule G-2 at 2-3; Prieto Dir. at 10-11; EPE's response to RFI TIEC 2-1.

[8] El Paso Electric Company Form 2019 10-K/A, Amendment No. 1, p. 24.

This recommendation is consistent with Commission precedent that non-qualified executive retirement benefits are not reasonable or necessary to provide utility service to the public, not in the public interest, and should not be included in cost of service.[9]

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION ON THIS ISSUE?

A. I recommend that the Company's SERP and Excess Benefit Plan expenses be removed from the revenue requirement. The adjustment to remove SERP expenses reduces the Texas revenue requirement by approximately **$875,549** and is presented in Exhibit KCH-1, while the adjustment to remove Excess Benefit Plan expenses reduces the Texas revenue requirement by approximately **$794,125** and is presented in Exhibit KCH-2.

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[9] *Application of Entergy Texas, Inc. for Authority to Change Rates, Reconcile Fuel Costs, and Obtain Deferred Accounting Treatment*, Docket No. 39896, Order at Finding of Fact 142 (Sept. 14, 2012); *see also Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 51415, Proposal for Decision, at 335 (Aug. 27, 2021) (where the ALJs acknowledge that SWEPCO removed the SERP expense that comes from pension benefits that exceed the compensation limit for qualified pension plans from its requested cost of service "based on the Commission's precedents in Docket Nos. 40443 and 46449.").

<u>Palo Verde Incentive Compensation</u>

Q. PLEASE DESCRIBE EPE'S OWNERSHIP INTEREST IN PALO VERDE NUCLEAR GENERATING STATION ("PVNGS").

A. PVNGS, the largest nuclear power station in the U.S., consists of three identical units with an electric design rating totaling 4,003 MW. EPE owns a 15.8% share of each of the three units and the common facilities and receives an allocation of approximately 633 MW when at full power.[10] PVNGS is jointly owned by seven southwestern utilities and operated by Arizona Public Service Company ("APS") under a Participation Agreement. The PVNGS capital and O&M budgets are reviewed and approved by the joint owners.[11]

Q. WHAT ADJUSTMENT DO YOU RECOMMEND FOR PALO VERDE INCENTIVE COMPENSATION?

A. My adjustment removes the incentive compensation included in the Test Year for PVNGS employees that is associated with APS's Company Earnings. EPE excludes incentive compensation for its own employees that is explicitly tied to financial performance from its requested cost of service,[12] but does not make the corresponding adjustment for financially-based incentive compensation for PVNGS employees.[13] It is appropriate to consistently apply this approach to financially-based incentive compensation allocated to EPE for PVNGS employees.

The Commission has found that the benefits of financially-based incentive compensation "inure most immediately and predominantly to…shareholders, rather than electric

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[10] Direct Testimony of Todd Horton at 2-3, 6 (Horton Dir.).

[11] *Id.* at 10, 32-33.

[12] Prieto Dir. at 7.

[13] EPE response to RFI CEP 10-17.

customers."[14] In the case of PVNGS incentive compensation tied to Company Earnings, it is APS's shareholders who are the primary beneficiaries, not EPE's ratepayers.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION ON THIS ISSUE?

A. I recommend that the PVNGS incentive compensation expense associated with APS Company Earnings be removed from the revenue requirement.[15] This adjustment reduces the Texas revenue requirement by approximately **$128,494** and is presented in Exhibit KCH-3.

<u>Revolving Credit Facility Commitment Fees</u>

Q. WHAT IS EPE PROPOSING REGARDING ITS REVOLVING CREDIT FACILITY ("RCF") FEES?

A. EPE maintains a $400 million RCF to fund nuclear fuel purchases, working capital requirements, and general corporate purposes.[16] Since nuclear fuel costs are recovered in the Fixed Fuel Factor, EPE does not seek to include associated commitment fees in its non-fuel revenue requirement. EPE proposes to include $571,211 in Total Company RCF commitment fees in its revenue requirement, which the Company asserts is the portion of commitment fees associated with non-nuclear fuel purposes.[17]

EPE is charged a commitment fee of 0.175% on the unused amount of the commitment.[18] EPE's RCF commitment fees thus represent a cost associated with EPE's use of short-term debt to finance its operations. EPE calculates its proposed RCF commitment fee by

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[14] *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 40443, Order on Rehearing at Finding of Fact No. 147 (Mar. 6, 2014).

[15] EPE provided data on the PVNGS incentive compensation in its response to RFI CEP 10-16.

[16] Direct Testimony of Lisa D. Budtke at 16-19 (Budtke Dir.).

[17] *Id.* at 19.

[18] *Id.* at 17.

subtracting the highest level of borrowing for nuclear fuel during the Test Year from its $400 million RCF, and multiplying the difference by 0.175%.

Q. YOU MENTIONED THAT THE RCF COMMITMENT FEES ARE ASSOCIATED WITH EPE'S USE OF SHORT-TERM DEBT. DOES EPE PROPOSE TO INCLUDE SHORT-TERM DEBT IN ITS CAPITAL STRUCTURE FOR RATEMAKING PURPOSES?

A. No. EPE's proposed capital structure that is used to determine the weighted average cost of capital does not include short-term debt, which has a lower interest rate than long-term debt. The weighted average interest rate on EPE's RCF notes payable outstanding as of December 31, 2020 was approximately 1.41%,[19] whereas EPE's proposed cost of long-term debt is 5.576%. EPE's proposed return on equity is 10.30%.[20] Thus, while EPE actually uses short-term debt as a source of capital, it proposes that its cost of capital be set as if it only used long-term debt and equity to finance its operations, both of which are far more expensive to ratepayers than short-term debt.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING THE INCLUSION OF RCF COMMITMENT FEES IN RATES?

A. I recommend that the RCF commitment fees not be included in EPE's revenue requirement. Since customers are not afforded the benefit of EPE's use of lower-cost short-term debt financing in the capital structure used for ratemaking, it is not appropriate for customers to fund the RCF commitment fees. Stated differently, if EPE's use of short-term debt is ignored for purposes of setting a ratemaking capital structure, it would not be appropriate to turn around and charge ratepayers for fees associated with that short-term debt. Accordingly, I recommend that the Company's RCF commitment fees be removed from the revenue requirement. This adjustment reduces the Texas revenue requirement by approximately **$468,164** and is presented in Exhibit KCH-4.

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[19] Derived from Schedule K-04.00_PUBLIC. Based on annual interest rates of 3.5% applicable to the RCF ABR Loan and 1.36% applied to the RCF Eurodollar loans.

[20] Schedule K-01.00.

<u>Accumulated Depreciation – Annualization Adjustment</u>

Q. PLEASE EXPLAIN YOUR ANNUALIZATION ADJUSTMENT TO ACCUMULATED DEPRECIATION.

A. EPE makes annualization adjustments to depreciation expense for new plant added during the Test Year.[21] That is, the Company adjusts depreciation expense to reflect the forward-going depreciation expense associated with new investments rather than using the depreciation expense actually booked during the Test Year ended December 31, 2020.

In making its annualization adjustments for depreciation, EPE does <u>not</u> make a corresponding annualization adjustment for accumulated depreciation.[22] That is, the adjusted depreciation expense that EPE proposes to recover is not accompanied by an annualized increase in accumulated depreciation to be offset against rate base. The absence of such a corresponding adjustment produces a mismatch for ratemaking purposes. EPE's approach is asymmetric. It provides the Company with the revenue benefit of the annualized depreciation expense without recognizing any corresponding reduction in the rate base against which the new plant is being depreciated. My adjustment corrects this mismatch by increasing accumulated depreciation for ratemaking purposes by the amount of the incremental depreciation expense added in EPE's annualization adjustment. This approach represents the increase in accumulated depreciation that corresponds to EPE's annualized depreciation expense adjustment.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION ON THIS ISSUE?

A. I recommend that the Commission adopt my annualization adjustment for accumulated depreciation to be consistent with the matching principle in ratemaking. My recommendation reflects a higher level of accumulated depreciation as an attendant impact of EPE's proposed depreciation expense annualization adjustment. This adjustment

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[21] Direct Testimony of Larry J. Hancock at 33 (Hancock Dir.).

[22] EPE's response to RFI TIEC 4-4 b.

reduces the Texas revenue requirement by approximately **$120,935** at EPE's requested rate of return and is presented in Exhibit KCH-5.

IV. JURISDICTIONAL COST ALLOCATION

Summary of EPE's Methods

Q. PLEASE SUMMARIZE THE METHODS USED BY EPE TO ALLOCATE PRODUCTION COSTS TO THE TEXAS JURISDICTION.

A. As explained in the Direct Testimony of Adrian Hernandez, EPE utilizes the A&E/4CP method to allocate its non-peaking production demand costs to the state of Texas. This method uses EPE's adjusted system coincident peaks during the summer months of June through September.[23] In this case, EPE calculated the load factor used to weight each jurisdiction's proportion of the system average firm demand (or energy) using the average of the adjusted firm 4CP demands, rather than the actual highest coincident firm peak (1CP) demand.[24]

Next, each jurisdiction's "excess" firm demand is weighted by 1 minus the load factor, where excess demand represents the difference between each jurisdiction's proportion of system 4CP demand and average demand. EPE has made adjustments to both the 4CP demand and energy components that are intended to remove the output of solar facilities directly assigned to the Texas and New Mexico jurisdictions from the jurisdictional allocation of costs.

In this case, EPE proposes to change the method used to allocate the cost of its peaking units (Montana Power Station Units 1-4, Rio Grande Generating Station Unit 9, and Copper Generating Station) from the A&E/4CP method to the 4CP method.[25]

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[23] Hernandez Dir. at 9.

[24] Direct Testimony of George Novela at 8-9 (Novela Dir.). *See also* EPE's response to RFI CEP 4-6, CEP 04-06_Attachment_02 VOLUMINOUS.

[25] Hernandez Dir. at 11.

EPE allocates production O&M expenses using a combination of A&E/4CP, 4CP, energy, direct assignment, and uses an A&E/12CP allocator for Generation System Control and Load Dispatching (Account 556).[26]

Q. PLEASE SUMMARIZE THE METHODS USED BY EPE TO ALLOCATE TRANSMISSION, DISTRIBUTION, AND OTHER COSTS TO THE TEXAS JURISDICTION.

To allocate transmission plant costs to the state of Texas, EPE utilizes a 4CP demand method, based on each jurisdiction's proportion of system firm coincident peak demand for the months June through September.[27]

EPE directly assigns distribution plant between Texas and New Mexico based on geographical location and allocates general plant using a labor allocator based on payroll costs for the production, transmission, distribution and customer service functions.[28]

EPE allocates most transmission O&M expenses using the 4CP allocator, but uses a 12CP method to allocate Transmission Load Dispatching costs (Account 561).[29] Distribution O&M expenses are allocated based on the jurisdictional distribution plant or a composite allocator. Texas customer O&M expenses are determined based on a combination of direct assignment, composite allocators, and customer-based allocators. Uncollectible accounts are allocated based on firm revenues excluding Other Public Authority and Large Commercial & Industrial classes.[30]

Many Administrative and General ("A&G") expenses are allocated using a labor allocator. Some A&G expenses are allocated consistent with their associated function, while others

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[26] *Id.* at 13. *See also* EPE Regulatory Case Working Model - As Filed - Dkt 52195.

[27] Hernandez Dir. at 11.

[28] *Id.*

[29] *Id.* at 14.

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

are directly assigned.[31] Depreciation and amortization expense is allocated consistent with the underlying plant.[32]

[31] *Id.*

[32] *Id.* at 16.

Solar Plant Capacity Attribution

Q. HOW DOES EPE TREAT THE OUTPUT FROM THE SOLAR PLANTS DIRECTLY ASSIGNED TO NEW MEXICO AND TEXAS IN THE JURISDICTIONAL COST ALLOCATION PROCESS?

A. For jurisdictional cost allocation, EPE removes the generation from the directly-assigned solar plants from each state's load used in the A&E/4CP allocator, its proposed 4CP generation allocator for peaking units, and its energy allocators. EPE's bases its 4CP adjustment on the output of a subset of the directly-assigned solar plants during the summer monthly peak hours.[33] EPE's adjustment reduces the 4CP for New Mexico by approximately 68% of its directly-assigned solar capacity and the 4CP for Texas by approximately 70% of its directly-assigned solar capacity.[34] This adjustment reduces New Mexico's 4CP demand by approximately 35.5 MW and reduces Texas's 4CP demand by approximately 120 kW. The combined effect of these reductions is to allocate more costs to Texas ratepayers.[35]

Q. IS THE COMPANY'S APPROACH CONSISTENT WITH THE METHOD IT USES TO IMPUTE CAPACITY COSTS TO THE NEWMAN 10 AND MACHO SPRINGS SOLAR RESOURCES?

A. No. As explained in the Direct Testimony of David C. Hawkins, EPE's imputed capacity rates for the Newman 10 and Macho Springs PPAs are $2.33/kW-month and $2.35/kW-month, respectively.[36] These rates were calculated by EPE in its last general rate case, Docket No. 46831, based on the energy production output percentages (i.e., annual capacity

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[33] *See* EPE's response to RFI CEP 4-07, CEP 04-07_Attachment_01. EPE's adjustment is based on the weighted average capacity factors of the NRG, Hatch, and Sun Edison 1&2 plants during the hour of the monthly CP each day of June – September 2020.

[34] Derived from EPE's response to RFI CEP 4-06, CEP 4-06_Attachment_02. This includes the impact of the loss factor gross-up EPE applies to solar output.

[35] Includes Holloman in the New Mexico 4CP impacts.

[36] Direct Testimony of David C. Hawkins at 8-9 (Hawkins Dir.).

factors) for Newman 10 and Macho Springs, of 32.3% and 32.6%, respectively.[37] This is approximately half the solar plant capacity level EPE uses in its jurisdictional allocation.[38]

To calculate the Newman 10 and Macho Springs imputed capacity rates, EPE started with the WSPP (formerly known as Western Systems Power Pool) Agreement capacity rate of $7.32/kW-month. EPE then discounted this rate for the additional ancillary services attributable to an intermittent resource to arrive at an adjusted rate of $7.20/kW-month. To this rate, EPE applied the energy production output percentages for Newman 10 and Macho Springs, resulting in the imputed capacity rates of $2.33/kW-month and $2.35/kW-month, respectively.[39]

The imputed capacity portion of the Newman 10 and Macho Springs PPA costs is allocated using the A&E/4CP method and included in the base revenue requirement. The remaining Texas-allocated portion of the PPA costs is deemed to be energy-related and included in the Fixed Fuel Factor.

Q. WHAT IS YOUR RECOMMENDATION ON THIS ISSUE?

A. I recommend reducing the adjustment to each jurisdiction's 4CP demands used for jurisdictional allocation purposes to be consistent with the Test Year energy production output (i.e., annual capacity factor) for the state-assigned solar plants. This is consistent with the approach used by EPE to impute capacity costs to the Newman 10 and Macho Springs solar resources. This change decreases the reduction to New Mexico's 4CP demand to 15.6 MW and to Texas's 4CP demand to 28 kW to reflect solar plant capacity. An illustration of the resulting jurisdictional A&E/4CP allocator is presented in Exhibit KCH-6.

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[37] EPE's response to RFI FMI 1-5. These capacity factors are based on the Docket No. 46831 Test Year ended September 30, 2016.

[38] Based on RFI CEP 4-07, CEP 04-07_Attachment_01, the weighted average summer peak capacity factors for NRG, Hatch, and Sun Edison 1&2 average approximately 65%.

[39] EPE's response to RFI FMI 1-5.

In the alternative, I recommend that the capacity value imputed to the Newman 10 and Macho Springs resources be increased to be consistent with the approach EPE uses to attribute capacity to the directly-assigned solar resources in its jurisdictional cost allocation. Based on the Test Year output of these plants at the monthly summer peak times, Newman 10 operated at an average of 73.3% of its capacity and Macho Springs at 66.2% of its capacity.[40] This would correspond to a capacity value of approximately $5.28/kW-month for Newman 10 and $4.76/kW-month for Macho Springs using the adjusted WSPP capacity rate of $7.20/kW-month.[41] Under this alternative, the base revenue requirement would be increased by approximately $1.8 million (Total Company) to reflect the incremental increase in imputed capacity for these resources,[42] with EPE being ordered to remove the corresponding amount from its fuel costs on the effective date of the rates set in this case. Any increase in imputed capacity costs should be allocated based on A&E/4CP, consistent with the current treatment of imputed capacity costs.

V. CLASS COST ALLOCATION

Q. PLEASE SUMMARIZE THE METHODS USED BY EPE TO ALLOCATE COSTS AMONG THE TEXAS RATE CLASSES.

A. EPE uses the A&E/4CP method for non-peaking production plant costs, using a system load factor based on the average of the adjusted firm 4CP demands. The 4CP method is used for peaking generation costs and transmission plant costs.[43]

EPE uses Maximum Class Demand to allocate substation and primary distribution feeder system costs and Non-Coincident Peak demand to allocate secondary voltage distribution feeders and line transformer costs.[44] Services are allocated using a service drop investment

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[40] Derived from EPE's response to RFI FMI 2-1, Attachment 15 2020 -Newman and Attachment 13 2020-Macho.

[41] 73.27% × $7.20 = $5.28. 66.18% × $7.20 = $4.76.

[42] ([$5.28 – $2.33] × 10,000 x 12) + ([$4.76 – $2.35] × 50,000 x 12) = $1,800,000.

[43] Hernandez Dir. at 20.

[44] *Id.*

allocator and meters are allocated using a weighted meter cost allocator.[45] General plant is allocated based on labor.[46]

Non-fuel production O&M expenses are allocated using A&E/4CP, 4CP, and energy allocators, while Generation System Control and Load Dispatching expense (Account 556) is allocated using an A&E/12CP method.[47]

Most transmission O&M expenses are allocated using the 4CP allocator, while Load Dispatching expense (Account 561) is allocated using a 12CP allocator.[48] Distribution O&M costs are largely allocated consistent with the related distribution plant.[49] Customer-based allocators are used for most customer-related O&M expenses. Uncollectible accounts are allocated based on firm revenues excluding Other Public Authority and Large Commercial & Industrial classes.[50]

Depreciation and amortization expense is allocated consistent with the underlying plant.[51] A&G expenses are allocated based on the labor allocator or their underlying functions.[52] Payroll and unemployment taxes are allocated based on labor, and property taxes are allocated consistent with their underlying functions.[53]

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[45] *Id.*at 22.

[46] *Id.*

[47] *Id.* at 23.

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

[49] *Id.* at 24.

[50] *Id.*

[51] *Id.* at 25.

[52] *Id.*

[53] *Id.*

Revenues from non-firm (interruptible) schedules are credited to the firm service schedules using the 4CP method.[54]

Q. WHAT IS YOUR GENERAL ASSESSMENT OF EPE'S APPROACH TO ALLOCATING PRODUCTION PLANT COSTS?

A. As a general proposition, I support EPE's use of the A&E/4CP method to allocate the majority of its production plant costs. However, I disagree with the way in which Company has applied the A&E/4CP method. I also recommend that A&E/4CP allocation method be applied to all allocable production plant, including EPE's peaking units, rather than adopting EPE's proposal to change to the 4CP method for these units. Accordingly, I recommend several changes to EPE's production plant allocations that I will explain below.

Q. BEFORE TURNING TO YOUR RECOMMENDED CHANGES, PLEASE EXPLAIN WHY YOU SUPPORT EPE'S USE OF THE A&E/4CP METHOD TO ALLOCATE PRODUCTION PLANT.

A. The Average and Excess Demand method is a well-accepted method for allocating production costs. The A&E/4CP method is widely used in Texas.

The A&E/4CP method recognizes both class energy usage (average demand) and class demand at the time of system peak (through the 4CP) in allocating costs to customer classes. In the case of EPE, the 4CP corresponds to the Company's system peak demands in each of the four summer months, when system demand is at its greatest levels. As such, the method accurately captures the requirements that each class makes on the need for investment in generating facilities.

Specifically, the A&E/4CP method uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor.[55] This portion of the cost is weighted by the system load factor. The cost of capacity above average demand is then

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[54] *Id.* at 26.

[55] This concept is discussed in the NARUC Electric Utility Cost Allocation Manual, January 1992, p. 49.

allocated in proportion to each class's excess demand, where excess demand is measured as the *difference* between each class's 4CP demand and its average demand. This portion of the cost is weighted by 1 minus the system load factor. In this manner, the incremental amount of production plant that is required to meet loads that are above average demand is assigned to the users who create the need for the additional capacity. In Texas, the A&E/4CP methodology has been adopted by the Commission for each of three other major non-ERCOT utilities.[56]

Load Factor

Q. WHAT ROLE DOES LOAD FACTOR PLAY IN THE A&E/4CP CALCULATION?

A. As I explained above, in the A&E/4CP method, system load factor is utilized to determine the proportion of production plant cost that is allocated on the basis of average demand (or energy). It thus plays a critical role in cost allocation.

Q. HOW IS LOAD FACTOR CALCULATED?

A. As a general matter, load factor is calculated by dividing the energy used by an entity during a time period by the product of the entity's single highest peak demand during the time period, multiplied by the number of hours in the same time period.[57] It thus provides a measure of an entity's actual energy usage relative to its theoretical maximum, given the peak demand of the measured entity (which can be a customer, customer class, or utility system). In the context of the A&E/4CP calculation, load factor should be calculated for the utility system based on its annual system coincident peak (1CP).

Q. DOES EPE ADHERE TO THIS NORMAL CONVENTION IN CALCULATING SYSTEM LOAD FACTOR?

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[56] *E.g.,* Docket No. 39896, Final Order at Finding of Fact 183 (Sept. 12, 2014); *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 46449, Final Order at Finding of Fact 277 (Jan. 11, 2018); *Application of Southwestern Public Service Company for Authority to Change Rates*, Docket No. 43695, Final Order at Finding of Fact 359 (Dec. 18, 2015).

[57] This calculation can also be expressed as average demand divided by peak demand.

No. EPE's calculation of system load factor departs from standard practice. Rather than using the single highest CP, EPE calculates system load factor using the average of the four summer CPs. I also note that EPE uses adjusted loads rather than actual (unadjusted) loads.

Q. HAS EPE PROVIDED AN EXPLANATION FOR ITS USE OF THE 4CP AVERAGE DEMANDS IN THE CALCULATION OF SYSTEM LOAD FACTOR?

A. Yes. EPE argues that using a load factor based on the average of the 4CP months is consistent with the purpose of the allocation factor, since 4CPs are used to determine the excess demand in the A&E/4CP method. In his Direct Testimony, George Novela argues that System Planning uses a forecasted CP, not an historical CP for planning. A forecasted CP is an estimate reflecting the expected value of the peak. Mr. Novela contends that using the single CP from the historical test year does not truly reflect the peak for planning purposes. Rather, he argues that averaging the 4CPs more likely reflects the expected peak value since it reflects a range of peak values, each of which has some expectation of occurring.[58]

Q. DO YOU FIND EPE'S EXPLANATION ADEQUATE?

A. No, not at all. System load factor for the Test Year should be based on the system's single highest peak demand for that year. This treatment is consistent with the method for measuring system load factor presented in the discussion of the Average and Excess Demand method in the Electric Utility Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners.[59] This measurement is not only the correct measurement of Test Year load factor, it is also the most appropriate measurement from a conceptual standpoint given the task at hand.

Q. PLEASE EXPLAIN THIS LATTER POINT.

A. Recall that the *purpose* of using system load factor in the A&E/4CP method is to identify the proportion of costs that are to be allocated on the basis of average demand, which in

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[58] Novela Dir. at 9-10.

[59] NARUC Electric Utility Cost Allocation Manual, January 1992, p. 50.

turn is capturing the production plant that each class would require if its respective kilowatt-hour usage was consumed at a 100% load factor for the entire year. Consistent with this purpose, the calculation of average demand in this exercise is a single annual value.

This point is critical to the logic here because excess demand, which is measured using 4CP, only exists as a concept in relation to annual average demand (i.e., it is the excess above average demand). Thus, the load factor weight that is attached to this annual average demand should be measured using the single peak demand for the test year. The number of CPs used in calculating excess demand – be it 1, 4, or some other number – is irrelevant to the determination of annual average demand and irrelevant to the determination of system load factor for the test period. There is but one system load factor during the year, not multiple load factors depending on how many CPs are used to calculate excess demand.

In addition to being conceptually correct from the standpoint of cost allocation, measuring load factor with respect to the maximum system peak demand is consistent with the approach EPE uses in assessing its loads and resources balance to calculate its planning reserve margin. For example, in its Integrated Resource Plan, EPE calculates its planning reserve based on its projected highest system demand annually, which is 2,122 MW in 2021.[60] Indeed, in EPE's last rate case, Docket No. 46831, Mr. Novela, who agreed with parties' recommendations to use a 1CP load factor in that case, specifically noted that, "The use of a 1CP load factor is also consistent with how EPE plans and builds its generation and transmission systems."[61]

Q. IS EPE'S USE OF THE 4CP AVERAGE DEMANDS IN THE CALCULATION OF SYSTEM LOAD FACTOR CONSISTENT WITH COMMISSION PRECEDENT?

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[60] *See* EPE 2021 Integrated Resource Plan (September 16, 2021), Figure 11. Initial L&R at 59. 2021 demand cited is Total System Demand net of Distributed Generation and Energy Efficiency. *See also* Hawkins Dir. at Exhibit DCH-3.

[61] *Application of El Paso Electric Company for Authority to Change Rates*, Docket No. 46831, Rebuttal Testimony of George Novella at 23 (July 21, 2017).

A. No. This issue was litigated in two recent cases before the Commission: Docket No. 43695 (Southwestern Public Service Company ["SPS"]),[62] and Docket No. 46449 (Southwestern Electric Power Company ["SWEPCO"]).[63] In both cases the Commission required the use of the single annual coincident peak in calculating the system load factor.

Q. SHOULD EPE USE ACTUAL OR ADJUSTED DEMANDS IN CALCULATING SYSTEM LOAD FACTOR?

A. I recommend using actual system firm loads in calculating system load factor. Using the actual (i.e., unadjusted) firm loads for this purpose best represents system load factor during the test period. In contrast, EPE used adjusted firm loads for this purpose.

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[62] Docket No. 43695, Final Order at 10-11, Findings of Fact 246A-251A (Dec. 18, 2015).

[63] Docket No. 46449, Final Order at Findings of Fact 277-284 (Jan. 11, 2018).

Q. WHAT LOAD FACTOR DOES EPE CALCULATE FOR CLASS COST ALLOCATION PURPOSES?

A. EPE's calculation using the average of the 4CPs artificially inflates the system load factor. Using the average of the adjusted firm 4CP demands of 1,841 MW, EPE calculates a system load factor of 49.73%.[64]

Q. WHAT IS THE CORRECT CALCULATION OF SYSTEM LOAD FACTOR FOR CLASS COST ALLOCATION PURPOSES?

A. Using the actual system firm peak demand in July 2020 of 2,106 MW,[65] I calculate that the system load factor is 45.47%. This calculation is shown in Exhibit KCH-7.[66] The derivation of the A&E/4CP class allocation factors using this correct system load factor is presented in Exhibit KCH-8.

<u>Peaking Generation Unit Allocation</u>

Q. HOW DO YOU RESPOND TO EPE'S PROPOSAL TO CHANGE FROM THE A&E/4CP METHOD TO A 4CP METHOD TO ALLOCATE THE COST OF ITS PEAKING UNITS?

A. I recommend that the A&E/4CP method, with the corrections I describe above, be applied to the entirety of EPE's generation demand costs. The A&E/4CP method is a robust cost allocation method that can properly be used to allocate a utility's entire generation fleet. It is neither necessary nor desirable to allocate individual generation facilities piecemeal on a different basis.

Further, my recommended correction to the load factor utilized in the A&E/4CP calculation to be based on the 1CP will place the proper emphasis on EPE's system peak demand for

[64] *See* EPE's WP P-07.

[65] Schedule O-01-03.

[66] Exhibit KCH-7 also presents the 1CP load factor applicable to the jurisdictional A&E/4CP allocator. The jurisdictional cost allocation includes an adjustment that removes from the calculation the solar generation that has been directly assigned to a jurisdiction.

cost allocation purposes. It is not necessary to carve out EPE's peaking units for a different allocation approach than the rest of its generation fleet.

For consistency, I also recommend using my corrected A&E/4CP allocator to allocate the non-firm revenue credit to firm classes, rather than EPE's recommended production 4CP allocator.

Palo Verde O&M Expense Allocation

Q. HOW DOES EPE ALLOCATE THE PVNGS GENERATION O&M EXPENSES?

A. EPE allocates Palo Verde generation O&M expenses using a combination of A&E/4CP and energy allocators.[67]

Q. DOES EPE PROPOSE TO CHANGE THE ALLOCATION METHOD USED FOR CERTAIN PVNGS O&M EXPENSES RELATIVE TO ITS LAST RATE CASE FILING, DOCKET NO. 46831?

A. Yes, EPE has changed from allocating FERC Accounts 519, 520, and 523 using A&E/4CP to an energy allocator.[68]

Q. DO YOU AGREE THAT ENERGY IS AN APPROPRIATE ALLOCATION BASIS FOR NON-FUEL PVNGS O&M EXPENSES?

A. No, PVNGS O&M expenses are a pass-through of costs from APS, based on EPE's 15.8% capacity share of PVNGS. These costs are more reasonably treated as a fixed cost related to EPE's capacity share than variable energy throughput.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE ALLOCATION OF PVNGS O&M EXPENSES?

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[67] EPE Regulatory Case Working Model - As Filed - Dkt 52195.

[68] *See* Docket No. 46831, Cross Rebuttal Testimony of Kevin C. Higgins, p. 12, lines 16-18.

A. I recommend that PVNGS non-fuel generation O&M expenses be allocated using A&E/4CP. I thus recommend that EPE's proposed allocation of Accounts 519, 520, 523, 530, 531, and 532 on an energy basis be replaced with an A&E/4CP allocation.

<u>Generation System Control & Load Dispatching Allocation</u>

Q. HOW DOES EPE PROPOSE TO ALLOCATE GENERATION SYSTEM CONTROL AND LOAD DISPATCHING (ACCOUNT 556) EXPENSE?

A. EPE allocates Account 556 using a variant of the Average & Excess method utilizing 12 coincident peaks, or A&E/12CP.[69]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE ALLOCATION OF ACCOUNT 556?

A. I recommend that Account 556 be allocated using the A&E/4CP allocator, consistent with EPE's allocation of most generation demand costs. The A&E/4CP method places greater emphasis on EPE's summer peaks, and therefore gives greater weight to the months in which meeting the system's demand is the most challenging. My recommended approach is consistent with the allocation method for Account 556 approved for SWEPCO[70] and ETI.[71]

<u>Transmission Load Dispatching Expense Allocation</u>

Q. GENERALLY, DO YOU SUPPORT EPE'S USE OF THE 4CP METHOD TO ALLOCATE ITS TRANSMISSION COSTS?

A. Yes. There is little basis for arguing that cost responsibility for transmission plant is anything but demand related. Therefore, using a 100% demand allocator such as the 4CP method is appropriate. In the case of EPE, with its summer peaking demand profile, allocating transmission plant using each class's share of system peak demand during the four summer months is reasonable. EPE utilizes the 4CP method to allocate all transmission costs except for Load Dispatching expense.

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[69] Hernandez Dir. at 13. The class DPROD12 allocator is derived in WP P-07, 12CP Adj tab (labeled "D1PROD 12CP-A&E").

[70] Docket No. 46449, Commission Number Run Based on December 14, 2017 Open Meeting Discussion, 46449 Commission Number Run CCOSS, Tab GEN DEMAND, line 421. (Dec. 20, 2017).

[71] *Application of Entergy Texas, Inc. for Authority to Change Rates*, Docket No. 48371, Cost Allocation/Rate Design Rebuttal Testimony of Richard Lain at 8-9 (Aug. 16, 2018).

Q. HOW DOES EPE PROPOSE TO ALLOCATE TRANSMISSION LOAD DISPATCHING (ACCOUNT 561) EXPENSE?

A. EPE proposes to allocate Account 561 using the 12CP method.[72]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE ALLOCATION OF ACCOUNT 561?

A. I recommend that Account 561 be allocated using the 4CP method, consistent with all other transmission costs. My recommendation is consistent with the Commission's Substantive Rule 25.192, under which ERCOT utilities recover Account 561 expenses in their transmission service rates on a 4CP basis. Although EPE is not an ERCOT utility, this substantive rule provides useful guidance for the proper allocation of Account 561 costs. And it is appropriate to allocate transmission load dispatching expense in the same manner as the underlying assets.

69 kV Transmission System Allocation

Q. PLEASE BRIEFLY DESCRIBE EPE'S TRANSMISSION SYSTEM.

A. According to the Direct Testimony of R. Clay Doyle, EPE owns, in whole or in part, approximately 946 miles of multiple 345 kV transmission lines, most of which are located within New Mexico. EPE also has a partial ownership interest in three 500 kV transmission lines in Arizona from PVNGS's switchyard to the Kyrene and Westwing substations in the Phoenix area.[73]

EPE's local high voltage transmission system consists of 115 kV lines and 69 kV lines in and around El Paso, Texas, and Las Cruces, New Mexico.[74]

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[72] Hernandez Dir. at 14.

[73] Direct Testimony of R. Clay Doyle at 5-6 .

[74] *Id.* at 6.

Q. HOW DOES EPE ALLOCATE THE COST OF ITS 69 KV TRANSMISSION LINES TO CUSTOMER CLASSES?

A. EPE does not separate the cost of its 69 kV lines in its cost-of-service study. Therefore, all customers are allocated a portion of the 69 kV transmission line costs based on the 4CP allocator.

Q. IS IT APPROPRIATE TO ALLOCATE 69 KV LINE COSTS TO CUSTOMER CLASSES SERVED AT 115 KV VOLTAGE?

A. No. Customers who take service directly at 115 kV voltage generally do not utilize the 69 kV system. It is not appropriate to allocate 69 kV line costs to rate schedules served at 115 kV voltage on the same basis as other classes who directly utilize the 69 kV system.

Q. HAVE YOU CHANGED THE ALLOCATION OF 69 KV TRANSMISSION COSTS IN YOUR MODIFIED VERSION OF THE COST-OF-SERVICE MODEL?

A. No. Since EPE does not separate its transmission costs into sub-functions based on voltage, I was not able to precisely reallocate the 69 kV costs in a manner excluding 115 kV rate schedules. However, EPE did estimate the 69 kV rate base, depreciation expense, O&M expense, and property tax in response to discovery.[75] Using this information, I have estimated the incremental impact of reallocating this portion of costs to customer classes excluding the 115 kV schedules. This calculation is presented in Exhibit KCH-9. Exhibit KCH-10, discussed below, incorporates this estimated impact into the summary of my modified version of the class cost-of-service study, using EPE's proposed revenue requirement.

Q. WHAT IS YOUR RECOMMENDATION ON THIS ISSUE?

A. I recommend that EPE separate the cost of its transmission system into (i) 69 kV and (ii) 115 kV and above sub-functions for class cost-of-service purposes, and exclude customers served at 115 kV from the allocation of 69 kV costs. This additional granularity will allow for more precise cost allocation that is aligned with the manner in which costs are incurred.

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[75] EPE's response to RFI TIEC 5-2, Attachments 1 and 2.

This treatment is also consistent with the differentiation of transmission loss factors between 69 kV and 115 kV, as reflected in this case.

Q. DO YOU HAVE ANY COMMENTS ON THE TRANSMISSION LOSS FACTORS EPE APPLIES TO 69 KV AND 115 KV LOADS IN ITS COST ALLOCATION?

Yes. I am concerned that the loss factors EPE uses to calculate its class loads at source exhibit some anomalies.[76] Namely, the energy loss factors that EPE applies to its 69 kV and 115 kV classes are higher than the demand loss factors for these classes. This is unusual because line losses should be greater during peak load conditions. While my cost allocation does not incorporate any corrections to the transmission loss factors, such corrections may be warranted.

Contributions and Donations Expense Allocation

Q. HOW DOES EPE ALLOCATE CONTRIBUTIONS AND DONATIONS EXPENSE?

A. EPE allocates Contributions and Donations expense using the Labor allocator.[77]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE ALLOCATION OF CONTRIBUTIONS AND DONATIONS EXPENSE?

A. I recommend that Contributions and Donations be allocated based on customer count. To the extent EPE is permitted to recover contributions and donations from customers instead of its shareholders, it is presumably due to the broad community benefit that these gifts provide. Consequently, allocating these costs in a manner that best reflects a wide dispersion of benefit is most appropriate. This is best achieved using the customer allocator.

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[76] EPE's loss factors are based on a 2017 Analysis of System Losses by Management Applications Consulting, Inc., provided in Schedule O-6.3.

[77] EPE Regulatory Case Working Model - As Filed - Dkt 52195, "Jurisdiction Allocation" and "Rate Class Allocation" tabs. Contributions and Donations are included in the "930200-GENL-MISC GENERAL EXP" item.

Summary of Recommended Allocation Impacts

Q. HAVE YOU SUMMARIZED THE EFFECT OF YOUR RECOMMENDED CHANGES ON CLASS COST ALLOCATION?

A. Yes. The effects of my recommended changes on class cost allocation – using EPE's proposed revenue requirement increase, are presented in Exhibit KCH-10. The estimated impact of my recommendation regarding the allocation of EPE's 69 kV transmission system is included as a separate column in this exhibit.

VI. REVENUE ALLOCATION

Q. WHAT GENERAL GUIDELINES SHOULD BE EMPLOYED IN SPREADING ANY CHANGE IN RATES?

A. In determining revenue allocation, it is important to align rates with cost causation to the greatest extent practicable. Properly aligning rates with the costs caused by each customer group is essential for ensuring fairness, as it minimizes cross-subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization. In some cases, the Commission has applied gradualism to mitigate the full movement to cost of service.

Q. PLEASE DESCRIBE THE APPROACH USED BY EPE TO DISTRIBUTE THE PROPOSED RATE INCREASE AMONG THE TEXAS RATE CLASSES.

A. According to the Direct Testimony of Manuel Carrasco, EPE is proposing to cap the base increase to certain classes (Residential and Water Heating) at 1.5 times the average non-fuel base revenue increase, as an initial step in the revenue allocation. EPE also applies a floor to the decreases for certain rate classes (Rate 2 – Small General Service, Rate 24 – General Service, and Rate 41 – City and County Service), initially limiting the decreases for these classes to 50% of the decreases indicated by the cost-of-service study.[78] Caps and floors are not applied to other classes. Then, after applying the initial caps and floors,

[78] Direct Testimony of Manuel Carrasco at 14-15, Exhibit MC-4.

EPE allocates the resulting revenue shortfall to all the classes in proportion to their allocated base revenue (after applying the initial cap or floor, as applicable).[79]

Q. WHAT IS YOUR RESPONSE TO EPE'S REVENUE ALLOCATION PROPOSAL?

A. As an initial matter, EPE's cap and floor are inconsistently applied among rate classes. For example, according to Mr. Carrasco's Table MC-8, the Residential class requires an increase of 18.67% under EPE's cost-of-service study and receives an increase of 13.59% under EPE's revenue allocation due to the proposed cap. However, Rate 26 – Petroleum Refinery Service, requires an increase of 17.57% under EPE's cost-of-service and receives an increase of 20.25% in order to fund the Residential/Water Heating subsidy.[80]

While I recommend eliminating cross-subsidies among rate classes in this case, it is particularly notable that EPE's inconsistent application of its proposed caps and floors produces inequitable results for certain classes.

Q. IS YOUR PROPOSAL TO ELIMINATE CROSS-SUBSIDIES CONSISTENT WITH YOUR UNDERSTANDING OF THE POLICIES ADOPTED BY THE COMMISSION IN RECENT YEARS?

A. Yes. I am aware that the Commission has shown a strong preference for aligning class revenue requirement with the costs that each class causes to be incurred. For example, the Commission's Order in the SPS rate case, Docket No. 43695, issued December 18, 2015, contained a clear statement affirming its commitment to aligning rates with the cost of service:

> The Commission declines to adopt any gradualism adjustment in this proceeding. The Commission has often stated that one of its primary responsibilities in setting rates is ensuring those rates are, to the greatest extent reasonable, consistent with cost causation. Further, as SPS conceded, the wisdom of a gradualism adjustment is affected by the size of the rate change. While there is no magic threshold at which a change in rates automatically justifies an aberration from basing rates on classes' costs of service, in Docket 40443, the Commission determined that an increase as

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[79] *Id.* at 15.

[80] The cited percentage increases do not include EPE's proposed COVID rider.

> large as 29% did not warrant rate mitigation. Here, SPS's overall Texas retail revenue requirement will be decreased by less than 1% and class allocations based purely on each classes' cost of service will result in relatively small rate changes. All but one class will experience less than a 14% change to its base-revenue responsibilities. The largest change will be borne by Street Lighting customers, whose revenue responsibility will increase 24.28%. Thus, moving from classes' costs of service and mandating inter-class cost subsidization is not warranted in this proceeding.[81]

In addition, in cases involving SWEPCO (Docket No. 40443) and ETI (Docket No. 39896), the Commission rejected the position of the parties that recommended gradualism and directed that rates be set at cost. In Docket No. 40443, the range was from a 17.05% decrease to a 29.20% increase,[82] and for Docket No. 39896, the range was from a 7.89% decrease to a 10.43% increase.[83] In each case the Commission set rates for each class at cost and rejected the application of gradualism proposals.

Q. WHAT IS YOUR RECOMMENDED APPROACH TO REVENUE ALLOCATION IN THIS CASE?

A. I recommend that all Texas rate classes be moved to full cost of service, at the revenue requirement ultimately approved in this proceeding and incorporating my recommended changes to cost allocation. Moving each class to full cost recovery eliminates inter-class subsidies, sets efficient price signals, and is consistent with the Commission's strong preference for aligning class revenues with costs. At EPE's requested revenue requirement, my recommended revenue allocation is the same as my recommended class cost allocation presented in Exhibit KCH-10.

VII. <u>RATE SCHEDULE NO. 25 – LARGE POWER SERVICE TARIFF LANGUAGE</u>

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING TARIFF LANGUAGE?

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[81] Docket No. 43695, Order at 10. (Dec. 18, 2015) (Citations omitted.)

[82] Docket No. 40443, Order on Rehearing, Attachment C, p. 1 (Mar. 6, 2014).

[83] Docket No. 39896, Commission Number Run 39896 ETI COS (Aug. 28, 2012).

A. Yes. Schedule No. 25 is the generally applicable rate schedule for customers with demands greater than 600 kW. However, the current and proposed EPE tariff indicates that Schedule No. 25 is "limited to Customers who otherwise do not qualify for service under the Company's other rate schedules…"[84] Thus, a customer who otherwise would qualify for Schedule No. 25, but also qualifies for another rate schedule, is ineligible for service under Schedule No. 25. I believe this exclusion is unreasonable.

Q. WHY DO YOU BELIEVE THIS PRECLUSION IS UNREASONABLE?

A. Customers should be permitted to choose the Commission-approved rate that best suits their needs, assuming they meet the applicable voltage and size requirements. The choice of rate schedule should belong to the customer. EPE's tariff language allows EPE to deny service on Schedule No. 25 to an otherwise eligible customer and require that the customer take service under a rate that may be more expensive or less compatible with the customer's needs. That is inappropriate.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION ON THIS ISSUE?

A. I recommend that the applicability provision in Schedule No. 25 be modified to remove the language that prohibits customers eligible for other rate schedules from taking service under this rate schedule.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

[84] Schedule Q-8.8, p. 51.